Qualified Persons Report

on

Kampung Minyak Oilfield, Indonesia

& Block D, offshore Cambodia

as of December 31, 2015

Prepared for Mirach Energy Limited

APEX Solutions, Inc.

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To: Mirach Energy Limited
3902 Cosco Tower
183 Queen's Road Central
Hong Kong, China

Attention: Mr. William Chan, Chairman

Date : May 10, 2016

Reference: **Qualified Person's Report as of December 31, 2015 for Kampung Minyak oilfield in Indonesia and Block D in offshore Cambodia**

Dear Sir,

With your request and appointment, we have conducted an independent resources evaluation review for Mirach Energy Limited ("Mirach") interests in the Kampung Minyak ("KM") KSO oilfield in Indonesia and Block D PSC concession in offshore Cambodia as of December 31, 2015.

This Qualified Person's Report ("QPR") was prepared for securities reporting and financing. The contingent and prospective resources have been reviewed in accordance with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System ("PRMS").

In preparing this QPR report, we relied upon factual information supplied by Mirach, including the previous years' 3rd party evaluation reports and the technical data to the end of December 2015. Apex's work primarily consisted of reviewing, checking, validating and auditing the available data and reports of KM oilfield KSO and Block D PSC. And we hereby confirmed that for year 2015 there were no material changes in the contingent and prospective resources in KM and Block D comparing with the Competent Person's Report 2014.

Yours faithfully,

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1 EXECUTIVE SUMMARY

Mirach has interests in oil-gas blocks in Indonesia and Cambodia.

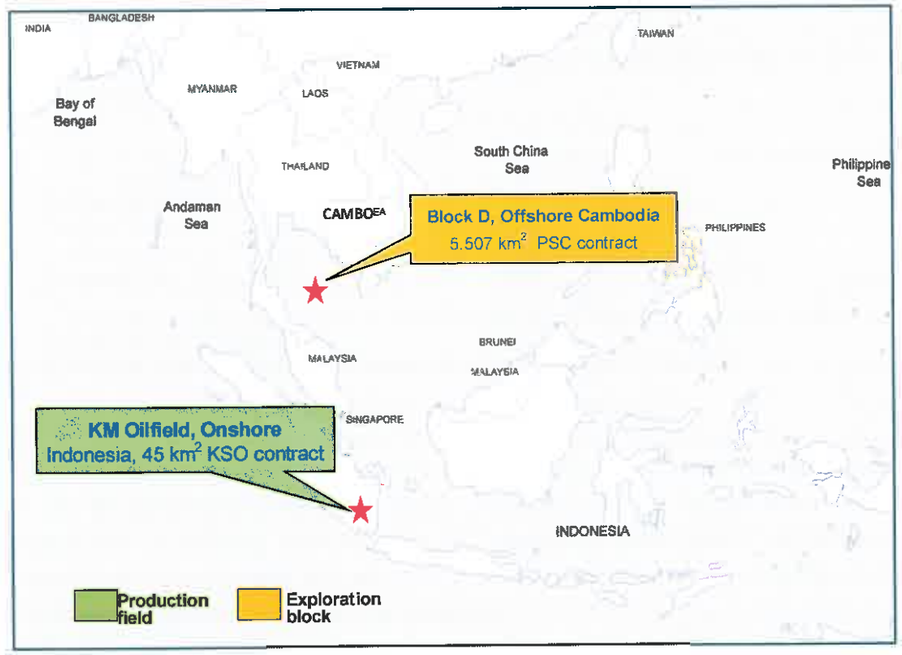


Figure 1 Regional Location Map for Mirach Blocks

Contract	Country	Operator Company	Mirach Interest	Status	Area (sq.km)	Comments
Kampung Minyak KSO	Indonesia	Prisma Kampung Minyak	100%	Production Enhancement till July 2026	45	Producing
Block D PSC	Cambodia	CPHL (Cambodia)	48%	Exploration	5,507	On extension

Table 1 Mirach Concession Summary

The Indonesia South Sumatra Kampung Minyak KSO (joint cooperation) Contract is a production enhancement contract with 15 years period (effective since July 15, 2011) signed with Pertamina, the Indonesian national oil and gas company. The KSO terms are similar with PSC (Production Sharing Contract). Mirach is entitled to some profit oil share above a baseline oil as defined in the KSO contract. The profit oil will be shared after deduct the recoverable cost from incremental oil revenue over baseline oil. Both contingent and prospective resources have been assigned to KM field.

The Cambodia offshore Block D PSC Contract has entered the third exploration period. A 30 year production period would apply to any subsequent commercial discovery on the block. Five (5) prospects have been identified based on 132 lines of

2-D seismic and 400 square kilometers 3-D seismic survey. No wells have been drilled to date. Five prospects have been assigned prospective resources.

1.1 Contingent Resources

Contingent resources have been assigned to KM field as of December 31, 2015 here is the summary:

Crude Oil, Mbbl	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Kampung Minyak			
Property Gross	619	2,188	4,365
Company Gross	482	2,051	4,228
Company Net	409	1,321	2,107

(1) Company Gross resources are based on the Mirach working interest share of the property gross resources excluding the baseline oil production.
(2) Company Net resources are based on the Mirach share of Cost Oil and Profit Oil revenues.

Table 2 – Mirach Contingent Resources Summary

Contingent Resources were assigned to KM Field, because the current KM operations are not yet break-even and it is some uncertain on the future economic. KM management is actively improve the KM operation. After more results become available and commerciality is confirmed, it should be possible to reclassify some, or all, of these contingent resources into reserves.

1.2 Prospective Resources

A summary of Prospective Resources assigned to the KM block was as of December 31, 2015. For both blocks, prospective resources were assigned to the prospects that have been identified by Mirach. The oil and condensate (or gas) initially in place is shown in the first column on a property gross basis for illustrative purposes only.

The geological chance of discovery for KM deep zones is extremely high at 95 percent. It assumes that the chance of discovery of any prospective zone is independent. The geological chance of discovery for the prospects in Block D ranges from 16 to 42 percent.

These estimates do not include the chance factor of commercial success, which is difficult to determine at this stage. The Block D gas prospective resources are with relatively small gas volumes and would likely be used for power generation within CPHL facilities.

Prospective Resources: Crude Oil and Condensate (MMbbl)

Prospect (1)	Property Gross (Unrisked) Initially In Place (Mean)	Low Estimate (P90)	Best Estimate (P50)	Mean	High Estimate (P10)	Prospect Geological Chance of Discovery (2)	Risked Mean Property Gross (3)	Company Gross (4)	Company Net (5)
KM Deep	*111*	10.7	19.9	22.3	36.3	95.3%	7.6	7.6	2.9
Block D (6)									
S1	*143*	11.8	27.1	31.4	59.3	42%	8.2	3.7	2.2
S2	*201*	7.1	26.8	44.1	107.1	34%	9.3	4.2	2.6
S3	*939*	77.3	170.9	191.0	420.5	32%	28.3	12.9	7.7
S4	*298*	19.7	49.4	62.7	139.6	16%	4.7	2.2	1.3
S5	*171*	10.8	29.4	37.5	79.0	30%	7.4	3.4	2.1
Subtotal	***1,751***	**126.6**	**303.6**	**366.8**	**805.4**		**57.9**	**26.4**	**15.9**
Total (7)	**1,862**	**137.3**	**323.5**	**389.1**	**841.7**		**65.5**	**34.0**	**18.8**

Prospective Resources: Natural Gas (Bcf)

Prospect (1)	Property Gross (Unrisked) Initially In Place (Mean)	Low Estimate (P90)	Best Estimate (P50)	Mean	High Estimate (P10)	Prospect Geological Chance of Discovery (2)	Risked Mean Property Gross (3)	Company Gross (4)	Company Net (5)
KM Deep	*93*	10.6	25.2	35.1	71.3	95.3%	6.6	6.6	2.7
Block D S3	210	16.5	73.1	129.6	323.5	5%	6.3	2.9	-
Block D S4	36	2.6	12.1	22.1	55.7	3%	0.7	0.3	-
Total (7)	**339**	**29.8**	**110.4**	**186.8**	**450.5**		**13.6**	**9.8**	**2.7**

(1) Separate zones within each prospect were added probabilistically using monte-carlo simulation.
(2) The prospect geological chance of discovery is based on the success of any one of the prospect zones and assumes independence and consequently is not equivalent to the [Risked Mean]/[Unrisked Mean]
(3) Prospect risked mean resources are equal to the summed product of the unrisked mean resources for each zone multiplied by the geological chance of success of each zone.
(4) Company gross prospective resources are based on the working interest share of the property gross prospective resources and assumes in Block D that CNPA exercise their option to take a 5 percent interest.
(5) Company Net resources are based on the Mirach share of Cost Oil and Profit Oil revenues.
For Natural Gas in Block D the net is zero as the gas is considered non commercial.
For the Crude Oil in Block D the net assumes CNPA exercise their option to take a 5 percent interest.
(6) The Block D S3 and S4 prospects contain a Pre-Tertiary zone which could be either crude oil (with no free gas) or natural gas (with no oil rim). The unrisked crude oil resources assume the zone contains only oil and the unrisked natural gas resources assume the zone contains only gas which means on an unrisked basis the prospective resources are mutually exclusive. This is accounted for though in the risked estimates which include the chance of the prospect being oil or gas filled.
(7) The total may appear to differ from the sum of the underlying assets due to rounding differences.

Table 3 - Mirach Prospective Resources Summary

2 KAMPUNG MINYAK OILFIELD INDONESIA

2.1 KM Oilfield Overview

Kampung Minyak ("KM") oilfield covers an area of 45 square kilometres in South Sumatra, Indonesia.

KM Field was discovered in 1896 by Muara Enim Petroleum Company, belongs to Royal Dutch Shell ("Shell"). Shell drilled over 250 wells and developed KM field until 1934. Production records for this period are limited but indicate that about nine (9) million barrels of oil were produced during 1896 ~ 1932. It is unclear what happened to KM field during Japanese occupation (1942 to 1945) and after Indonesia independent in 1945.

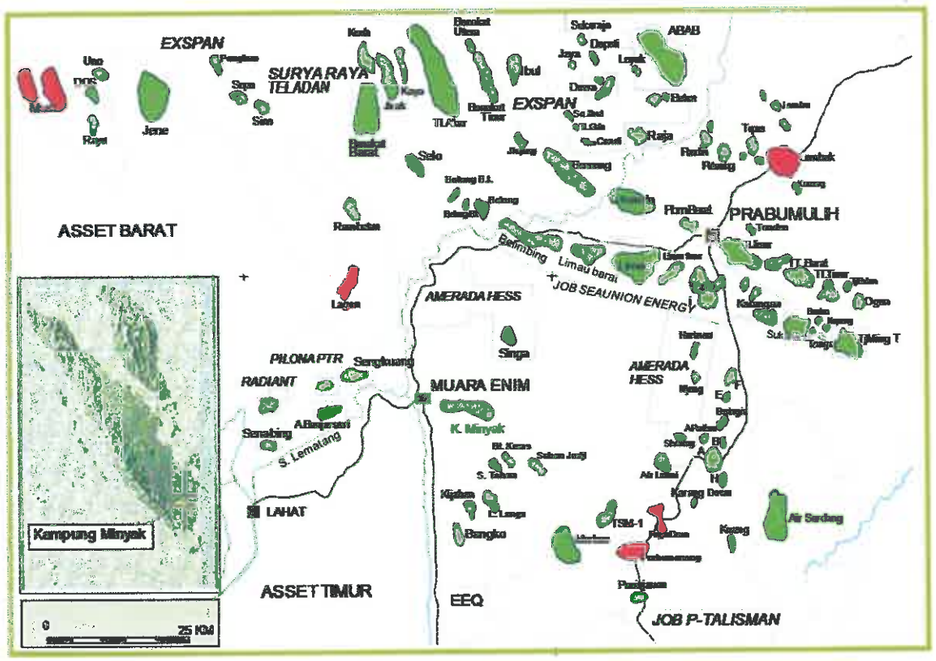


Figure 2 KM Field, South Sumatra Area Map

The next recorded activity at KM field was in 1974-1975 when the Canadian company Bow Valley Energy drilled a number of appraisal wells. It is not clear when Bow Valley's involvement in the field ended. In 1984-1988, USA company Nordell International Resources ("Nordell") worked over a number of old wells and drilled eight (8) new wells. In addition, a rehabilitation and secondary contract for the Enim fields (including KM field) was agreed between Nordell and Pertamina which led to the startup of production in 1988. In September 1988 USA company Triton Energy ("Triton") agreed with Nordell to take over operatorship of KM field. Triton implemented a water injection project on the LSTC zone and continued drilling both

producers and water injection wells. Production peaked at 1,400 bopd in 1991. Water injection appears to have been stopped in 1997 at a time of low oil price. In 1996 Triton exited KM field and Pertamina taken over operatorship in October 1996.

Totally about 312 wells have been drilled to date and the cumulative production is estimated to be about 12 million barrels. In 2009 Pertamina began to find operator and then signed KSO contract in July 15, 2011 with Mirach's subsidiary company, Prisma Kampung Minyak (PKM).

Mirach believes there is the potential to increase production on the existing zones by stimulating, recompleting, infill drilling, and re-introducing water injection. The contingent resources are evaluated associating with these activities. In addition, Mirach believes there is additional potential below the producing zones, and one deeper zone (S8) has been confirmed productive by Mirach's drilling.

The main production facilities consist of two production stations (station KM and KM500) where there are simple atmospheric separation and venting of the gas with an approximately 600 bbl capacity holding tank (one at each station) to allow gravity separation of the oil and water. Oil from the KM station is pumped to the KM500 station for further processing to improve the export crude oil quality.

In addition to the main 600 bbl tank the KM500 station has two 150 and 220 bbl tanks to allow further separation and storage of the oil prior to export. Currently a pump runs intermittently to export crude to a Pertamina operated facility about 25 kilometres away. Demulsifier is also being added at the KM500 station to improve separation of the oil and water. Additional tanks will be required if production is to be increased to the levels envisaged in this evaluation. The produced water is disposed into some disposal wells.

Mirach owns a 12.5 kilometre, 2.875-inch pipeline to the Batu Keras Field. Here the crude oil joins a Pertamina operated 6.9 kilometre, 3-inch pipeline to the SPU66 production station where KM Field oil production is metered. From SPU66 the crude oil joins the Pertamina local pipeline system and is transported 150 kilometres to the refinery. Pertamina is responsible for sales and marketing of the crude.

Travel within KM field is on unmade, rutted roads which could become impassable after heavy rain.

Since taking over KM field in July 2011, Mirach has focused on optimizing production from the existing wells, carrying out basic maintenance of the existing facilities and drilling nine new wells.

During 2015, the field production rate averaged 129bopd with a water cut of 90 percent from up to 32 wells. Mirach has continued to dispose of water into a number of different wells. Initially there was no attempt to optimize the location of the water injection. Since mid-2013, three wells have been used to attempt to boost pressures and sweep bypassed oil in the main STC zone within Blocks 3, 4 and 5. During 2015 the average injection rate was approximately 1210 bpd.

The KSO contract requires minimum work program comprising of 25 square kilometres of 3-D seismic, drilling of 3 new wells, re-opening of 25 wells, work-over of 30 wells and the building of a water injection facility. To date all the minimum work program is almost finished or replaced by many workover, re-perforation and re-opening activities.

2.2 Historical Activities and Data

Generally the KM data is poor. The 312 wells have coordinates and 114 wells have log data available. 59 wells have sufficient log data to enable basic petrophysical interpretation. The better log data concentrate in better development areas and is somewhat limited in the other areas. Core data (porosity-permeability) was provided for 13 wells and the core description was provided for couple wells.

The historical production data was also limited. Monthly production data was provided for individual well/zones for the period 1989 to 1996 and 2001 to December 2015. It means that only 25 percent production is in a monthly format. Mirach has also provided daily and monthly water disposal data by well for the period since taking over the operations. For reservoir pressure, KM field only has some indirect data such as fluid level height.

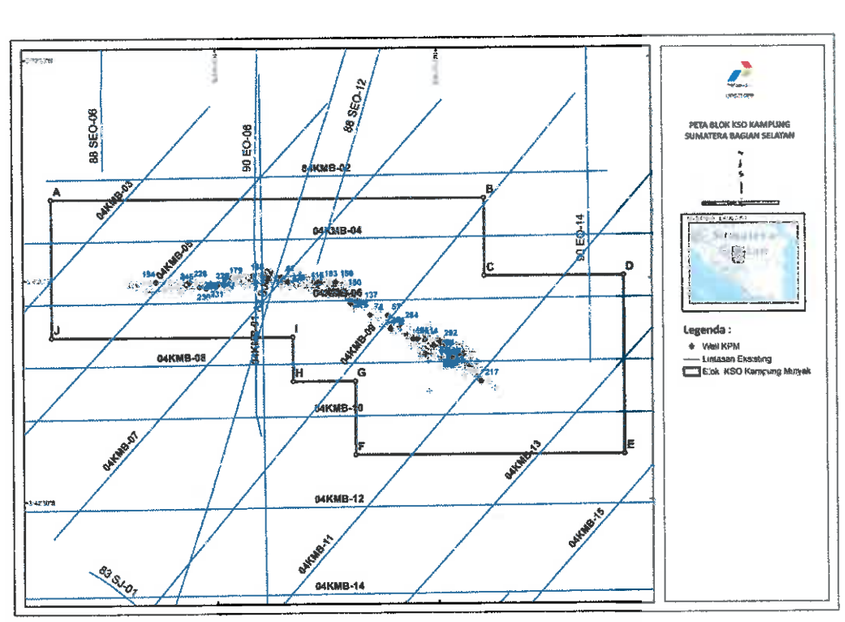


Figure 3 KM field Seismic lines and Wells Location Map

Seismic coverage over KM field consists of 13, 2-D lines, covering coarsely the main structure. The seismic data was acquired in 2004 over KM and neighbouring structures. A seismic interpretation for the Air Benekat and deeper formations was provided by

Mirach and found to be reasonable. Top structure maps provided for the main prospective reservoirs were considered reasonable and used as the basis for the prospective resources assigned in this QPR.

2.3 Regional and Kampung Minyak Geology

2.3.1 Regional Geology

KM oilfield locates in the South Palembang depression of the South Sumatra Basin in Indonesia. The South Palembang is the larger of the two rift provinces within South Sumatra.

The sediments that make up the reservoir zones in the KM field were laid down in a late post-rift stage. During this time a phase of deltaic progradation distributed the sediments across the basin.

In the literature, three main tectonic phases are recognized in the late post-rift stage:

Paleocene to Early Miocene extension and Graben Formation.

Early Miocene to Early Pliocene quiescence.

Pliocene to Recent, transpression and inversion forming extensive sub-parallel west- northwest to east-southeast anticlinal trends.

2.3.2 KM Structure

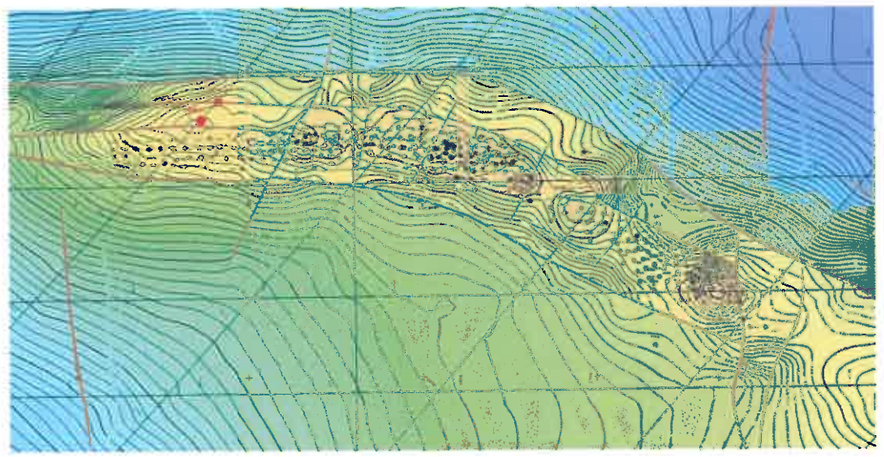


Figure 4 KM Field USTC Zone Top Structure Map (Source Mirach)

Kampong Minyak field comprises a narrow anticline striking in a southeast to northwest (and west) direction. The field has a total length (east-west) of approximately 8 kilometres and a maximum width of approximately 1 kilometre. The structure is broken along its length into 10 separate blocks by formal faults striking

perpendicular to the trend of the anticline. Seismic sections show very obvious relief and block segregation along the field with the main trapping component anticlinal.

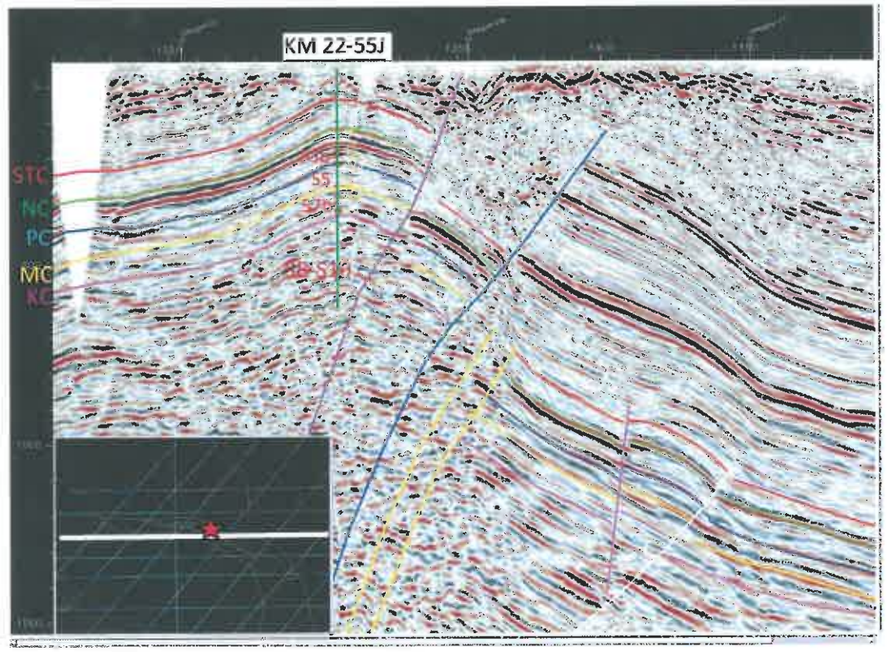


Figure 5 KM Field Seismic Line 04kmb-06 (Source Mirach)

2.3.3 Stratigraphy

KM field has two main formations: Muara Enim and Air Benakat (Figure 6).

2.3.4 Muara Enim Formation

Muara Enim Formation sediments are of the late Miocene to early Pliocene age. From the wireline logs it appears deposits as low relief coastal area in numerous of laterally extensive coals interbedded with fine grained sands and shales.

A large proportion of KM oil production comes from the shallow LSTC zone sand. It is the best developed sands in terms of thickness, consistent reservoir quality, and lateral sand continuity.

The sand zones below LSTC are designated Suban 1 (S1) to Suban 7 (S7) going deeper. The S3 is further subdivided into the S3a, S3b and S3c and the S7 is subdivided into the S7a, S7b and S7c, which makes with USTC and LSTC a total of 13 reservoir zones.

AGE	FORMATION	COAL SUBDIVISION	GENERAL LITHOLOGY (not to scale)	LAYER NAME	LITHOLOGY DESCRIPTION
	KASAI			NON MARINE	Tuffclays alternating with pumice bearing sands
LATE MIOCENE	MUARA ENIM FORMATION	UPPER COAL MEMBER		NIRU COAL	Hard brown clay
				JELAWATIN COAL	
				ENIM COAL	*Blak, dark-grey, soft,*
				KEBON COAL	
				BENUANG COAL	
				BURUNG COAL	*Black, dense,hd-brit,woody strc*
				UPPER STC SAND	Sandstone, clear-white-green, loose-friable, occasionally
				LOWER STC SAND	abundant glauconit, pyrite, calcareous-carbonaceous.
		MIDDLE COAL MEMBER		MANGUS COAL	Black, brittle hard, vitrous, luster, fissile
				SUBAN 1 SAND	Sandstone,qtz,wh,occ drty,m-poor srtd,vf,glauc,mod hd-fri.
				SUBAN COAL	Dark brown-black,brittle-hard,woody,dull luster,lignite-sub bitm
				SUBAN 2 SAND	Sandstone,qtz,grey,occ drty,m-poor srtd,vf,glauc,mod hd-fri, cmtd,cly mtx.
				LWR SUBAN COAL	
				SUBAN 3 SAND	Sandstone,qtz,wh, fri-mhd, vf-f, mod srt,cmtd,glauc,tr pyr carb speck
				PETAI COAL	*Dark brown-black, bittle-hard,vitreous,luster*
		LOWER COAL MEMBER		SUBAN 4 SAND	Sandstone,qtz,lt gy-brn, fri-hd, rnd vf-f,glauc, non-calc, occ carb's
				SUBAN 5 SAND	Sandstone,qtz,wh lt gy, sb ang-sb rnd,vf - f, mod-por srtd mod vis por, glauc, pyr, calc.
				SUBAN 6 SAND	Sandstone,qtz,wh lt gy, sb ang-sb rnd,vf - f, mod-por srtd mod vis por, glauc, pyr.
				MERAPI COAL	*Dark brown,brittle-hard, vit luster*
				SUBAN 7 SAND	Sandstone, qtz, lt grey-grn grey,vf-f, w mod srtd,rnd-sub rnd, brit glauc, tr pyrite, friable
MIDDLE MIOCENE	AIR BENAKAT FM			KLADI COAL	*Black, sl lignitic, brittle*
				SUBAN 8 SAND	Sandstone, qtz, lt grey,vf-f,shly,carbn lam,por g-poor.
				SUBAN 9 SAND	Sandstone,wh,vf-f,occ mid gr,friable, carbn's
				BASAL COAL	*Black, brittle, lustrious*
				SUBAN 10 SAND	Sandstone,clear to wh,vf-f, friable to loose,soft,por g-poor
				SUBAN 11 SAND	Sandstone,grey,vf-f to silt, friable to med firm,sl glauc,loc clyey
				SUBAN 12 SAND	Sandstone,wh,fine gr,poorly cmtd, sl calc, clyey

Figure 6 KM Field Stratigraphic Chart (Source Mirach)

A Nordell core description from well KPM-1 across the S7 zone (divided into the S7b and S7c) gives further evidence that the sands are interlaminated and very fine to fine grained. The S7b is described as a thinly interlaminated claystone and sandstone with laminations that are 0.5 to several millimetres thick. The sand laminations are described as very fine to fine grained and argillaceous in part. The S7b and S7c were

produced together in KPM-01 and during 1989 to 1990 recovered approximately 11,000 barrels of oil.

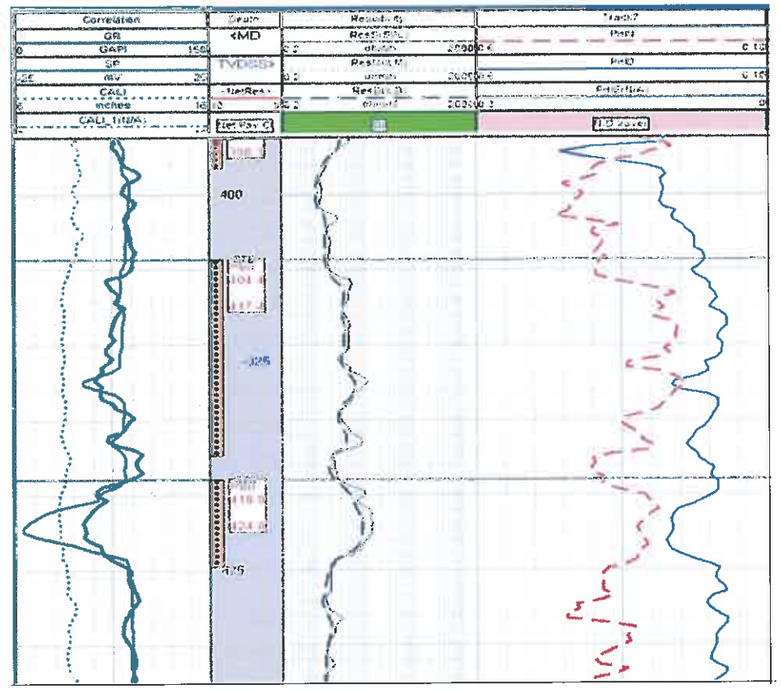


Figure 7 KM Field Log Section from KPM-1 (drilled 1974)

The analysis of well logs indicates that the majority of the S1 to S7 interval is of relatively poor reservoir quality. Occasionally there are some better quality sand which are most frequently seen in the S7c, S7b, S6 and S3a zones. These zones tend to show more lateral sand continuity than the other zones and have the log characteristics of a slightly higher energy deposit with fair to good log responses on the Gamma Ray, SP, calliper, and Neutron-Density logs. The S2, S3c and S4 zones were excluded from the evaluation as net pay could not be identified.

2.3.5 Air Benakat Formation

Similar to Muara Enim, Air Benakat Formation made up of interbedded shales and sands subdivided into separate zones by coal deposits. The zones are named from top to bottom S8 to S13 respectively.

The deposits of the Air Benakat represent the beginning of a major phase of regression and comprises finer grained, delta front to delta plain deposits, whereas the Muara Enim is more characterized by delta plain to continental plain deposits.

KM Field only has five (5) wells with log data penetrate this sequence and, of these, only two wells, KM 55/23-96 and KM-612, go deep enough to cover all the zones to

S13. KM-612 was drilled in 2014 and was completed on the S13 zone. There is some doubt over whether the well was perforated at the correct depth and attempts to swab the well for 3 to 4 days were unsuccessful. Mirach is planning to workover and re-perforate well KM-612. Apart from this only one of the wells appears to have been production tested (KM 55/22-55J) and no longer term production data exists.

Some oil production (13,000 bbl) is reported from the S8 zone from two other wells, KM-52 and KM-370, but no well data is available for these wells to establish if this is reliable. Four of the new wells drilled during 2012 and 2013 drilled to the base of the S8 zone but only KM-607 is interpreted to have net pay within the S8 which was subsequently confirmed by testing initially at rates over 200 bopd with no water. The KM-607 oil rate declined rapidly and in December 2015 the well was producing at 4 bopd with 89 percent water cut (cumulative oil production is 8,293 bbl).

Overall the sands appear to be quite shaly resulting in subtle log responses on the SP and resistivity curves. One notable exception is zone S10, which is developed in well KM 55/22-55J and appears as a package of three stacked sands totalling 20 metres of net sand with a positive SP response and a good density porosity reading, ranging from 18 to 25 percent. This zone was tested in 1985 and after acidizing and swabbing produced 103 bopd with a 50 percent water cut.

Contingent resources were assigned to the S8 formation around well KM-607. Prospective resources were assigned to the S8 beyond well KM-607 and to the S9 to S13 sands.

2.3.6 Gumai Formation

Gumai Formation lies immediately below Air Benakat Formation and is regionally a thick marine shale deposited during a high stand in the early Miocene. It is regarded as a potential regional seal for the deeper Talang Akar and Batu Raja formations in South Sumatra basin. In some shelfal areas around the basin margins the shale is intercalated with thin limestones and calcareous sandstones with good reservoir quality and some associated hydrocarbon accumulations, especially in the Jambi depression (north of the South Palembang depression). In some other areas, especially to the west towards the Talang Babat Deep, the sand to shale ratio increases as result of turbidite incursions and again has reservoir potential.

Although there is a possibility of hydrocarbon potential in KM area, too little data was made available for this evaluation to be able to quantify this and so no prospective resources have been assigned.

2.3.7 Batu Raja Formation

In the early Miocene a sudden reduction in the supply of clastic sediments into the basin resulted in the deposition of large carbonate platforms around the basin margins and on basement highs. Later, these platforms became the foundations

for buildups of reefal and detrital bank buildups with considerable relief. This whole carbonate unit is the Batu Raja Formation. The average thickness is 60 to 75 metres but can be up to 200 metres. Off structure the zone can grade into the shaly facies of the Gumai Formation.

In the topographical highs the porosity in the carbonate buildups was enhanced by sub-aerial leaching, and hence the best reservoir potential is usually in the upper part of the reservoir. This zone is an important secondary target as is considered to have the greatest remaining potential in the South Sumatra basin.

Although there is a possibility of hydrocarbon potential in KM area, too little data was made available for this evaluation to be able to quantify this and so no prospective resources have been assigned.

2.3.8 Talang Akar Formation

Talang Akar Formation is the most significant play and petroleum system in South Sumatra Basin. It is a thick regressive sequence of interbedded sands, shales, and coals deposited in the Late Oligocene. The lower part of the zone, often referred to as the Gritsand Member, is composed of coarse grained fluvial sandstones alternating with shale and coal deposited in a deltaic environment with gross thickness ranging between 200 and 500 metres. The upper portion, known as the Transitional Member, becomes more marine influenced with finer grained sandstones alternating with shales and coals. The gross thickness of this section is on the order of 300 metres.

Most of the Talang Akar plays are associated with anticlinal folds or reverse faults resulting in rollover anticlines. In addition some plays exist as stratigrapahic pinchouts of sand lenses against basement highs. In KM the Talang Akar depth is interpreted to be deeper than 2,300 metres and as such may contain gas due to the over-mature source rock. The close proximity of several fields producing from this formation suggests it has potential at the KM field and hence prospective resources have been assigned.

2.4 Production Performance Analysis

2.4.1 Production History

The recent production history for the field since 1989 indicates that the water cut has been rising to 90 percent. Total fluid rates though have also declined in line with the oil rates suggesting some zones have declined in pressure and are not receiving aquifer support.

For the purposes of this evaluation the USTC and LSTC are combined as the STC; the S3a and S3b are combined as the S3; the S5 and S6 are combined as the S5&6; and the S7a, S7b and S7c are combined as the S7.

The production history since 1989 illustrates that historically the development focused

on STC zone coinciding with water injection implementation in some central faulty blocks. A number of water injectors were located in peripheral locations in the Block 3, 4 and 5, together with some new wells, boosted production significantly. During this period water injection slightly exceeded reservoir voidage on these blocks. The lower field rate experienced after 2001 is most likely caused by the stopping of water injection in 1997. Based on these results further water injection should be implemented on the STC blocks which have good sand development.

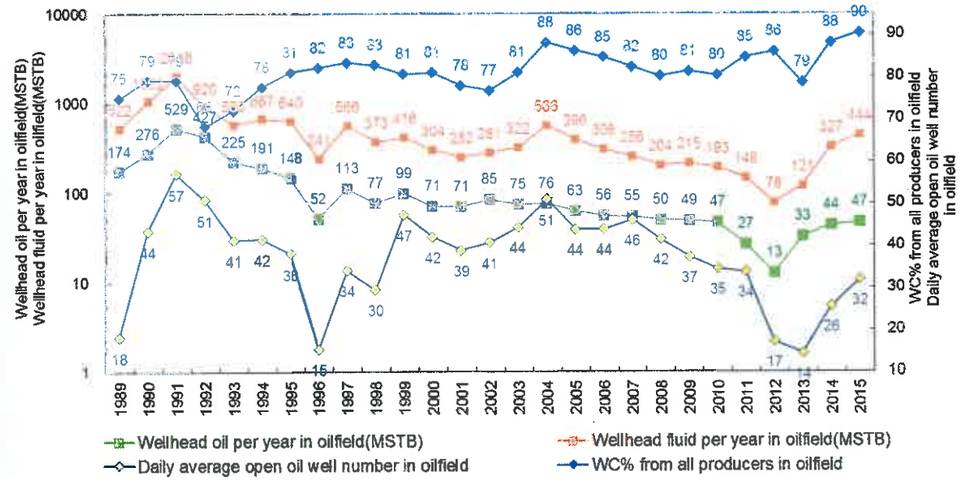


Figure 12 KM Field Recent Production History

The large numbers of wells indicates that the average well spacing for each pool is already relatively small. The deeper zones have progressively fewer wells, although even the deepest zone (Suban7) has an existing spacing of between 12 and 33 acres (depending on the pool). The STC zone in the most developed areas has a well spacing of less than 10 acres per well (wells space is less than 200 meters). This type of close well spacing is not normally associated with light oil reservoirs unless there is significant compartmentalization through faulting or lithological changes.

Production allocation to the individual zones should be considered approximate due to commingling that has sometimes occurred. Furthermore, the recently drilled wells have all commingled production across the S1 to S7 zones in order to maximize rates. Attempting to allocate production back to the individual zones no longer makes sense and for the purposes of this evaluation the USTC and LSTC were treated as a combined STC zone and the S1 through to S7 were combined as a S1-7 zone.

The production performance since the second half of 2013 has improved and the field is now producing more than the baseline production forecast. Since 2013 Mirach has put on production 9 new wells (7 successfully) with an average gain of 14 bopd per well, carried out 16 workover activities (typically re-perforating) and 11 well reactivations (typically replacing failed pumps), resulting in an average gain of 3.5 bopd per well.

2.4.2 Production 2015 Analysis

By end of December 2015, oil and water Wells is totally 42 in KM oilfield, consisting of 36 oil producer wells, 6 water disposal wells. The cumulative production of crude oil is slightly higher than 2014. Water injection volume was 442332 BBL which was more than 2014's 148426 BBL. Oil field water cut was 90.4% which is 2.3% higher than 2014.

In terms of production indicator comprehensive comparison between 2015 and 2014, most indicators rose. For the new wells put into production before 2014, production decline rapidly because there is no sufficient complement formation energy. 2015's work to reopen old well effectively make up the gap of the new well production decline.

Cumulative oil production in 2015 is 47067 BBL, the old well is 33535 BBL, accounting for 71.2% of the total oil production. 2015 reopened old well oil production was 16612 BBL, accounting for 49.5% of the old oil produced.

Since 2014, with the increase of open well number and well service workload, the oil production increased stably. But the water cut also rose. In August 2015, the working fluid level drops fast. The formation energy consumption fast.

2.4.2 Well Service 2015 Analysis

In 2015, totally 68 "well x time" well services has been conducted. It increased 64054 barrels of liquid and 4450 barrels of oil. The pull string operations has been conducted on 22 Wells.

The producing formation sand-out was serious and influenced the pump. It is important to deal with sand-out, ensure the reasonable pump setting depth. Meanwhile the pumping speed should not be over fast, otherwise the borehole fluid disturbance would be bad. To improve the pump adaptability, the optimum evaluation shall be conducted for sand control and sand/mud prevent.

2.4.3 Oil field monitoring work in 2015

In 2015 Mirach comprehensively strengthen the oilfield monitoring: conduct dynamometer at 38 Wells (totally 106 well x times) which is more than 2014 (28 Wells, and 56 well x times). Reasonable working condition of pumping unit area is not high.

The liquid level data is insufficient. The site team overcame difficulties to measured more than 30 Wells liquid-level. Based on comparing the liquid level with PSN depth, 7 Wells' PSN was adjusted.

Water cut rising rate is closely related with flowing pressure. In current production conditions, the dynamic liquid level depth has a certain relationship with the depth of the PSN. Production is a dynamic change. The working fluid level data is still limited.

2.4.4 Reopening work in 2015

31 wells reopened in 2015, including 2 water disposal wells. Among these, 7 oil wells was

operated successfully, 7 well have fish blocked, 10 wells have high water cut, 1 well has gas lock, 3 Wells do not have fluid. After well services, totally 16 wells have production. And 7 wells have stable oil production. 4 wells produced oil in small amount. 5 wells have WC 100%. The reopened wells reached 12.5 BOPD production at the end of the year.

category	NO.	SMR	production day	fluid(bbl)	oil(bbl)	WC(%)	BFPD	BOPD
stable production oil	1	288	256	878	694	21.0	3.4	2.7
	2	203	55	188	88	53.2	3.4	1.6
	3	518	290	1863	600	67.8	6.4	2.1
	4	158	166	3696	769	79.2	22.3	4.6
	5	134	7	64	7	89.1	9.1	1.0
	6	114	84	1675	84	95.0	19.9	1.0
	7	129	8	102	18	82.4	12.8	2.3
small production oil	8	110	53	1561	17	98.9	29.5	0.3
	9	100A	223	8644	279	96.8	38.8	1.3
	10	61	33	1842	22	98.8	55.8	0.7
	11	92	16	108	11	89.6	6.7	0.7
all water	12	17J	21	441	0	100.0	21.0	0
	13	227	4	28	0	100.0	7.0	0
	14	299	32	1202	0	100.0	37.6	0
	15	117	23	127	0	100.0	5.5	0
	16	107	35	854	0	100.0	24.4	0
Total				23272	2589		304	18

Table 4 KM production situation of reopened wells in 2015

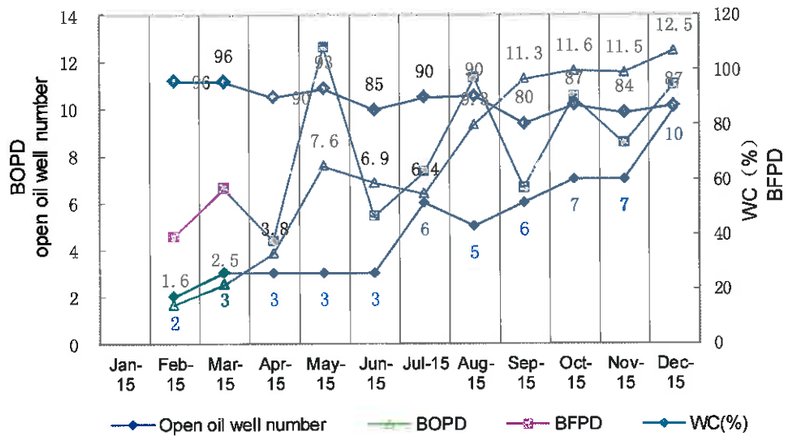


Figure 5 Reopening well Production curve

2.5 Contingent Resources

KM Field has many wells and is considered relatively mature. The total production to date is estimated to be approximately 12 million barrels for the zones evaluated which represents approximately 18.5 percent of the estimated OOIP. With a field at this stage of development, the analysis of the production history is very important and can typically be used to estimate both the developed and undeveloped future potential. However, the absence of the complete monthly production data on a well by well basis throughout the field history limits the usefulness of the production analysis in this case. Instead more

weight had to be given to a volumetric approach for estimating future performance.

The future development potential will therefore need to be established by piloting further infill drilling in different areas of the field, gathering production data across all the zones and by expanding the use of water injection. So far the results of drilling new wells has failed to boost the overall production rates sufficiently to cover the costs of the production operations.

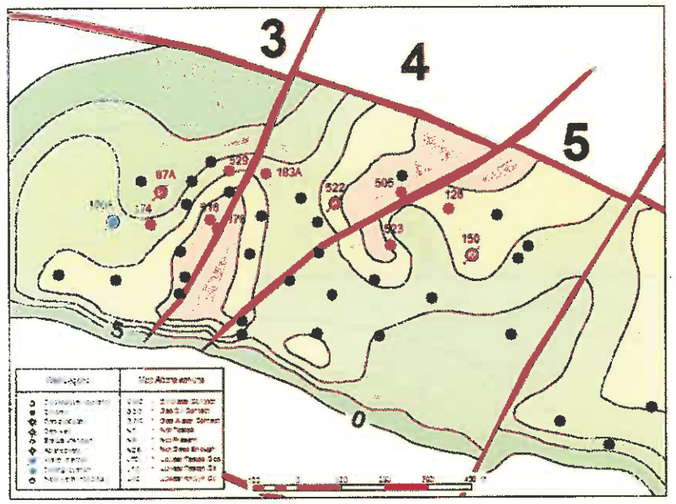


Figure 8 KM STC Zone Net Pay Map covering Water disposal Area

STC zone Net Pay map shows the location of the four water disposal wells and the current producers within the block 3,4,5. Since July 2011 a total of 344,000 bbl of water has been disposed/injected into the STC zone within Blocks 3, 4 and 5. There are eight producers within these blocks which may in time benefit from this injection. Unfortunately there have been no pressure measurements taken to establish what effect this has had on reservoir pressure.

To date there has been little impact on the oil production within these blocks, but it may be that the wells are not pumped off and require larger pumps and/or higher stroke rates. In the future it is important that reservoir pressure data is gathered to see how much pressures are increasing and fluid levels should be measured in the pumped wells to see if there is potential to increase offtake rates.

2.5.1 Volumetrics

The OOIP volumetric estimation for KM field was undertaken. We audited the maps based on the petrophysical interpretation of the wireline logs together with the production. In our opinion, the net pay maps in certain zones have some overstating. To compensate for this, net rock volume for each zone was adjusted by a percentage. This percentage represents the difference in net pay from our interpretation compared to the

mapped net pay.

Reservoir Zone	[Audited Net Pay] / [Mapped Net Pay] %
USTC	100
LSTC	100
S1	60
S3a	60
S3b	70
S5	75
S6	75
S7a	50
S7b	65
S7c	90

Table 5 KM Field Net Pay Adjustment

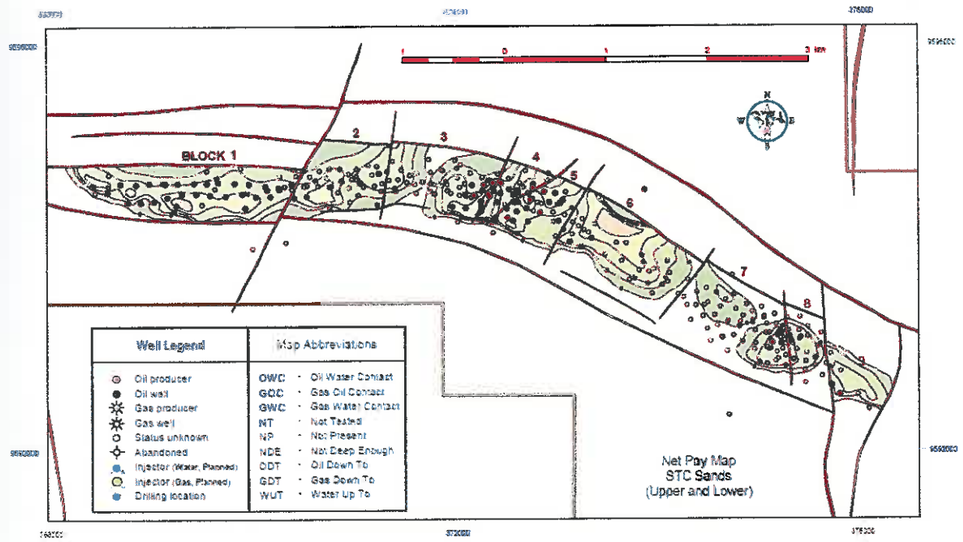


Figure 9 KM Net Pay Map for STC sands

The USTC and LSTC net pay maps were combined to generate an overall STC net pay map. A combined net pay map was also prepared for the S1 through to S7 zones.



Figure 10 KM Net Pay Map for S1-S7 sands

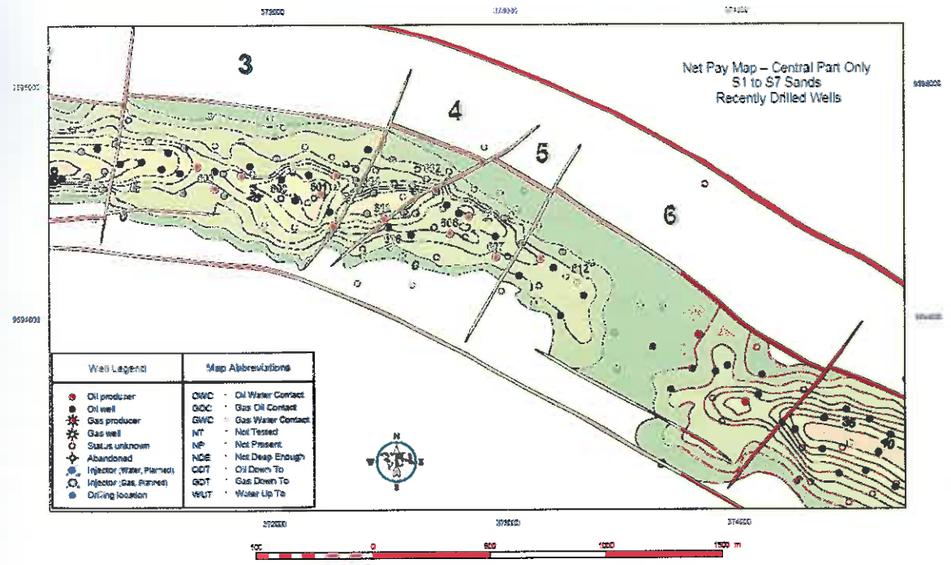


Figure 11 KM Net Pay Map for S1-S7 sands (Central Part)

The average porosity from the STC sands is 32 percent with the majority of the samples having a permeability ranging from 50 to 300mD. The porosity in the S1 to S7 sands generally decreases with depth and the average porosity ranges from 31 percent in the S1 to 27 percent at the S7 level. Permeability varies again with each sample point and within each layer, from a few millidarcy to a few hundred millidarcy.
For water saturations, the calculating by conventional methods would result in incorrect high water saturations because of the low response on the resistivity curves

often seen across very fine clastic grain sizes. The water saturations used for the OOIP calculations range from 35 percent in the STC units to a high of 44 percent in the S5. The evidence that oil does exist in these zones has been confirmed by some production and by good indications of oil shows in the core description.

KM crude oil is of good quality ranging in API gravity from 35 to 45 degrees and has a gas oil ratio ("GOR") from 100 to 500 scf/stb. No PVT data was available for the field and a formation volume factor of 1.15 was used for all zones based on a reserves estimate made by Pertamina in 2005.

The net rock volumes determined from the net pay maps were combined with the other reservoir parameters to determine the OOIP on a zone/block basis and is summarized below.

Zone /Block	1	2	3	4	5	6	7	8	9	Total
USTC	4,676	2,865	2,600	1,440	2,605	2,037	2,037	1,020	-	19,279
LSTC	7,054	2,436	1,782	1,699	1,727	6,221	251	-	2,029	23,199
S1	126	593	485	169	73	451	700	111	266	2,974
S3a	241	924	1,124	220	232	-	1,158	378	-	4,276
S3b	259	-	-	-	-	649	1,980	374	-	3,262
S5	122	464	-	-	-	-	-	-	-	585
S6	-	226	256	162	235	260	902	-	-	2,040
S7a	-	-	-	-	-	83	708	-	-	791
S7b	-	1,114	895	305	299	328	1,705	-	-	4,646
S7c	-	701	728	110	199	97	1,893	-	-	3,727
S8	-	-	-	-	161	-	-	-	-	161
Total	12,478	9,323	7,870	4,104	5,530	10,125	11,334	1,882	2,295	**64,940**

Table 6 KM Field Original Oil In Place Summary (Mbbl)

2.5.2 Plan of Development and Contingent Resources

Given the current operations are uneconomic and the benefits of water injection are still uncertain, contingent resources rather than reserves were assigned. The contingent resources were estimated taking into account the existing well performance together with the benefits of reactivating old wells, increasing water-handling capacity, drilling infill wells and water injection.

The recent water injection has really been more of a water disposal scheme. At this stage it is too early to say whether this will result in production gains, but the chances would likely be improved if the injection was better managed including regular monitoring of pressures and fluid levels.

An overall summary of the contingent resources is presented in Table 1 of the Appendix. The tables also provide details of the future well requirements for each of the contingent resources categories.

The future production forecasts make an allowance for the reopening of some old wells, future production optimization, benefits from water injection and the drilling of new infill wells.

By getting more well reopened, and monitoring their performance would give good scheme

to have proper water injection scheme. The drilling activities will refer and depend on Reopening and Work Over results. From the ongoing progress of Reopening production, the KM Wells definitely need Injection (Water Flood) as a Reservoir Support Pressure Drive. The first Pattern Water Flood Injection (KM-107) is planned to be commissioning in May 2016. It will take 3 ~ 6 months as a monitoring period.

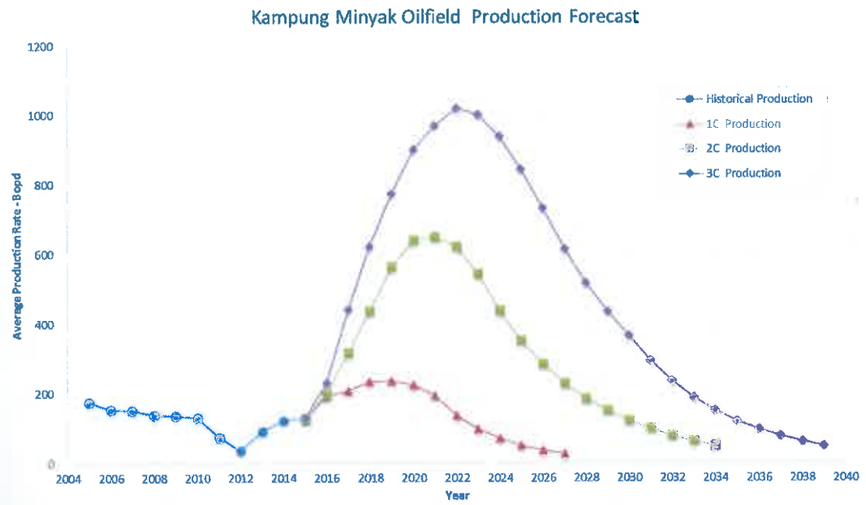


Figure 13 KM Field Production Forcast

Mirach's share of the crude oil contingent resources is summarized here.

Crude Oil Contingent Resources	1C Low Est.	2C Best Est.	3C High Est.
Property Gross (1), Mbbl	619	2,188	4,307
Company Gross Share (2), Mbbl	482	2,051	4,170
Company Net Share (3), Mbbl	409	1,415	2,213

(1) Property gross resources include the baseline production
(2) Company gross resources are based on the Mirach working interest share of the property gross resources less the baseline production.
(3) Company Net resources are based on the Mirach share of Cost Oil and Profit Oil revenues.

Table 7 KM Field Contingent Resources Summary

Basically during 2011 ~ 2014, KM did not conduct proper Water Flood Injection but just simple water disposal. In December 2014, KM reopened KM-513A as producer and put KM-87A as injector. Both them ran good. In 2015 KM rapidly did Reopening Wells to get better actual Reservoir Pressure. It gave encouraging result that KM field is good enough to introduce Water Flood Injection Program. On 12th October 2015, the KM-107 (LSTC zone) has been decided as the APPROVED Pilot Water Flood Injection well by PERTAMINA, including the facilities support for this.

2.6 Prospective Resources

Prospective Resources have been assigned to a number of zones within the Air Benekat and Talang Akar formations which underlay the producing Muara Enim Formation zones.

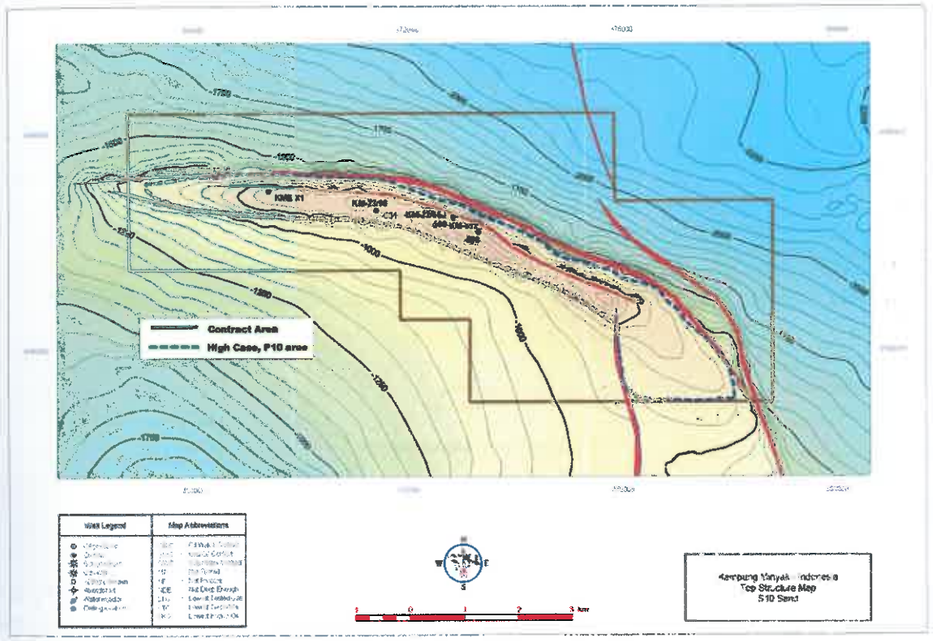


Figure 14 KM Field Top Structure map of S10 Sand

Prospective resources for each prospect zone are based on probabilistic volumetric calculations. Low (P90) and High (P10) estimates were used to define the distributions which are assumed to be log normal. The parameters used were pool area, average net pay, porosity, oil or gas saturation together with estimated PVT parameters and recovery factors. The pool area was based on the prospect outlines estimated from the structure maps interpreted from the seismic data. For all prospects a geometric correction factor (frequently referred to as a shape factor) was used to account for the reduction in net pay at the edges of the field.

For the Air Benekat Formation the reservoir parameters were derived from the available logs, including well KM-612 drilled in 2014, and compared against those parameters from nearby fields such as the Suban Jeriji, Suban Taham and Batu Keras oil fields. The main risk attached to these zones is the presence of reservoir quality rock. The S10 was assigned the highest chance of success. The area around the wells where sands could be identified on the logs was used to define the Low case (P90) pool area (for the S8 this also included wells KM-52 and KM-370, which have been allocated a small amount of production). The high case (P10) pool area is based on the lowest closing contour (limited if necessary to the block boundary).

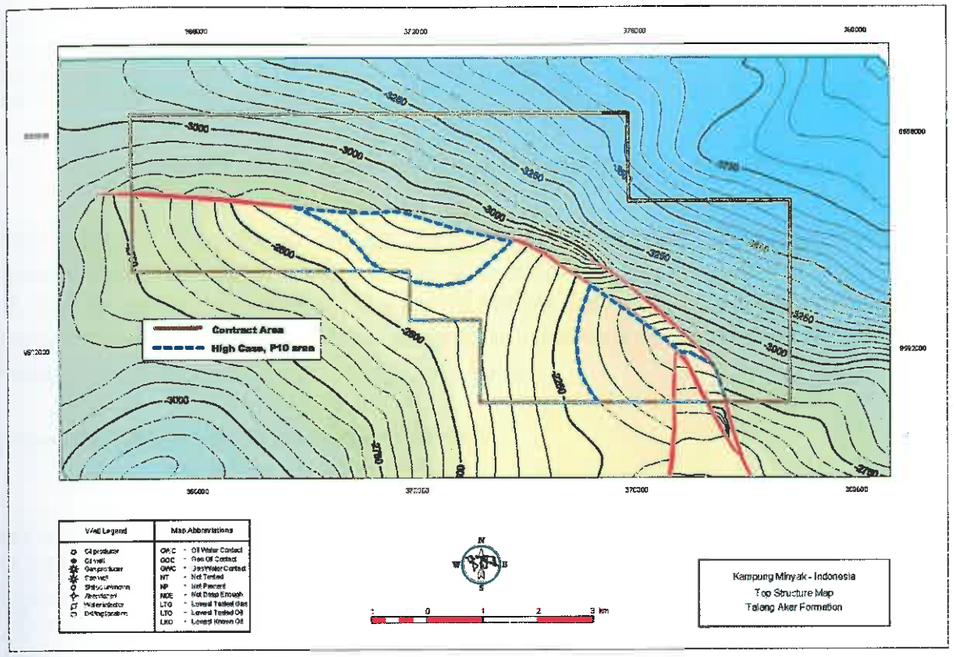


Figure 15 KM Field Top Structure map of Talang Akar Formation

For the Talang Akar Formation the reservoir parameters are based on parameters from the Benakat Barat and Limau fields which are the nearest analogues at distances of 50 and 30 kilometres respectively. The greater depth of the formation, which is expected to be below 2,300 metres, suggests there may be gas present and a 50:50 split between oil and gas has been assigned. The trap at KM is interpreted to be formed by sands abutting against a major fault, which is unlike most of the established traps that are associated with anticlinal structures.

		Air Benekat						
Parameter	**Estimate**	**S8**	**S9**	**S10**	**S11**	**S12**	**S13**	**Talang Akar**
Pool Area, acres	P90	207.0	160.0	400.0	315.0	190.0	245.0	160.0
Pool Area, acres	P10	2,070.0	2,916.0	2,768.0	2,405.0	2,324.0	2,051.0	1,532.0
Gross Pay, ft	P90	15.0	120.0	75.0	50.0	50.0	50.0	800.0
Gross Pay, ft	P10	50.0	230.0	180.0	150.0	150.0	200.0	1,400.0
NTG Ratio, %	P90	20.0	5.0	20.0	5.0	20.0	10.0	10.0
NTG Ratio, %	P10	50.0	20.0	40.0	20.0	50.0	35.0	17.0
Porosity, %	P90	13.0	12.0	10.0	10.0	10.0	12.0	8.0
Porosity, %	P10	19.0	18.0	16.0	16.0	16.0	18.0	16.0

Table 8 KM Field Prospective Resources Main Input Parameters

The prospect was risked using the parameters summarized here.

	Air Benekat						
Parameter	**S8**	**S9**	**S10**	**S11**	**S12**	**S13**	**Talang Akar**
Source	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Migration & Time	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Reservoir	0.60	0.60	0.80	0.60	0.80	0.80	0.50
Structure	1.00	1.00	1.00	1.00	1.00	1.00	0.50
Seal	0.80	0.50	0.50	0.50	0.50	0.50	0.60

Table 9 KM Field Prospective Resources Geological Chance of Discovery

The chance of discovery for any one zone has been assumed to be independent of the chance of discovery for the others and as such the overall chance of discovery is very high at over 95 percent. A summary of some of the key input parameters for all the zones is presented here. A summary of the prospective resources for each zone is presented in Table 2 of the Appendix on a property gross basis.

Prospective Resources: Crude Oil and Condensate (MMbbl)

	Property Gross (Unrisked)					Prospect	Risked Mean		
Prospect (1)	Initially In Place (Mean)	Low Estimate (P90)	Best Estimate (P50)	Mean	High Estimate (P10)	Geological Chance of Discovery (2)	Property Gross (3)	Company Gross (4)	Company Net (5)
KM									
Deep	*111*	10.7	19.9	22.3	36.3	95.3%	7.6	7.6	2.9
Total (6)	***111***	**10.7**	**19.9**	**22.3**	**36.3**		**7.6**	**7.6**	**2.9**

Prospective Resources: Natural Gas (Bcf)

	Property Gross (Unrisked)					Prospect	Risked Mean		
Prospect (1)	Initially In Place (Mean)	Low Estimate (P90)	Best Estimate (P50)	Mean	High Estimate (P10)	Geological Chance of Discovery (2)	Property Gross (3)	Company Gross (4)	Company Net (5)
KM									
Deep	*93*	10.6	25.2	35.1	71.3	95.3%	6.6	6.6	2.72
Total (6)	*93*	10.6	25.2	35.1	71.3		6.6	6.6	2.7

(1) Separate zones within each prospect were added probabilistically using monte-carlo simulation.

(2) The prospect geological chance of discovery is based on the success of any one of the prospect zones and assumes independence and consequently is not equivalent to the [Risked Mean]/[Unrisked Mean]

(3) Prospect risked mean resources are equal to the summed product of the unrisked mean resources for each zone multiplied by the geological chance of success of each zone.

(4) Company gross prospective resources are based on the working interest share of the property gross prospective resources

(5) Company Net resources are based on the Mirach share of Cost Oil and Profit Oil revenues.

(6) The total may appear to differ from the sum of the underlying assets due to rounding differences.

Table 10 KM Deep Prospective Resources Summary

3 BLOCK D OFFSHORE CAMBODIA

Block D Production Sharing Contract ("Block D PSC") is between the Cambodian Government represented by the Cambodian National Petroleum Authority ("CNPA") and China Zhenrong Cambodian Energy Co. Ltd ("Zhenrong", Contractor). In February 2007, Zhenrong renamed to CPHL (Cambodia) Company Limited. Mirach acquired 48% working interest in CPHL. Block D PSC is effective since March 27, 2006 and covers both the exploration period and any subsequent production period. CNPA was integrated into Ministry of Mines and Energy ("MME") in early 2014.

3.1 Block D Overview

Block D locates at west offshore Cambodia, east part of Gulf of Thailand.

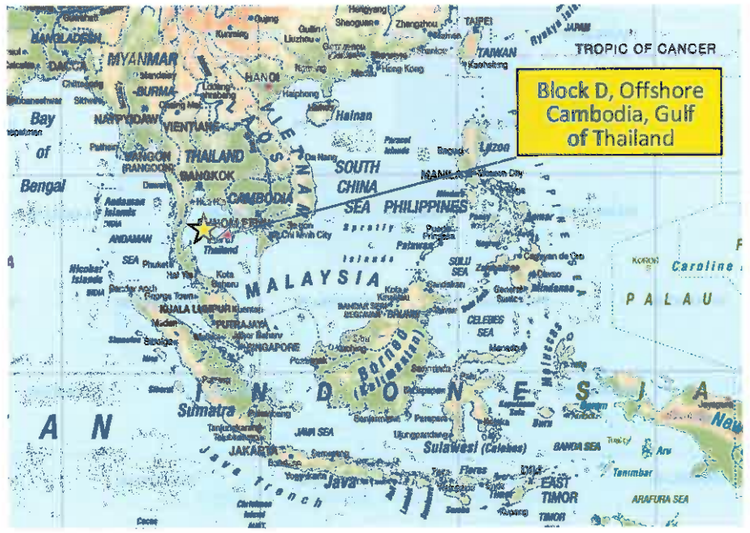


Figure 16 Block D Regional Location Map

Cambodian offshore area is divided into six offshore blocks (A to F) with Block D covering an area of 5,507 square kilometres. Block D borders Blocks A, C, E and F, and the Cambodia-Thailand joint development area. In Block A to the southwest (operated by ChevronTexaco) there have been a number of oil and gas discoveries to date.

In end of 2006 CPHL acquired a 400 square kilometre 3-D seismic survey over the prolific south west area of Block D on basis of 2D seismic interpretation. During 2007 and 2008 a number of prospects were identified. In 2010, the 3-D seismic was reprocessed resulting in an improvement in imaging data quality, and the updated Geophysical and Geological study followed. In 2013, CPHL completed an Environmental Impact Assessment preparing for exploration well drillings.

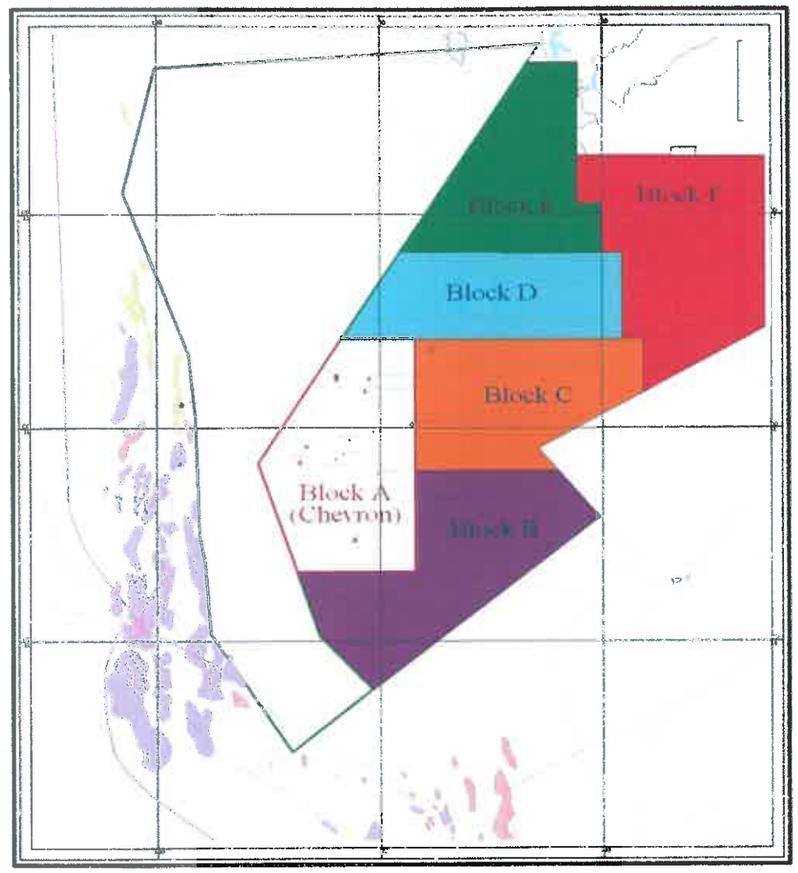


Figure 17 Cambodia Offshore License Map

3.2 Historical Activities and Data

The data for preparation of this QPR was obtained from CPHL. The seismic data consists of 6,762 kilometres of interpreted 2-D seismic lines (132 lines) and 400 square kilometres of 3-D which are of fair to good data quality. The 3-D data was reprocessed in 2009 and 2010 and re-interpreted. We quickly reviewed the reprocessed data and confirmed it is reasonable.

The seismic data quality is sufficient to generate reliable structural maps. The two seismic datasets have not yet been merged (but will be in due course) and separate 2-D and 3-D interpretations were provided. Two sets of structure maps created by CPHL and based on the two different seismic interpretations were reviewed and found to be reasonable. The 3-D seismic interpretation was considered more reliable. But none of the prospects, **as** currently mapped, are entirely contained within the 3-D seismic area and hence the 2-D seismic interpretation had also to be used.

Wireline logs were provided in digital format for 10 wells drilled in the surrounding

blocks. All the wells were loaded into petrophysical analysis software. And basically we mainly focus on wells B1-1 and Kaoh Tang-1 which are the closest to Block D.

CPHL Geophysical and Geological study report on the exploration potential of Block D dated February, 2010 was provided together with a number of regional studies including a Core Lab study undertaken in 1998 on behalf of the Government and the results of a Woodside Petroleum study undertaken in 2000.

Structure Top map of the basement of Block D and its neighborhood area showing the location of the seismic and the wells drilled in the adjacent blocks is presented below.

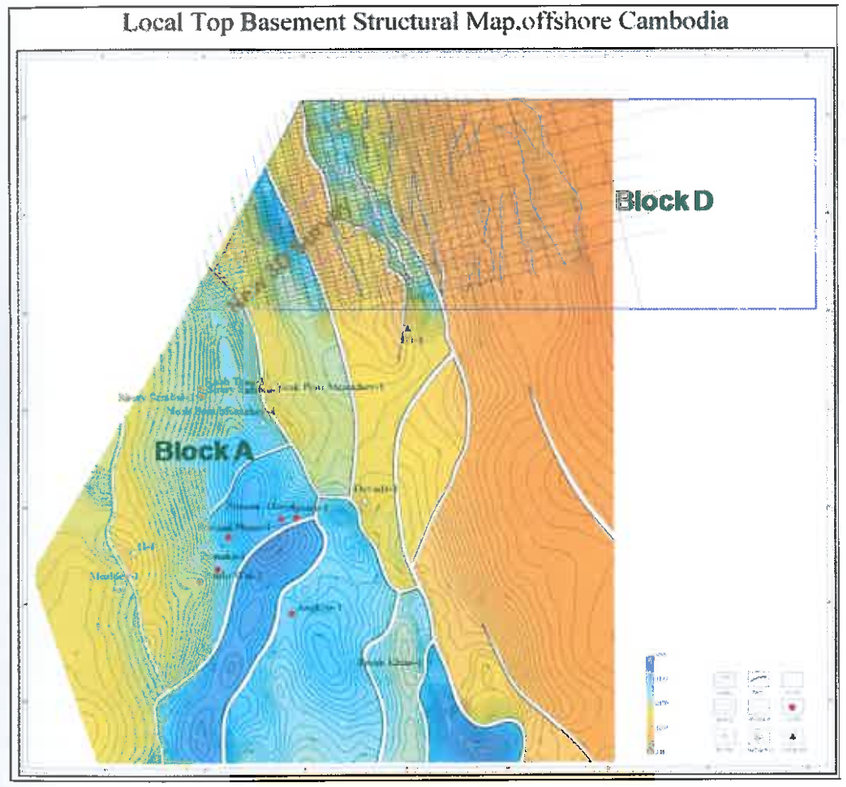


Figure 18 Block D Basement Top Structure Map

3.3 Regional and Block D Geology

Block D lies on the edge of the Khmer basin, a proven petroleum province and the third largest sub-basin in the Gulf of Thailand. A regional structure map for the Gulf of Thailand area is presented below.

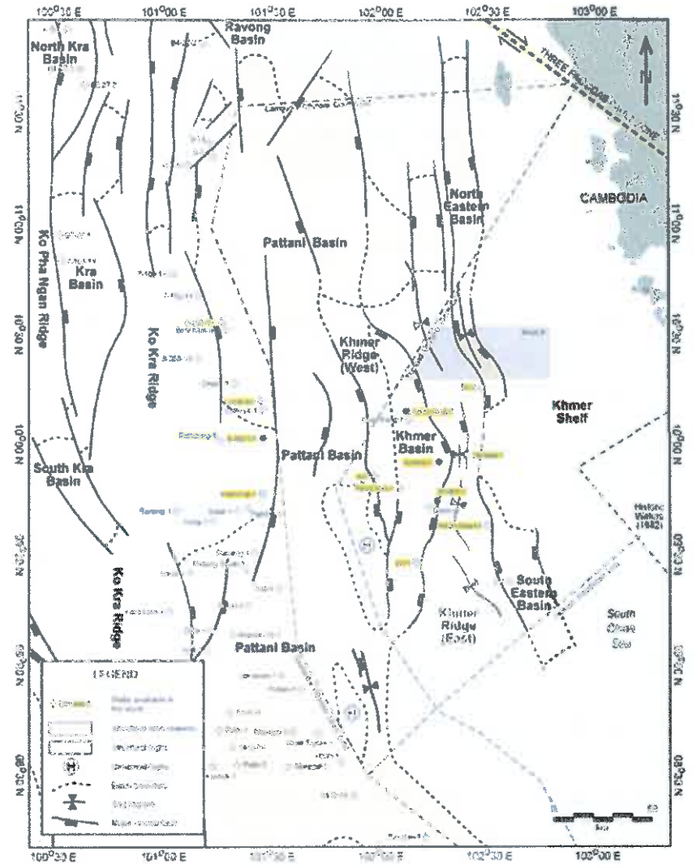


Figure 19 Block D Regional Structure Location Map

In the Pattani Trough, the main reservoir is the delta deposition of middle Miocene units II and III. In addition, some gas was produced from upper Oligocen – lower Miocene unit I and upper Miocene unit IV.

Reservoir is mainly channel sand body. The sand body is generally discontinuous and thin. Simultaneously, diverging sand body and mouth bar sand body deposited in delta-plain environment also developed. These sand bodies superposed each other and 10~20 layers of gas-bearing sand bodies are often discovered in 1 well. Porosity of the sand body reduces with the increase of depth. It is observed from core that the correlation of permeability and porosity is good.

Reservoir characteristics in the western graben are also very similar. The Permian marine carbonate rock (corresponding to Ratburi Formation) at shallow formation is also good reservoir, and oil was discovered in the Chumphon and Songkhla Basins.

3.3.1 Structure Conditions

The Gulf of Thailand was a large Pre-Tertiary rift basin that separated into sub-basins through extensional faulting which resulted in a horst and graben surface. The sub-basins filled with Tertiary sediments. The structural history of the Tertiary can be divided into three periods; fault depression, depression and thermal subsidence periods.

The structural history can be divided into three periods, including fault depression (SQ1~2), depression (SQ3~4) and thermal subsidence (SQ5~6). Two groups of faults, including near-North-Northwest-trending major faults and near-North-Northeast-trending induced faults, are developed in Block D forming numerous potential fault traps. The Central Uplift may also have large associated structural closures.

Fault depression period: 43-22Ma (early synrift period). In this period, strong extension occurred in this basin, resulting in the development of 4 major faults which control the sizes of the eastern and western half-grabens and grabens and the formation of local semi-deep lake sedimentary setting.

Depression period: 22-13Ma (late synrift period). The extension continued in this basin and the study area became the northern slope of Khmer Trough. The basin subsided as a whole and large scale transgression occurred, forming a marine sedimentary environment. The eastern boundary fault controlled the structural framework of the basin. Shallow marine environment occurred in the west of the fault, while littoral to continental environments existed in the east of the fault, where large delta are developed and brought large amount of detrital materials. The depression period is marked by continued basin extension combined with large scale transgression forming marine depositional environments in which the sediments of the SQ3 and SQ4 formations were laid down.

Thermal subsidence period: 13Ma to present (post-rift period). After the beginning of deposition of SQ5-2 (13Ma), the basin basically stopped extension and began to subside mainly due to the compaction and lowering of geo-temperature. But after the beginning of deposition of SQ5-2 (6.7Ma), the basin experienced a tilting and the whole strata dipped west regionally, resulting in a series of induced echelon faults. Up to this point, structural evolution ended and the basin disappeared, giving rise to the current structural framework.

The structural events formed seven structural belts within Block D. From west to east (from deeper basement structure to shallower) they are as follows: Western Slope (on the slope edge of the Khmer basin), Western Low Uplift, Western Sag (known as the Northern Khmer basin), Central Uplift, Eastern Sag (known as the North Eastern basin), Eastern Slope, Eastern Uplift.

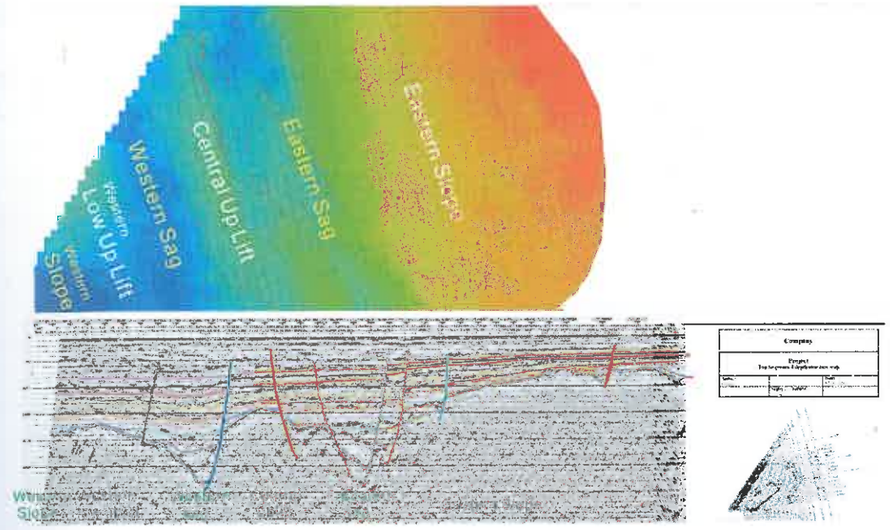


Figure 20 Structure Belts Division

3.3.2 Stratigraphy Conditions

The paleomorphology of Block D during the Tertiary is a slope area which resulted in a wedge of sediments thickening in a southeast direction. Further to the south and to the west, the Tertiary package lies directly onto a basement of metamorphic rock. However, in Block D it is suggested that Triassic and Permian rock underlie the Tertiary beds as they do onshore to the east, where an angular unconformity separates Tertiary and Pre-Tertiary sediments.

In the Tertiary, six separated sequences have been identified with increasing marine influence from older to younger deposits. From bottom to top they are sequentially named SQ1 to SQ6, and are separated by unconformities. They consist of thin sands interbedded with thick mudstone, limestones, and coals. The source of the sands in Block D is believed to be derived from the east.

In general, the SQ1 and SQ2 are dominated by lake sediments deposited in the Oligocene. The SQ3 to SQ6 is dominated by marine sediments with local incursions of continental fluvial depositions which have been reworked into shoreline sands. Occasional turbidite deposits are also interbedded in these sections of rock. The majority of this section was deposited in the Miocene.

The SQ2 and SQ3 are the most prospective and their depositional environment interpretation will be discussed in further detail.

The lower portion of SQ2, named SQ2-1, consists mainly of thick lake facies (mudstones) with local intrusions of fan deltas, basin floor fans, and alluvial plain facies. The upper portion of the SQ2, the SQ2-2, contains thick mudstones with some alluvial plain facies. The SQ3 represents the start of a shallower marine facies

with submarine fans and deltas being developed.

The upper portion is still dominated with shallow marine facies but now shows more littoral environments including the formation of barrier bars.

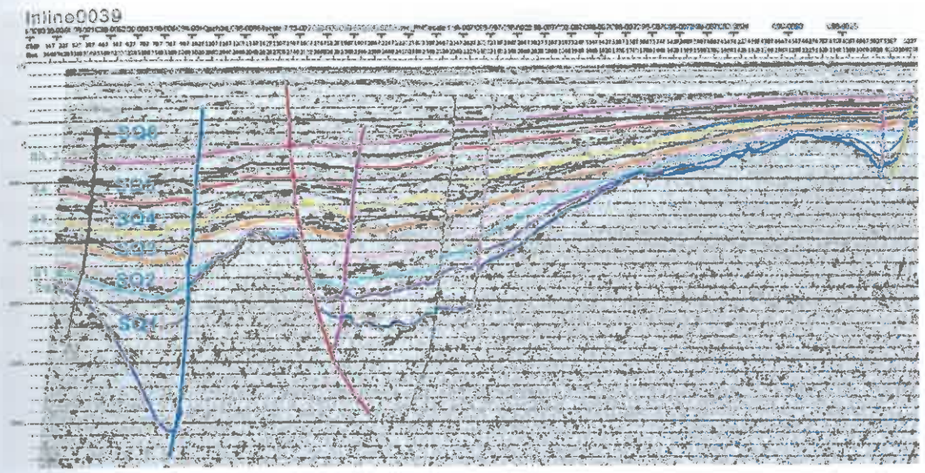


Figure 21 Sequences Division and Stratigraphy

3.3.3 Reservoir Conditions

Sands within the SQ2 and SQ3 sequences are the best potential reservoirs within the Block D Contract area. The results of the Block A wells indicate that the SQ2 and SQ3 are on average 200 metres and 350 metres thick respectively with a net sand content of 10 to 20 percent. Within the SQ2, a single sand layer is relatively thin with an average thickness of six metres and a maximum thickness of 18 metres. The SQ3 average single sand thickness is eight metres.

There are two types of reservoirs in Block D: Tertiary sandstone reservoirs and the Pre-Tertiary (presumably from Jurassic to Permian) metamorphic dolomite, sandstone, and limestone reservoir. Tertiary complex lithology, they are sandstone, mudstone, coal and carbonate, sandstone is the main reservoir based on drilling data. Tertiary sandstone reservoirs include channel sand, under water submarine fan and delta sand, the sand bar; this reservoir has been found commercial oil and gas in the block A.

In addition, there may be potential reservoirs if fractured metamorphic rock or carbonates are encountered within the Pre-Tertiary. Whether these reservoir types exist within Block D is unknown. Within Block A the Pre-Tertiary has been variable consisting of metamorphic rock, igneous rock (basalt and pyroclastics), limestone, dolomite, shale and quartz sandstone. CPHL believes that the presence of the buried hills within the Pre-Tertiary of Block D could suggest the formations may have been exposed to surface weathering, which could have enhanced their reservoir potential.

For fractured metamorphic basement the main porosity type will be fracture porosity.

Indirect evidence of this was found in Block A, in the Devada-1 well, where the presence of fractures was inferred from the wireline logs and the drill cuttings in the metamorphic basement rock. Fractured metamorphic basement plays are known to exist within the region (China and Vietnam); however, there are no known fields within the Gulf of Thailand. It may also be possible to encounter Permian carbonates within the Pre-Tertiary section as this type of reservoir exists within the Gulf of Thailand in the Chumphon and Songkha sub-basins.

SQ2 is deposited in semi-deep to shallow lake environment and the sandbodies are dominated by fan delta, submarine fan and sand sheet with a relatively small thickness. These understandings are in accordance with the drilling results in Block A. But the distribution of sandbodies is extensive, with three submarine fans recognized almost covering the whole area to the west of the No.2 fault. The poroperm characteristics of the sandbodies may be improved to some extent due to their shallow burial depth, thus are relatively good reservoirs.

- SQ3 is deposited in littoral-shallow marine environment and the sandbodies are dominated by underwater distributary channel, mouth bars and submarine fan at the delta front. Based on the average porosity of 18% obtained from the drilling data in Block A, the sandbodies in the study area may have a higher porosity as theri burial depth are shallower, thus are good reservoirs.
- SQ4 and SQ5 are also deposited in littoral-shallow marine environment and the sandbodies are mainly of underwater distributary channel, mouth bars and submarine fan at the delta front. The thickness of SQ4 and SQ5 are large due to sufficient sediment supply. The drilling data in Block A reveal an average porosity over 20% and maximum porosity up to 30%, thus they are quality reservoirs.

3.3.4 Source Conditions

The most likely source material within Block D lies within the SQ2-1 and the SQ1 sequences. Drill cuttings examined in Block A show that both of these sequences are composed of lake facies shales containing abundant organic matter. These shales can be up to 1,000 metres thick in the central part of the Khmer Trough.

The drilling data of Block A have verified that SQ1 contains organic matter of mainly III and II types. Analyses of physical property of crude oil reveal both crude oil with high wax but low sulfur contents and relatively low saturated/aromatic hydrocarbon ratio and crude oil with low wax and low sulfur contents (I type) and relatively high saturated/aromatic hydrocarbon ratio (II type), indicating oils of different sources. In combination with the biomarkers, it is predicted that the crude oil with low wax and low sulfur contents may be sourced from the source rocks in SQ1. In addition, just like the Northwest subbasin, the Oligocene deposits (SQ1) located in the eastern part of the basin also might be good source rocks.

Based on the seismic reflection signatures of the western and Eastern Sags in Block D, it is predicted that good source rocks may be developed in SQ1. The thickness of SQ1-1 may be 700-1000m in the Western Sag, while 500-700m in the Eastern Sag,

forecast 10% organic-rich shale.

SQ1-2 is 400-500m thick in the Western Sag, while 300-350m thick in the Eastern Sag. Mudstones with high content of organic matter account for 30%.

It is likely that any oil generated will have been sourced locally in the sub-basins like the Northern Khmer Basin and the North Eastern Basin where depths would be sufficient for proper maturity levels in the lower SQ zones. These sources are connected through the numerous fractures to the reservoir rock in the various trapping configurations. Although most of the migration is believed to be vertical as opposed to lateral, there could be oil migrating from the deep Khmer Basin up-dip into Block D, especially onto the Western Slope of the block.

In surrounding basins it has been shown that the Pre-Tertiary sources rocks may also be developed and mature enough to generate hydrocarbons. Two types of crude oil have been discovered in the area: high wax, low sulfur oil; and a low wax, low sulfur oil.

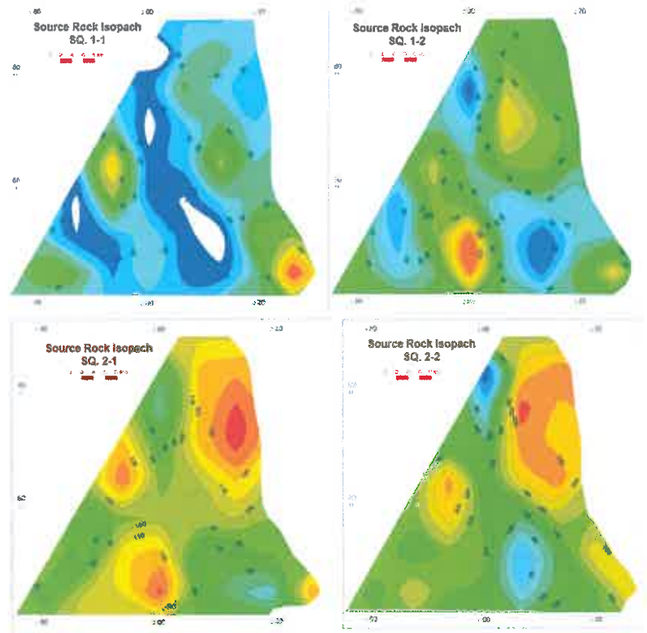


Figure 22 Block D West Source Rock Distribution Estimation

3.3.5 Seal Conditions

In Block D the faulting has occurred over a long time period, even into the age of SQ6 sequence. On seismic it can be seen that some faults reach up to the seabed which implies there is risk that even the regional seals may be breached in places by faults.

The thick mudstone in the SQ2-2 sequence acts as the main source rock and the first regional seal in the Block D area. The SQ6 sequence consists mainly of mudstone

and is interpreted to be the second regional seal in Block D area. On seismic these mudstones appear as a high amplitude reflector with good continuity. The SQ3~4~5 and SQ5 sequences also contain mudstone seals but these are localized to specific areas and are not as continuous as the regional SQ2-2 and SQ6 seals.

At least two sets of regional seals are developed in the study area. In addition, the sand content in Block D generally is below 20%, indicating well developed shale, and the sand and shale are intebedded, thus the reservoir-seal combinations are good.

- SQ2-2 is of semi-deep to littoral-shallow lake facies and contains thick mudstone, acting as the main source rocks and the first regional seal in the study area. Logging data of Block A verify that SQ2-2 is mainly of mudstone with thin sand interbeds. SQ2-2 is basically blank on seismic section, thus is a mudstone reflector.
- SQ6 consists mainly of mudstone and is the second regional seal in the study area. Logging data of Block A show that SQ6 contains a set of strata dominated by mudstone, which appears as seismic facies with dense reflections, high amplitude and good continuity on seismic section.
- SQ3, SQ4 and SQ5 are all deposits of littoral to shallow marine facies dominated by mudstone and all contain mudstone seals.

The caprock of Oligocene – Miocene sandstone oil reservoir is mainly the shale interbed in it, simultaneously, the sealing process of fault also exists. In the Pattani Trough, more shale than sandstone distributed in the Oligocene – middle Miocene synrift reservoir and the overburden upper Miocene post synrift formation, therefore, there is no problem as for the caprock. From Pliocene to present, the deposition scope of the upper mudstone of unit IV (corresponding to SQ6 in Block D) is more extensive. It is the uppermost of the Thailand Gulf Basin, and is also the last caprock.

3.4 Prospective Resources

Prospective Resources have been assigned to five prospects identified by CPHL within the Contract Area and are referred to as S1, S2, S3, S4 and S5. Each prospect has potential in a number of different zones of which the Pre-Tertiary basement and the Tertiary SQ2 and SQ3 are thought to be the most prospective.

The hydrocarbon expulsion is later in this area, to a certain extent; it reduces the risk of preservation. For the shallow, a fault increases the risk, for the deep layer the risk decrease, particularly under the sequence SQ3, smaller risk.

Source rock is not the biggest risk in this area, sequence SQ2 in the eastern and western depressions have thick sedimentary, sequence SQ1 possible source rocks, therefore less risk of hydrocarbon source; but not confirmed before drilling can not rule out the source rock risks.

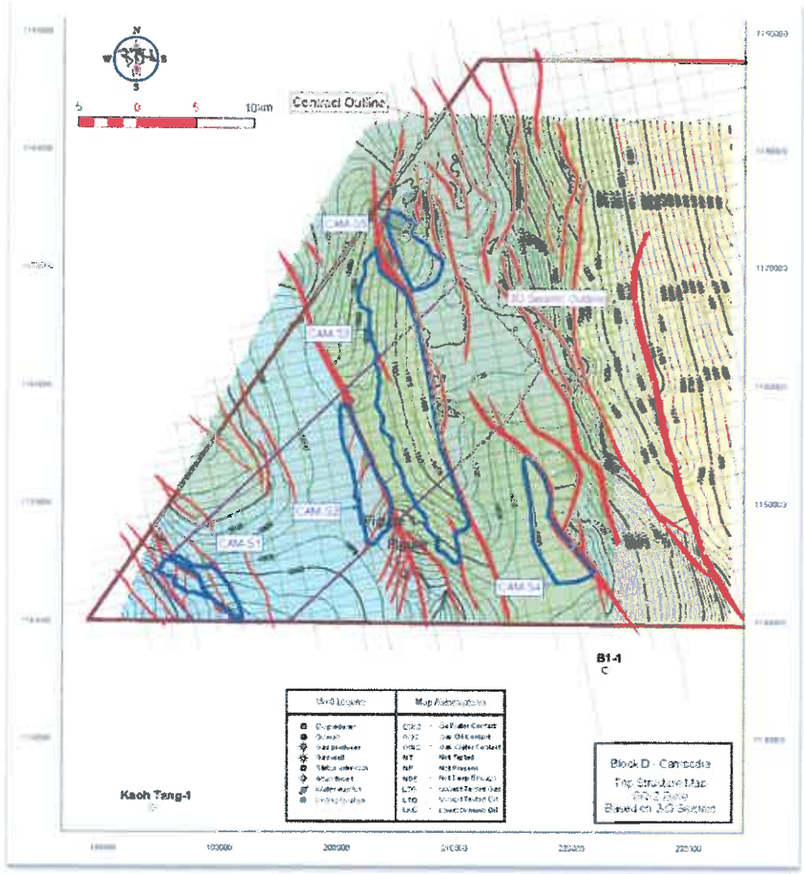


Figure 23 Block D SQ2 Top Structure Map

A top structure map of the SQ2 Formation based on the 2-D seismic interpretation is presented in Figure 20 and includes the five prospect outlines applicable to the SQ2 and SQ3 zones (the prospect outlines were picked within the seismic project using the gridded time horizons and therefore do not exactly overlay the top depth structure map). The SQ3 was not mapped separately as the zone is believed to be parallel to the underlying SQ2 and influenced by the same underlying structure. Another top structure map of the SQ2 Formation, this time based on the 3-D seismic, is presented in Figure 21. A top structure map of the Pre-Tertiary basement is presented in Figure 22 and includes the two prospect outlines applicable to this zone.

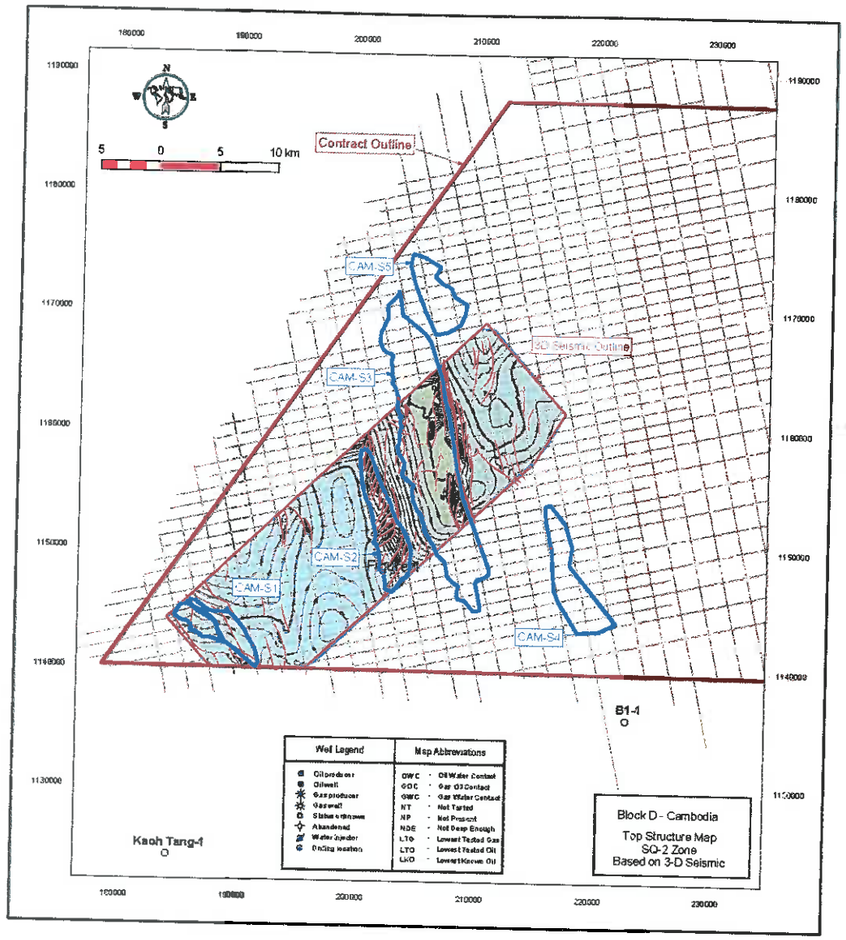


Figure 24 Block D SQ2 Top Structure Map (3-D Seismic)

The prospective resources for each zone were aggregated probabilistically, as statistically the High ("P10") Estimate at the prospect level is less than the sum of the P10 estimates at the zone level.

A summary of the prospective resources for each prospect and prospect zone is presented in Table 3 of the Appendix on a property gross basis. The prospective resources at a prospect level are summarized below. It should be noted that the "mean" is considered the most representative average to use when assessing a portfolio of assets as it captures the full range of outcomes.

3.4.1 Assessment Methodology

Prospective resources for each prospect zone are based on probabilistic volumetric calculations. Low (P90) and High (P10) estimates were used to define the distributions which are assumed to be log normal.

Prospective Resources: Crude Oil and Condensate (MMbbl)

Prospect (1)	Property Gross (Unrisked) Initially In Place (Mean)	Low Estimate (P90)	Best Estimate (P50)	Mean	High Estimate (P10)	Prospect Geological Chance of Discovery (2)	Risked Mean Property Gross (3)	Company Gross (4)	Company Net (5)
Block D (6)									
S1	*143*	11.8	27.1	31.4	59.3	42%	8.2	3.7	2.2
S2	*201*	7.1	26.8	44.1	107.1	34%	9.3	4.2	2.6
S3	*939*	77.3	170.9	191.0	420.5	32%	28.3	12.9	7.7
S4	*298*	19.7	49.4	62.7	139.6	16%	4.7	2.2	1.3
S5	*171*	10.8	29.4	37.5	79.0	30%	7.4	3.4	2.1
Total (7)	***1,751***	**126.6**	**303.6**	**366.8**	**805.4**		**57.9**	**26.4**	**15.9**

Prospective Resources: Natural Gas (Bcf)

Prospect (1)	Property Gross (Unrisked) Initially In Place (Mean)	Low Estimate (P90)	Best Estimate (P50)	Mean	High Estimate (P10)	Prospect Geological Chance of Discovery (2)	Risked Mean Property Gross (3)	Company Gross (4)	Company Net (5)
Block D (6)									
S3	*210*	16.5	73.1	129.6	323.5	5%	6.3	2.9	-
S4	*36*	2.6	12.1	22.1	55.7	3%	0.7	0.3	-
Total (7)	***246***	**19.2**	**85.2**	**151.7**	**379.2**		**7.0**	**3.2**	-

(1) Separate zones within each prospect were added probabilistically using monte-carlo simulation.

(2) The prospect geological chance of discovery is based on the success of any one of the prospect zones and assumes independence and consequently is not equivalent to the [Risked Mean]/[Unrisked Mean]

(3) Prospect risked mean resources are equal to the summed product of the unrisked mean resources for each zone multiplied by the geological chance of success of each zone.

(4) Company gross prospective resources are based on the working interest share of the property gross prospective resources assuming CNPA exercise their option to take a 5 percent interest.

(5) Company Net resources are based on the Mirach share of Cost Oil and Profit Oil revenues assuming CNPA exercise their option to take a 5 percent interest. For Natural Gas the net is zero as the gas is considered noncommercial.

(6) The Block D S3 and S4 prospects contain a Pre-Tertiary zone which could be either crude oil (with no free gas) or natural gas (with no oil rim). The unrisked crude oil resources assume the zone contains only oil and the unrisked natural gas resources assume the zone contains only gas which means on an unrisked basis the prospective resources are mutually exclusive. This is accounted for though in the risked estimates which include the chance of the prospect being oil or gas filled.

(7) The total may appear to differ from the sum of the underlying assets due to rounding differences.

Table 11 Block D Prospective Resources Summary

The SQ2 and SQ3 zones are likely to be oil bearing. The parameters used for evaluating the SQ2 and SQ3 zones were pool area, average net pay, porosity, oil saturation together with estimated pressure volume temperature ("PVT") parameters (the API oil gravity was assumed to vary between 35 and 40) and recovery factors. For any one prospect the pool area for the SQ2 and the pool area for SQ3 was assumed to be the same.

Fault activity in Block D a long time, SQ6 age has another times fault activity, fault almost reaches the sea level, this is very detrimental to oil and gas accumulation;

The main trap type of Block D is fault nose, fault block, sealing ability, fault communicates reservoir and source rocks case, and they are effect on hydrocarbon accumulation. Chevron Texaco Exploration Block A summary experience that beyond 200m from the fault has not oil and gas, showing a fault the role of oil and gas accumulation.

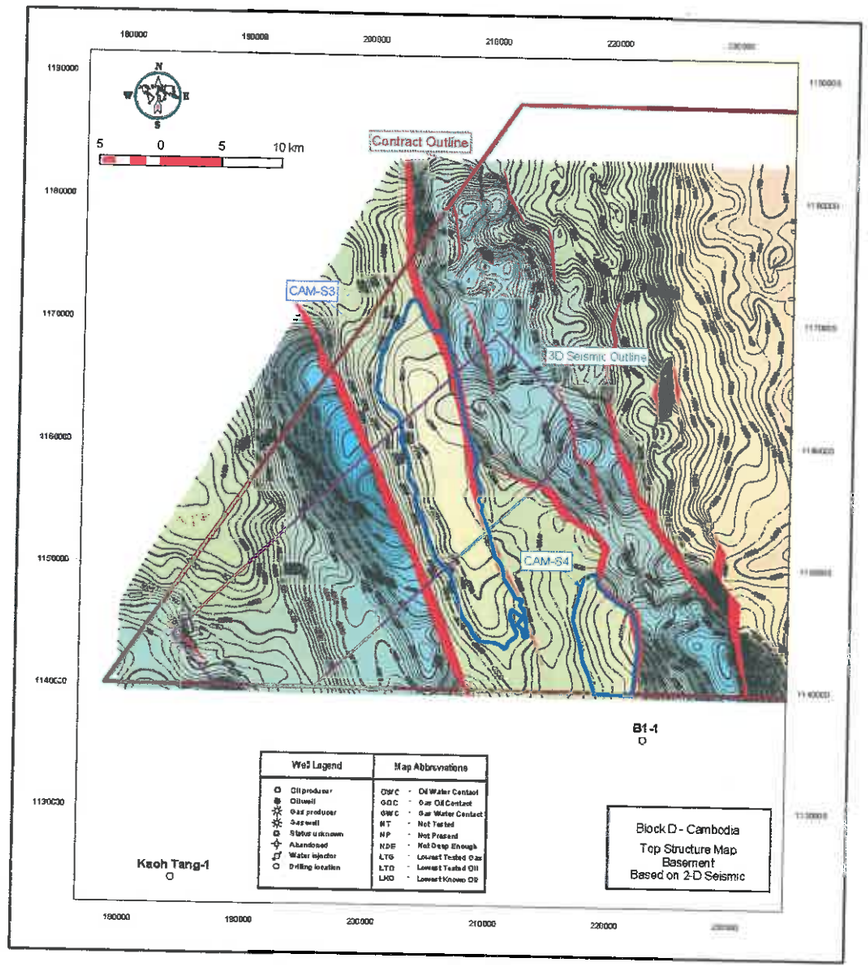


Figure 25 Block D Basement Top Structure Map

The hydrocarbon expulsion is later in this area, to a certain extent; it reduces the risk of preservation. For the shallow, a fault increases the risk, for the deep layer the risk decrease, particularly under the sequence SQ3, smaller risk.

Source rock is not the biggest risk in this area, sequence SQ2 in the eastern and western depressions have thick sedimentary, sequence SQ1 possible source rocks, therefore less risk of hydrocarbon source; but not confirmed before drilling can not rule out the source rock risks.

In summary, Block D has favorable geological conditions of forming large, medium-sized oil and gas fields.

The basement zone is interpreted to be prospective in the S3 and S4 prospects. The zone was assessed assuming a 50 percent chance of encountering natural gas (with virtually no condensate) and a 50 percent chance of fairly heavy oil (API gravity of 15). The unrisked prospective resources presented in Table 3 of the Appendix assume the zone contains only oil and the unrisked natural gas resources assume the zone contains only gas which means on an unrisked basis the prospective resources are mutually exclusive. This is accounted for though in the risked estimates which include the chance of the prospect being oil or gas filled.

	SQ2 Zone		SQ3 Zone	
Parameter	**P90**	**P10**	**P90**	**P10**
Average Net Pay,ft	45	85	65	105
Porosity, %	16	25	17	26
Oil Saturation, %	55	70	55	70
Oil FVF, rb/stb	1.30	1.50	1.30	1.50
Oil Recovery Factor, %	10.0	40.0	10.0	40.0

Table 12 Block D SQ2 and SQ3 Input Parameters

In addition, two alternative reservoir rocks were considered: one being a fractured basement rock with no matrix porosity; and the other being a weathered Permian carbonate rock. Analysis shows that the effective pore volume of both these reservoirs within the specific structural setting of the prospects is likely to be similar, as the much lower porosity of the fractured basement reservoir is offset by the greater thickness. The parameters used for the basement were pool area, average gross pay, porosity, net-to-gross, oil and gas saturation together with estimated PVT parameters and recovery factors. The parameters were assumed to be the same for both prospects, whereas the pool area and gross pay were varied. The common parameters are summarized and assuming a fractured basement reservoir.

Parameter	**P90**	**P10**
Net-to-Gross, %	60	85
Porosity, %	0.1	1.5
Oil or Gas Saturation, %	60	80
Oil FVF, rb/stb	1.10	1.20
Oil Recovery Factor, %	10.0	25.0
Gas Expansion Factor	117	119
Gas Recovery Factor,%	50	80
Gas Shrinkage, %	2.5	5

Table 13 Block D Basement Input Parameters

For the SQ2 and SQ3 zones a geometric correction factor (frequently referred to as a shape factor) of 0.9 was used to account for the reduction in net pay at the edges of

the field. For the basement zone a gross pay map was used and consequently a shape factor was not required.

Each prospect zone was risked using five parameters: source, migration, reservoir, structure and seal. Source, migration and structure were assumed to be fully dependent for the SQ2 and SQ3 zones within the same prospect. This means that if a source is present for one zone it will also be present for the other zones in the same prospect. The influx of sand is interpreted to be from the east and so the reservoir chance was varied to reflect the higher sand/shale ratio likely to exist there (0.9 in the east to 0.7 in the west).

Conversely the seal chance was increased in a westward direction as the increase in shale is likely to improve the chance of sealing faults. The seal on the SQ3 was given a slightly higher risk as it is overlain by only one regional seal (compared to the two for the SQ2). Structure chance of success was taken to be 0.6 except in the cases where the pool outline is at least partly defined on 3-D seismic where a 0.7 chance was assigned.

3.4.2 S1 Prospect

The S1 prospect lies in the southwest corner of Block D (see Figure 20 and Figure 21) and as such is the only prospect, which is within the Khmer Basin. The prospect area is broken up by a number of faults and the closure area is uncertain. Pool areas of 543 and 2,850 acres were estimated for the P90 and P10 respectively.

The prospect was risked using the parameters summarized. The source risk is considered very low as the prospect is interpreted to lie within the Khmer Basin, which has a proven source.

Parameter	SQ2 Zone	SQ3 Zone
Source	0.95 (Dependent)	
Migration & Time	0.90 (Dependent)	
Reservoir	0.70	0.70
Structure	0.70 (Dependent)	
Seal	0.65	0.60

Table 14 Block D Prospect S1 Geological Chance of Discovery

3.4.3 S2 Prospect

The Tertiary at the S2 prospect is highly faulted and interpreted to be a flower structure on the 3-D seismic (Figure 21). It is likely that traps will have formed in this structural setting but it maybe that individual fault blocks will be small with some having hydrocarbons but others having breached. Pool areas of 200 and 5,500 acres were estimated for the P90 and P10 respectively with an allowance made for the extension of the prospect into the 2-D seismic area.

The prospect was risked using the parameters summarized. The seal risk was

increased due to the greater degree of faulting.

Parameter	SQ2 Zone	SQ3 Zone
Source	0.90 (Dependent)	
Migration & Time	0.80 (Dependent)	
Reservoir	0.80	0.80
Structure	0.70 (Dependent)	
Seal	0.55	0.50

Table 15 Block D Prospect S2 Geological Chance of Discovery

3.4.4 S3 Prospect

The S3 prospect is potentially the largest of the five prospects with potential in the Tertiary (SQ2 and SQ3) and the basement (see Figure 20 and Figure 22). A dip line from the 3-D seismic is presented below and shows what appears to be a basement horst with an associated compactional drape of Tertiary sediments, which in turn have some vertical offset due to the reactivation of the faulting during the Tertiary on the down-dip and up-dip sides of the block.

However, any large closure within the Tertiary is subtle and relies on the 2-D seismic to close the structure in a strike direction. A P10 and P90 pool area of 875 acres and 17,500 acres were chosen to reflect the uncertainty. The smaller area reflects the possibility that only one of a number of potential small closures evident on the 3-D seismic is successful. The larger pool area reflects a much greater closure area defined by the 2-D seismic. The closure at the basement level is more robust and potentially very large with a P90 of 15,000 and a P10 of 35,000 acres assigned.

The high (P10) un-risked prospective resources for the SQ2 and SQ3 zones are 165 and 228 MMbbls respectively. As such, these volumes are much larger than anything reportedly found in Block A after drilling 27 wells. CPHL believe that the structural setting of this prospect is unlike anything present in Block A allowing for the formation of a bigger trap and that a better analogue would be the large fields present in the Pattani basin of Thailand. However, there was no geological data available as part of this evaluation to be able to corroborate this.

The prospect was risked using the parameters summarized. The basement was assigned a probability of containing oil of 0.5 which, as gas is not considered commercial, reduces the overall chance of discovery by 50 percent.

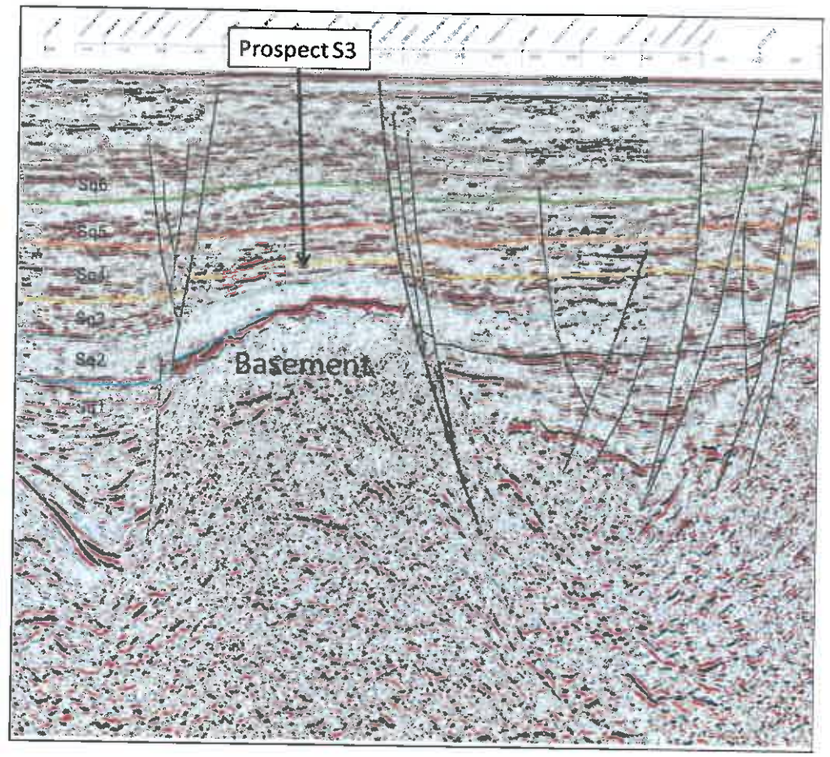


Figure 26 Block D Prospect S3 Dip Line from 3-D Seismic Survey

Parameter	SQ2 Zone	SQ3 Zone	Basement
Source	0.70 (Dependent)		0.5
Migration & Time	0.80 (Dependent)		0.6
Reservoir	0.80	0.80	0.6
Structure	0.70 (Dependent)		0.9
Seal	0.60	0.55	0.6

Table 16 Block D Prospect S3 Geological Chance of Discovery

3.4.5 S4 Prospect

The S4 prospect lies just to the north of well B1-1 and is prospective in the SQ2, SQ3 and basement zones (see Figure 20 and Figure 22). For the Tertiary the closure to the south is uncertain and pool areas of 330 and 6,600 acres were assigned for the P90 and P10 respectively. The basement is slightly better defined and pool areas of 3,000 and 9,000 acres were assigned for the P90 and P10 respectively. It is not clear why the well B1-1 failed but source and seal were assumed to be an issue and so the S4 prospect has been risked accordingly with the parameters summarized. The basement was assigned a probability of containing oil of 0.5 which, as gas is not considered commercial reduces the overall chance of success by 50 percent.

Parameter	SQ2 Zone	SQ3 Zone	Basement
Source	0.40 (Dependent)		0.5
Migration & Time	0.80 (Dependent)		0.6
Reservoir	0.90	0.90	0.6
Structure	0.60 (Dependent)		0.7
Seal	0.50	0.45	0.5

Table 17 Block D Prospect S4 Geological Chance of Discovery

3.4.6 S5 Prospect

The S5 prospect appears reasonably well defined on 2-D seismic (see Figure 20). Pool areas of 400 and 4,000 acres were assigned to be P90 and P10 input parameters respectively.

The prospect was risked using the parameters summarized. A structure chance of 0.6 was assigned as there is no 3-D seismic over the prospect and even though the prospect appears to be clear on 2-D seismic the trap is complex with faulting and dip reversal.

Parameter	SQ2 Zone	SQ3 Zone
Source	0.80 (Dependent)	
Migration & Time	0.80 (Dependent)	
Reservoir	0.90	0.90
Structure	0.60 (Dependent)	
Seal	0.60	0.55

Table 18 Block D Prospect S5 Geological Chance of Discovery

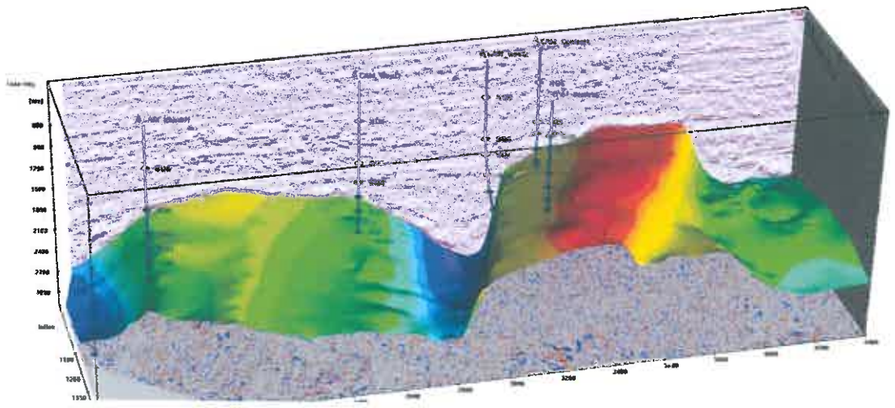


Figure 27 The proposed drilling locations within 3D survey

4 PROFESSIONAL QUALIFICATIONS

APEX Solutions, Inc. is an American company founded in Houston, Texas in 1995. It composed of three primary business segments: Software Sales and Support; Oil and Gas Technical Service and Consultant; and Reserve Estimation and Economic Evaluation.

The company has strong expertise in the areas of Geology, Geophysics, Petroleum Engineering and Reserve Economic Analyses and equips with Dell PC Cluster, Sun and Dell Workstations, as well as computers and related software. APEX performs about 30 domestic and overseas research projects annually for China and international oil companies in Asia, Africa, Middle East and South America.

Since the establishment of its service and consultant department in 2003, the company has earned nationwide recognition for reliably predicting the performance of complex oil and gas reservoirs and reserve estimation. It conducts geology studies, petrophysics analyses, reservoir prediction, field development and EOR design, reservoir simulation, reserves evaluations and economic analysis.

APEX has a technical team of 40 geologists and engineers, many of whom are outstanding experienced experts in exploration and development and China's national registered reserves evaluation experts. Many of the exploration and development technological personnel have more than 20 years' experience working in China and abroad.

APEX is the first company in China to apply and introduce domestic and overseas resources and reserves standards to evaluate oil and gas resources using PRMS ((Petroleum Resources Management System), SEC (Securities and Exchange Commission) and China oil and gas reserves evaluation standards. The Service Scope includes: Reserve hierarchical classification study; Reserve report compilation; Listed reserve evaluation; Unconventional reservoir reserve study; Rapid evaluation of reserve assets in market trading

APEX has been consistently working on realizing its "3T" goal - Top Personnel, Top Technology, and Top Services to contribute to the oil and gas industry.

4.1 Qualified Person Statement (Mr. Lin Hao)

I, Lin Hao, confirms that I am the Chief Engineer of APEX Solution, Inc. and that am responsible for this QPR and the information therein.

I hold a Qualified Certificate for Valuer of Mineral Reserves in the People's Republic of China with the Registration Number of 0000496. I have over 35 years of experience in oil and gas exploration and production activities. I have participated and was responsible for the following reserves evaluation projects for the following companies listed on the Hong Kong Stock Exchange:

- POLY-GCL Petroleum Investments Limited–03800.HK
- PetroAsian Energy Holdings Limited-00850.HK
- Polytec Asset Holdings Limited–00208.HK
- China Huarong Energy Company Limited–01101.HK

I am a qualified person pursuant to the Mainboard Listing Rules of the Singapore Exchange Limited as a person of appropriate experience in the types of activities undertaken by Mirach Energy Limited, meeting the following requirements:

1) I am professionally qualified and a good standing member of a relevant Recognised Professional Association;

2) I have at least five years of professional experience in the estimation, assessment and evaluation of oil and gas exploration and production assets;

3) I have not been found in breach of any relevant rule or law and am not;

   a) denied or disqualified from membership of;

   b) subject to any sanction imposed;

   c) the subject of any disciplinary proceedings; or

   d) the subject of any investigation which might lead to disciplinary action by any relevant regulatory authority or professional association.

I have read and understood the requirements of the November 2011 Petroleum Resource Management System ("PRMS"). These are to be found in Appendix IV.

I verify that this QPR is based on, and fairly and accurately reflects, in the form and context in which it appears, the information in my supporting documentation relating to exploration results and oil resources and reserves. I have reviewed this QPR, to which this consent statement applies, and I consent to the release of this QPR.

Signature:

Date: March 31, 2016

4.2 Qualified Person Statement (Mr. Li Qinghao)

I, Li Qinghao, confirms that I am the Chief Engineer of APEX Solution, Inc. and that am responsible for this QPR and the information therein.

I hold a Qualified Certificate for Valuer of Mineral Reserves in the People's Republic of China with the Registration Number of 0000496. I have over 35 years of experience in oil and gas exploration and production activities. I have participated and was responsible for

the following reserves evaluation projects for the following companies listed on the Hong Kong Stock Exchange:

- POLY-GCL Petroleum Investments Limited–03800.HK
- PetroAsian Energy Holdings Limited-00850.HK
- Polytec Asset Holdings Limited–00208.HK
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1) I am professionally qualified and a good standing member of a relevant Recognised Professional Association;

2) I have at least five years of professional experience in the estimation, assessment and evaluation of oil and gas exploration and production assets;

3) I have not been found in breach of any relevant rule or law and am not;

   a) denied or disqualified from membership of;
   b) subject to any sanction imposed;
   c) the subject of any disciplinary proceedings; or
   d) the subject of any investigation which might lead to disciplinary action by any relevant regulatory authority or professional association.

I have read and understood the requirements of the November 2011 Petroleum Resource Management System ("PRMS").

I verify that this QPR is based on, and fairly and accurately reflects, in the form and context in which it appears, the information in my supporting documentation relating to exploration results and oil resources and reserves. I have reviewed this QPR, to which this consent statement applies, and I consent to the release of this QPR.

Signature:

Date: March 31, 2016

5 GLOSSARY OF TECHNICAL TERMS AND ABBREVIATIONS

The following is a glossary of technical terms and a list of the abbreviations used in this report:

Term/Abbreviation	Meaning
2-D Seismic	seismic data acquired in a grid of lines that is relatively broad spaced, and is processed in two dimensions
3-D Seismic	seismic data acquired in a grid that is relatively close-spaced and dense, and is processed in three dimensions
API	a specific gravity scale development by the American Petroleum Institute for measuring the relative density of various petroleum fluids, expressed in degrees
appraisal well	a well drilled as part of an appraisal drilling programme which is carried out to determine the physical extent, reserves and likely production rate of a field
bbl	one barrel of oil; 1 barrel = 35 Imperial gallons (approx.), or 159 litres (approx.); 7.5 barrels = 1 tonne (approximately depending upon the oil density); 6.29 barrels = 1 cubic metre
bbl/MMcf	barrels per million of cubic feet
Bcf	billion cubic feet
block	term commonly used to describe contract areas or tract, as in block of land
bopd	barrels of oil production per day
bpd	barrels per day
BS&W	means base sediments and water
bwpd	barrels of water production per day
chance of discovery	the chance that the potential accumulation will result in the discovery of petroleum
completion	the operation of perforating, stimulating and equipping an oil or gas well
condensate	hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons
contingent resources	Quantities of petroleum estimated, as at a given date, to be potentially recoverable from known accumulations, but applied project(s) are not yet considered mature enough for commercial development due to one of more contingencies
CNPA	Cambodian National Petroleum Authority
cost oil	the sum of a party's investment and operating costs recovered from the production of oil from the relevant field
QPR	Qualified Person's Report
dip	the inclination of a horizontal structure from the horizontal
discovery	A defined term under PRMS. A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.
exploration phase	the phase of operations which covers the search for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling
exploration well	a well in an unproven area or prospect, may also be known as a wildcat well
field	a geographical area under which an oil or gas reservoir lies
formation	a unit of rock
gas field	a field containing natural gas but no oil
GOC	gas oil contact
GOR	gas oil ratio
gross pay	the total thickness of hydrocarbon bearing sediments
hydrocarbon	a compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate
kg/m3	Kilograms per cubic metre
km	kilometres
KM	Kampung Minyak
KSO	a joint operations contract in the Indonesian language
mD	milli Darcy (permeability)
M	thousands
MM	millions

Mbbl	thousands of barrels
MMbbl	millions of barrels
Mcfpd	thousands of cubic feet per day "MMcfpd"
net pay	the total thickness of hydrocarbon bearing sediments that is classified as reservoir
oil field	a geographic area under which an oil reservoir lies
OOIP	original oil in place
operator	the company that has legal authority to undertake petroleum operations
OWC	oil water contact
P10	the term used to describe the volume of reserves defined as having a better than 10% chance of being technically and economically viable
P50	the term used to describe the volume of reserves defined as having a better than 50% chance of being technically and economically viable
P90	the term used to describe the volume of reserves defined as having a better than 90% chance of being technically and economically viable
permeability	the property of a formation which quantifies the flow of a fluid through the pore spaces and into the wellbore
Permian	a geological period between 250 to 295 million years ago
petroleum	a generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products
pool	a individual and separate accumulation of petroleum in a reservoir
porosity	the percentage of void in a porous rock compared to the total rock volume
PRMS	Petroleum Resource Management System
probabilistic	a method of estimating an uncertain outcome whereby a range of values is used for each parameter in a calculation. Results are generally expressed as a range with an associated probability of occurrence
profit oil	means a party's share of production from the relevant field in excess of Cost Oil
property gross	the total reserves or resources for the property
PSC	a production sharing contract
recompletion	to repeat the initial "completion" of a well, at a later stage, to either enhance production from the existing "zone", or to allow production from a new zone
reserves	generally the amount of economically recoverable oil or gas in a particular reservoir that is available for production
reservoir	the underground formation where oil and gas has accumulated. It consists of a porous and permeable rock to hold the oil or gas, and a cap rock that prevents its escape
risked	after accounting for chance of success or discovery "saturated oil"
unrisked	prior to taking into account the chance of discovery
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
stratigraphic trap	a mode of trapping hydrocarbons which is not dependent on structural entrapment
structural high	an area where rocks have been elevated due to tectonic activity
swabbing	the process of mechanically producing a pressure drop in the wellbore by rapidly pulling out of the hole, usually with a cup shaped tool
Tcf	trillion cubic feet
TD	total depth of a well, when drilling has finished
US$ M	thousands United States dollars
US$ MM	millions United States dollars
well log	a record of geological formation penetrated during drilling, including technical details of the operation
zone	a general term meaning an interval or unit of rock. A zone in a well would be an interval typically defined by a top and bottom depth. A fault zone would be the unit of rock associated and the area around a fault

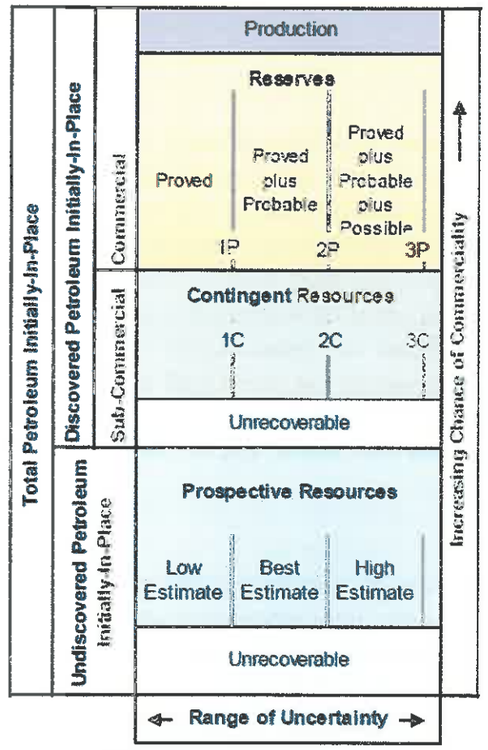
6 RESERVES AND RESOURCES DEFINITIONS

The definitions employed in this evaluation conform to the 2011 Petroleum Resource Management System (PRMS) jointly published by the Society of Petroleum Engineers ("SPE"), World Petroleum Council ("WPC"), American Association of Petroleum Geology ("AAPG") and the Society of Petroleum Evaluation Engineers ("SPEE").

Resources

The term "resources" is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

The resources classification framework is summarized below.



Resource Classification Framework

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality", that is, the chance that the project that will be developed and reach commercial producing status.

The quantities estimated to be initially-in-place are defined as Total Petroleum-

initially-in-place, Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, and the recoverable portions are defined separately as Reserves, Contingent Resources, and Prospective Resources. Reserves constitute a subset of resources, being those quantities that are discovered (i.e. in known accumulations), recoverable, commercial and remaining.

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 categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

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

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. Prospective Resources 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.

Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a Low, Best, and High Estimate shall be provided such that:

There should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the Low Estimate.

There should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

There should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the High Estimate.

When using the deterministic scenario method, typically there should also be Low, Best, and High Estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately.

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

Reserves Categories and Status

For Reserves, the general cumulative terms Low/Best/High Estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system.

Proved Reserves

Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined 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 percent probability that the quantities actually recovered will equal or exceed the estimate.

Probable Reserves

Probable Reserves are those additional Reserves which 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 plus Probable Reserves (2P). In this

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

Possible Reserves

Possible Reserves are those additional Reserves which 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 plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10 percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

Reserves status categories define the development and producing status of wells and reservoirs.

Developed Reserves

Developed Reserves are expected quantities to be recovered from existing wells and facilities. 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. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or, (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

Undeveloped Reserves

Undeveloped Reserves are expected quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage, (2) from

deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Contingent Resource Categories

For Contingent Resources, the general cumulative terms Low/Best/High Estimates are denoted as 1C/2C/3C respectively. No specific terms are defined for incremental quantities within Prospective Resources.

Prospective Resource Categories

For Prospective Resources, the general cumulative terms Low/Best/High Estimates apply. No specific terms are defined for incremental quantities within Prospective Resources.

Prospective Resource Sub Classes

Prospective resources can be sub classified in terms of project maturity into prospects, leads and plays.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Lead

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

Play

A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

APPENDIX

ADDITIONAL TABLES

Table 1 KM Crude Oil Contingent Resource Overall Summary
Table 2 KM Summary of Prospective Resource Estimates
Table 3 Block D Summary of Prospective Resource Estimates

Table 1

Kampung Minyak Field - Indonesia
Crude Oil Contingent Resource Overall Summary
As of December 31, 2015

Zone Block	STC 1-9	S1-8 1-9	Total
Original Oil in Place, Mbbl	42,479	22,462	64,940
Cumulative Production, Mbbl	4,665	7,308	11,973
Cumulative Recovery, %	11.0	32.5	18.4
Wells with Production	90	188	278
Existing Producers	10	20	30
End Dec 2015 Production Rate, bopd	34	130	164
Cum Oil per Prod. Well, Mbbl	52	39	43
Low Contingent Resources (1C)			
Recovery Factor, %	12.0	33.3	19.4
Original Recoverable, Mbbl	5,113	7,478	12,592
Cumulative Production, Mbbl	4,665	7,308	11,973
Remaining Recoverable, Mbbl	449	170	619
Best Estimate Contingent Resources (2C)			
Recovery Factor, %	14.6	35.5	21.8
Original Recoverable, Mbbl	6,190	7,970	14,161
Cumulative Production, Mbbl	4,665	7,308	11,973
Remaining Recoverable, Mbbl	1,526	662	2,188
High Estimate Contingent Resources (3C)			
Recovery Factor, %	16.9	40.7	25.2
Original Recoverable, Mbbl	7,188	9,150	16,338
Cumulative Production, Mbbl	4,665	7,308	11,973
Remaining Recoverable, Mbbl	2,523	1,841	4,365
Total 1C Well Requirements			
Production Wells Required	33	29	62
Existing Wells Returned to Production	16	23	39
New Producers	17	6	23
Water Injectors Required	16	-	16
New Water Injectors	4	-	4
Average Well Productivity, bopd/w	10	8	9
Total Pool Productivity, bopd	315	233	548
Remaining Res per Prod. Well, Mbbl	14	6	10
Resource Life Index, years	4	2	3
Total 2C Well Requirements			
Production Wells Required	50	42	92
Existing Wells Returned to Production	26	27	53
New Producers	24	15	39
Water Injectors Required	32	8	40
New Water Injectors	6	-	6
Average Well Productivity, bopd/w	15	11	13
Total Pool Productivity, bopd	750	453	1,203
Remaining Res per Prod. Well, Mbbl	31	16	24
Resource Life Index, years	6	4	5
Total 3C Well Requirements			
Production Wells Required	60	67	127
Existing Wells Returned to Production	34	42	76
New Producers	26	25	51
Water Injectors Required	38	14	52
New Water Injectors	8	-	8
Average Well Productivity, bopd/w	20	13	16
Total Pool Productivity, bopd	1,200	841	2,041
Remaining Res per Prod. Well, Mbbl	42	27	34
Resource Life Index, years	6	6	6

Kampung Minyak Field - Indonesia
Summary of Prospective Resource Estimates - Property Gross Values
as of December 31, 2015

Prospective Resources - Crude Oil

Lead/Prospect	Zone	Prospective Resources - Unrisked (1) (2) (3) (4) Low Mbbl	Best Est. Mbbl	Mean Mbbl	High Mbbl	Risked Resources Chance of Mean Mbbl	Discovery %
KM Deep	S8	172	809	1,428	3,325	685	48
KM Deep	S9	266	1,530	3,209	7,870	963	30
KM Deep	S10	1,007	3,607	5,523	12,342	2,209	40
KM Deep	S11	193	907	1,527	3,505	458	30
KM Deep	S12	404	1,979	3,779	8,976	1,512	40
KM Deep	S13	367	1,785	3,084	7,224	1,234	40
KM Deep	Talang Akar	601	2,278	3,715	8,538	557	15
KM Deep	**Crude Oil Total**	**10,735**	**19,927**	**22,264**	**36,163**	**7,618**	

Prospective Resources - Natural Gas

Lead/Prospect	Zone	Prospective Resources - Unrisked (1) (2) (3) (4) Low MMcf	Best Est. MMcf	Mean MMcf	High MMcf	Risked Resources Mean MMcf	Chance of Discovery %
KM Deep	S8	31	148	264	614	127	48
KM Deep	S9	52	305	672	1,646	202	30
KM Deep	S10	242	900	1,404	3,194	562	40
KM Deep	S11	60	284	495	1,159	148	30
KM Deep	S12	138	702	1,347	3,164	539	40
KM Deep	S13	164	798	1,423	3,330	569	40
KM Deep	Talang Akar	5,697	19,385	29,478	65,063	4,422	15
KM Deep	**Natural Gas Total**	**10,588**	**25,171**	**35,083**	**71,197**	**6,568**	

(1) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be economically viable or technically feasible to produce any portion of the resources.

(2) These are partially risked prospective resources that have been risked for chance of discovery, but have not been risked for chance of development.

(3) Individual zone estimates statistically aggregated to the prospect/lead level.

(4) Natural gas prospective resources for the S8 to S13 are unlikley to be commercial if discovered

Block D - Cambodia
Summary of Prospective Resource Estimates - Property Gross Values
As of December 31, 2015

Prospective Resources - Crude Oil

Lead/Prospect	Zone	Prospective Resources - Unrisked (1) (2) (3) (4) Low Mbbl	Best Est. Mbbl	Mean Mbbl	High Mbbl	Risked Resources Mean Mbbl	Chance of Discovery %
CAM-S1	SQ2	3,002	9,546	13,141	30,356	3,579	27
CAM-S1	SQ3	4,305	13,405	18,213	41,736	4,578	25
CAM-S1	**Total**	**11,760**	**27,104**	**31,354**	**59,268**	**8,157**	
CAM-S2	SQ2	1,274	8,048	18,498	50,834	4,102	22
CAM-S2	SQ3	1,813	11,301	25,637	70,447	5,168	20
CAM-S2	**Total**	**7,112**	**26,761**	**44,135**	**107,083**	**9,271**	
CAM-S3	SQ2	5,478	30,029	61,140	164,600	11,504	19
CAM-S3	SQ3	7,803	42,165	84,737	227,855	14,615	17
CAM-S3	Pre-Tertiary (oil case)	5,348	24,805	45,163	115,044	2,195	5
CAM-S3	**Total**	**77,252**	**170,948**	**191,040**	**420,488**	**28,315**	
CAM-S4	SQ2	2,066	11,325	23,059	62,078	1,992	9
CAM-S4	SQ3	2,943	15,902	31,958	85,934	2,485	8
CAM-S4	Pre-Tertiary (oil case)	857	4,117	7,717	19,779	243	3
CAM-S4	**Total**	**19,737**	**49,356**	**62,734**	**139,567**	**4,720**	
CAM-S5	SQ2	2,380	9,707	15,737	39,595	3,263	21
CAM-S5	SQ3	3,400	13,630	21,811	54,646	4,146	19
CAM-S5	**Total**	**10,766**	**29,436**	**37,548**	**79,035**	**7,409**	
	Crude Oil Total	**126,628**	**303,605**	**366,811**	**805,441**	**57,871**	

Prospective Resources - Natural Gas

Lead/Prospect	Zone	Prospective Resources - Unrisked (1) (2) (3) (4) Low MMcf	Best Est. MMcf	Mean MMcf	High MMcf	Risked Resources Mean MMcf	Chance of Discovery %
CAM-S3	Pre-Tertiary (gas case)	16,521	73,104	129,579	323,478	6,298	5
CAM-S3	**Total**	**16,521**	**73,104**	**129,579**	**323,478**	**6,298**	
CAM-S4	Pre-Tertiary (gas case)	2,645	12,134	22,141	55,676	697	3
CAM-S4	**Total**	**2,645**	**12,134**	**22,141**	**55,676**	**697**	
	Natural Gas Total	**19,166**	**85,239**	**151,721**	**379,154**	**6,995**	

(1) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be economically viable or technically feasible to produce any portion of the resources.

(2) These are partially risked prospective resources that have been risked for chance of discovery, but have not been risked for chance of development.

(3) Individual zone estimates statistically aggregated to the prospect/lead level.

(4) The CAM-S3 and S4 prospects contain a Pre-Tertiary zone which could be either crude oil (with no free gas) or natural gas (with no oil rim).

The unrisked crude oil resources assume the zone contains only oil and the unrisked natural gas resources assume the zone contains only gas which means on an unrisked basis the prospective resources are mutually exclusive. This is accounted for though in the risked estimates which include the chance of the prospect being oil or gas filled.