13th February 2014

The Directors
African Petroleum Corporation Ltd
Stratton House
5 Stratton Street
London
W1J 8LA

Dear Sirs

Re: Review of Exploration Acreage: African Petroleum Corporation Ltd

Introduction

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has reviewed the prospectivity of the petroleum exploration interests of African Petroleum Corporation Limited and its associated companies ("APCL"), in Blocks 8 & 9 offshore Liberia, Licences CI-509 and CI-513, offshore Cote d'Ivoire and Block SL-03, offshore Sierra Leone, and we have prepared estimates as of today's date of the prospective petroleum resources associated with the following high-graded prospects: Narina West, Barbet, Sunbird, Lovebird, Wildbird and Night Heron in Liberia, the Ayame, Ayame West, Sassandra, Agnéby and Cavalla prospects in Cote d'Ivoire and the Altair prospect in Sierra Leone. We have used information and data available up to 31st December 2013. No reserves are attributable to APCL in any of the properties assessed.

For the prospective resources we have included an assessment of the geological chance of success. This dimension of risk does not incorporate the consideration of economic uncertainty and commerciality. In presenting prospective resources, ERCE assumes that the Operator of licences in which such prospective resources exist will behave in a competent manner, and execute any work programme designed to test such prospective resources in a timely and safe manner during the term specified for the licence.

We have carried out this work using the March 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Appendix 1.

This letter is for the sole use of APCL and financial advisors. It may not be disclosed to any other person or used for any other purpose without the prior written approval of a director of "ERCE".

The Licence Terms and Summary Results for Licences where Prospective Resources are Attributable

Liberia

APCL holds a 100% contractor interest in a Production Sharing Contract ("PSC") covering Blocks 8 & 9 offshore Liberia. Both blocks are in their second exploration period, which began on 12th June 2012. In January 2014, the Board of Directors of the National Oil Company of Liberia (NOCAL) approved a two year extension to the second exploration period for both Block 8 and Block 9 until 11 June 2016. There are currently no exploration drilling commitments on either block within this second period. APCL is working with NOCAL to implement a work program which includes additional 3D seismic acquisition on both Block 8 and 9. At the end of this second phase, a further 25% of each licence must be relinquished.

There are no further exploration drilling commitments in Block 9 for the duration of the remaining exploration periods. Well Apalis-1, Narina-1 and BeeEater-1 have fulfilled all exploration drilling commitments for Block 9. On Block 8, all exploration drilling commitments have been moved to the third period, which includes three exploration wells (to a minimum depth of 2,000m). At the end of the third period all areas not retained for appraisal and development are to be relinquished. There are also provisions for an appraisal period and an exploitation period of 25 years (with an additional term of 10 years if necessary) for each development area.

Our independent Best Estimate (P50) of prospective oil resources for the six prospects we have assessed (Table 1) in aggregate is 2,013 MMstb unrisked, net attributable to APCL is 1,953 MMstb unrisked and 307 MMstb risked. Our independent Mean estimate of prospective oil resources for the six prospects in aggregate is 3,339 MMstb unrisked, net is 3,230 MMstb unrisked and 496 MMstb net risked.

Cote D'Ivoire

APCL holds a 90% contractor interest in PSCs covering Blocks CI-509 and CI-513 offshore Cote D'Ivoire. Petroci has the remaining 10% as a carried interest. The licences were awarded on 16th March 2012 and 19th December 2011 for CI-509 and CI-513 respectively. For CI-509 the licence consists of three terms of three, three and two years respectively, with a 25% relinquishment after each of the first and second terms. For CI-513 the licence consists of three exploration terms of three, two and two years respectively, with a 25% relinquishment after each of the first and second terms.

The commitment, during the first period of licence CI-509 is to purchase existing 2D seismic, acquire 1,091 km^2 3D seismic data, perform geological and geophysical studies and drill one exploration well to a depth of 100 m into the Albian, with a minimum financial commitment of US $60 MM. The seismic commitment has already been met. The commitment, during the first period of licence CI-513 is to purchase existing 2D seismic data, acquire 1446 km^2 3D data, perform geological and geophysical studies and drill one exploration well to a depth of 100 m into the Albian, with a minimum financial commitment of US $60 MM. The seismic commitment has already been met.

Our independent Best Estimate (P50) of prospective oil resources for the five reviewed prospects (Table 2) in aggregate is 999 MMstb unrisked, net attributable to APCL is 863 MMstb unrisked and 116.4

MMstb net risked. Our independent Mean estimate of prospective oil resources for the prospects in aggregate is 1808 MMstb unrisked, net is 1560 MMstb unrisked and 209.4 MMstb net risked.

Sierra Leone

APCL holds a 100% contractor interest in a PSC covering Block SL-03, offshore Sierra Leone, through its wholly owned subsidiary European Hydrocarbons Ltd. The licence was ratified by the government on 22nd February 2011. The licence has a duration of 30 years, the first seven of which are termed the exploration period, which is further subdivided into an initial period of three years, followed by two extension periods of two years each. APCL was recently awarded a two year extension to the initial exploration period, which now expires on 23rd April 2015.

Work commitments during the initial period (and extension phase) for Block SL-03 are to purchase and interpret the existing 2D seismic data over the licence and acquire a minimum of 500 km^2 of 3D seismic data. APCL has purchased the 2D seismic data and has acquired 2535 km^2 of multi-client 3D seismic data over Block SL-03, fulfilling the seismic commitment for the initial phase. The first and second extension periods require the drilling of one exploration well to a minimum depth (below mud line) of 1300 m, or a minimum equivalent investment of US$ 30 MM. Entry to the first extension period requires a 50% relinquishment of the licence area, and a further 25% of the initial licence area must be relinquished on entry to the second extension period. The area of the licence is 3860 km^2, and water depth varies from 100 m to over 4000 m, with the south-western half of the block being at water depths greater than 3000 m.

Our independent Best Estimate (P50) of prospective oil resources for the Altair prospect in Block SL-03 (Table 3) is 278 MMstb (gross and net) unrisked and 50.4 MMstb net risked. Our independent Mean estimate of prospective oil resources for the prospect is 434 MMstb (gross and net) unrisked and 78.8 MMstb net risked.

Work Done

In carrying out our evaluation of the interests, we have relied upon information provided by APCL which comprised details of APCL's licence interests, offset well data and associated analysis, seismic data including interpretation, basic exploration data, technical reports and volumetric estimates, where appropriate.

Our approach has been to commence our investigations with the most recent technical reports and interpreted data. From these we have been able to identify those items of basic data which require re-assessment. Where only basic data have been available or where previous interpretations of data have been considered incomplete, we have undertaken our own interpretation. A site visit was not undertaken.

In estimating petroleum in place and recoverable, we have used the standard techniques of prospect analysis. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. We have estimated the degree of this uncertainty and have used statistical methods to calculate the range of petroleum initially in place and recoverable.

We have estimated the chance of success for drilling the identified exploration prospects, using the industry standard approach of assessing the likelihood of source rock, charge, reservoir trap and seal. The result is the chance or probability of discovering hydrocarbons in sufficient quantity and which test at a sufficient rate to permit consideration for subsequent appraisal and development.

The nomenclature used in this report is presented in Appendix 2.

Professional Qualifications

ERC Equipoise is an independent consultancy specialising in petroleum reservoir evaluation. Except for the provision of professional services on a fee basis, ERC Equipoise has no commercial arrangement with any other person or company involved in the interests that are the subject of this report.

The work has been supervised by Dr Adam Law, Geoscience Director of ERCE, a post-graduate in Geology, a Fellow of the Geological Society and a member of the Society of Petroleum Evaluation Engineers (number 726). He has 19 years relevant experience in the evaluation of oil and gas fields and exploration acreage, preparation of development plans and assessment of reserves and resources.

Yours faithfully

ERC Equipoise Limited

Adam Law

Geoscience Director

Table 1 STOIIP and Prospective Oil Resources, Liberia Blocks 8 and 9

Prospect	Reservoir	STOIIP				Unrisked Prospective Resource				APCL Interest	Net Unrisked Prospective Resource				Prospect Risk	Play Risk	COS (%)	Net Risked Prospective Resource			
		Low (Mmstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	Low (Mmstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	(%)	Low (Mmstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)	(%)	(%)		Low (Mmstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
Barbet	Turonian	166	500	1,479	718	60	186	558	270	100	60	186	558	270	22	1	22	13	41	123	59
Sunbird	Campanian	177	461	1,187	609	63	172	448	229	100	63	172	448	229	27	1	27	17	46	122	62
	Turonian	107	307	863	429	39	115	327	162	100	39	115	327	162	19	1	19	7	22	62	31
	Cenomanian	91	264	779	376	33	99	294	141	100	33	99	294	141	18	1	18	6	18	53	25
Lovebird (Isopach)	Blue Horizon	68	293	1,218	536	25	109	456	201	100	25	109	456	201	20	1	20	5	22	91	40
	Pink Horizon	59	262	1,066	474	22	96	400	178	100	22	96	1,070	178	20	1	20	4	19	214	36
	Green Horizon	48	210	896	399	18	78	337	150	100	18	78	337	150	20	1	20	4	16	67	30
Night Heron	Turonian	254	1,117	4,603	1,904	92	416	1,742	759	100	87	356	1,338	650	14	1	14	12	50	187	91
Narina West	Turonian	144	372	963	490	52	138	364	184	100	52	138	364	184	16	1	16	8	22	58	29
Wildbird	Light Blue Horizon	552	2,289	8,700	3,946	144	605	2,377	1,065	100	144	605	2,377	1,065	38	24	9	13	54	214	96
TOTAL		**1,666**	**6,076**	**21,754**	**9,882**	**549**	**2,013**	**7,304**	**3,339**		**544**	**1,953**	**7,569**	**3,230**				**90**	**310**	**1,192**	**499**

Table 2 STOIIP and Prospective Oil Resources – Cote D'Ivoire

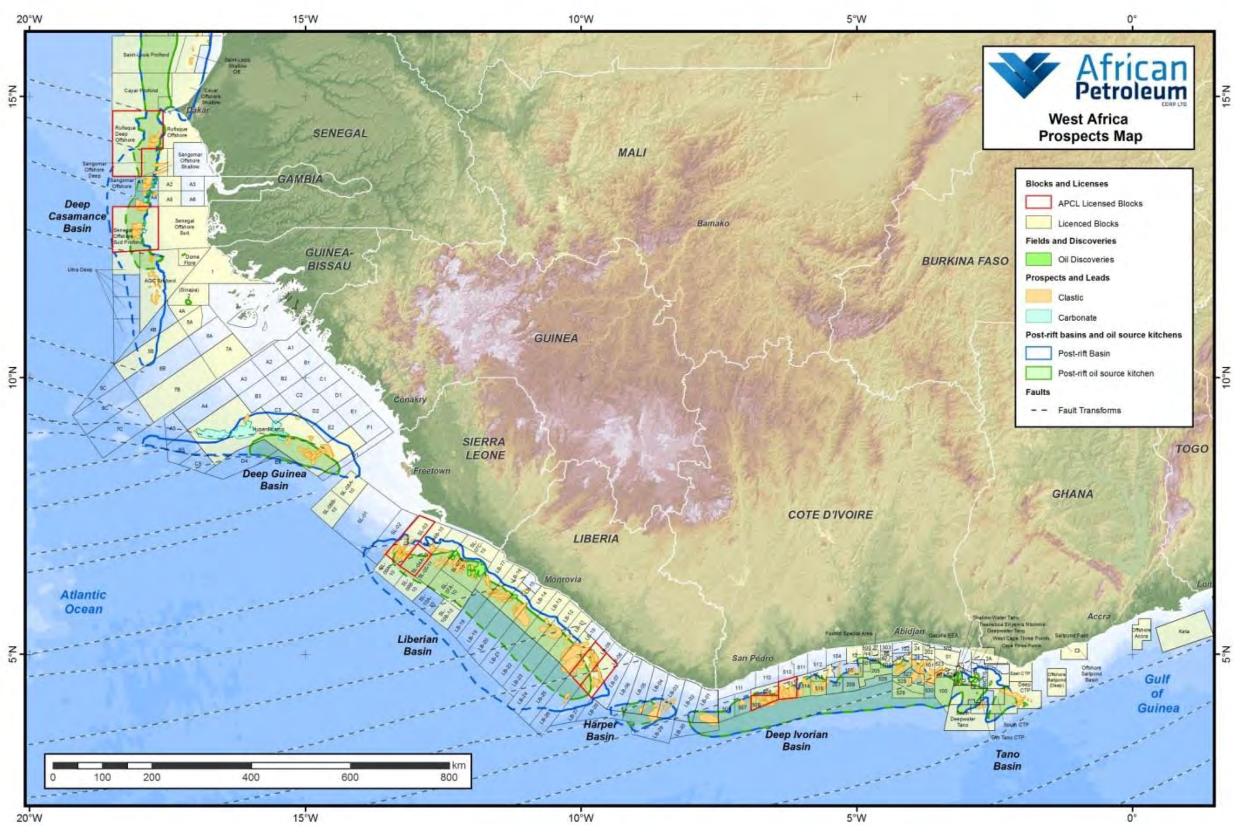
Prospect	Reservoir	STOIIP			Unrisked Prospective Resource				Interest (%)	Net Unrisked Prospective Resource				Play Risk (%)	Prospect Risk (%)	COS (%)	Net Risked Prospective Resource			
		Low (MMstb)	Best (MMstb)	High (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)		Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)				Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
Ayame	Upper Cretaceous	179	815	3,474	65	302	1,318	569	90	58	267	1,138	502	49	28	14	8.0	36.3	154.9	68.3
Ayame West	Upper Cretaceous	161	585	2,085	58	216	788	352	90	52	183	626	298	49	28	14	7.1	24.9	85.2	40.6
Sassandra	Upper Cretaceous	71	320	1,408	26	118	521	237	90	23	87	300	175	49	20	10	2.2	8.3	28.6	16.6
Cavalla	Upper Cretaceous	67	281	1,142	25	104	431	190	90	22	93	388	171	49	20	10	2.1	8.9	37.0	16.3
Agnéby	Upper Cretaceous	252	997	3,682	55	258	1,039	460	90	50	232	935	414	49	34	16	8.2	38.0	152.7	67.6
TOTAL		**731**	**2,998**	**11,792**	**229**	**999**	**4,097**	**1,808**		**206**	**863**	**3,387**	**1,560**				**27.5**	**116.4**	**458.3**	**209.4**

Table 3 STOIIP and Prospective Oil Resources - Sierra Leone

Prospect	Reservoir	STOIIP			Unrisked Prospective Resource				Interest (%)	Net Unrisked Prospective Resource				Play Risk (%)	Prospect Risk (%)	COS (%)	Net Risked Prospective Resource			
		Low (MMstb)	Best (MMstb)	High (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)		Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)				Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
Altair	Upper Cretaceous	218	755	2,473	79	278	938	434	100	79	278	938	434	65	28	18	14.4	50.4	170.2	78.8

Competent Person's Report:

African Petroleum Corporation Limited



PREPARED FOR: African Petroleum Corporation Limited

BY: ERC Equipoise Limited

February 2014

Authors: Adam Law, Michael Braim, Glyn Pugh, Kate Overy, Don Munn

Approved by: Adam Law

Date released to client: 13th February 2014

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1. Introduction

At the time of writing, African Petroleum Corporation Limited (APCL) holds interests in and operates exploration licences offshore West Africa, within the territorial waters of Senegal, Sierra Leone, Liberia and Cote d'Ivoire (Figure 1.1). The status of these licences is summarised in Table 1.1 below. ERC Equipoise Ltd (ERCE) has reviewed the prospectivity of these licences, using data as of 31st December 2013.

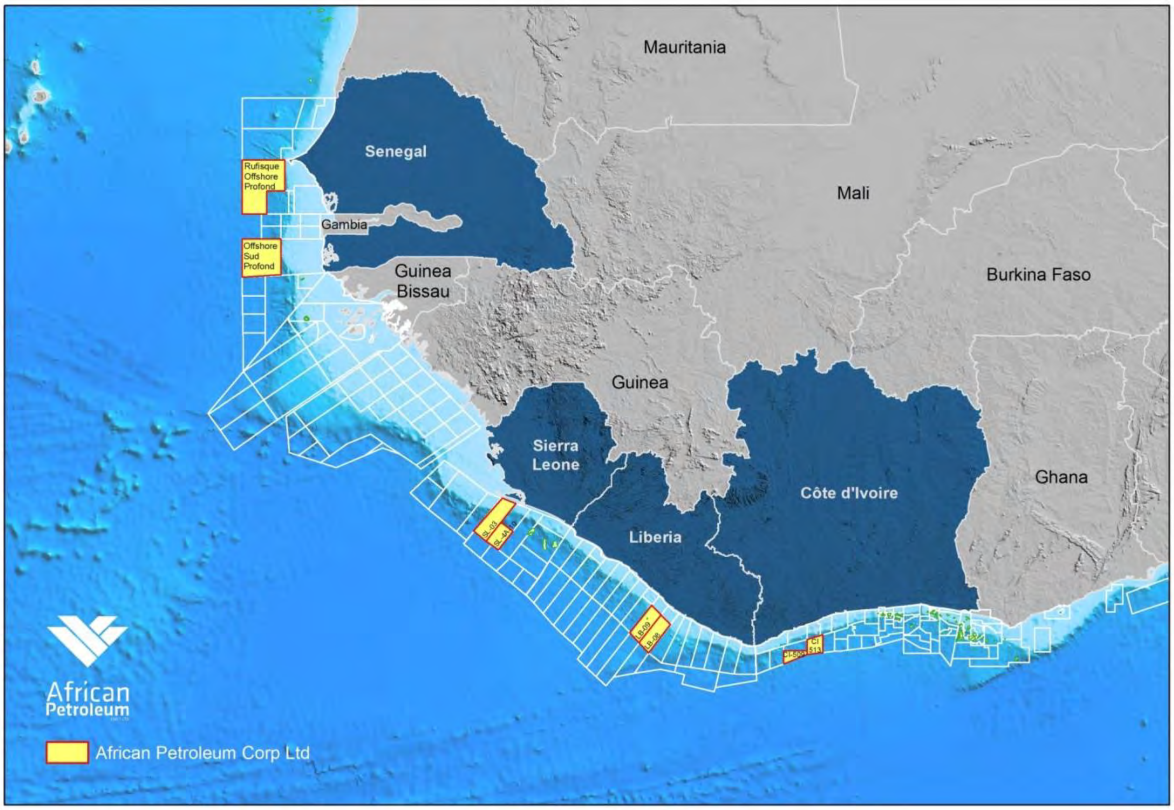

Figure 1.1 Location of APCL licences, West Africa

Currently, prospective resources are identified by APCL within the Liberia, Sierra Leone and Cote d'Ivoire licences. We have made independent estimates of prospective resources and geological chance of success for certain prospects within these countries, which are identified by APCL as near-term drilling opportunities. The evaluation of the offshore Senegal licences is on-going, and no prospects have been identified as of the date of this report. We summarise qualitatively the prospectivity of the licences held by APCL in this country. No reserves are attributable to APCL in any of the properties examined. A site visit was not undertaken.

Country	Block/ Licence	Operator	APCL (%)	Status	Licence		Area (km^2)	Outstanding Commitment in this Phase
					Start of Current Phase	End of Current Phase		
Liberia	8	APCL	100%	Expl	June 2012	June 2016	2717	None[3]
Liberia	9	APCL	100%	Expl	June 2012	June 2016	2634	None
Senegal	Rufisque Offshore Profond	APCL	81%[2]	Expl	Oct 2011	Oct 2015	10357	One exploration well
Senegal	Senegal Offshore Sud Profond	APCL	81%[2]	Expl	Oct 2011	Oct 2014	7920	None
Sierra Leone	SL-03	APCL	100%	Expl	Feb 2011	April 2015	3860	Further geoscience work
Sierra Leone	SL-04A	APCL	100%	Expl	Sept 2012	Sept 2015	1995	One exploration well [1]
Cote d'Ivoire	CI-509	APCL	90%	Expl	March 2012	March 2015	1091	One exploration well
Cote d'Ivoire	CI-513	APCL	90%	Expl	Dec 2011	Dec 2014	1446	One exploration well

1) Contingent on results of 3D and that technology is available to drill in such water depths
2) African Petroleum Senegal Ltd (APSL) holds 90% contractor interest. APCL ownership in APSL results in net 81% interest to APCL
3) Commitments now moved to third exploration period

Table 1.1 Licence summary table

1.1. Liberia: PSC Overview

APCL holds a 100% contractor interest in a Production Sharing Contract ("PSC") covering Blocks 8 & 9 offshore Liberia (Figure 1.2). Both blocks are in their second exploration period, which began on 12th June 2012 and lasts for two years. In January 2014, the Board of Directors of the National Oil Company of Liberia (NOCAL) approved a two year extension to the second exploration period for both Block 8 and Block 9 until 11 June 2016. There are currently no exploration drilling commitments on either block within this second period. APCL is working with NOCAL to implement a work program which includes additional 3D seismic acquisition on both Block 8 and 9. At the end of this second phase, a further 25% of each licence must be relinquished.

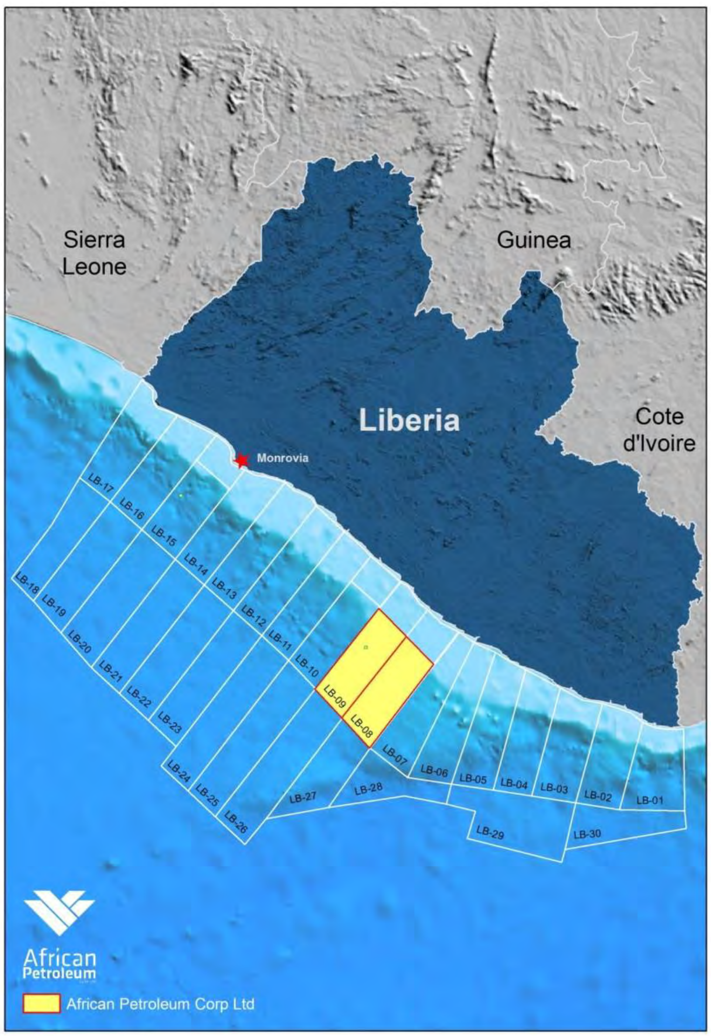

Figure 1.2 Location of Liberia Blocks 8 and 9

There are no further exploration drilling commitments in Block 9 for the duration of the remaining exploration periods. Well Apalis-1, Narina-1 and BeeEater-1 have fulfilled all exploration drilling commitments for Block 9. On Block 8, all exploration drilling commitments have been moved to the third period, which includes three exploration wells (to a minimum depth of 2,000m). At the end of the third period all areas not retained for appraisal and development are to be relinquished. There are also provisions for an appraisal period and an exploitation period of 25 years (with an additional term of 10 years if necessary) for each development area.

Following a 25% relinquishment at the end of the first exploration phase, Block 8 comprises an area of 2717 km^2, and Block 9 comprises 2634 km^2. Water depths range from less than 100 m to over 3000 m. Most of the block areas lie in water depths greater than 500 m.

1.2. Senegal: PSC Review

African Petroleum Senegal Ltd (APSL) holds a 90% contractor interest in Exploration and Production Sharing Contracts (EPSC) covering Blocks Rufisque Offshore Profond (ROP) and Senegal Offshore Sud Profonde (SOSP), offshore Senegal, (Figure 1.3). Petrosen, the state oil company, hold a 10% carried interest. APCL's equity interest in APSL results in a net 81% interest to APCL.

The EPSC governing block SOSP has an effective date of 25th October 2011. The first 8.5 years of the EPSC are termed the exploration phase, which is subdivided into an initial period of three years, with two subsequent extension periods of three and two and a half years each. Work commitment in the initial exploration period is to acquire and reprocess the existing seismic data within the licence area, and also to acquire a further 2500 km^2 of 3D seismic data, all with a minimum investment of US$ 10 MM. The two extension periods have a commitment of one exploration well to a minimum depth of 3500 m in each period, or a minimum investment of US$ 20 MM. Entry to the first extension period requires a 30% relinquishment of the licence area, and a further 20% of the initial licence area must be relinquished on entry to the third phase. The area of the licence is currently 7920 km^2. Water depth is between 1000 and 4000 m over the block.

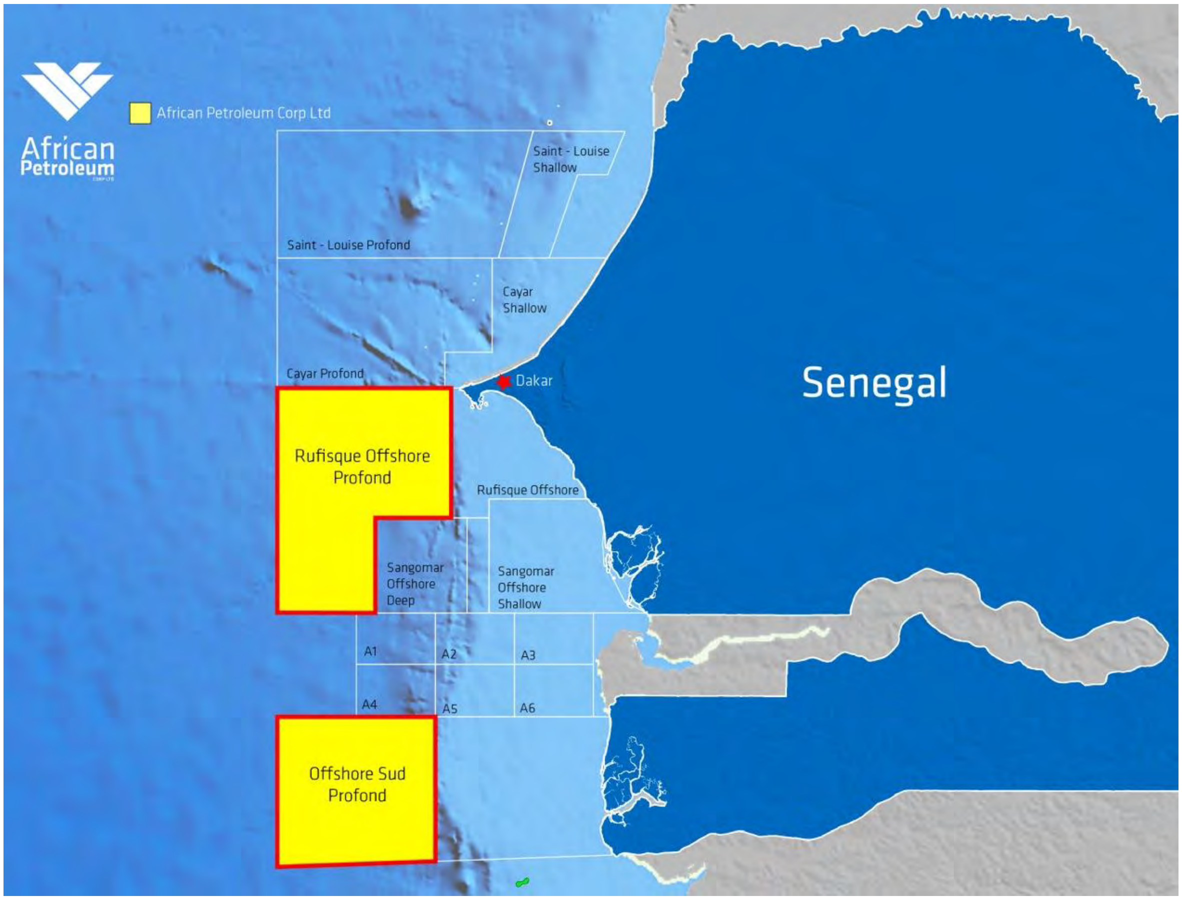

Figure 1.3 Location of Senegal ROP and SOSP Licences

The EPSC governing Block ROP is of similar structure to that governing Block SOSP. It has an effective date of 25th October 2011. The first eight years of the EPSC are termed the exploration phase, which is subdivided into an initial period of four years, with two subsequent extension periods of two years each. Work commitment in the initial exploration period is to acquire the existing seismic data within the licence area for a minimum of US$ 2 MM, and drill one exploration well to a minimum depth of 3500 m TVDSS or a minimum investment of US$ 20 MM. The two extension periods have a further commitment of one exploration well to a minimum depth of 3500 m TVDSS in each period, or a minimum investment of US$ 20 MM. Entry to the first extension period requires a 30% relinquishment of the licence area, and a further 20% of the initial licence area must be relinquished on entry to the third period. The area of the licence is currently 10357 km^2. Water depth is between 1500 and 3000 m over the block.

APCL has met the seismic commitment of the first exploration period.

Petrosen has a back-in right if an exploitation period is authorised for up to 20% of the licence, subject to contribution of its share of forward costs (excluding training). The duration of an exploitation period is 25 years from authorisation, with option for two ten year extensions at the discretion of the state.

1.3. Sierra Leone: PSC Review

APCL holds a 100% contractor interest in a PSC covering Block SL-03, offshore Sierra Leone, (Figure 1.4) through its wholly owned subsidiary European Hydrocarbons Ltd. The licence was awarded on 23rd April 2010 and ratified on 22nd February 2011. APCL also holds a 100% contractor interest in a PSC covering Block SL-04A, through its wholly owned subsidiary African Petroleum Sierra Leone Ltd. The PSC governing Block SL-04A was ratified on 21st September 2012.

The SL-03 licence has a duration of thirty years, the first seven of which are termed the exploration period, which is further subdivided into an initial period of three years, followed by two extension periods of two years each. APCL were recently awarded a two year extension to the initial exploration period, which now expires on 23rd April 2015.

Work commitments during the initial period for Block SL-03 are to purchase and interpret the existing 2D seismic data over the licence and acquire a minimum of 500 km^2 of 3D seismic data. APCL has purchased the 2D seismic data and has acquired 2535 km^2 of multi-client 3D seismic data over Block SL-03, fulfilling the seismic commitment for the initial phase. An additional geoscience study programme is associated with the extension of the initial exploration phase.

The first and second extension periods require the drilling of one exploration well to a minimum depth (below mud line) of 1300 m, or a minimum equivalent investment of US$ 30 MM. Entry to the first extension period requires a 50% relinquishment of the licence area, and a further 25% of the initial licence area must be relinquished on entry to the second extension period. The area of the licence is 3860 km^2, and water depth varies from 100m to over 4000m, with the south-western half of the block being at water depths greater than 3000m.

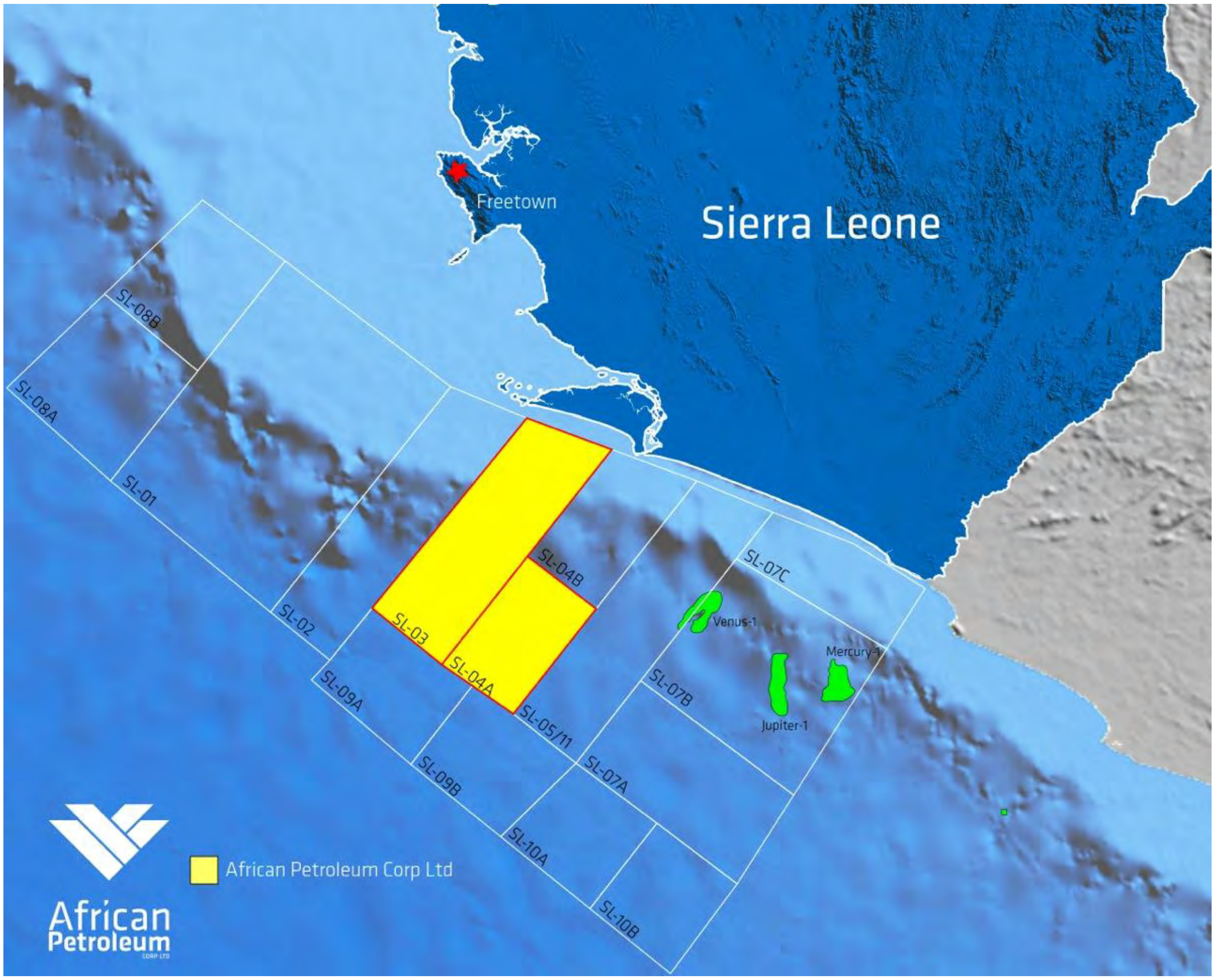

Figure 1.4 Location of Blocks SL-03 and SL-04A

The PSC covering Block SL-04A was ratified on 21st September 2012. The licence term is for thirty years, the first seven years of which are defined as the exploration period, which is further subdivided into an initial period of three years, and two subsequent periods of two years. Each well drilled in the initial exploration period extends this period by three months. Work commitments during the initial phase are to acquire at least 1500 km^2 of 3D seismic data, and drill one exploration well, (to a minimum depth of 2500m), contingent on the results of the 3D and the availability of drilling technology for such deep water. The minimum equivalent investment is US$ 10 MM. In 2011, TGS acquired 1085 km^2 of multi-client 3D seismic data over Block SL-04A. Upon licencing these data, APCL will have fulfilled the seismic commitment for the initial phase.

The subsequent two exploration periods require the drilling of one exploration well in each period, (to a minimum depth of 2500 m), or a minimum investment of US$ 50 MM. Entry to the second period requires a 50% relinquishment of the licence area, and a further 25% of the initial licence area must be relinquished on entry to the third phase. The area of the licence is currently 1995 km^2. Water depth is between 3000 and 4000 m over the block.

The state retains the right to a 10% carried interest during any development phase in both licences, with the option to acquire a further 5% by covering an equivalent proportion of any development costs.

1.4. Cote d'Ivoire: PSC Review

APCL holds a 90 per cent contractor interest in two PSCs governing Block CI-509 and Block CI-513, offshore Cote d'Ivoire, (Figure 1.5) via its wholly owned subsidiary African Petroleum Cote d'Ivoire Limited. The state oil company, Petroci, has a 10% carried interest.

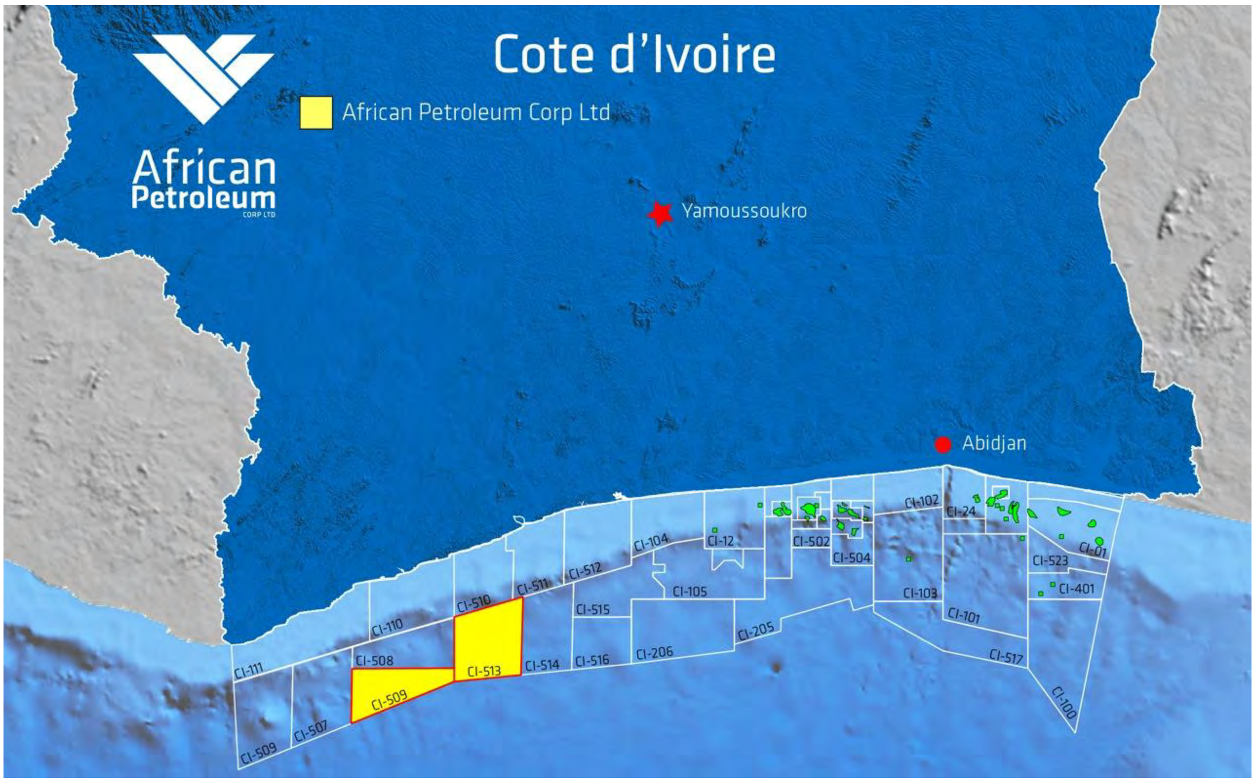

Figure 1.5 Location of Blocks CI-509 and CI-513

The PSC for Block CI-509 was awarded on 16th March 2012. The first eight years of the PSC are termed the exploration period, which is further divided into three terms of three, three and two years respectively. The licence is currently in its first exploration term. Work commitments during the first exploration term are to purchase the existing 2D seismic data, acquire 1091 km^2 (i.e. a block wide) 3D seismic survey and drill one exploration well at least 100 m into the Albian (Lower Cretaceous) section. The minimum investment is US$ 60 MM. The second and third terms have a further commitment to drill one exploration well to at least 100 m into the Albian (Lower Cretaceous) section, with a minimum investment of US$ 50 MM. Entry to the second term requires a 25% relinquishment of the licence area, and a further 25% of the initial licence area must be relinquished on entry to the third term. The area of the licence is currently 1091 km^2. Water depth is between 1900 and 3250 m over the block.

The PSC covering Block CI-513 has an effective date of 19th December 2011. It has a similar structure to that governing Block CI-509. The first seven years are termed the exploration period, subdivided into three terms of three, two and two years. The licence is currently in its first exploration term. Work commitments during the first exploration term are to purchase the existing 2D seismic data, acquire 1446 km^2 (i.e. a block wide) 3D seismic survey and drill one exploration well at least 100 m into the Albian (Lower Cretaceous) section. The minimum investment is US$ 60 MM. The second and third terms have a further commitment to drill one exploration well to at least 100 m into the Albian (Lower Cretaceous) section, with a minimum investment of US$ 50 MM. Entry to the second term requires a 25% relinquishment of the licence area, and a further 25% of the initial licence area must be relinquished on entry to the third term. The area under licence is currently 1446 km^2. Water depth is between 900 and 3100 m over the block.

The exploitation period of both licences is for 25 years, subject to successful award in the event of a commercial discovery. On development, Petroci has the right to acquire an interest of up to 20% in each licence, subject to payment of its portion of future costs.

In October 2012, APCL completed acquisition of 4200 km^2 of 3D seismic data covering blocks CI-508, CI-509 and CI-513, fulfilling the seismic work commitments of the first exploration phase of both PSCs. APCL is planning a two well drilling programme for the licences during 2014.

1.5. Evaluation Methodology: Prospective Resources

We have used probabilistic methods to evaluate selected prospects within Liberia Blocks 8 and 9, Sierra Leone Block SL-03 and Cote d'Ivoire Blocks CI-513 and CI-509. We classify the results of our simulation as Low, Best and High estimates of prospective resources following the Petroleum Resources Management System, or PRMS (Appendix 1). We have assigned geological chance of success to each of the prospects, using the methodology described below. Estimates are made for oil only, although we recognise that, due to the significant uncertainties in the available geological information, that there is a possibility of gas charge in all licences. We present a summary of input estimates, output STOIIP and gross resources, and geological chance of success as a resource summary sheet for each prospective interval investigated.

Inputs to our probabilistic simulation are evaluated in a consistent manner. For the structurally trapped prospective intervals in Liberia, (the Lovebird and Wildbird prospects), we have made a low and high deterministic estimate of closing contour for each trap, to reflect the uncertainty in both mapping and depth conversion. For Liberia we use the gross-rock volume (GRV) derived in this manner to constrain the P90 and P10 of our GRV distribution in our probabilistic simulation.

For the stratigraphically trapped prospects in Liberia (Narina West, Barbet, Night Heron and Sunbird), Cote d'Ivoire, (Sassandra, Ayame, Ayame West, Cavalla and Agnéby), and Sierra Leone, (Altair), we have made low and high estimates of area of closure, using both structural and amplitude support where possible. We have then made low and high estimates of gross reservoir thickness, derived from regional observations, calibrated against seismic data where possible. As such depositional systems also have laterally variable sand distributions, often supported by seismic data, we employ the concept of an areal net to gross ratio, varying the percentage of sand areally within the overall stratigraphic trap based on the uncertainty in seismic amplitude strength. Where appropriate, a geological shape factor is used, depending on trap shape and structural relief relative to reservoir thickness.

Estimates of reservoir porosity and net to gross ratio are made with reference to regional data, offset wells, including recent drilling by APCL in Liberia, and account for compaction and a degree of overpressure (Figure 2.4). We make low, mid and high deterministic estimates, and use these to constrain the P90, P50 and P10 inputs to a probabilistic simulation. Inputs for hydrocarbon saturation are constrained in a similar manner, with reference to regional porosity and permeability trends, calibrated to APCL's recent drilling results in Liberia.

We have estimated oil formation volume factors for a range of gas oil ratios (GOR) (from an appropriate minimum to fully saturated) for each of the prospective intervals, assuming 4^{o}C at the mudline (seabed) and geothermal gradients between 2.5 and 3.5^{o}C per 100 m, consistent with regional observation and the available well data. We assume that the minimum GOR will increase with depth below the mudline. Our estimates are calibrated against the oil samples in Well Narina-1 when estimating resources for the Liberian prospects.

Some degree of overpressure is accounted for, as it has been in our estimates of porosity, but, by reference to offset discoveries, we assume that it is unlikely to exceed 500 psi over the depth range investigated.

Recovery factors for the clastic reservoirs are estimated with reference to published information from discoveries in similar reservoir types, examples of which are tabulated below (Table 1.2). Based on this table, we estimate low, best and high recovery factors of 30%, 37.5% and 45% respectively. Again, these are used to constrain the P90, P50 and P10 of our input distribution during probabilistic simulation.

Some prospects are deep relative to mud line, and we expect reservoir quality to be reduced, despite overpressure. We reduce our recovery factor estimates accordingly where this is the case. Some prospects are relatively shallow to mud line. Where this is the case, we model a more viscous oil, (prospects materially less than 1500m below sea bed), and have reduced our low, best and high recovery factor range to 15%, 27.5% and 40% respectively. In all cases we assume that a development is able to effectively dispose of any associated gas.

Recovery factors for the carbonate reservoirs of the Wildbird prospect in Liberia are estimated by reference to more regional analogues, and are discussed in the relevant sections.

Country	Field	Start Date	Max Water Depth (m)	Ult Recovery (MMstb)	Rec Factor	Recovery / Prod (MMstb)	STOIIP (MMstb)
Eq Guinea	Ceiba	Nov-00	800	187	40%	10	468
Eq Guinea	Zafiro	Aug-96	850	1583	40%	26	4008
Angola	Girassol	Dec-01	1360	958	45%	30	2129
Angola	Kuito	Dec-99	410	650	46%	18	1413
Brasil	Espadarte	Aug-00	877	261	31%	26	842
Brasil	Marlim	Mar-91	853	2878	33%	28	8721
UK	Schiehallion	Jul-98	375	765	57%	17	1342
USA	Auger	Apr-94	873	384	76%	13	505
USA	Mars	Jul-96	1014	954	25%	34	3816
USA	Troika	Jan-98	968	230	59%	23	390
USA	Ursa	Mar-99	1225	464	26%	33	1785
Total				9314			25418
Average - Arithmetic					**43%**	23	
Average - Weighted by STOIIP / Ult Rec					**37%**	24	

Table 1.2 Estimated oil recovery factors from producing Atlantic Margin fields

Due to the early stage of exploration within many of APCL's licences, we have adopted a six component risk matrix in all areas barring Liberia to estimate geological chance of success (COS), separated into play and prospect specific risks, (Table 1.3). We have adopted this form of presentation of COS to reflect the fact that deep water exploration in much of the West African Atlantic Margin is at a very early stage, and also that a number of the identified prospects have risk dependence, and thus can be grouped as a play.

PLAY RISK				PROSPECT RISK		
SOURCE	RESERVOIR	SEAL		TRAP*	CHARGE	RESERVOIR
(Presence and Maturity)	(Presence)	(Presence)		(Definition and Efficacy)	(Migration)	(Efficacy)

*Incorporates trap definition and seal risk (including biodegradation risk where necessary)

Table 1.3 Play and prospect risk system

The play risk segment focuses solely on the elements required in a given play to make a hypothetical prospect successful; source, reflecting the presence and thermal maturity of available source rocks, with sufficient generation and expulsion to charge prospects; reservoir, reflecting the presence regionally of geological intervals that could potentially contain reservoir rock, and seal – the regional presence of a sealing formation with sufficient thickness and extent to trap hydrocarbons.

Prospect risk is divided into three elements. Commonly, we present seal and trap risk combined as an overall illustration of the integrity of the container, here labelled trap risk. Charge risk reflects the risk to migration of hydrocarbons from the source rock into the prospect, and reservoir risk reflects solely the efficacy, (i.e. porosity and permeability), of any identified reservoir interval.

Note that a successful well on a given prospect may reduce or remove the play risk, should the well prove reservoir, charge and seal in a given play. This will have the effect of de-risking further prospects associated with that play.

Recent drilling within Liberia Blocks 8 and 9 has de-risked the play. As a result, we adopt prospect specific risking alone, as source, reservoir, trap and seal (Table 1.4).

PROSPECT RISK			
SOURCE	RESERVOIR	TRAP	SEAL
(Migration)	(Efficacy)	(Definition and Efficacy)	(Presence and Efficacy)

Table 1.4 Four component prospect risk matrix

Prospect risk is divided into four elements. Trap risk is defined as both definition and efficacy. Seal refers to the presence and efficacy of an identified seal, both top and side. Source risk reflects the risk to migration of hydrocarbons from the source rock into the prospect, and reservoir risk reflects solely the efficacy, (i.e. porosity and permeability), of any identified reservoir interval.

2. Liberia: Prospectivity and Plays

2.1. Introduction

All of the available deep-water acreage offshore Liberia-Sierra Leone basin is under licence (Figure 1.2). Regionally, hydrocarbons have been discovered within sandstones at a number of stratigraphic levels, from the pre-rift to early syn-rift Albian in Cote d'Ivoire, (Espoir, Foxtrot fields and a number of other discoveries), to turbiditic sandstones that have Late Cretaceous (Cenomanian/Turonian, Maastrichtian/Coniacian) to early Tertiary (Palaeocene to Eocene) ages. Recent drilling offshore Ghana has yielded a number of discoveries within these Upper Cretaceous sandstones, such as the Jubilee oil field, and the Enyenra, Tweneboa and Odum oil and gas/condensate discoveries. In the Liberia-Sierra Leone basin, recent drilling has yielded six hydrocarbon discoveries (Bee Eater, Narina, Monterrado, Mercury, Venus and Jupiter), but as yet, none has been declared commercial (Figure 2.1). Although reservoir quality in the Albian sandstones is variable, reservoir quality in the Upper Cretaceous and Tertiary sandstones is often good. Successful trap types encountered regionally are both structural and stratigraphic.

Of significance to the evaluation of the petroleum systems of Blocks 8 and 9, APCL has drilled three wells within the deeper water parts of the blocks: Wells Apalis-1, Narina-1 and Bee Eater-1. Well Apalis-1 found source rock intervals of Albian to Cenomanian age, but failed to find the prognosed reservoir. Well Narina-1 found light oil within deep-marine sandstones of Cretaceous age. The sandstones were of variable reservoir quality; the well appears to have been drilled on the edge of a fan system which can be interpreted from seismic data.

Well Bee Eater-1, completed in February 2013, also discovered hydrocarbons within similar sandstones of Cretaceous age. However, the oil bearing Turonian reservoir at Bee Eater is interpreted as being of very low permeability and hence non-commercial. APCL interprets that Well Bee Eater-1 was drilled in a canyon system that may have been largely bypassed by sediment input.

Both wells demonstrate the viability of Cretaceous petroleum systems within the licence area.

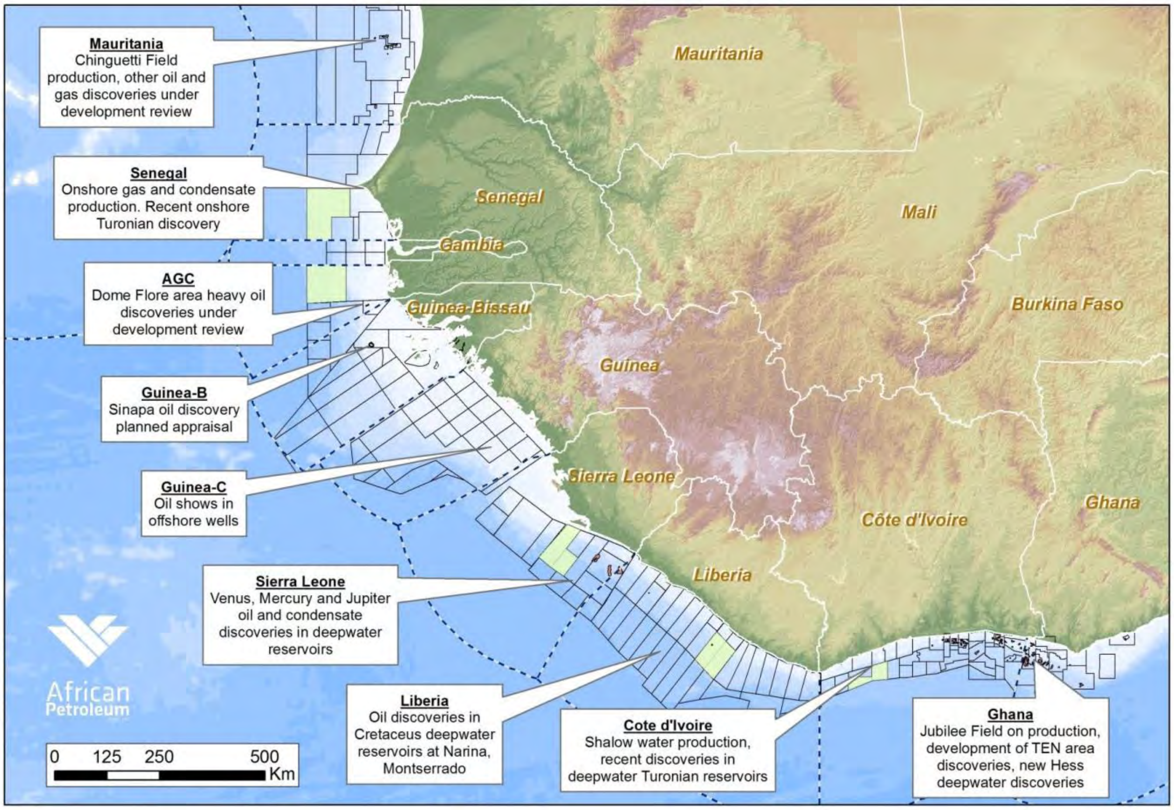

Figure 2.1 Notable discoveries, West Africa offshore

2.2. Well and Seismic Database

Exploration offshore Liberia is at an early stage. To date, five wells have been drilled in the deeper water areas in 2011 and 2012, with historical exploration drilling (up to 1985) restricted to the more shelfal areas (Figure 2.2). Data from two of these shallow water wells, Wells S/3-1 and Cestos-1, were made available to us for this evaluation. Well S/3-1 encountered oil shows in sandstones of Late Cretaceous age.

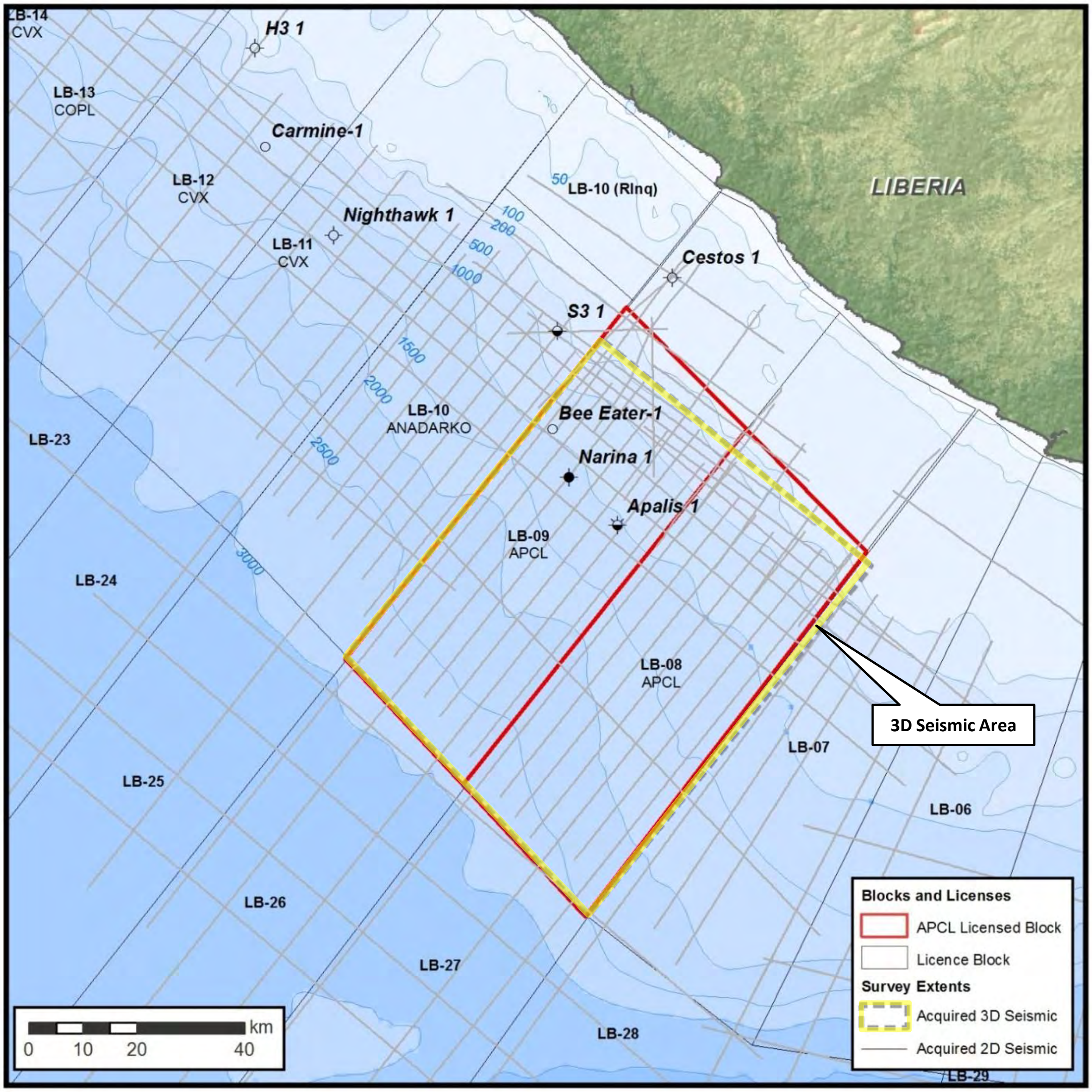

Figure 2.2 Well and seismic database, Liberia Blocks 8 and 9

APCL has drilled three exploration wells offshore Liberia in the deep water part of Block 9: Wells Narina-1, Bee Eater 1 and Apalis-1 (Figure 1.2, Figure 2.2). Well Apalis-1 was drilled in 2011, targeting a four-way dip-closed structure with possible AvO support. The well found traces of hydrocarbons, plus source rock intervals, but the prognosed reservoir sands were absent at target depth, and the well was plugged and abandoned.

Well Narina-1 was drilled by APCL in 2012, and found 16 to 21 m of net pay (light oil) within sandstones of Turonian (Cretaceous) age. Hydrocarbons were also discovered in the underlying Albian. Oil samples were collected, but no drill-stem testing was undertaken. Analysis of the oil samples indicates an API gravity for the Turonian oil of about 38 degrees, and about 45 degrees for the Albian hydrocarbons. Mobilities from formation pressure measurements and permeability from side-wall core measurements show the reservoir to be of relatively low permeability at this location.

Well Bee Eater-1 was drilled by APCL in January and February 2013. The well found oil-bearing sandstones of Cretaceous age, but of very low permeability and hence the well is considered non-commercial. Post-drill interpretation of the seismic data has helped APCL revise the depositional model for this Turonian fan system. The Bee Eater-1 well is interpreted to have encountered a bypass zone in both the Turonian and Cenomanian, with immature sandstones that are poorly sorted and tight. Post-well mapping of key seismic events, tied to Well Bee Eater-1, reveals the possibility of finding better quality sandstones in 'basin-floor fan' units down-dip. Potentially sealing shale units and source rock units were also found in the Bee-Eater-1 well.

Well Apalis-1 and in particular Wells Bee Eater-1 and Narina-1 help de-risk seal and hydrocarbon charge for the Cretaceous play on-block.

The primary seismic dataset for our evaluation was the recently acquired 5170 km^2 of 3D seismic data over the deeper water area of Blocks 8 and 9, including certain products to review amplitude versus offset (AvO) effects. These seismic data cover both recently drilled deep water wells. In addition, a grid of 2D seismic data was also made available, with average line spacing of around 4.5 km. These data provide a tie to Well S/3-1, although the well lies some 200 m from the nearest seismic line. In general, the data quality of the 3D volume is good, and of suitable fidelity to enable us to undertake our review of identified prospectivity. However, local complexity in the shallow geology causes the signal to degrade considerably at the prospective levels in certain areas, despite recent reprocessing efforts.

2.3. Plays and Petroleum Geology: Blocks 8 and 9

APCL has identified a number of plays within Blocks 8 and 9, at similar stratigraphic levels to those proven successful elsewhere along the West African margin (Figure 2.3). Recent drilling within Blocks 8 and 9 has demonstrated a working petroleum system within the mid to lower Cretaceous, with drilling finding light oil within deep marine sandstones of Turonian age, and also in sandstones of Albo-Aptian age.

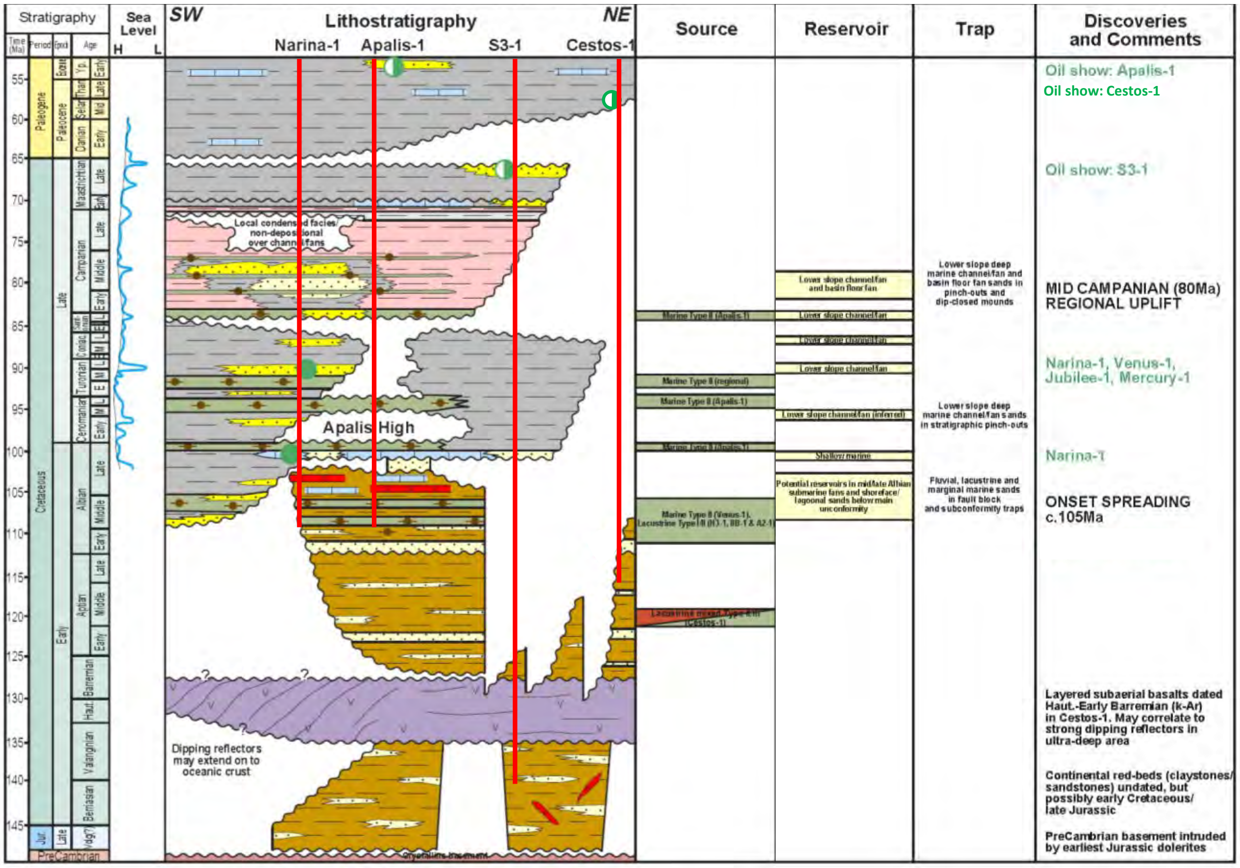

Figure 2.3 Petroleum systems and plays, Liberia Blocks 8 and 9

Structural traps are identified at the pre-rift to early syn-rift (Albian) level, as tilted fault blocks, with hydrocarbons sourced from the Albian or Lower Cretaceous source rocks, and seal provided by post-rift mud drape. Structural and stratigraphic traps are also identified at several potential reservoir levels within the Late Cretaceous and Lower Tertiary, again potentially sourced from the Turonian and / or Albian source rocks. Traps are sealed by coeval marine shales and muds. As is encountered regionally, there is reasonable seismic evidence for the presence of reservoir bearing intervals within the Upper Cretaceous and Early Tertiary section, and this seismic evidence has been used in trap definition.

The most significant play in the area is that of Cenomanian to Turonian age deep-marine channel-fan systems, as structural and stratigraphic traps. In addition, an emerging lower Cretaceous microbial carbonate reservoir play has been identified, sourced from coeval lacustrine source rocks and sealed by shales deposited during the subsequent drowning of the lacustrine systems by the onset of significant subsidence and marine inundation later in the Cretaceous. We have evaluated prospects within both of these play systems. Prospectivity in the shallower Cretaceous and Tertiary intervals is still being re-evaluated by APCL as of the date of this report, and no leads have been matured to prospect status.

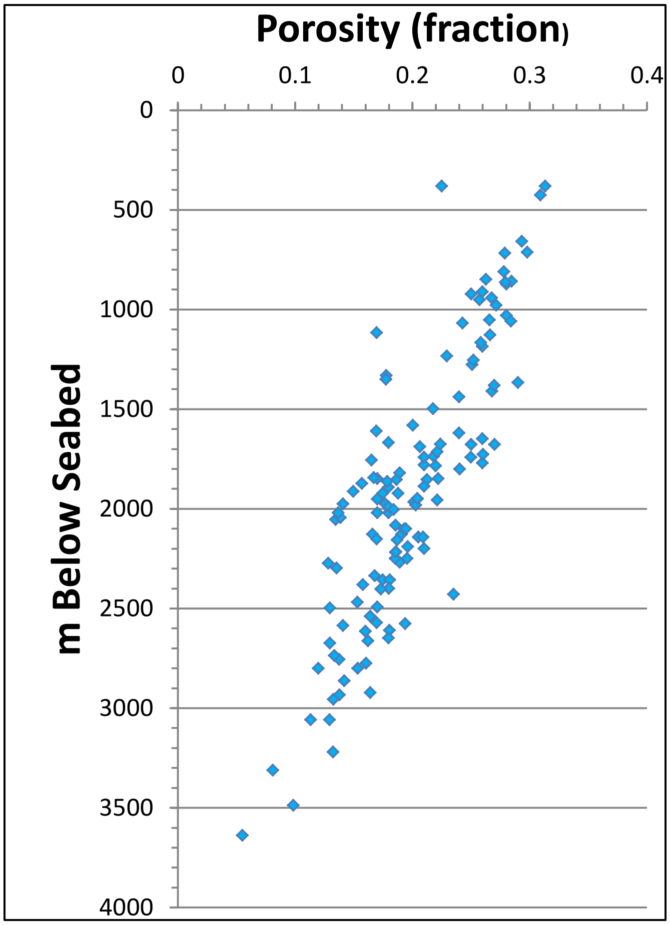

Figure 2.4 Porosity/depth trend, published West Africa turbidite reservoirs

2.4. Play and Prospect Risk: Liberia Blocks 8 and 9

Of the prospects reviewed, all but the Wildbird prospect fall within the Cenomanian to Turonian channel/fan play. In our opinion, recent drilling has de-risked source and reservoir presence for this play. However, reservoir quality in recent wells is variable. In our risking of Cenomanian to Turonian prospectivity, (Barbet, Sunbird, Lovebird and Night Heron prospects), we have removed the play element to our risking matrix, and see a low risk to hydrocarbon charge for individual prospects. Key risk is therefore to trap integrity and reservoir quality. We use a four component risk matrix as outlined in Section 1.5 to define geological chance of success for these prospects.

The Wildbird prospect has been recently identified by APCL as part of its review of further play fairways within the Liberian licences. The play concept is of early Aptian bio-constructed carbonate build-ups within the restricted lacustrine environment that existed at this time. Porosity and permeability within the bioclastic microbial limestones is potentially enhanced by hydrothermal activity resulting from the early rifting. Later post-rift subsidence and drowning by marine conditions provides the top seal via the deposition of Cretaceous marine muds. It is envisaged that the play is charged or by Aptian source rocks deposited in the offset lagoonal facies, with possible charge from later (but on-lapping) Cretaceous marine source rocks (as other plays on the blocks). Both potential source rocks provide lateral seal (Figure 2.18). Regionally, lacustrine microbial carbonate reservoirs can be found in Congo and Angola, where there is some production, but also in the Campos and Santos basins in Brazil.

The microbial carbonate play is emerging within Blocks 8 and 9, and has not been demonstrated to be effective by drilling. We adopt the play and prospect risking as discussed in Section 1.5 to risk the Wildbird prospect as a result, discounting biodegradation risk as the prospect is at significant depth. Our estimate of play risk for the Cretaceous microbial carbonate play is summarized in below.

PLAY	Source	Reservoir Presence	Seal	Play Risk
Cretaceous Carbonate	0.8	0.6	0.5	20%

Table 2.1 Play risk: Cretaceous carbonate play, Liberia Blocks 8 and 9

2.5. Liberia Blocks 8 and 9: Leads and Prospects

Following the drilling of Wells Narina-1 and Bee Eater-1, APCL is re-evaluating the prospectivity within Blocks 8 and 9, and has developed a number of potential traps (Figure 2.5), several of which (marked in orange, Figure 2.5) have been matured to prospect status. We have assessed the prospective resources for certain of these prospects that APCL has identified as viable near-term drilling opportunities, Barbet, Sunbird, Lovebird, Night Heron, Narina West and Wildbird. A number of the prospects have multiple reservoir targets. Our evaluation of these prospects follows the methodology described in Section 1.5. The results of Wells Narina-1 and Bee Eater-1 would indicate that oil charge is probable, and thus only oil cases have been evaluated. However, as we state in Section 1.5, a gas charge cannot be discounted due to the uncertainties in source rock evaluation and basin modelling.

A summary of prospective resources and geological chance of success for the prospective layers evaluated is given in Table 1 of the covering letter to this report.

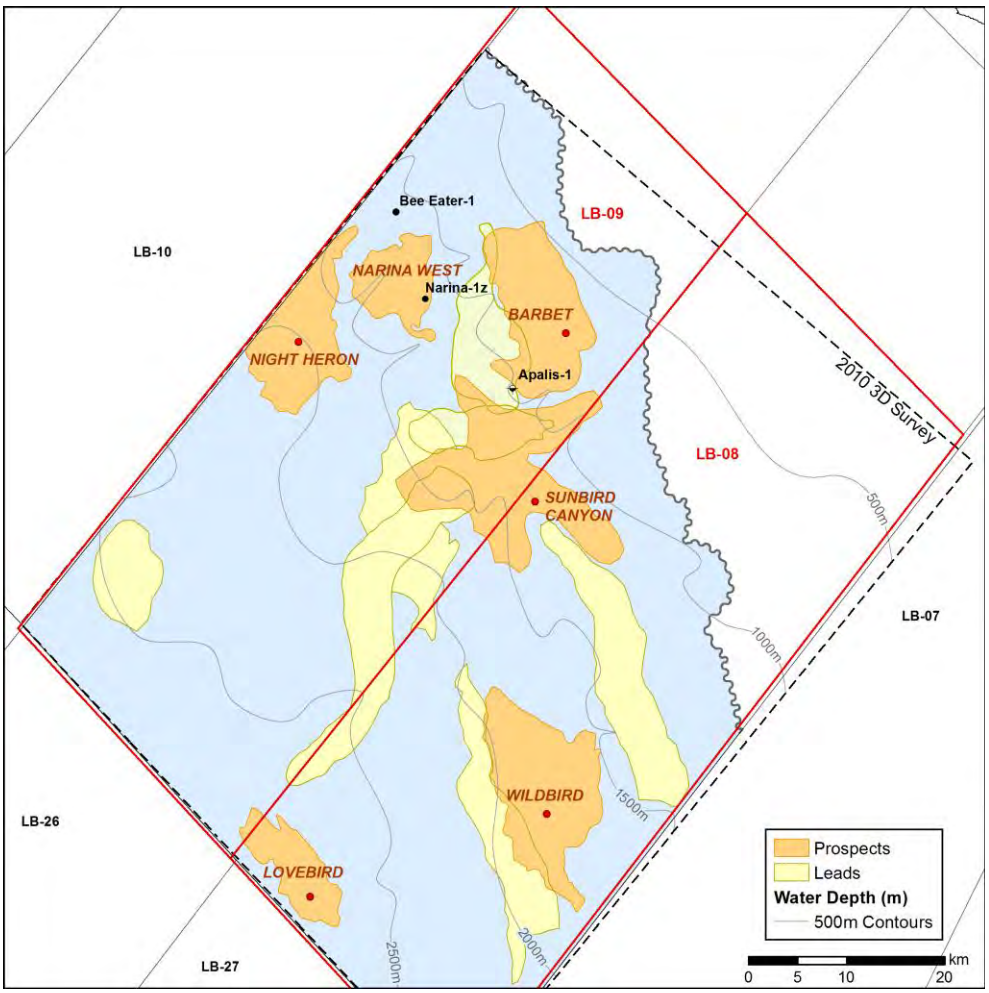

Figure 2.5 Leads and Prospects, Liberia Blocks 8 and 9

2.5.1. Narina West Prospect

The Narina West prospect is mapped as a stratigraphic trap, to the west of Well Narina-1 within Block 9 (Figure 2.6). The primary reservoir target is prognosed within the Turonian, up-dip of the ODT encountered in Well Narina-1. An additional, secondary reservoir target is recognised within the younger Campanian reservoir, although at present this is still being matured to prospect status by APCL.

Trap geometry is mapped as a basin floor fan, thickening from the Turonian interval in Well Narina-1, and onlapping onto the older Night Heron basin floor fan. There are seismic anomalies within the area of the trap that may provide support for reservoir development, and this is required for the development of the trap. The Turonian is mapped between 3400 m and 3850 m TVDSS over the area of the prospect. Water depth is around 1200 m TVDSS.

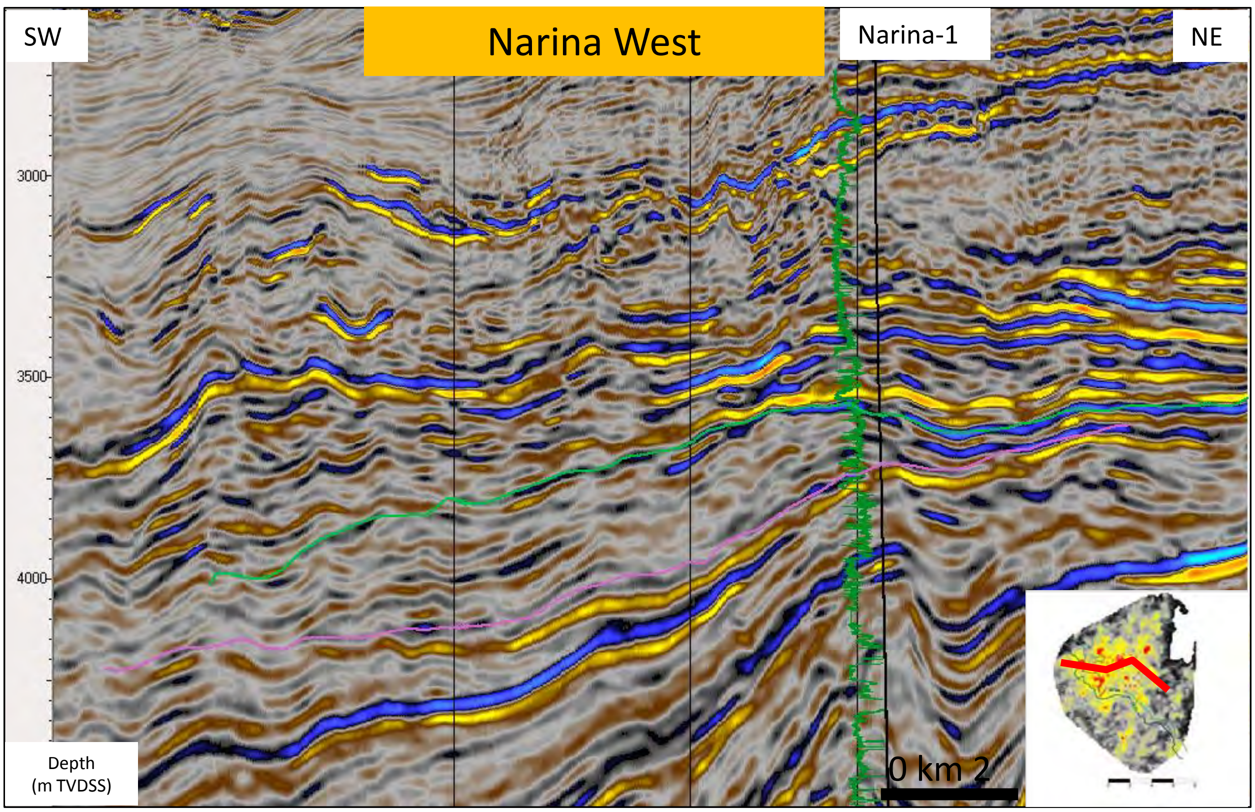

Figure 2.6 Seismic line (m TVDSS) over the Narina West prospect, showing the tie to Well Narina-1

We have used an area/net pay methodology to estimate prospective resources for the Narina West prospect. Firstly, we recognise that the reservoir quality in the Turonian interval in Well Narina-1 is unlikely to deliver a sustained flow rate at the levels required for development in these waters (the reservoir model being risked – see Section 1.5), and thus must improve away from the well for the Narina West prospect to be a success. Well Narina-1 is therefore excluded from the area of the prospect. However, it is possible that Well Narina-1 is in charge communication with the Narina West prospect. We therefore use the oil down to (ODT) level observes on logs in the well (3784 m TVDSS) and an oil water contact (OWC) derived from pressure data (3845 m TVDSS), to control the degree of fill of the prospect.

In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes on the far offsets, closed to the ODT in Well Narina-1. Our high case extends the prospect areally, to include a larger area of anomalous amplitudes above an observed amplitude shut-off, and the thick area of the basin floor fan isopach mapped for the prospect (Figure 2.7), and down-dip to the formation pressure derived OWC from Well Narina-1. These are used to constrain the P90 and P10 inputs of our probabilistic simulation. These polygons approximate to an oil column height of 200 and 400 m respectively.

Amplitudes are variable within the area of closure, and we apply an areal net to gross ratio to better constrain sand distribution within the trap. Gross reservoir thickness estimates are computed from the mapped seismic interval, net to gross ratio from regional analogue, and porosity from a regional porosity/depth trend (Figure 2.4). Fluid parameters and recovery factors are estimated as described in Section 1.5.

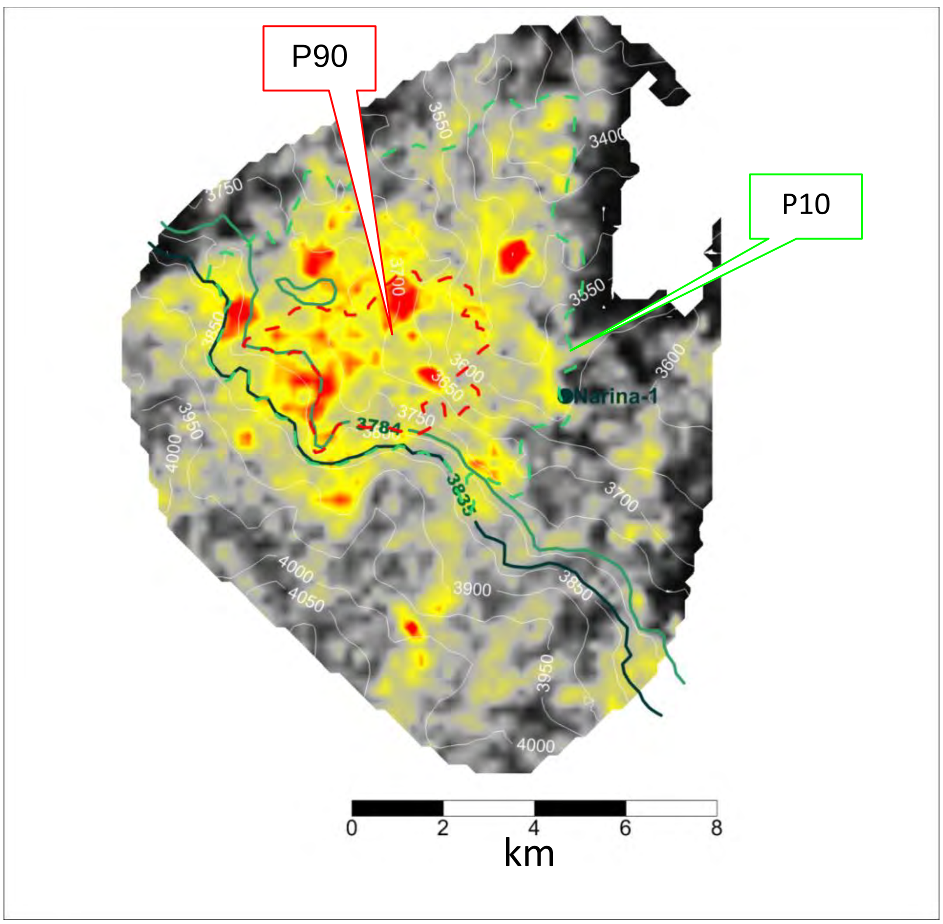

Figure 2.7 Narina West: amplitudes with Top Turonian depth contours (m TVDSS)

ODT and OWC from Well Narina-1 are also indicated by the green contours

We have used the prospect risk matrix presented in Section 1.5 to determine the geological chance of success for the Narina West prospect. Key risks are to trap/containment and reservoir. The trap requires pinch-out of the reservoir in three directions to seal, and the reservoir encountered in Wells Narina-1 and Bee Eater-1 is of relatively poor quality. As a result, we attribute a geological chance of success of 16% to the Narina West prospect.

2.5.2. Barbet Prospect

The Barbet prospect is identified as a stratigraphic trap, around 14 km to the east of and up-dip from Well Narina-1 within Block 9 (Figure 2.8). A single target reservoir is mapped within the Turonian. Seismic amplitude anomalies are also identified within the area of the trap that may provide support for reservoir development. The Turonian is mapped at between 3000 and 3600 m TVDSS over the area of the prospect, in a water depth of around 750 to 770 m.

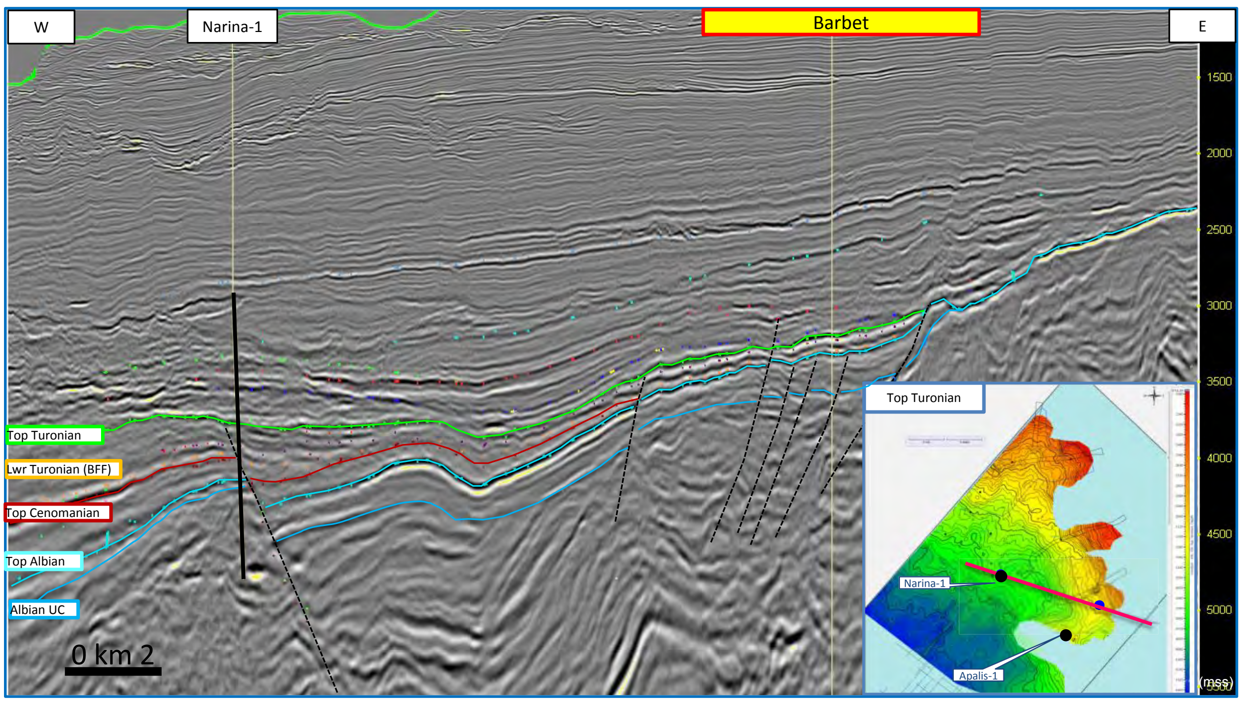

Figure 2.8 Seismic line - depth (m TVDSS) over the Barbet prospect

We have used an area/net pay methodology to estimate prospective resources for the Barbet prospect. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes on the far offsets. Our high case extends the prospect down-dip, to include a larger area of anomalous amplitudes above an observed amplitude shut-off (Figure 2.9). These are used to constrain the P90 and P10 inputs of our probabilistic simulation. These polygons approximate to an oil column height of 200 and 700 m respectively.

Amplitudes are variable within the area of closure, and we apply an areal net to gross ratio to better constrain sand distribution within the trap. Gross reservoir thickness estimates are computed from the mapped seismic interval, net to gross ratio from regional analogue, and porosity from a regional porosity/depth trend (Figure 2.4). Fluid parameters and recovery factors are estimated as described in Section 1.5.

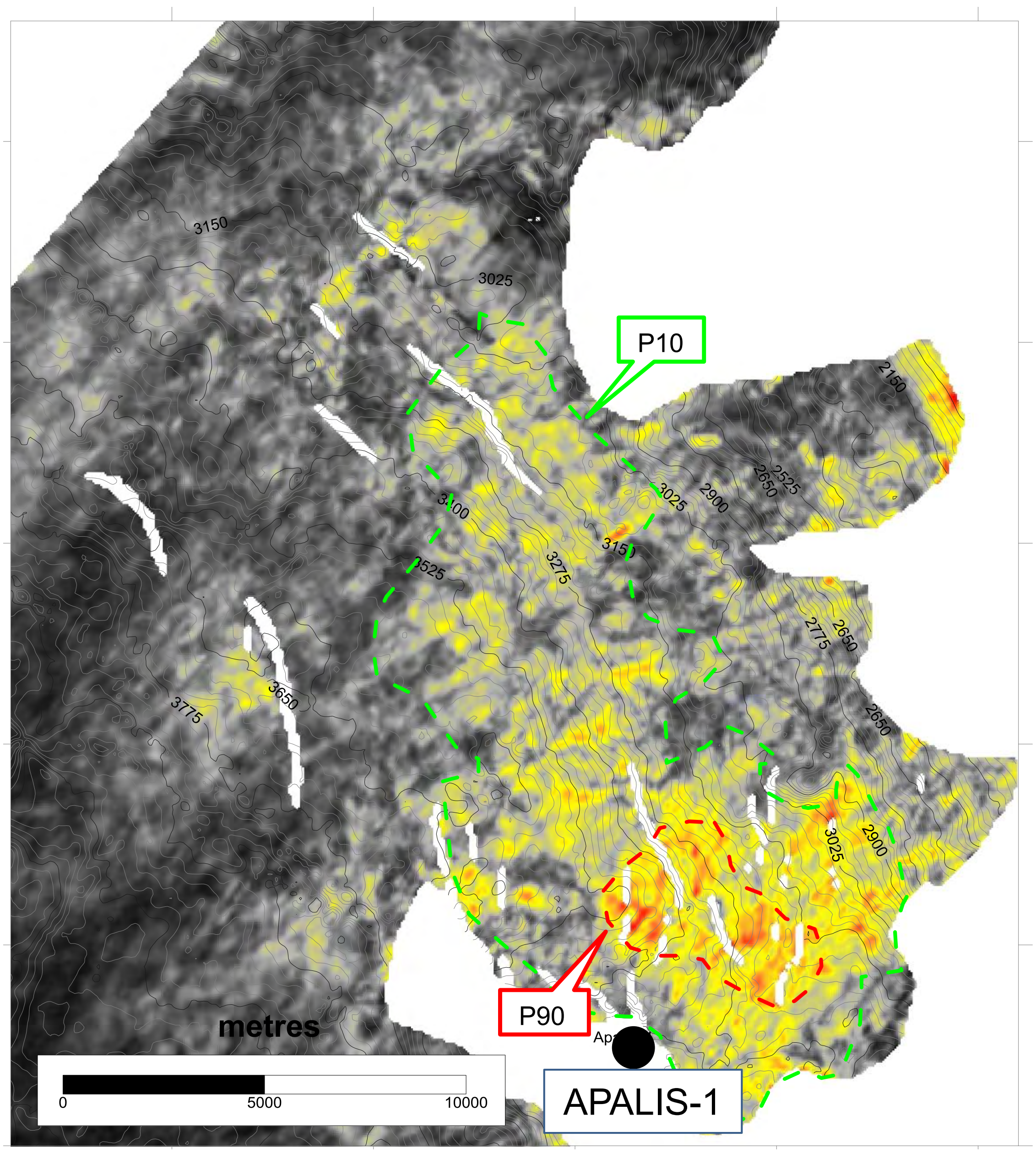

Figure 2.9 Barbet: far offset amplitudes with Top Turonian depth contours (m TVDSS)

We have used the prospect risk matrix presented in Section 1.5 to determine the geological chance of success for the Barbet prospect. Key risk to the Barbet prospect is to trap/containment, as the trap requires pinch-out of the reservoir in three directions to seal. There is also a subsidiary risk to reservoir, as the Turonian reservoir encountered in Well Narina-1 is of relatively poor quality, which is countered by seismic evidence over the prospect to support reservoir development. As a result, we attribute a geological chance of success of 22% to the Barbet prospect.

2.5.3. Sunbird Canyon Prospect

The Sunbird canyon prospect is also identified as a stratigraphic trap, around 5 km to the south of Well Apalis-1, within Blocks 8 and 9, mapped as a large canyon system. There are three potential reservoir targets within the prospect; within the Campanian, the Turonian, (as encountered in Well Narina-1), and in the underlying Cenomanian. Reservoir is prognosed at between 3000 m TVDSS and 3600 m TVDSS in a water depth of around 1300 m.

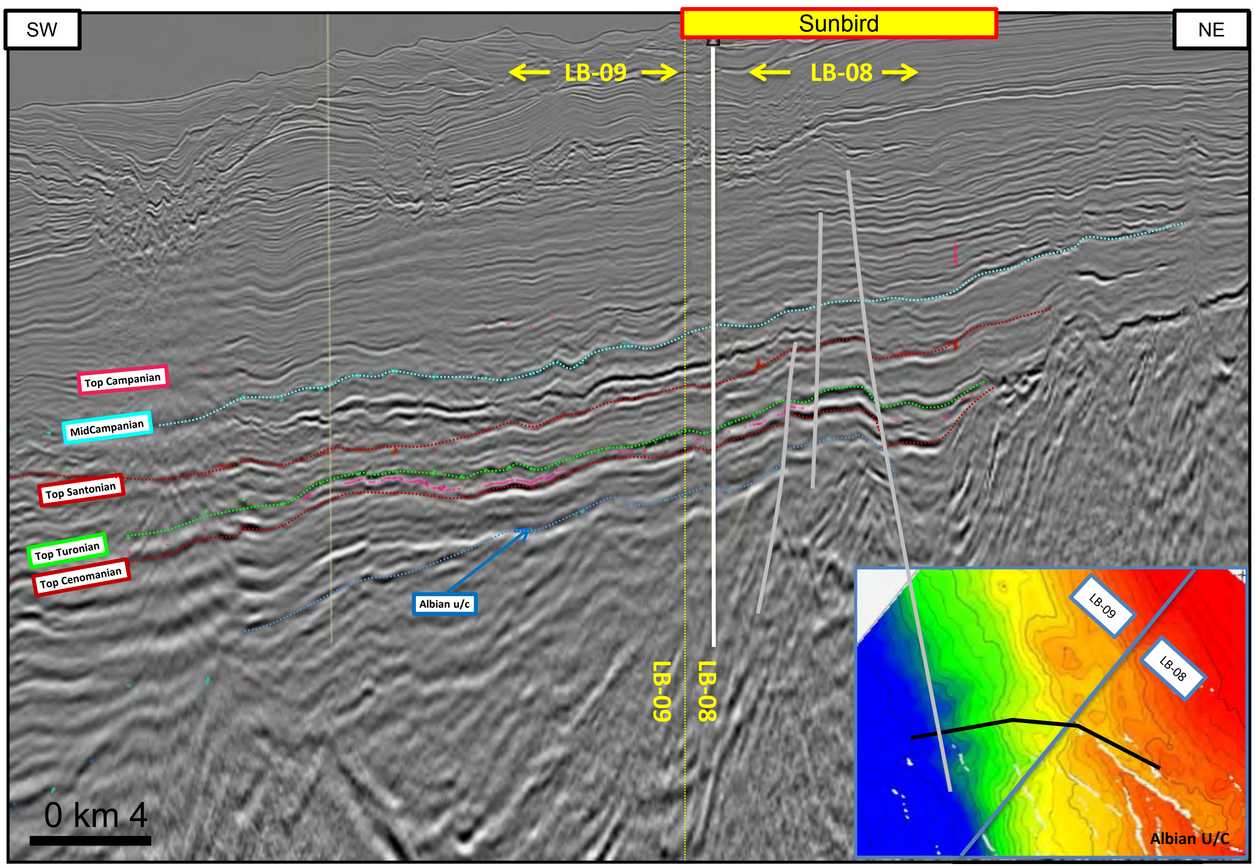

Figure 2.10 Regional seismic line along axis of the Sunbird canyon system

We have used an area/net pay methodology to estimate prospective resources for the Sunbird canyon prospect. At all three prospective layers, the prospect divides into two discrete 'canyons' separated by an intra-basinal high (e.g. Figure 2.11). For the Campanian and Turonian prospective intervals, in the low case we restrict the area of the accumulation to the brightest area of anomalous amplitudes on the far offsets in the northerly of the two canyons, where amplitude response is better. Our high case extends the prospect down-dip, to include a larger area of anomalous amplitudes above an observed amplitude shut-off, and also includes the southerly of the two canyons, as this would now be in charge communication. The low and high case polygons approximate to an oil column height of 200 m and 600 m respectively.

For the deeper Cenomanian, the prospect is mapped as a single canyon to the south of the intra-basinal high. The low and high case polygons approximate to an oil column height of 200 m and 700 m respectively. Our low and high estimates of area are used to constrain the P90 and P10 of our probabilistic simulation.

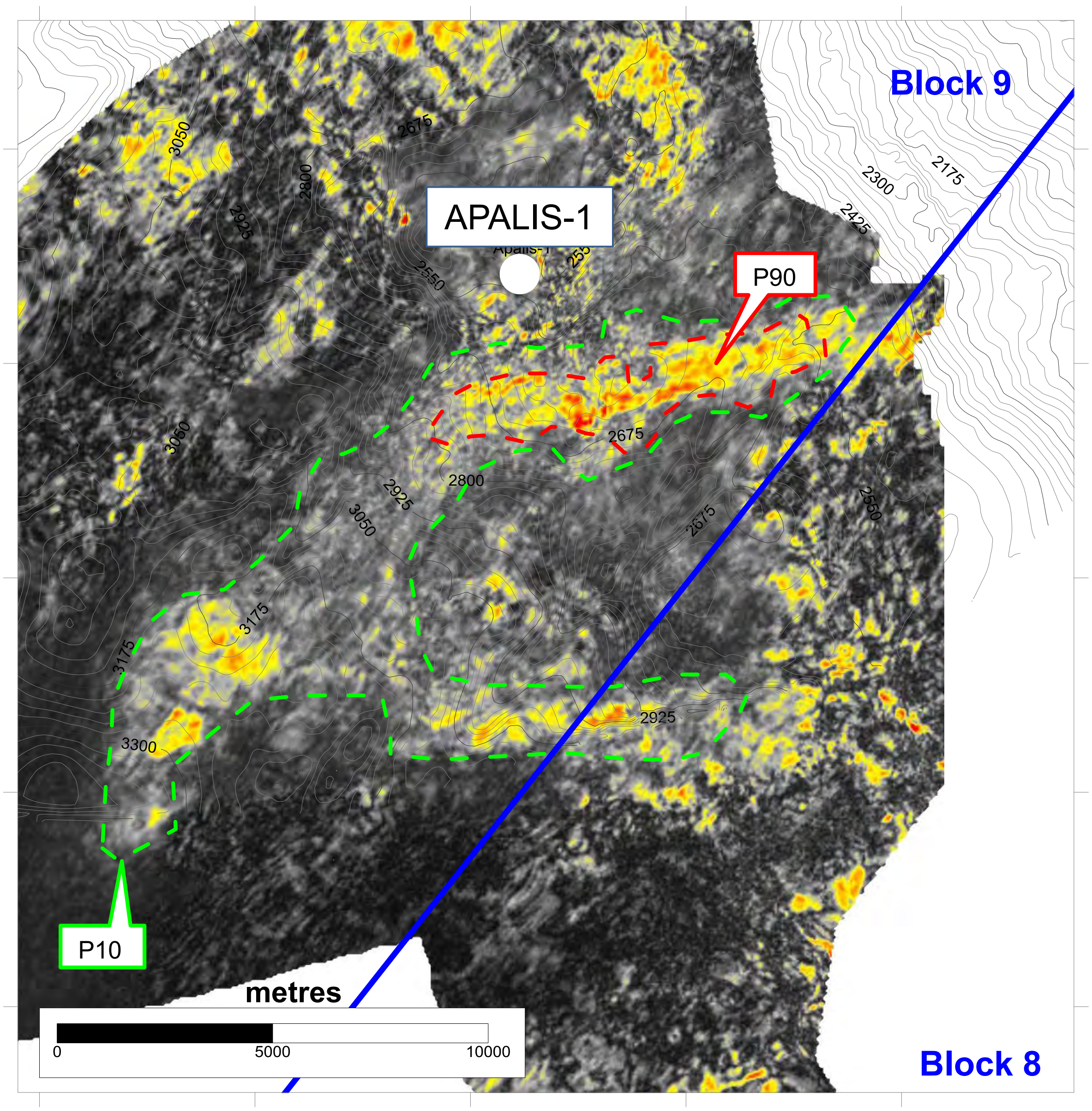

Figure 2.11 Sunbird: Campanian far offset amplitudes with Cenomanian depth contours (m TVDSS)

Amplitudes are variable within the area of closure, and we apply an areal net to gross ratio to better constrain sand distribution within the trap for all three prospective layers. Gross reservoir thickness estimates are computed from the mapped seismic interval, net to gross from regional analogue, and porosity from the observed porosity/depth trend (Figure 2.4). Fluid parameters and recovery factors are estimated as described in Section 1.5.

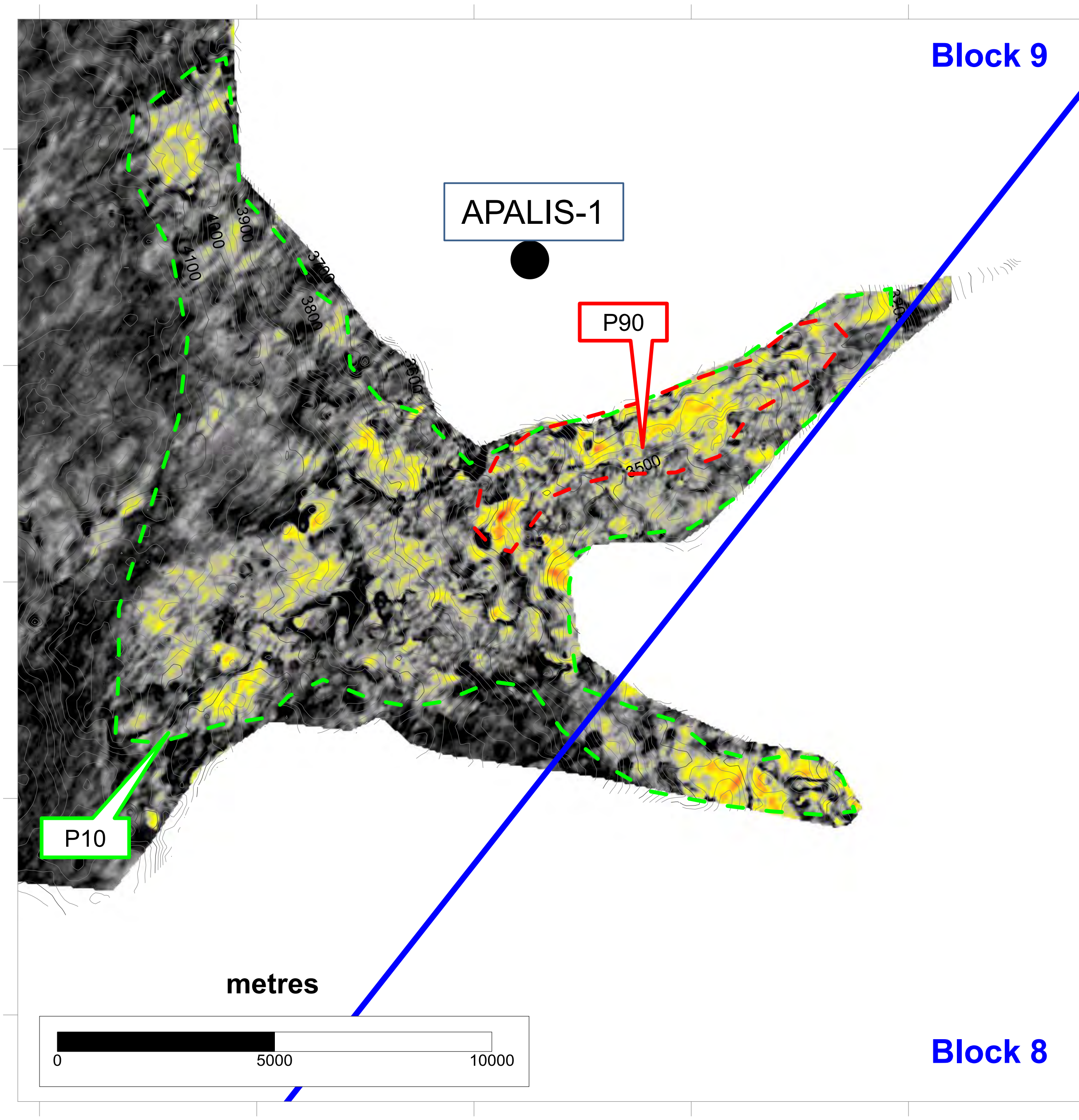

Figure 2.12 Sunbird Turonian: far offset amplitudes with Top Turonian depth contours (m TVDSS)

We have used the prospect risk matrix presented in Section 1.5 to determine the geological chance of success for the three prospective intervals of the Sunbird prospect. Key risk to all three prospective layers is to trap/containment, as the trap requires pinch-out of the reservoir in three directions to seal.

There is also a subsidiary risk to reservoir at the two deeper levels, as the Turonian reservoir encountered in Well Narina-1 is of relatively poor quality, and Cenomanian reservoirs are yet to be proven on block. However, there is seismic evidence for reservoir development, and hence we see this risk as favourable. Reservoir risk is low for the Campanian as it is developed in the offset Well Narina-1, and there is seismic evidence for reservoir presence. As a result, we attribute a geological chance of success of 27%, 19% and 18% to the Campanian, Turonian and Cenomanian prospective intervals of the Sunbird canyon prospect.

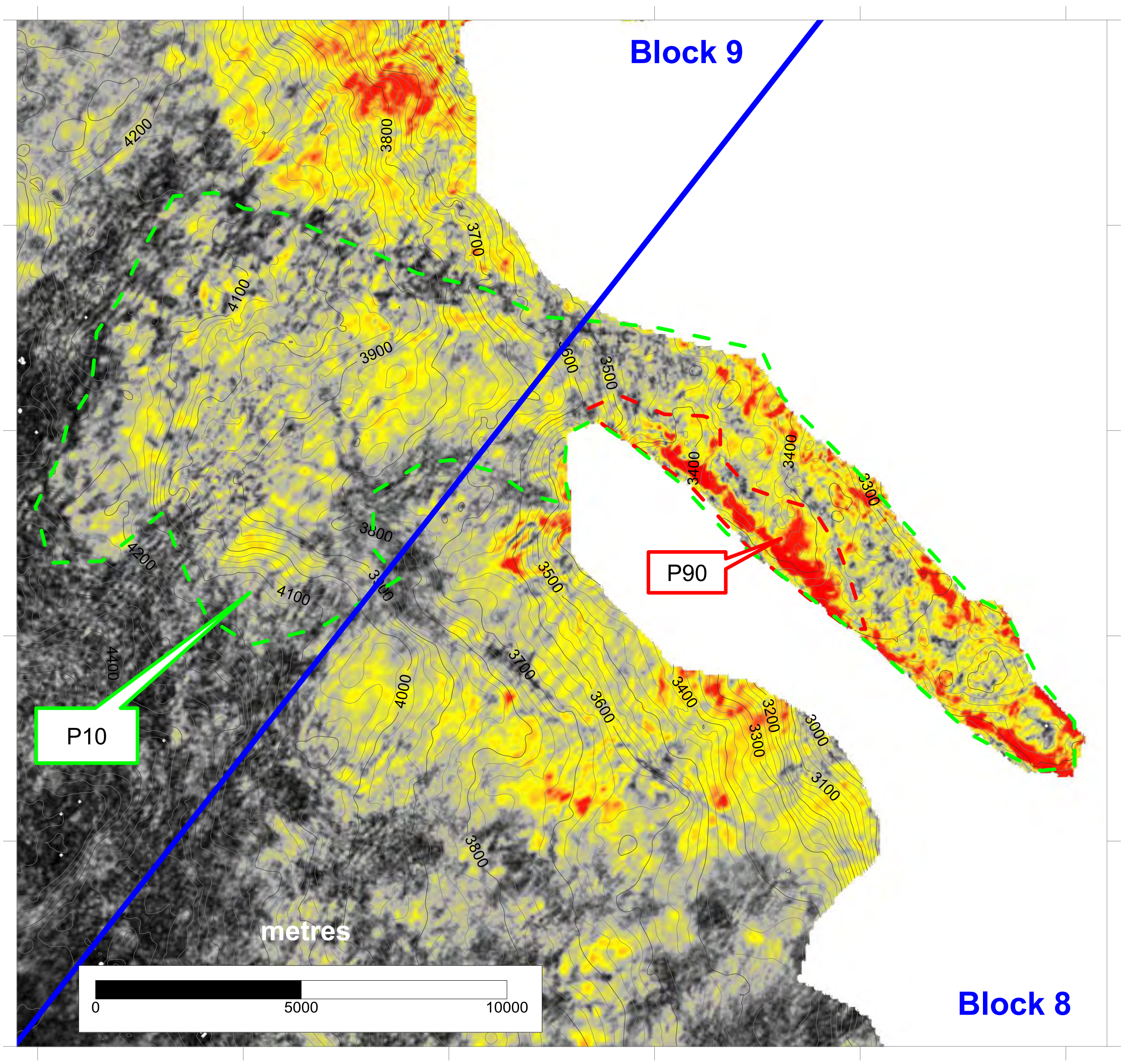

Figure 2.13 Sunbird Cenomanian: far offset amplitudes with Cenomanian depth contours (m TVDSS)

2.5.4. **Night Heron**

Night Heron is a Turonian basin floor fan system which lies 8 Km south west of Well Bee Eater-1. It is mainly within Block 9, but extends into Block 10. It is identified as a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinch-out. Reservoir is prognosed at between 4100 m TVDSS and 4700 m TVDSS in a water depth of around 1750 m (Figure 2.14) APCL has selected a provisional well location which lies on the 3D survey location – In-line 1098, X-line 6103.

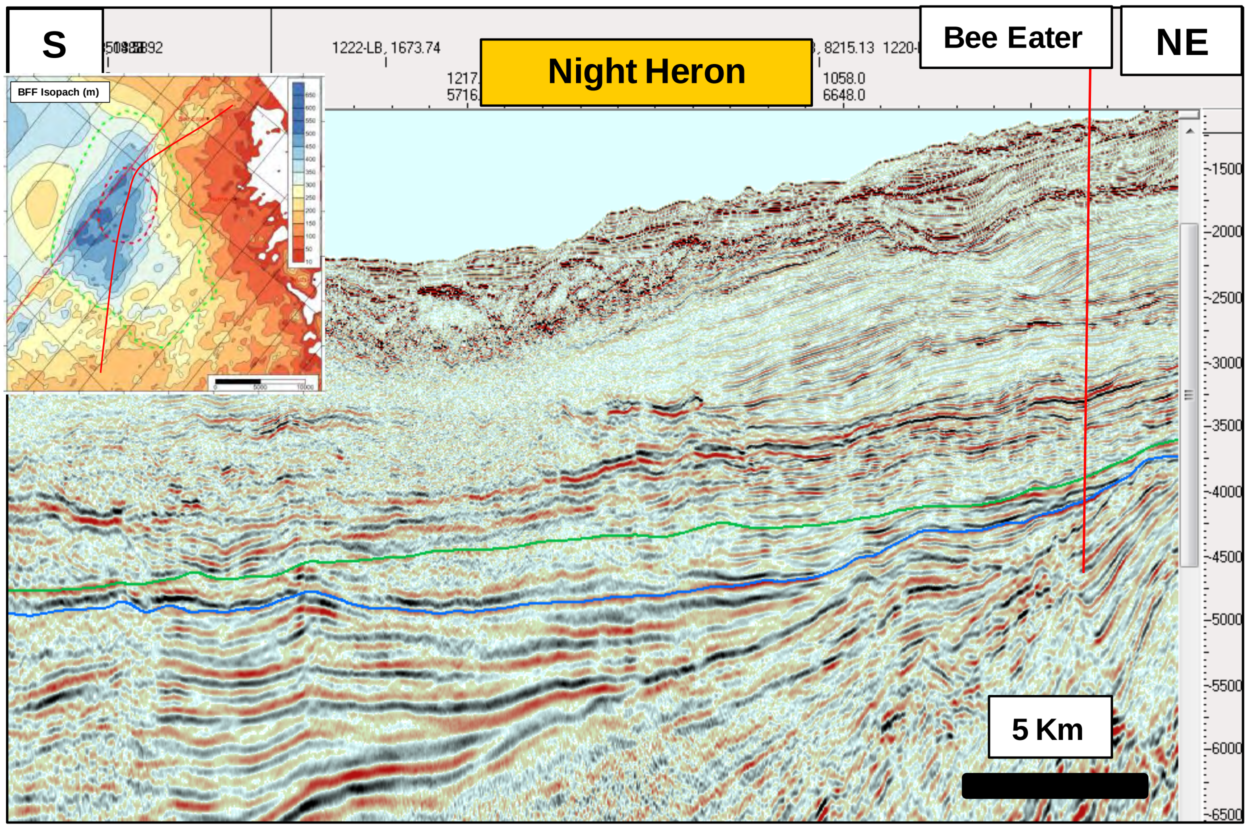

Figure 2.14: Arbitrary line across Night Heron, PSDM - Depth (m TVDSS)

Cenomanian reservoir potential also exists beneath the Turonian basin floor fan and work by APCL is on-going to determine prospectivity.

Well Bee Eater-1 found an organic-rich Turonian shale section overlying a hydrocarbon bearing thin-bedded low permeability sandstone. Another shale dominated package underlies the sandstone. Although the Turonian interval is considered non-commercial for Bee Eater, the prospectivity down-dip is appealing. APCL interprets that the well was drilled in a canyon system that may have been largely bypassed by sediment input. The 3D seismic indicates a significant thickening of this Turonian interval towards the south west and there is some amplitude support for the occurrence of a lobate fan straddling Blocks 9 & 10.

An area times net approach was adopted using the full stack PSDM depth volume to provide an SNA extraction and constrain areal extent and estimate an areal N/G to account for lateral variability within the reservoir (Figure 2.15). As night Heron falls partly off block, ERCE correct for this using the ratio of on-block to off-block area in reporting of net unrisked and net risked results.

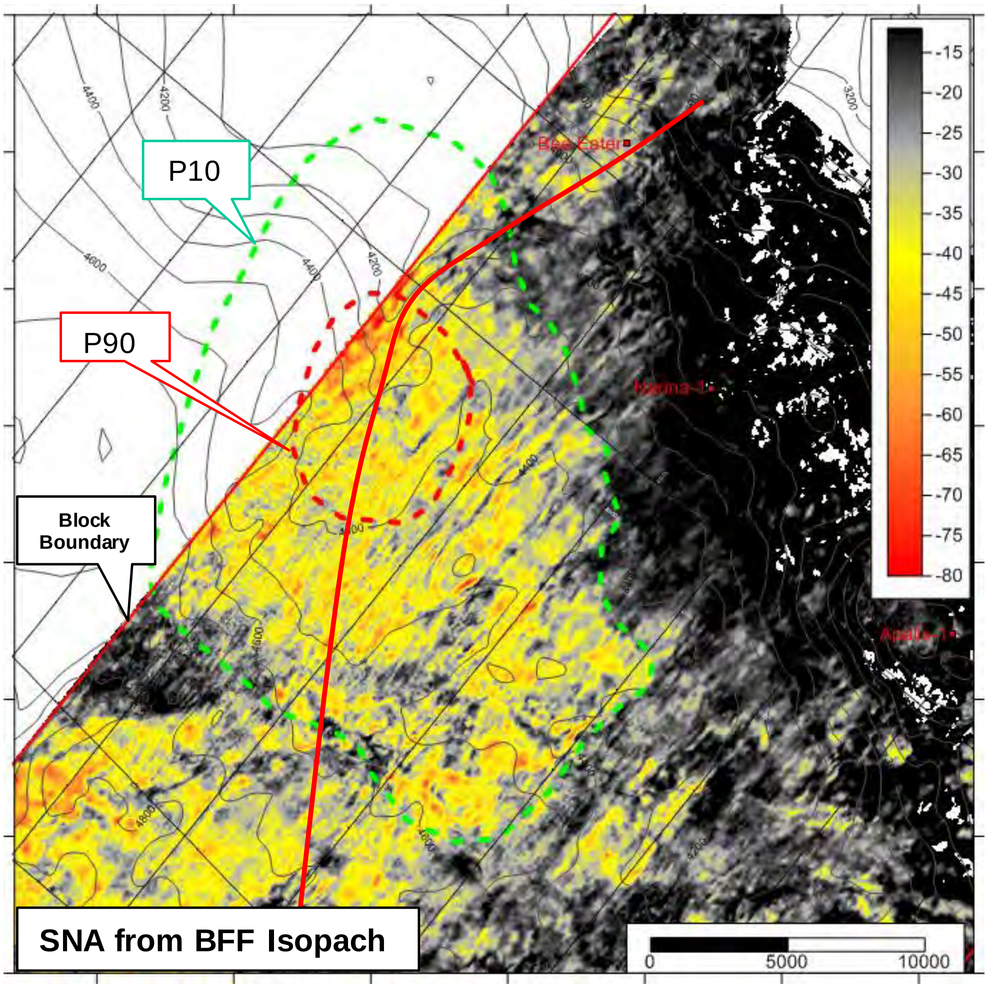

Figure 2.15: SNA from Basin Floor Fan Isopach (m) - PSDM

We have used the prospect risk matrix presented in Section 1.5 to determine the geological chance of success for the Turonian interval of the Night Heron prospect. Recent drilling results suggest that there is a low risk to hydrocarbon charge. The observations at Bee Eater-1 also indicate that shale seals are also likely at a coeval interval. Reservoir is a significant risk due to the poor Turonian reservoir development in Well Bee Eater-1. The Turonian reservoir encountered in Well Narina-1 is also of relatively poor quality. However, there is seismic evidence on the 3D survey for a possible improvement in reservoir development over the prospective area. The definition of the trap is the key risk, as the seismic evidence for closure/reservoir pinch-out is ambiguous over the 2D data in Block 10. There appears to be evidence of the reservoir interval thinning in the critical north westerly direction but 3D data would be required to reduce trap risk any further. As a result, we attribute a geological chance of success of 14 %, to the Night Heron prospect.

2.5.5. **Lovebird Prospect**

The Lovebird prospect is mapped as a four-way dip closure to the south of Block 8 (Figure 2.16). Three prospective layers are mapped by correlation to up-dip wells, and are prognosed to be of Cenomanian age. Thus, as with the Sunbird canyon prospect, these reservoirs are not proven on block, but seismic mapping and regional geological work suggests the sands may be derived from the east, via a canyon system identified in block LB-07. The three prospective intervals are termed Upper, Middle and Lower, or, Blue, Pink, and Green, based on horizon colour. Structural relief at the Pink horizon is between 50 and 200 m, depending on the estimate, and thus the prospect is relatively low relief in some realisations.

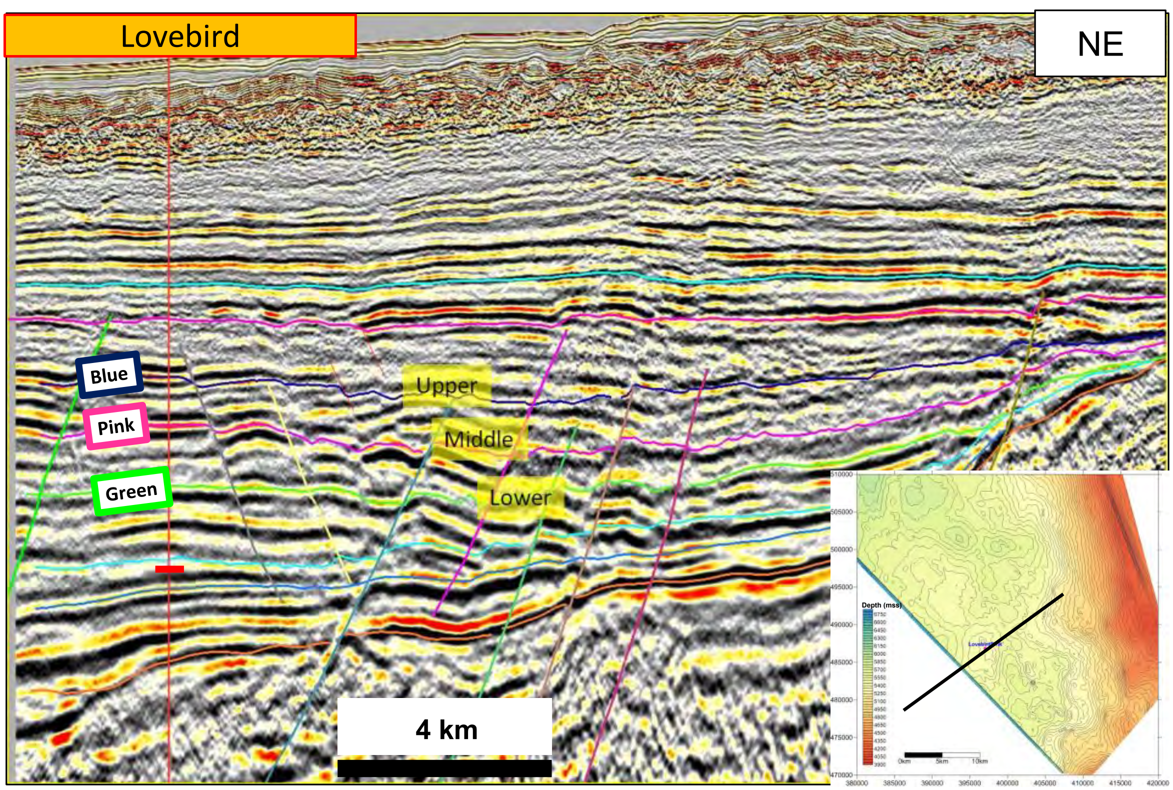

Figure 2.16 Seismic line over the Lovebird prospect

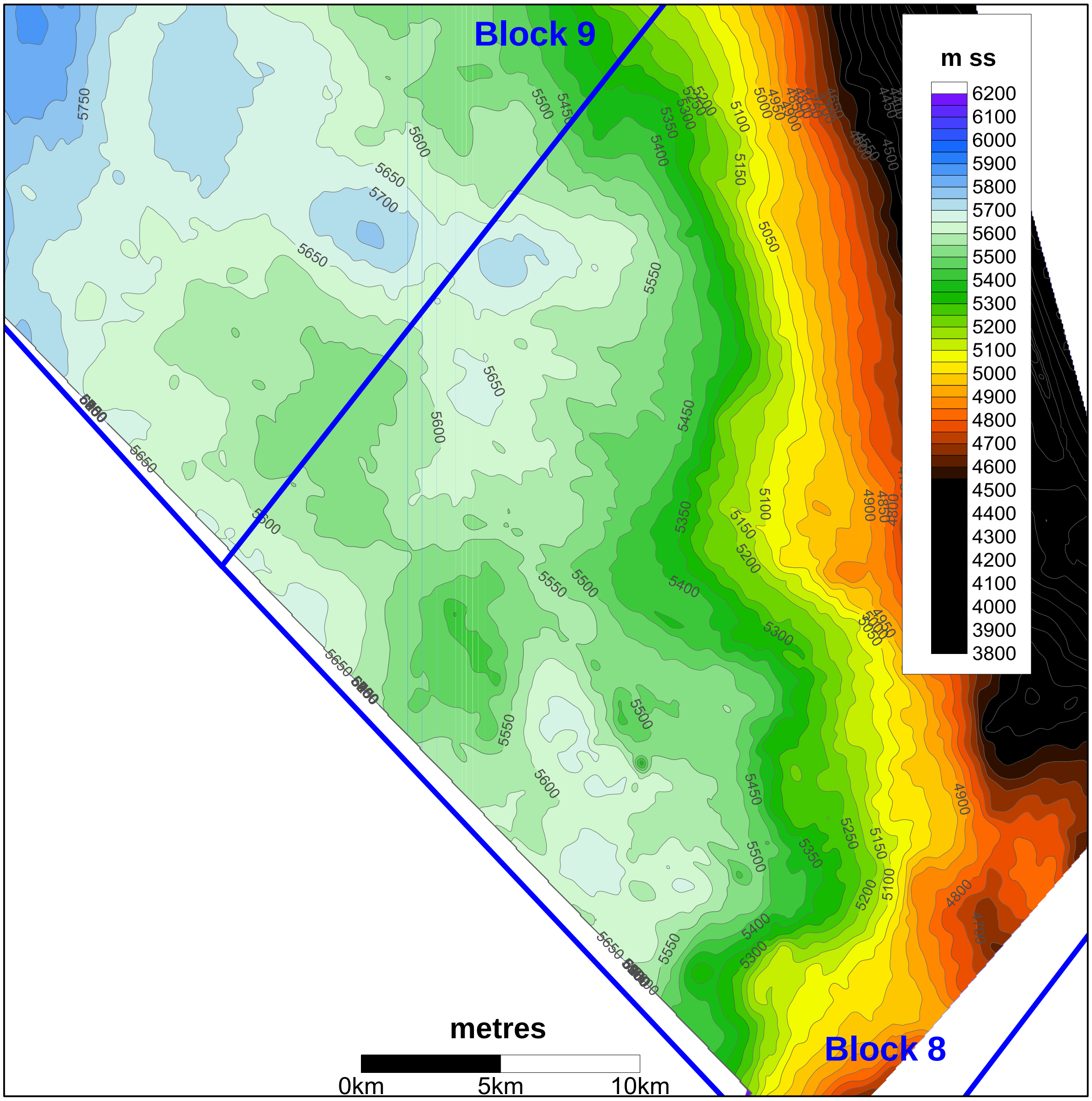

Figure 2.17 Lovebird prospect: Top Pink horizon depth (m TVDSS), high case.

The prospect is mapped to the edge of the available 3D (Figure 2.17), which coincides with the southern boundary of Block 8, but closure can be mapped south of the 3D area on the available 2D lines. Reservoir depth is prognosed at between 5000 and 5900 m TVDSS, in a water depth of 2850 m at the prospect crest. Thus, reservoir rock, if present, will be at comparable depths below mud line to the Barbet prospect.

We use a gross-rock volume/net to gross methodology to estimate prospective resources for the Lovebird prospect. APCL's evaluation of the Lovebird prospect is on-going, and of the three interpreted horizons, the Pink horizon is the best defined. We review pick, depth conversion and thickness uncertainty for this interval to generate a range of gross-rock volumes for this interval, with the prospect full to spill (Figure 2.17). Assuming the Pink horizon provides an accurate representation of the Blue and Green horizons, we then estimate gross-rock volumes for these two intervals by isopach.

Reservoir thickness and net to gross ratio estimates are derived from regional analogues, with reservoir porosity derived from our regional porosity/depth trend (Figure 2.4). Fluid properties and recovery factors are estimated as described in Section 1.5. Our volumetrics are restricted to the portion of the Lovebird prospect on Block 8. We would expect a further evaluation of the prospective resources of the Lovebird prospect to occur subsequent to the completion of the APCL evaluation, and the prospective resources associated with the prospect in this report may therefore be subject to change.

The key risks to the Lovebird prospect are to the development of reservoir at the prognosed Cenomanian intervals, as they are not proved in wells elsewhere on the block, and to source, as the prospect requires a source rock deeper than that proven by drilling. There is also risk to trap/containment, as the structure is not fully defined by the 3D seismic data volume, and is of low relief in some realisations. We assign a geological chance of success to the Lovebird prospect of 20% as a result.

2.5.6. **Wildbird Prospect**

The Wildbird prospect is mapped on 3D seismic data towards the south of Block 8 as a large four-way dip-closed high (Figure 2.19), at a depth of between 4000 to 4600 m TVDSS, in a water depth of around 2000 m. Structural relief is up to 600 m and area of closure up to 170 km^2. The conceptual geological model is discussed above, but is that the prognosed microbial carbonate reservoir of Albian age is developed between the mapped 'red' and 'light blue' seismic events (Figure 2.18), with lateral seal developed to the north-east of the prospect within contemporaneous lagoonal facies which also provide the primary source rock. This lateral seal is required to close the prospect. Basin modelling undertaken by APCL suggests that the Albian lagoonal and later Cretaceous source rocks would be mature for oil generation.

We have accepted this model as a geological concept and have used it to make estimates of prospective resources for the Wildbird prospect. We then risk the model accordingly.

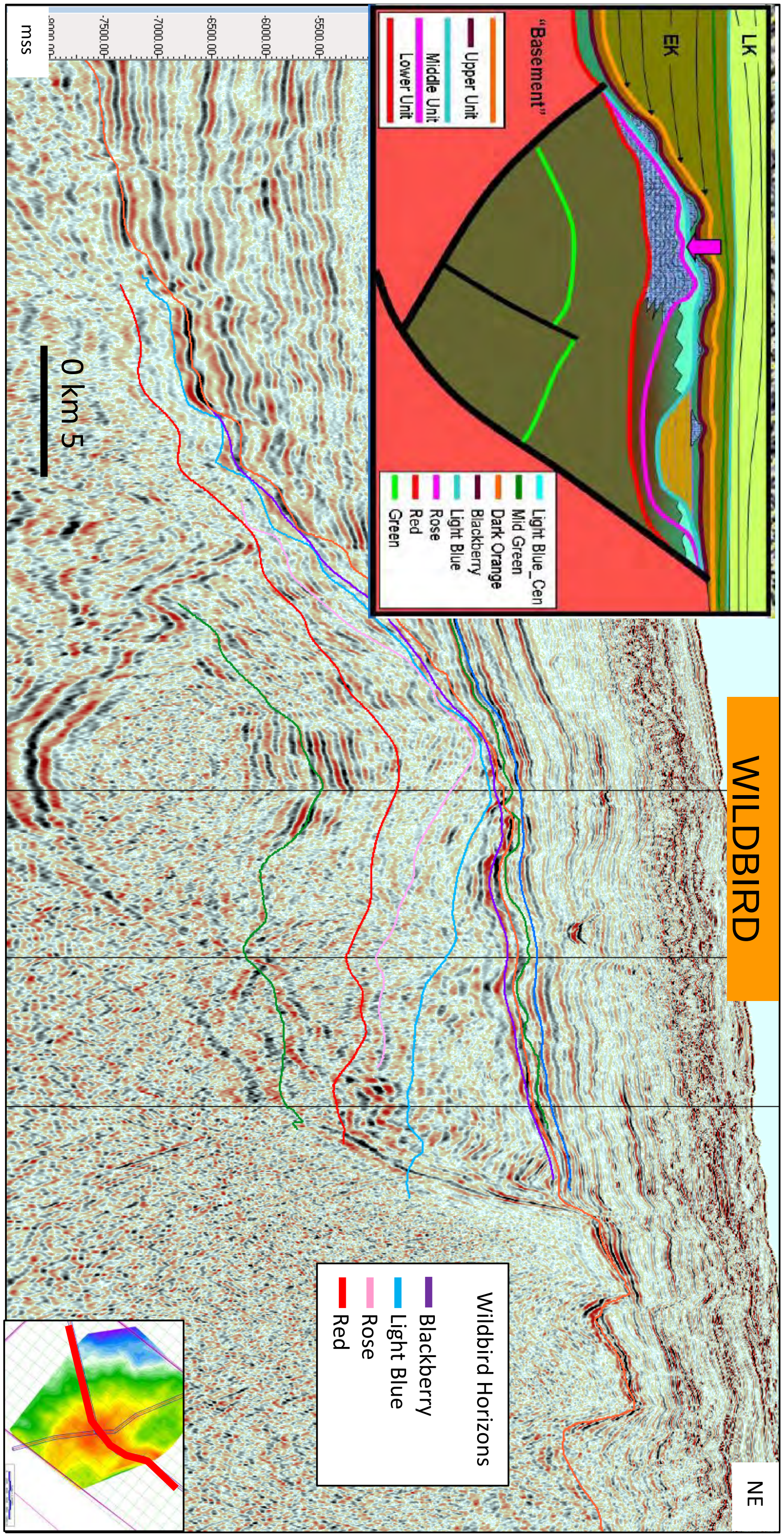

Figure 2.18 Seismic line and prospect geo-seismic sketch, Wildbird prospect

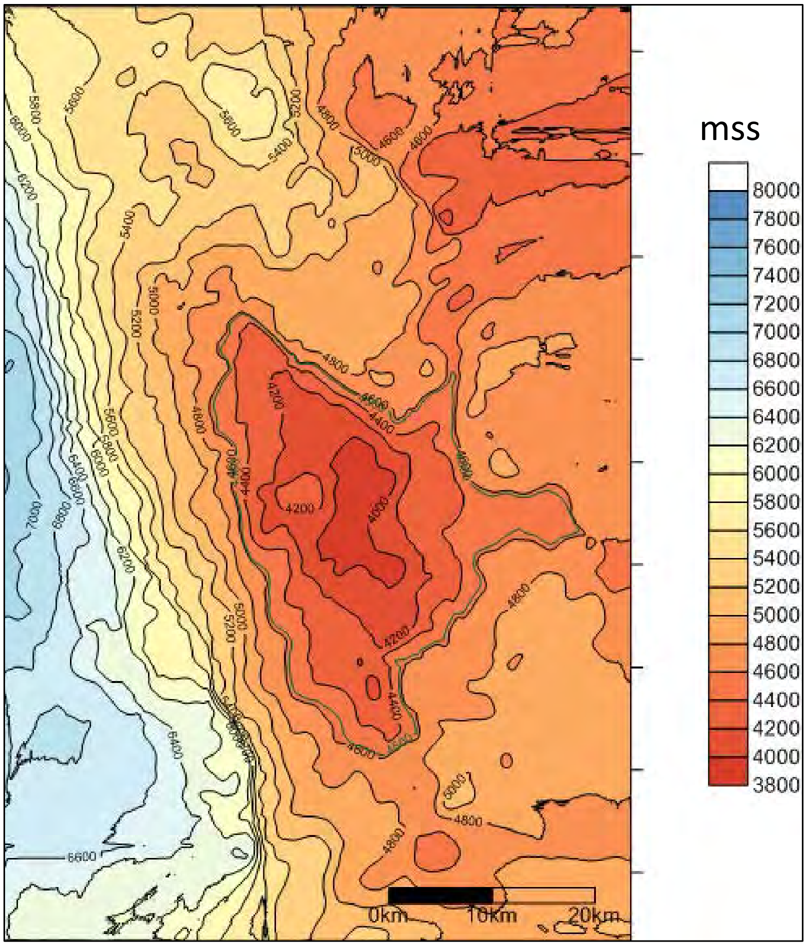

Figure 2.19 Wildbird: Top Reservoir depth map (m TVDSS). Spill point - green contour.

The Wildbird prospect is a large container, but there is considerable uncertainty in reservoir thickness, structural mapping and degree of charge from the offset kitchen areas. We evaluate the prospect in a similar manner to the Lovebird prospect, by perturbing the above variables. In our low case, we choose a shallow contact at 4250 m TVDSS to simulate under-filling or lateral breach via onlapping thief zones, and also employ a reservoir thickness of 80 m from offset analogue. Our high case assumes the prospect is filled to spill, and that the 'red' seismic event marks base reservoir. Estimates of reservoir net to gross ratio and porosity are derived from the available analogues, and are necessarily wide. Fluid parameters and recovery factors are derived as described in Section 1.5.

The Wildbird play is emerging and is of high risk. We attribute a play risk of 24% as a result (Section 2.4). The key prospect risk to the Wildbird prospect is that of containment or trap, as there is evidence for erosion at the crest of the feature, and it is reliant on the development of lagoonal facies to the north-east and overlying marine shales to provide lateral seal and support the hydrocarbon column heights modelled here. We attribute a prospect risk of 38% Wildbird, which, when combined with the play risk, gives an overall chance of success for the Wildbird prospect of 9%.

3. Sierra Leone: Prospectivity and Plays

As with offshore Liberia, to the south-east, all of the deep-water acreage offshore Sierra Leone is under licence (Figure 3.1). A discussion of regional hydrocarbon occurrences is presented in Section 2.1. APCL's licences, SL-03 and SL-04A-10 lie to the north-west of the country's territorial waters, around 200 to 300 km north-west of the recent Venus, Mercury and Jupiter discoveries made by Anadarko (Figure 3.1).

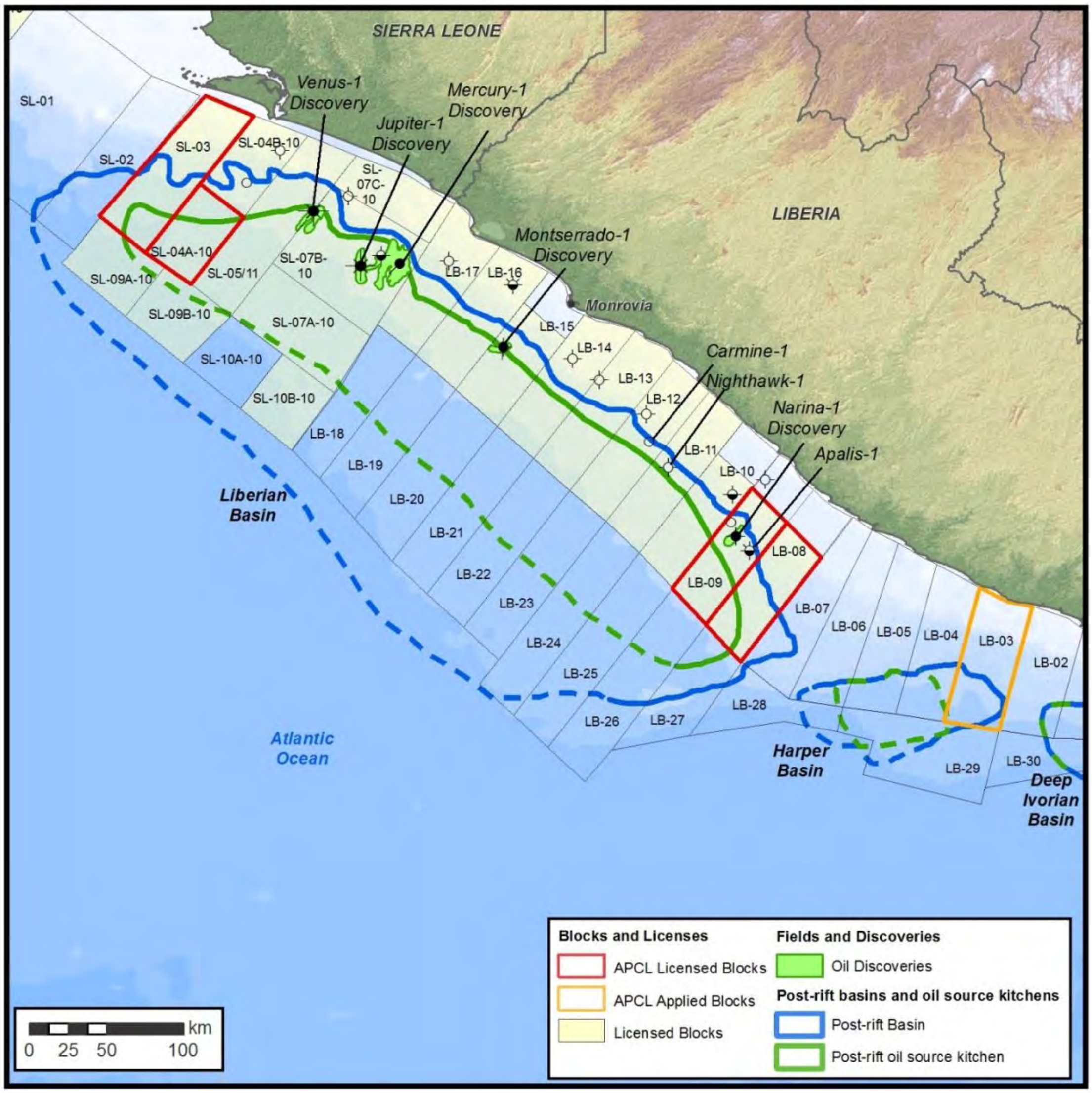

Figure 3.1 Offshore licences and discoveries, Liberia and Sierra Leone

A regional grid of 2D seismic data is available to APCL for the evaluation of offshore Sierra Leone (Figure 3.2). In addition APCL has licenced c. 2500 km^2 of 3D seismic data covering the deeper water area of Block SL-03, and is negotiating the licencing of further 3D seismic data covering part of Block SL-04A-10.

Well data offshore Sierra Leone are sparse. Historical exploration was restricted to the shelf, and resulted in the drilling of two exploration wells (Wells A-1 and A-1-2), which were plugged and abandoned as dry holes. Data from both wells are available to APCL. Recent drilling by Anadarko in the deeper waters of licence SL-07B-10 has yielded a number of discoveries, (Wells Jupiter-1, Venus-1 and Mercury-1), but these well data are not available to APCL. The government of Sierra Leone also reported that Lukoil recently encountered oil in the Turonian in licence SL-5-11 with Well Savannah-1X.

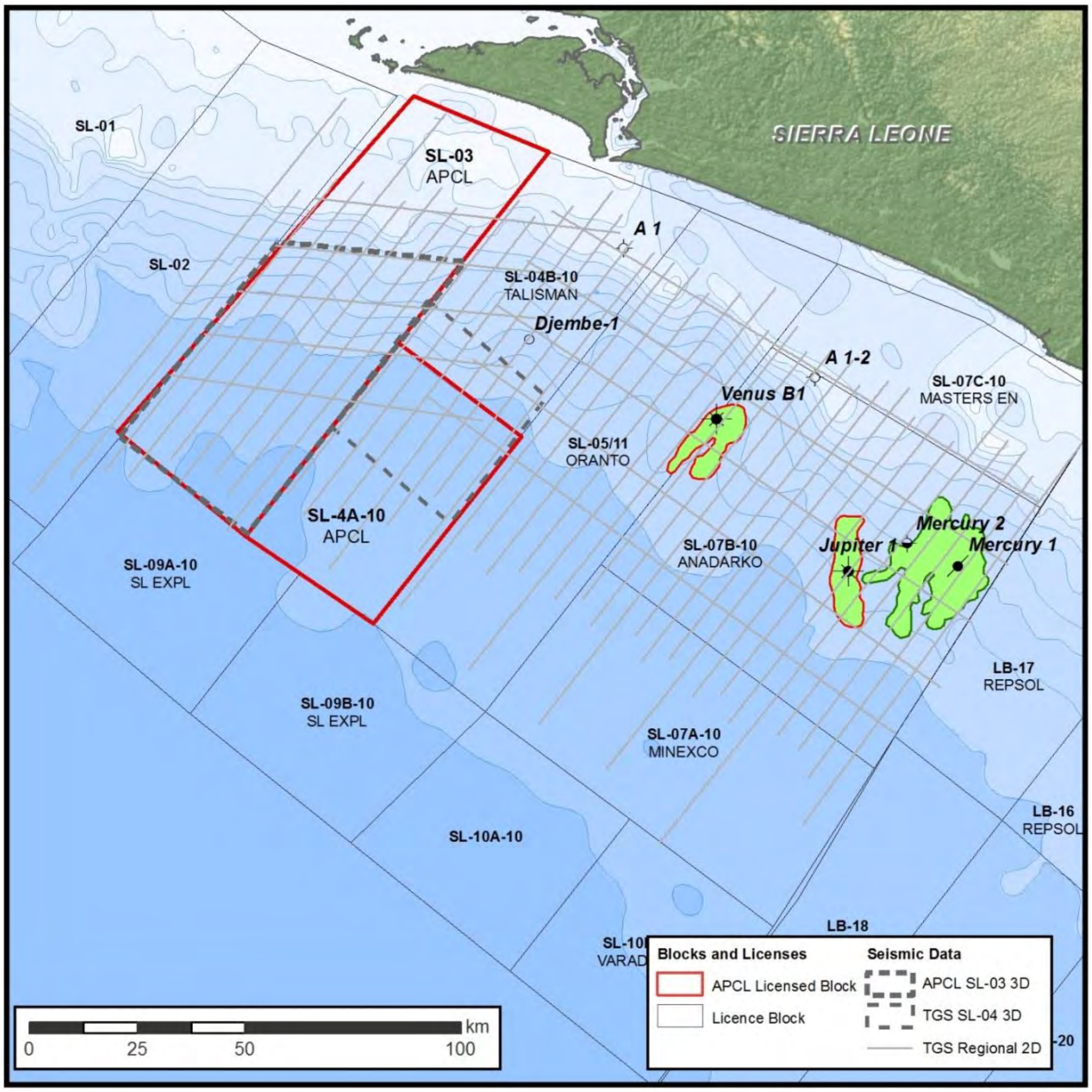

Figure 3.2 Well and seismic database, offshore Sierra Leone

The play fairways identified offshore Sierra Leone are very similar to those identified offshore Liberia (Figure 2.3), as structural traps within the Lower Cretaceous syn-rift section, and, primarily, as stratigraphic traps within turbiditic sands of Cretaceous age, (Campanian, Cenomanian and Turonian). Sourcing from regional marine (Cenomanian) or lacustrine (Albo-Aptian) source rocks is hypothesized. For the syn-rift structural play, the presence of Albo-Aptian reservoirs is demonstrated by the shallow water Wells A-1 and A-1-2, which also had indications of the development of source rocks within the Cretaceous syn-rift section. Although the data are not available, the recent Anadarko wells are publically documented as having found hydrocarbons within post-rift Cretaceous turbidites, potentially de-risking this play.

Blocks SL-03 and SL-04A-10 are towards the north-western edge of the seismically identified Cretaceous basin, immediately adjacent to a large structural lineament, the Sierra Leone Transform System. Submarine canyon development is therefore prognosed to occur to the south and east of this lineament, providing sediment input into the blocks during Cretaceous time. As is encountered regionally, there is reasonable seismic evidence for the presence of reservoir bearing intervals within the Upper Cretaceous section in the blocks.

APCL's evaluation of the recently licenced 3D seismic data is on-going, and as yet only one prospect Altair has been matured to drillable prospect status. However, a number of other Cretaceous channel/fan systems have been identified within Block SL- 03 (Figure 3.3).

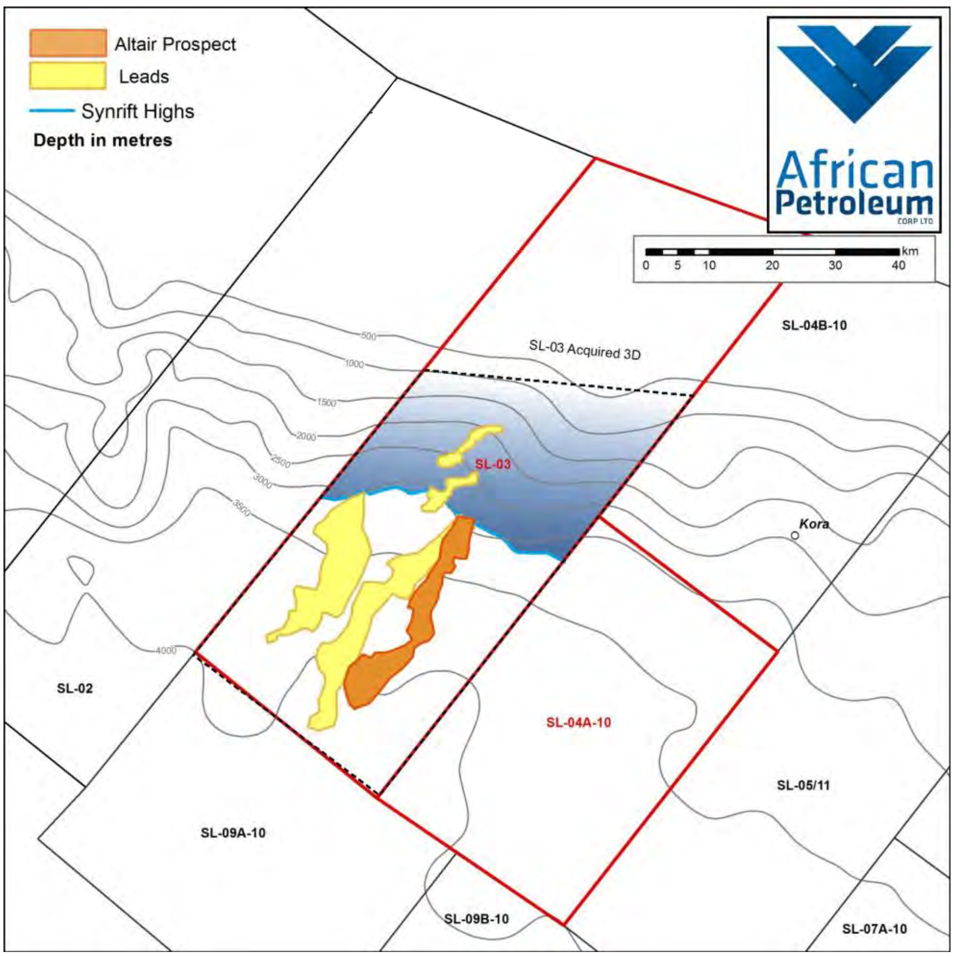

Figure 3.3 Leads, Sierra Leone Block SL-03

3.1. Play Risk

Although there has been recent drilling along strike of APCL's Sierra Leone licences, these wells lie some 100 km to the east. We have therefore attributed a play risk, albeit favourable, to Cretaceous channel-fan prospectivity within Blocks SL-03 and SL-04A-10. As with our review of Liberia, there is strong seismic evidence for reservoir and seal rocks being present, and offset drilling would indicate the same, from the limited published information. However, there is as yet no proven source rock within APCL's licences, and we see this as the key risk to play. The reported results of offset drilling, and APCL's own basin modelling would suggest that source risk would be favourable.

Our final play risk for the Cretaceous channel-fan systems in APCL's Sierra Leone licences is summarised in Table 3.1 below.

PLAY	Source	Reservoir Presence	Seal	**Play Risk**
Cretaceous Play	0.8	0.9	0.9	**65%**

Table 3.1 Play risk, Sierra Leone Block SL-03

3.1. Sierra Leone: Leads and Prospects

APCL is currently evaluating the recently licenced 3D seismic data over Block SL-03, and has identified a number of Cretaceous channel-fan systems, varying in areal extent from 20 km^2 to 150 km^2. Of the mapped channel fan systems, one, Altair, has been matured to prospect status by APCL, and we have made independent estimates of prospective resources and risks for this prospect.

A summary of prospective resources and geological chance of success for the prospective layers evaluated is given in Table 2 of the covering letter to this report.

3.1.1. Altair

The Altair prospect is a turbidite channel prospect mapped at a seismic event described as Turonian by APCL (Figure 3.4). There is, however, uncertainty in this stratigraphy, as it is established by jump correlation using regional seismic data, due to the lack of deep water wells on block. It is a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinch-out, in a similar manner to prospectivity within APCL's Liberia and Cote d'Ivoire acreage. A single target reservoir is identified within the trapped area. The prospect has anomalous seismic amplitudes associated with it, (Figure 3.5), which may indicate reservoir development. The top structure is mapped between 6200 – 6800 ms TWT over the area of the prospect. Our depth conversion indicates a crestal depth of approximately 5400 m TVDSS beneath a water depth of 3300 m, giving 2100 m of sediment above top reservoir.

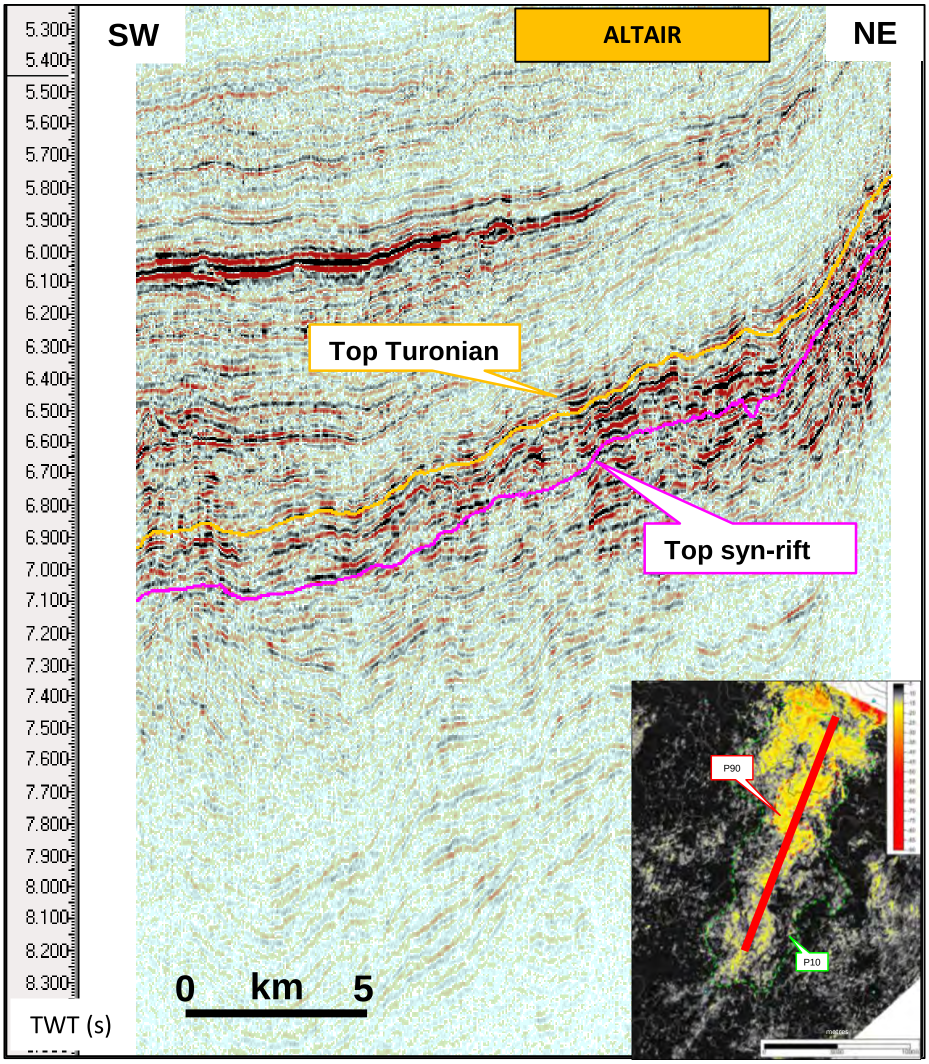

Figure 3.4 Dip seismic line (full offsets), Altair prospect

The seismic image suggests that Altair is a turbidite channel constrained in the north east by a well-defined canyon. Two distinct canyon systems feed erosive channels at the break of slope. A south west trending fault, which is almost perpendicular to the main canyon feeders, alters bathymetric relief and diverts the Altair channel southwards.

ERCE has made estimates of prospective resources for the Altair prospect using an identical methodology to our evaluation of Liberian prospectivity. An area net approach was adopted using optimized seismic amplitudes to constrain areal extent and define an areal net to gross to account for lateral variability of sand distribution within the reservoir. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes and a column height of 200 m. Our high case extends the prospect down-dip to a column height of 800 m, and laterally to incorporate weaker amplitude responses (Figure 3.5). These polygons were used to constrain the P90 and P10 area inputs of our probabilistic simulation.

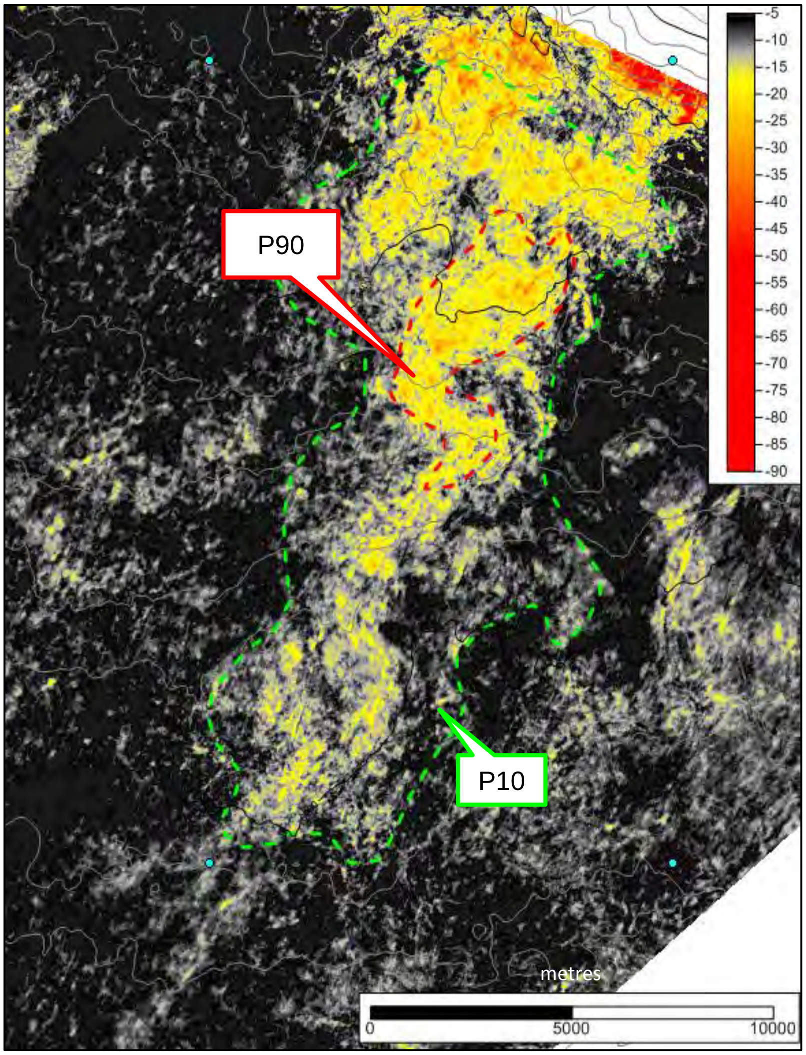

Figure 3.5 Seismic amplitude (gradient stack) and Top Turonian depth (m TVDSS), Altair prospect

Net pay is estimated from the mapped seismic interval and regional analogue, with porosities and fluid properties estimated as described in Section 1.5.

We have used the prospect risk matrix presented in Section 1.5 to determine the geological chance of success for the Altair prospect. Key risk is to trap integrity, due to the coalescing of a number of mapped fan systems up dip towards the pinch-out of Altair, with subsidiary risk to charge, as this is as yet unproven on block. This gives a prospect specific risk of 28% which, when combined with the play risk, gives an overall chance of success of 18% for the Altair prospect.

4. Cote d’Ivoire: Prospectivity and Plays

4.1. Introduction

Offshore Cote d’Ivoire has been actively explored for hydrocarbons for a number of years, and much of the offshore shelf is under licence. Recently, exploration has moved into deeper waters, targeting the regional post-rift (Cretaceous) play and APCL has identified a number of prospects and leads within the western licence Blocks of CI-513 and CI-509 (Figure 4.1).

There are two main play types identifiable offshore Cote d’Ivoire, (Figure 4.2), as structural traps within the Lower Cretaceous (Aptian to Albian) syn-rift section, and as stratigraphic traps within post rift turbiditic sands of Cenomanian to Turonian age. Sourcing is prognosed from regional marine (Turonian) or lacustrine (Albo-Aptian) source rocks.

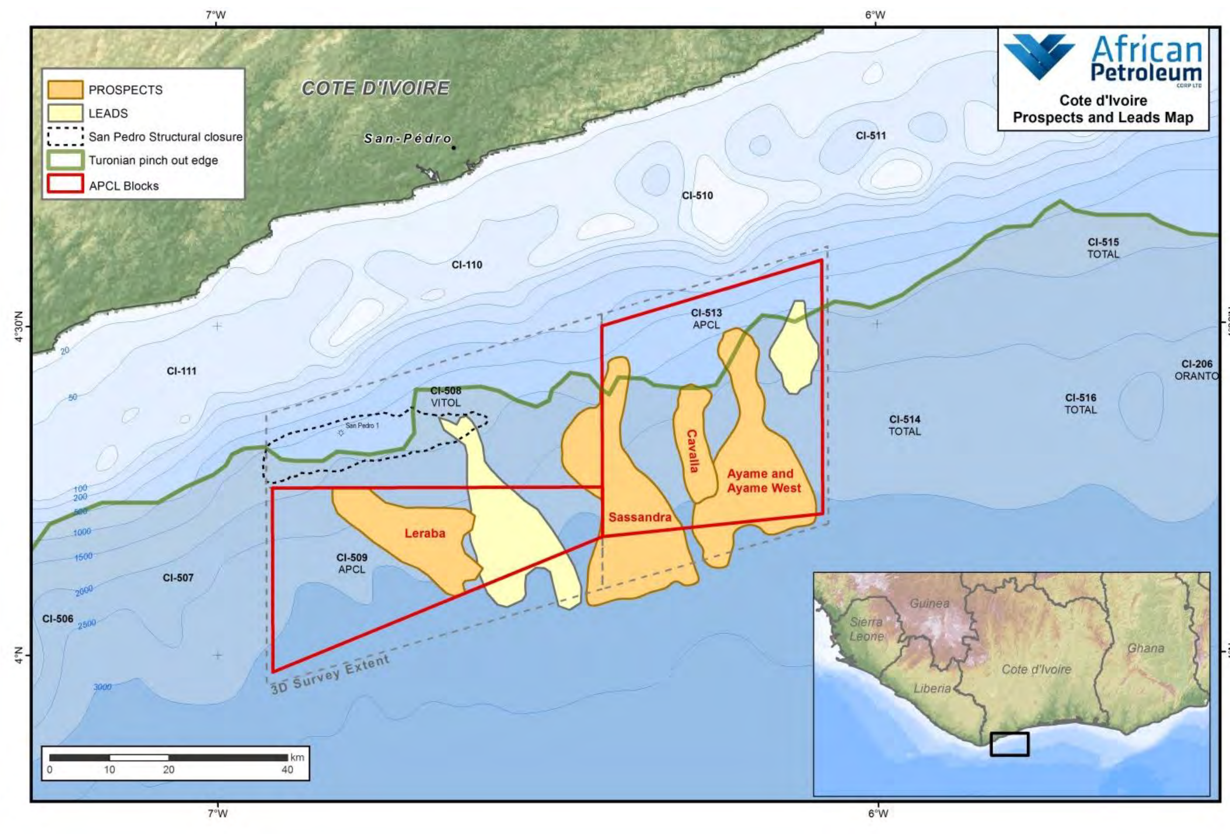

Figure 4.1 CI-509 and CI-513 Prospects and Leads, offshore Cote d’Ivoire

Historically, exploration has been restricted to the narrow shelf area, and has yielded a number of commercial fields, both oil and gas, including Foxtrot, Baobab and Espoir. All of these fields lie within the Lower Cretaceous (Aptian) syn-rift play. Recently, exploration has moved into deeper waters, targeting the regional post-rift (Cretaceous) play. Well Paon-1X, c. 300 km to the east of Blocks CI-105 and CI-513, drilled by Tullow Oil plc and partners in licence CI-103 during 2012, is reported to have found hydrocarbons in turbiditic sandstones of Cretaceous age. Well Kosrou-1X, some 150 km east of Blocks CI-105 and CI-513 shows reservoir development within the post-rift Cretaceous section, particularly within the Turonian to Cenomanian section.

Evaluation of prospectivity within Blocks CI-509 and CI-513 is at an early stage, and a working petroleum system is not proven on the block. However, a number of Cretaceous channel/fan systems have been identified using both 2D and 3D seismic data, which have generated around seven potential traps at the date of this report, five of which are considered prospects for this report (Figure 4.1).

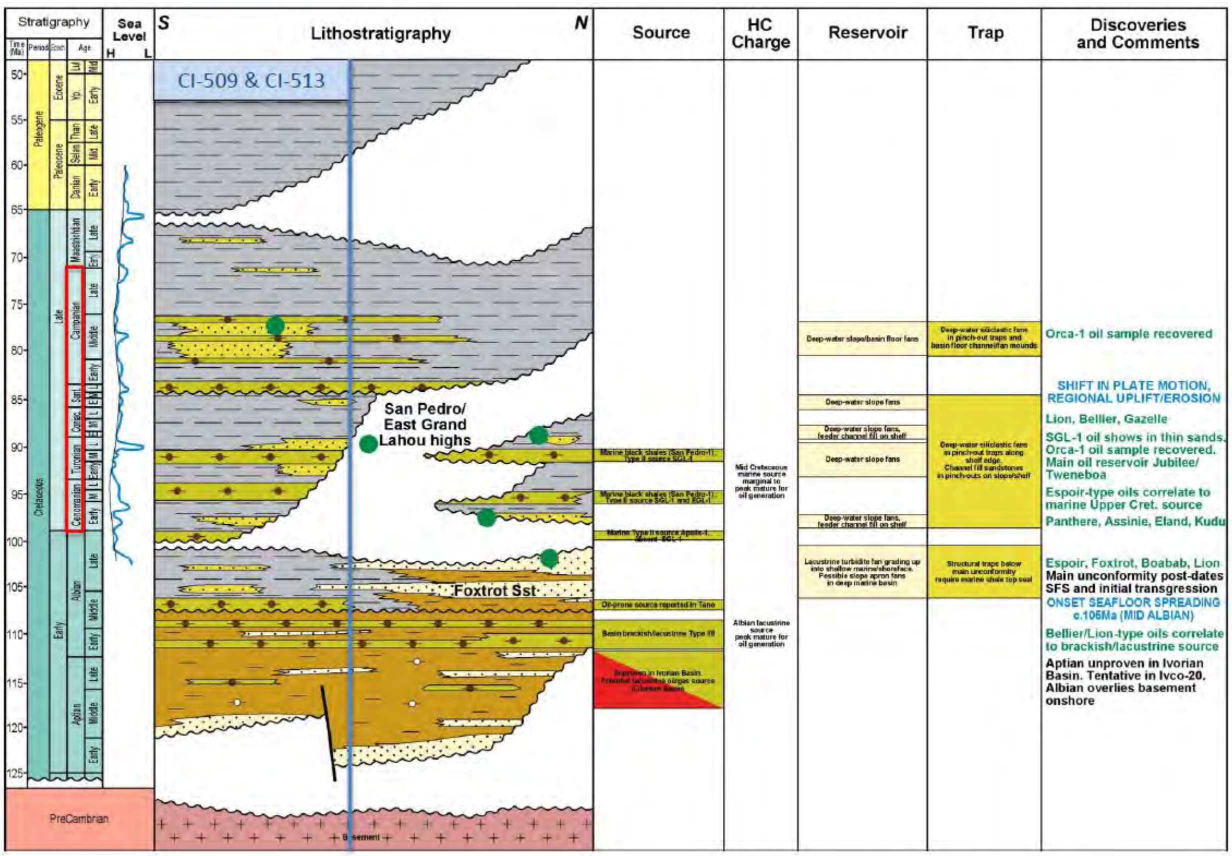

Figure 4.2 Petroleum systems and plays, offshore Cote d'Ivoire

4.2. Well and Seismic Database

APCL has obtained a regional database of 2D seismic data offshore Cote d'Ivoire, which provides well to seismic ties to Well San Pedro-1 (Figure 4.3). The primary data set used for our evaluation is that provided by the recently acquired 3D seismic data. At the time of writing, these data were processed to pre-stack time-migration, and we have used this volume, plus available AvO processed volumes, to evaluate the prospectivity of the CI-513 licence, currently only the full-stack seismic product has been used to assess the prospectivity in Block CI-509.

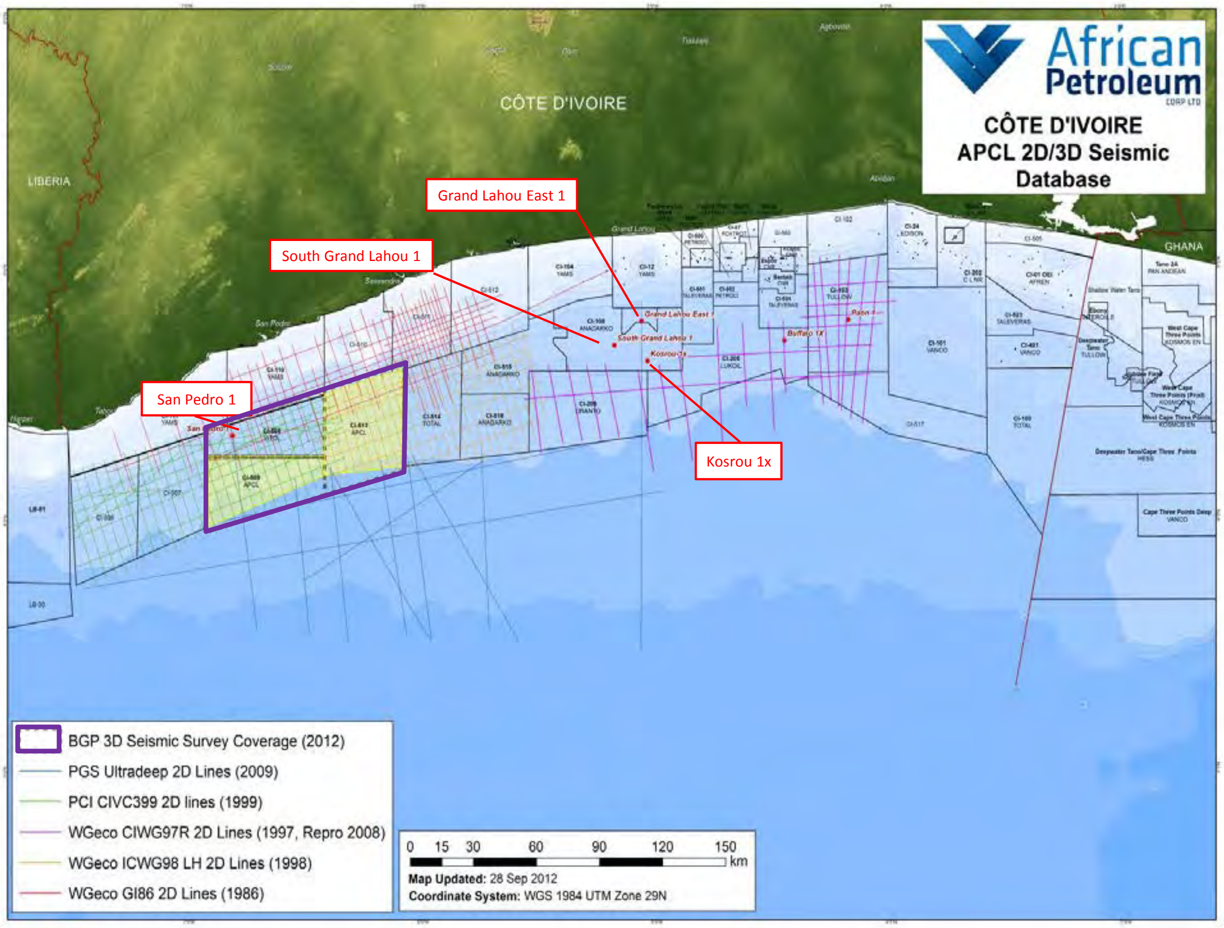

Figure 4.3 Well and seismic database, offshore Sierra Leone

4.3. Plays and Petroleum Geology: Blocks CI-509 and CI-513

The primary play being explored within Blocks CI-509 and CI-513 is the Cretaceous post-rift turbidite play (Figure 4.2). There is reasonable seismic evidence for the presence of reservoir bearing intervals within the Upper Cretaceous section of the blocks. However, dating of the age of these post-rift turbidite channel/fan systems is uncertain, due to the paucity of well and seismic data, with stratigraphy extrapolated into APCL's licences via regional seismic correlation. The presence of a regional Turonian source rock is hypothesized to charge any identified traps. This is not proven on the block, but evidence from offset drilling in Block CI-105 demonstrates the presence of source rocks developed within the

Cenomanian to Turonian, and basin modelling studies indicate that the Turonian may be mature for oil generation local to the licences.

A number of Cretaceous channel/fan systems have been identified using both 2D and 3D seismic data (Figure 4.1) and we have independently evaluated the Prospective Resources and geological chance of success for five of these. In addition, the Lower Cretaceous syn-rift play may be viable within the licences, particularly to the north. Evaluation of this play by APCL is on-going, and no prospective resources have been assessed for this play.

4.4. Play Risk

Exploration offshore Cote d'Ivoire is at an early stage, and there are limited well data available. As a result, ERCE has adopted a play and prospect risk system in our evaluation of the Cote d'Ivoire prospective resources within the Cretaceous channel-fan play, in an identical manner to our review of Liberia and Sierra Leone.

There is seismic evidence for the presence of seal and reservoir rock, and thus the key risk is to source, and we see source risk as the key risk to the Creteaceous clastic play. Sourcing is prognosed from regional marine (Turonian), modelled as having limited hydrocarbon generating potential, or lacustrine (Albo-Aptian) source rocks, the maturity of which are interpreted to be in the very early oil window. As a result, we assign a play source risk of 0.6. Note that the uncertainty in both source rock presence and thermal maturity is such that there is a possibility of gas charge, although it is impossible to quantify this chance at present.

Our final play risk is summarised in Table 4.1 below.

PLAY	Source	Reservoir Presence	Seal	**Play Risk**
Cretaceous Clastic Play	0.6	0.9	0.9	**0.49**

Table 4.1 Play risk, Cote d'Ivoire Blocks CI-509 and CI-513

4.5. Cote d'Ivoire Blocks CI-509 and CI-503: Leads and Prospects

Prospectivity has been identified by APCL at a number of levels, with the evaluation of the Cretaceous clastic turbidite channel-fan play being the most advanced. ERCE has made independent assessments of prospective resources and geological chance of success for five prospects within this play: Ayame, Ayame West, Sassandra, Cavalla and Agnéby (Figure 4.1).

A summary of prospective resources and geological chance of success for the prospective layers evaluated is given in Table 3 of the covering letter to this report.

4.5.1. Ayame & Ayame West

The Ayame and Ayame West prospects are identified as Upper Cretaceous fans which lie mainly within Block CI-513 (Figure 4.4). The prognosed trapping mechanism is stratigraphic, with areal extents defined by amplitude truncation and structural pinch-out. A single target reservoir is prognosed for both, within stratigraphy identified as Turonian, although stratigraphy is uncertain in both licences, as it is established via long distance seismic ties. The prospects have anomalous seismic amplitudes associated with them, (Figure 4.5), which may indicate reservoir development. The top structure is mapped between 5400 – 6300 ms TWT over the area of the prospect, and our depth conversion places the crest of the trap at approximately 4200 m TVDSS beneath a water depth of 2500 m.

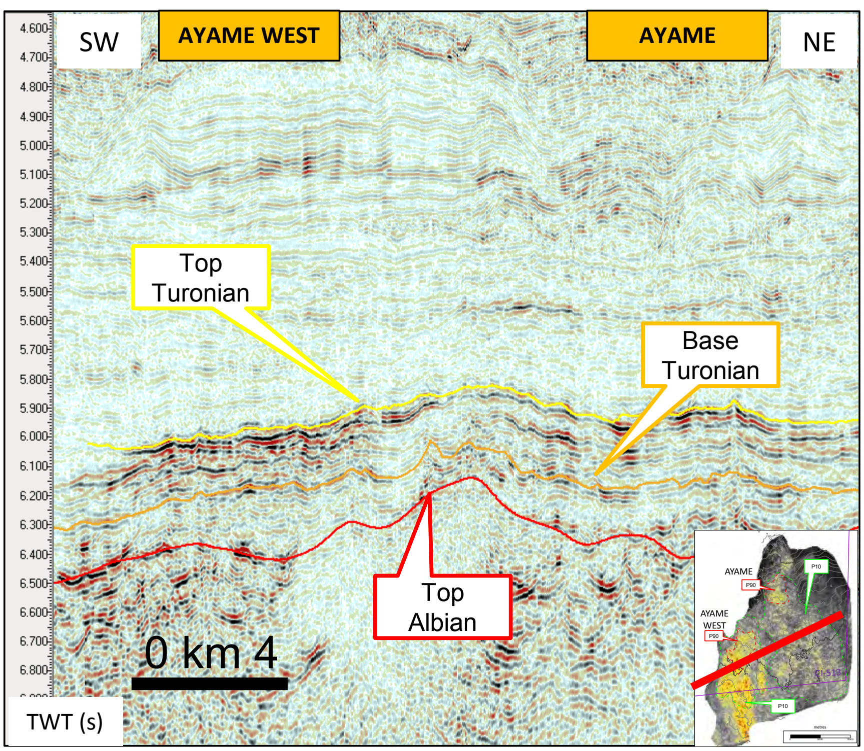

Figure 4.4 Strike Line, Ayame and Ayame West prospects

Evaluation of the Ayame and Ayame West prospects is undertaken in an identical manner to our evaluations of the stratigraphically trapped channel-fan prospects in APCL's Liberia and Sierra Leone licences. An area net approach is adopted using anomalous seismic amplitudes to constrain areal extent and define an areal net to gross to account for lateral variability of sand distribution within the closure area. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes and a 200 m column height. Our high case extends the prospect down-dip to 800 m of column height, to include a larger area of anomalous amplitudes (Figure 4.5). These polygons are used to constrain the P90 and P10 area inputs of our probabilistic simulation.

Net pay estimates are estimated from mapped seismic interval thickness and from regional analogues with porosity, fluid parameters and recovery factors estimated as described in Section 1.5.

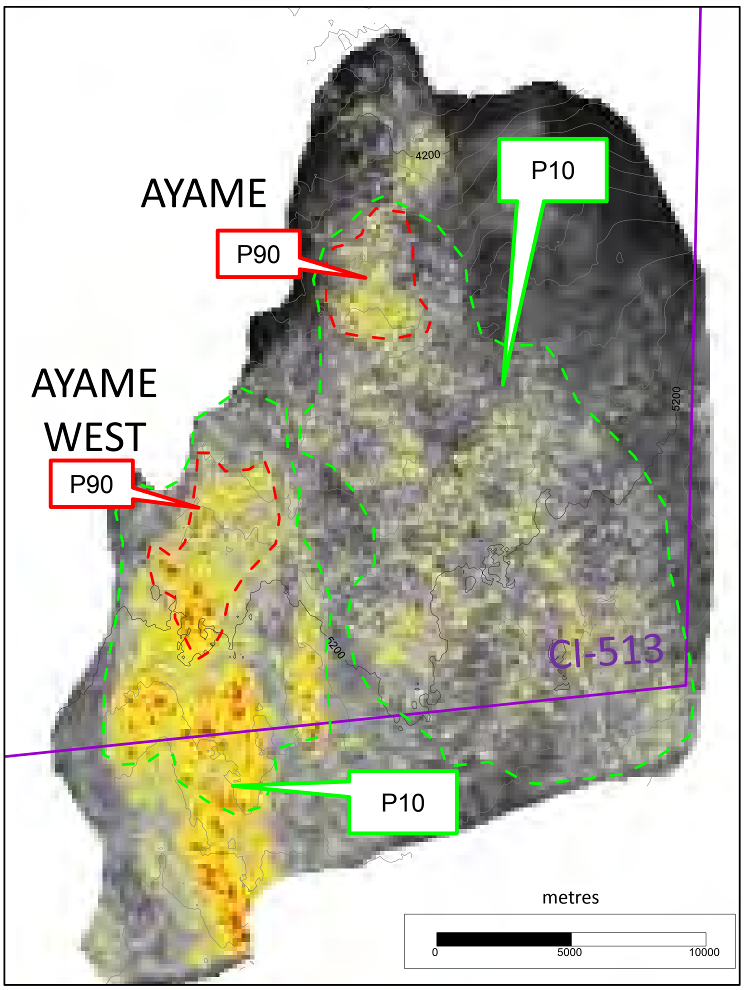

Figure 4.5 Ayame: Seismic amplitude (gradient stack) and Top Turonian depth (m TVDSS)

We use the prospect risk matrix presented in Section 1.5 to determine the geological chance of success for the Ayame and Ayame West prospects. Key risk is to trap, and we attribute a trap risk of 50% to both prospects, giving a prospect specific chance of success of 28% for both prospects. When combined with the play risk, this gives an overall chance of success of 14%.

A proportion of the closure areas for both the Ayame and Ayame West prospects fall outside Block CI-513 in our high case (6 km^2 and 11 km^2 respectively). This is corrected for in our summary tables of net risked and unrisked prospective resources at the beginning of this document by computing the area of the prospect off-block at P90, P50 and P10 and scaling accordingly.

4.5.2. Sassandra

The Sassandra prospect is mapped as a deep-water fan system at Top Turonian level, and lies within Blocks CI-513 and CI-509, approximately 20km west along strike from the Ayame prospect. It is a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinch-out (Figure 4.6). A single target reservoir is prognosed within the Turonian, and, as with other prospects on the block, has similar uncertainty in the stratigraphic age of the prospective interval. The prospect has anomalous amplitudes associated with it (Figure 4.7) which may indicate reservoir development. The top structure is mapped between 5000 – 6000 ms TWT over the area of the prospect, and our depth conversion predicts a crestal depth of approximately 4400 m TVDSS beneath a water depth of 2500 m.

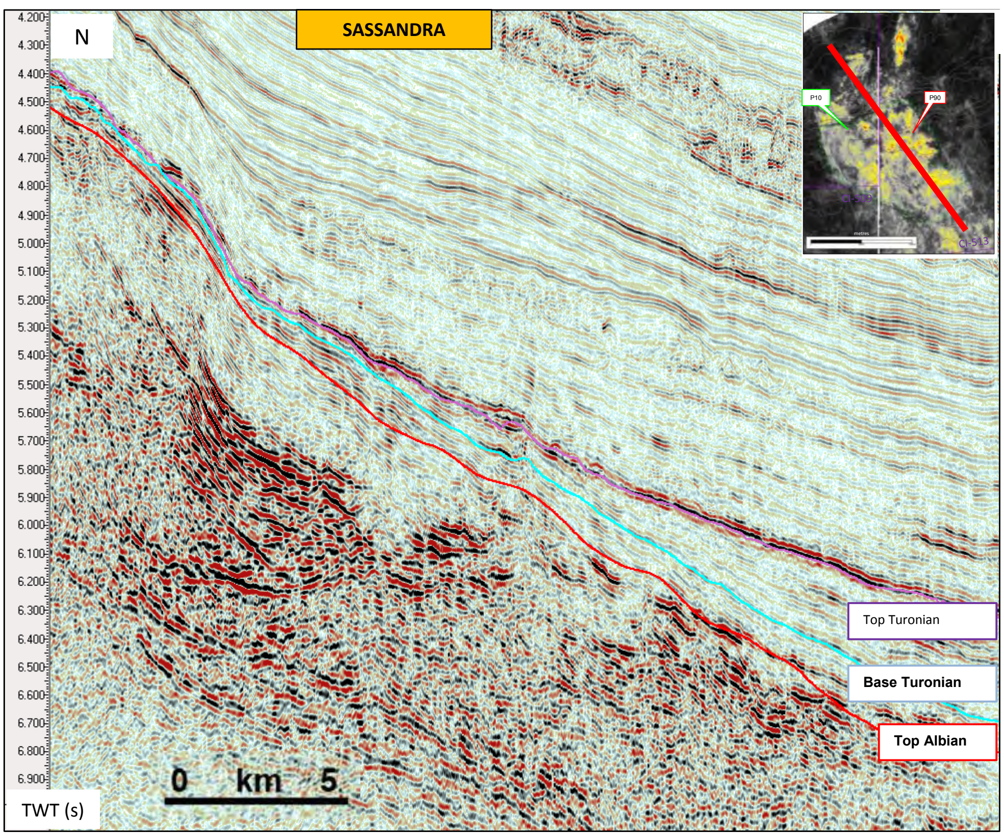

Figure 4.6 Dip seismic line, Sassandra prospect

Evaluation of the Sassandra prospect is undertaken in an identical manner to our evaluation of the Ayame and Ayame West prospects. An area net approach is adopted using anomalous seismic amplitudes to constrain areal extent and define an areal net to gross to account for lateral variability of sand distribution within the closure area. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes and a 200 m column height. Our high case extends the prospect down-dip to 800 m of column height, to include a larger area of anomalous amplitudes (Figure 4.7). These polygons are used to constrain the P90 and P10 area inputs of our probabilistic simulation. As far offset data are only available for CI-513 (at the time of writing) we have used amplitudes from the full-stack volume to map the extent of the prospect to the west, off block (Figure 4.7).

Net pay estimates are estimated from mapped seismic interval thickness and from regional analogues with porosity, fluid parameters and recovery factors estimated as described in Section 1.5.

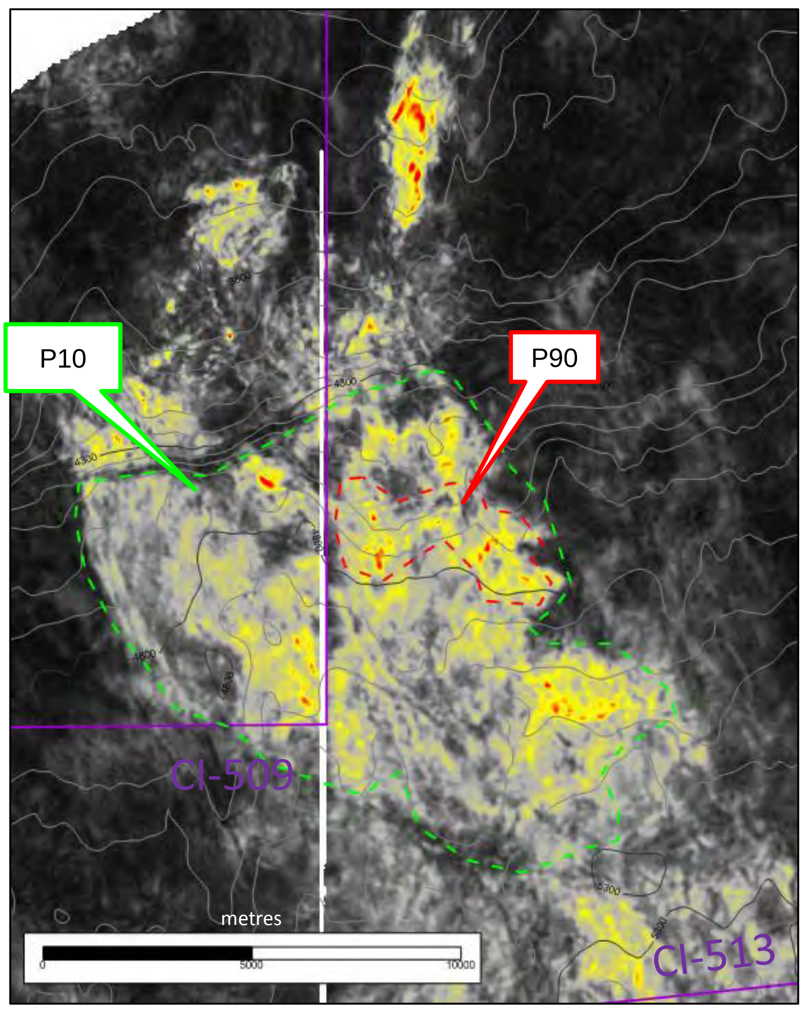

Figure 4.7 Sassandra prospect: Seismic amplitude and Top Turonian depth (m TVDSS)

We use the prospect risk matrix presented in Section 1.5 to determine the geological chance of success for the Sassandra prospect. Key risk is to trap, and we attribute a trap risk of 40%. This is a lower value than our estimates for the Ayame and Ayame West prospects, as the up-dip termination of the trap is less well defined, and requires a larger area for pinch-out or bypass. Seismic amplitude support for reservoir presence is less over the Sassandra prospect relative to Ayame. Thus, we estimate a prospect specific chance of success for the Sassandra prospect of 20%, which, when combined with the play risk, gives an overall chance of success for the Sassandra prospect of 10%.

A proportion of the closure area for the Sassandra prospect falls outside Blocks CI-513 and CI-509 in our high case (33 km^2). This is corrected for in our summary tables of net risked and unrisked prospective resources at the beginning of this document by computing the area of the prospect off-block at P90, P50 and P10 and scaling accordingly.

4.5.3. Cavalla

The Cavalla prospect is an Upper Cretaceous Fan which lies between the Ayame and Sassandra prospects within Block CI-513. It is identified as a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinch-out (Figure 4.8). A single target reservoir is prognosed within the Turonian/Cenomanian interval, (with similar stratigraphic uncertainty to other prospects on block), which lies stratigraphically beneath the Ayame prospect. The prospect has anomalous seismic amplitudes associated with it (Figure 4.9) which may indicate reservoir development. The top structure is mapped between 4600 – 5900 ms TWT over the area of the prospect, and we estimate a crestal depth of approximately 3900 m TVDSS beneath a water depth of 2500 m. The prospect is more steeply dipping than other fan systems mapped on block.

Evaluation of the Cavalla prospect is undertaken in an identical manner to our evaluation of the Ayame, Ayame West and Sassandra prospects. An area net approach is adopted using anomalous seismic amplitudes to constrain areal extent and define an areal net to gross to account for lateral variability of sand distribution within the closure area. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes and a 200 m column height. Our high case extends the prospect down-dip to 800 m of column height, to include a larger area of anomalous amplitudes (Figure 4.9). These polygons are used to constrain the P90 and P10 area inputs of our probabilistic simulation.

Net pay estimates are estimated from mapped seismic interval thickness and from regional analogues with porosity, fluid parameters and recovery factors estimated as described in Section 1.5.

We use the prospect risk matrix presented in Section 1.5 to determine the geological chance of success for the Cavalla prospect. Key risk is to trap, and we attribute a trap risk of 40%. As with the Sassandra prospect, this is a lower value than our estimates for the Ayame and Ayame West prospects, as the up-dip termination of the trap is less well defined, and requires a larger area for pinch-out or bypass. Seismic amplitude support for reservoir presence is less over the Cavalla prospect relative to Ayame. Thus, we estimate a prospect specific chance of success for the Cavalla prospect of 20%, which, when combined with the play risk, gives an overall chance of success for the Cavalla prospect of 10%.

The Cavalla prospect is contained entirely within APCL's licences.

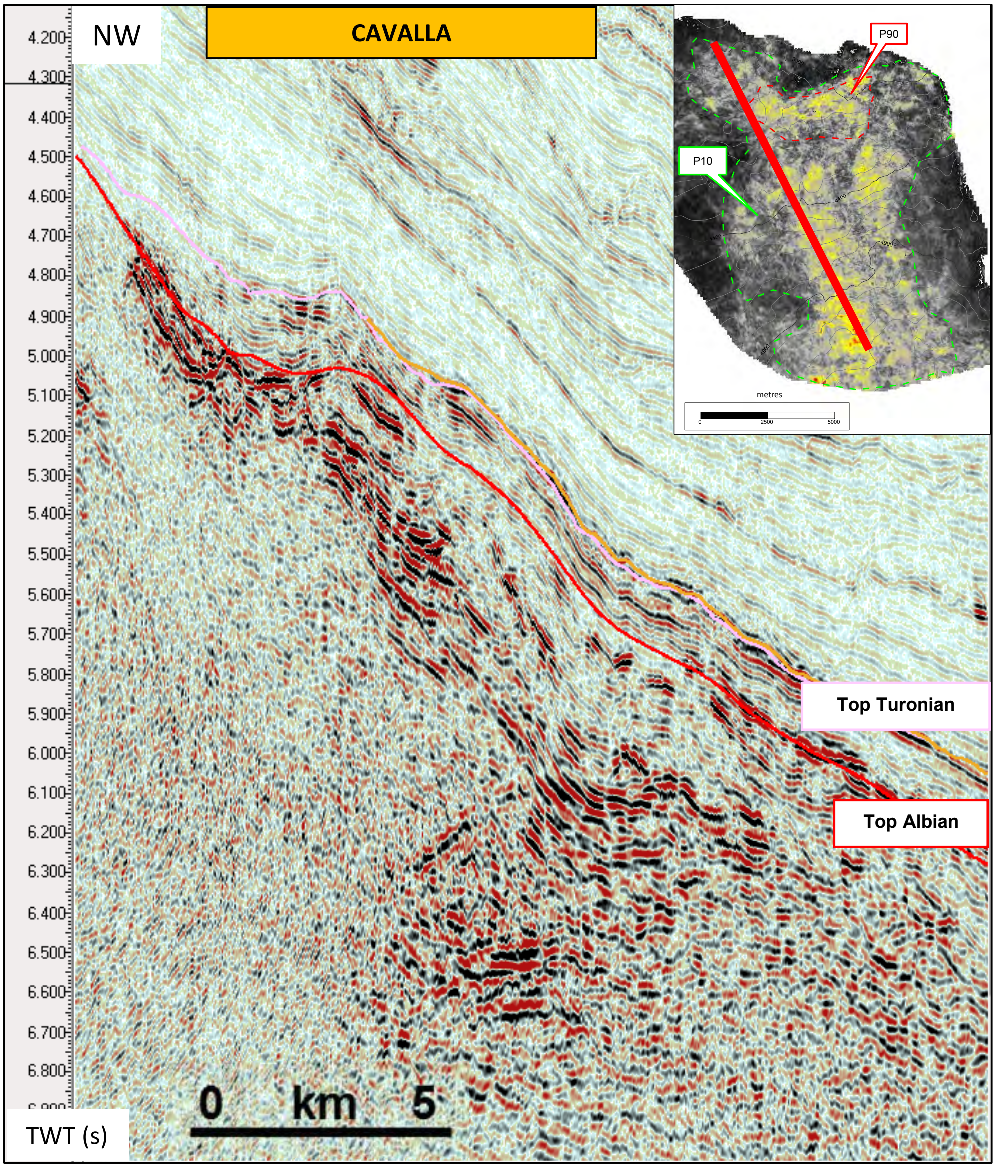

Figure 4.8 Dip seismic line, Cavalla prospect

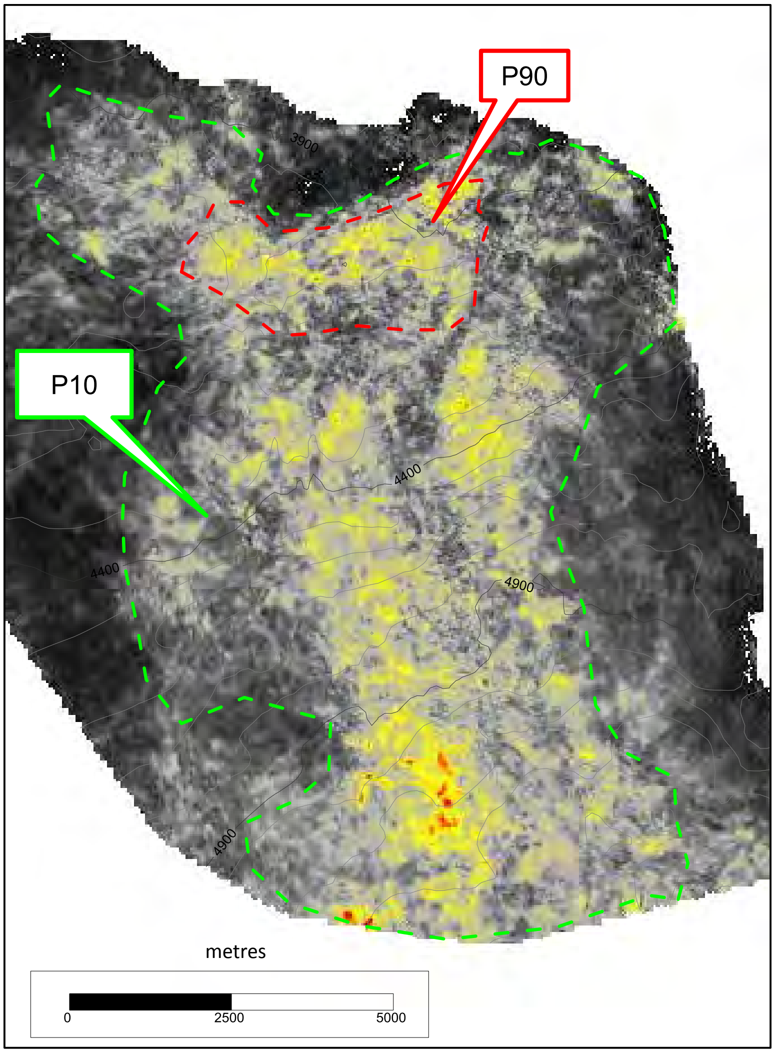

Figure 4.9 Seismic amplitude (gradient stack) and Top fan depth (m TVDSS), Cavalla prospect

4.5.4. **Agnéby**

As with the other evaluated prospectivity within Blocks CI-509 and CI-513, the Agnéby prospect is an Upper Cretaceous fan which lies within Block CI-509. It is identified as a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinch-out (Figure 4.10). The prospect has anomalous seismic amplitudes associated with it (Figure 4.11) which may indicate reservoir development. Unlike the other Cote D'Ivoire prospects evaluated in this report, no offset seismic volumes were available for our review of Agnéby at the time of writing. The seismic amplitude response and character on the full-stack data is however consistent with that observed over other prospects in Block CI-513 where more seismic products were available.

The top structure is mapped between 4600 – 5200 ms TWT over the area of the prospect, and we estimate a depth at the crest of approximately 3700 m TVDSS beneath a water depth of 2500 m.

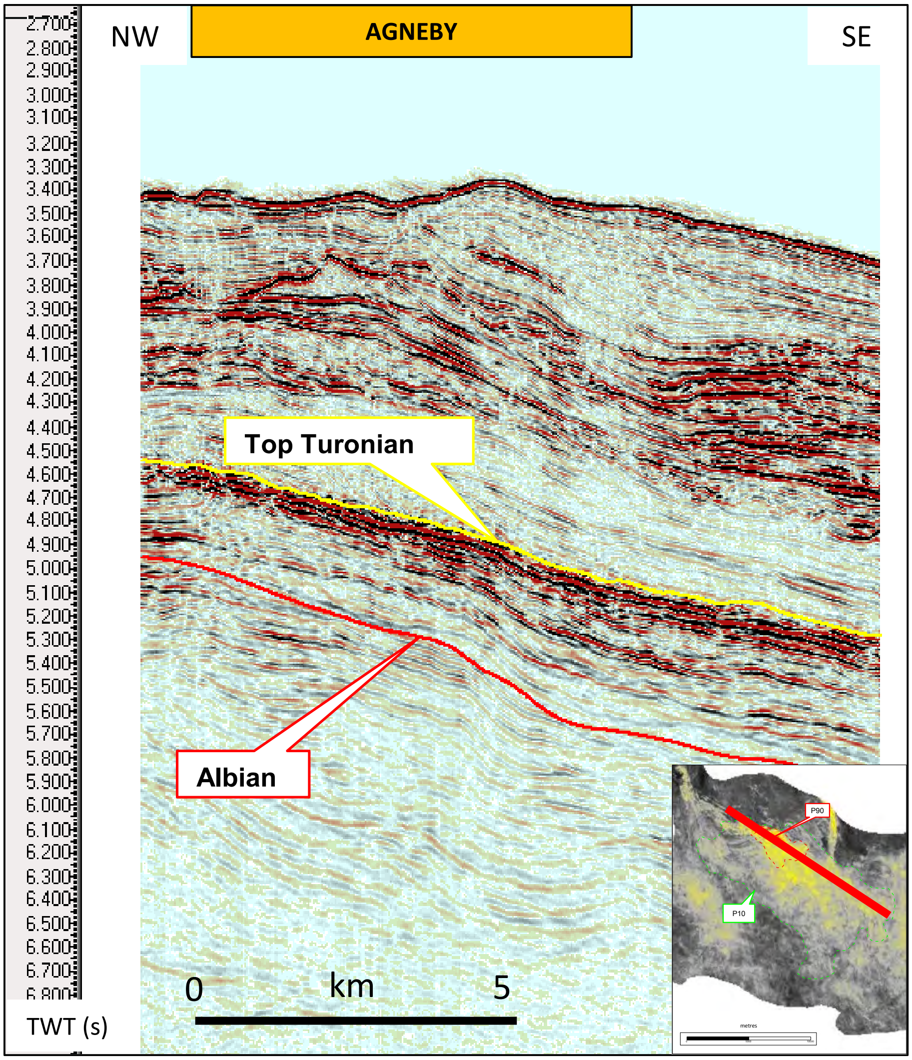

Figure 4.10 Dip seismic line, Agnéby prospect

Evaluation of the Agnéby prospect is undertaken in an identical manner to our evaluation of the other Cretaceous fan systems evaluated in this section. An area net approach is adopted using anomalous seismic amplitudes to constrain areal extent and define an areal net to gross to account for lateral variability of sand distribution within the closure area. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes and a 200 m column height. Our high case extends the prospect down-dip to 800 m of column height, to include a larger area of anomalous amplitudes (Figure 4.11). These polygons are used to constrain the P90 and P10 area inputs of our probabilistic simulation.

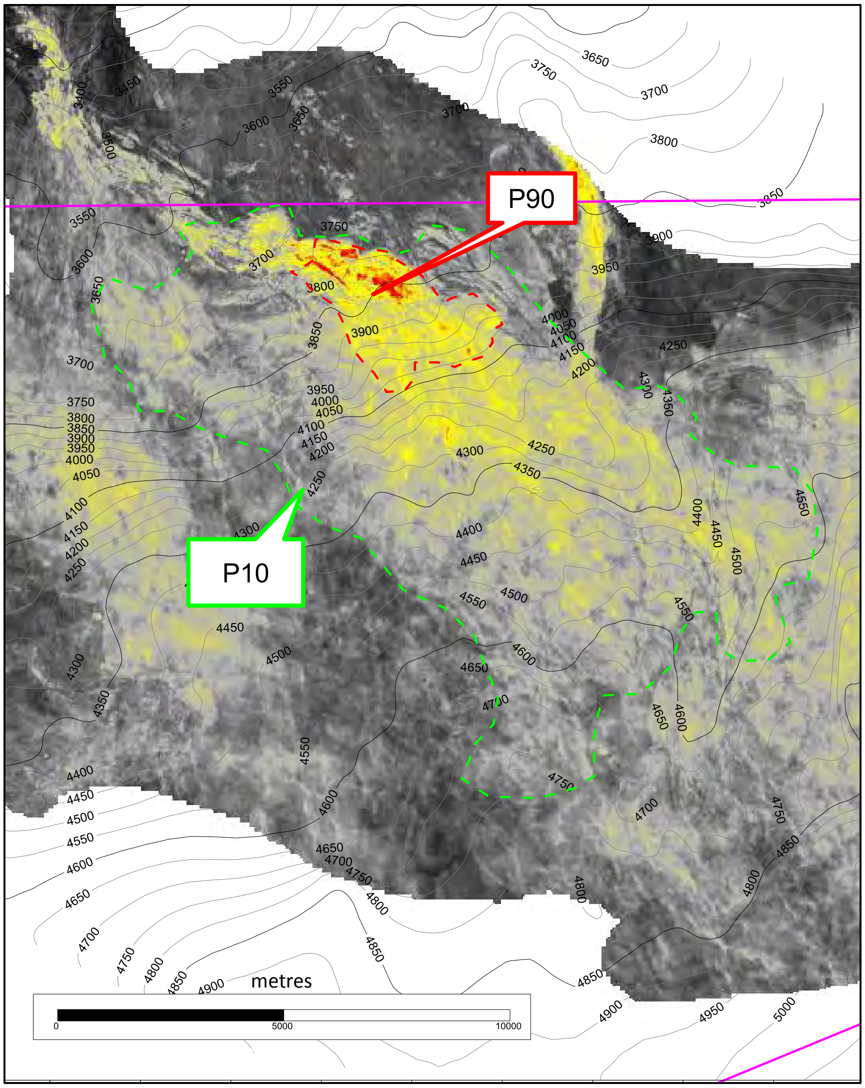

Figure 4.11: Seismic amplitudes, Agnéby prospect, overlay of Top Reservoir m TVDSS

Net pay estimates are derived from mapped seismic interval thickness and from regional analogues with porosity, fluid parameters and recovery factors estimated as described in Section 1.5. The prospect is relatively shallow to mud line, and we have modelled a more viscous oil, as described in Section 1.6.

We use the prospect risk matrix presented in Section 1.5 to determine the geological chance of success for the Agnéby prospect. Key risk is to trap, and we attribute a trap risk of 60%, as the up-dip extent of the prospect is fairly well defined on seismic data. Although no off-set 3D seismic data were available, the seismic evidence for reservoir presence is again comparable to that of Ayame West. Thus, we estimate a prospect specific chance of success for the Agnéby prospect of 34%, which, when combined with the play risk, gives an overall chance of success for the Agnéby prospect of 16%.

The Agnéby prospect is contained entirely within APCL's licences.

5. Senegal: Prospectivity and Plays

5.1. Introduction

Although there are no deep water wells offshore Senegal (or the Gambia), there has been historical drilling in shallower waters (Figure 5.3), and a number of plays can be identified on a regional basis (Figure 5.1, Figure 5.2). Several oil and gas discoveries have been made onshore Senegal, and the Dome Flore and Dome Gea discoveries to the south are each reported to contain a million barrels of biodegraded oil (c.10-13° API gravity) in place within sandstones of Oligocene (Tertiary) age. Some lighter (30-34° API gravity) oil has also been encountered in deeper intervals. More regionally, oil and gas discoveries have been made to the north offshore Mauritania and in Guinea Bissau (Sinapa). The recently drilled Venus and Mercury wells in Sierra Leone have also reportedly encountered hydrocarbons.

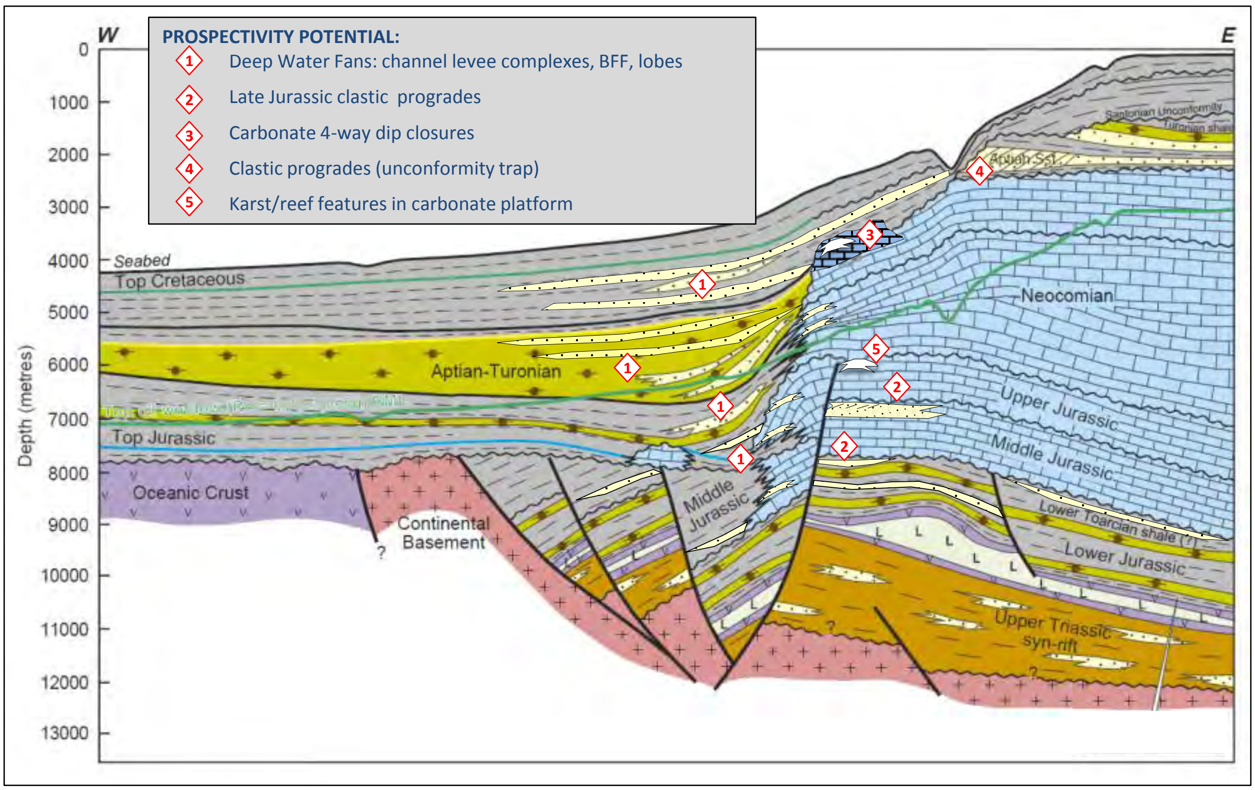

Figure 5.1 Plays, Senegal SOSP and ROP Blocks

The range of hydrocarbon types encountered is suggestive of multiple sourcing, and the age of the reservoirs suggest late timing of oil generation, consistent with a late Cretaceous source for the heavy oil, although there are no published data to confirm this.

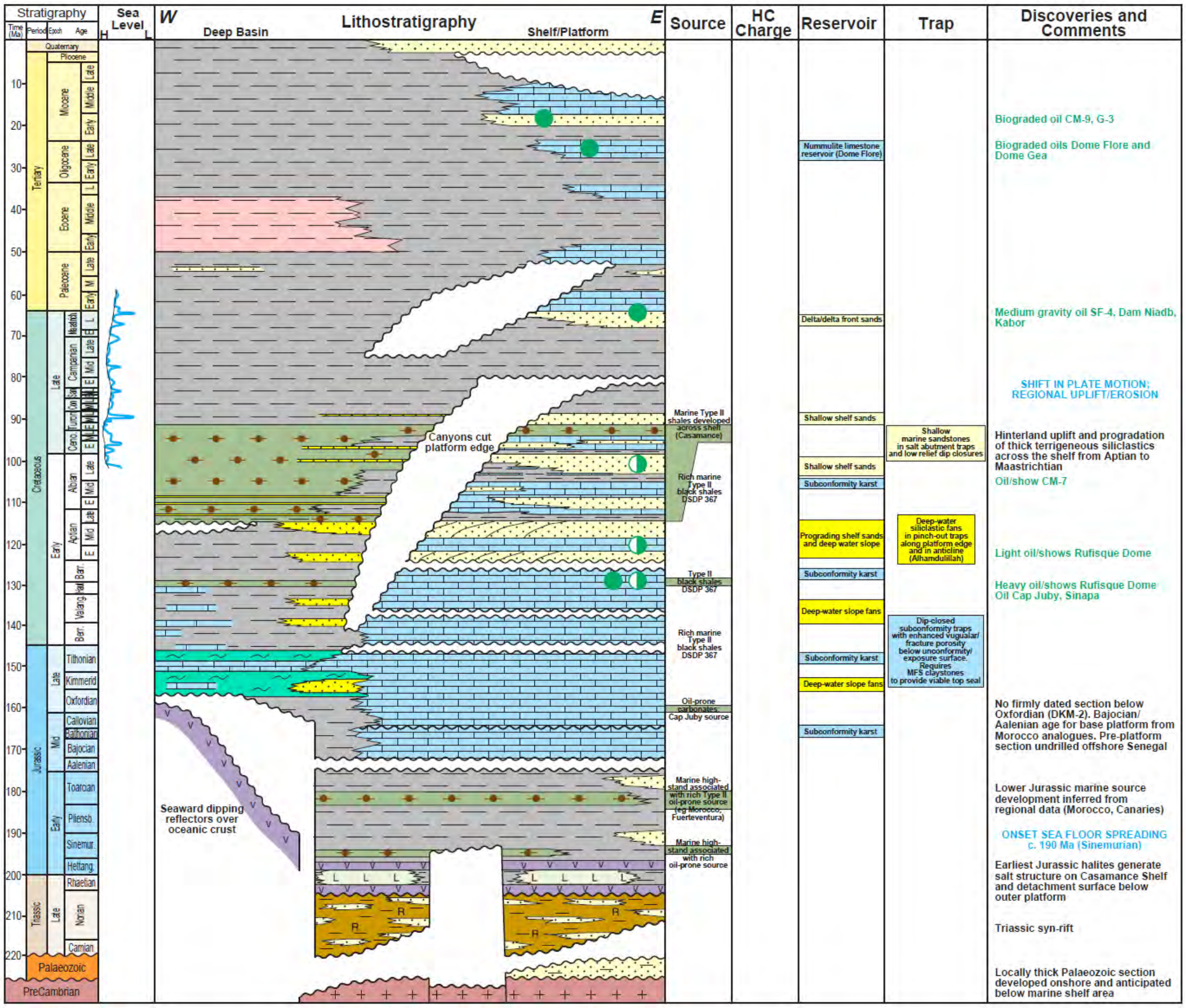

Figure 5.2 Petroleum systems and stratigraphy, offshore Senegal

5.2. Well and Seismic Database

In 2012, APCL acquired 3600 km^2 of multi-client 3D seismic data over the Offshore Sud Profond licence (Figure 5.3). In addition, 1500 km^2 of legacy 3D data over the Rufisque Offshore Profond licence is currently being reprocessed by APCL, and legacy 2D seismic data (c. 7000 line km) have also been acquired.

No wells have been drilled within the deeper waters of the ROP and SOSP licences, and stratigraphy is established by regional seismic correlation.

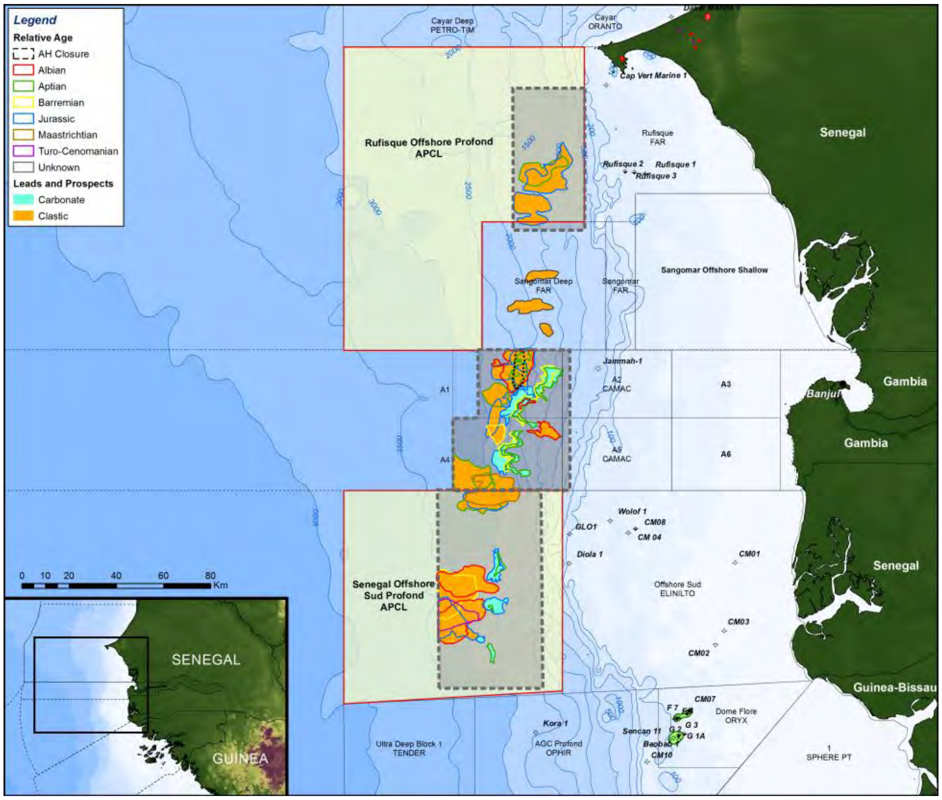

Figure 5.3 Well and seismic database, offshore Senegal Blocks ROP and SOSP
Locations of currently identified leads are also shown

5.3. Plays and Petroleum Geology

Of the regional plays identified in Section 5.1, two are being pursued by APCL, particularly in the SOSP block, where current exploration efforts have been focussed.

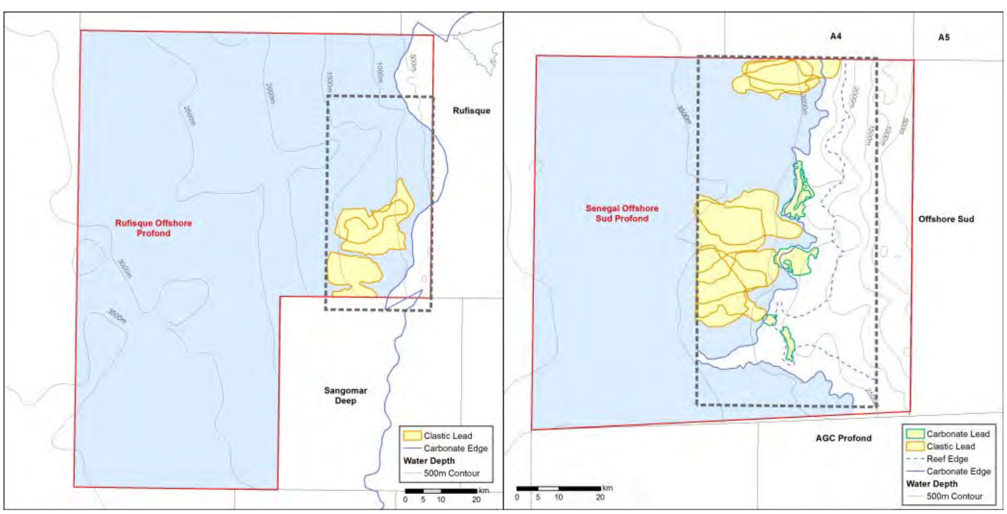

Figure 5.4 Leads, ROP and SOSP blocks, Senegal

At present, a number of conceptual Cretaceous post-rift leads are identified by APCL (Figure 5.3), particularly to the south and centre of the SOSP block. Here, seismic amplitude evidence suggests the development of basin floor fans and a shallower, more channelized system, within what is interpreted as a mid to upper Cretaceous section (Figure 5.5). Overburden thickness is around 2700 m to 3400 m for the deeper stratigraphy interpreted as basin floor fans, which may affect reservoir quality (Figure 2.4). The shallower more channelised system has an overburden thickness of around 1400 m to 2600 m. Water depth varies from 2500 m to 3000 m over the mapped play.

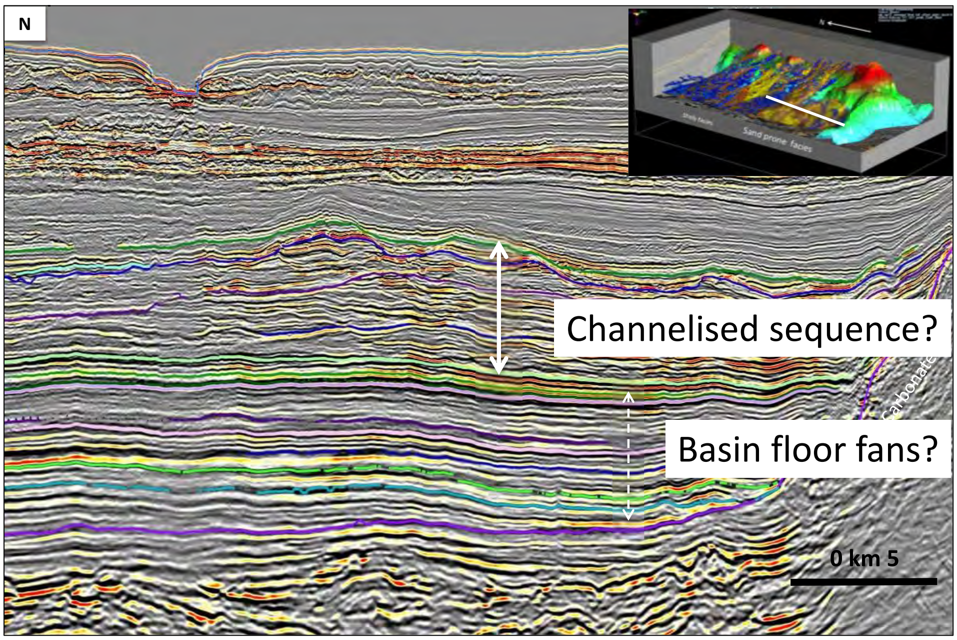

Figure 5.5 Regional seismic line, SOSP block, showing mapped Cretaceous section and interpreted depositional systems

A Lower Cretaceous carbonate play is also being developed to the east and south of the SOSP block, along the edges of the mapped carbonate platform (Figure 5.6). There is seismic evidence for potential karstification and build-up within the 3D seismic data, which may be favourable for reservoir development. Mapped depth at the edge of the Lower Cretaceous carbonate platform is around 3500 m to 5500 m in a water depth of 2000 m to 3000 m in the area of the mapped play.

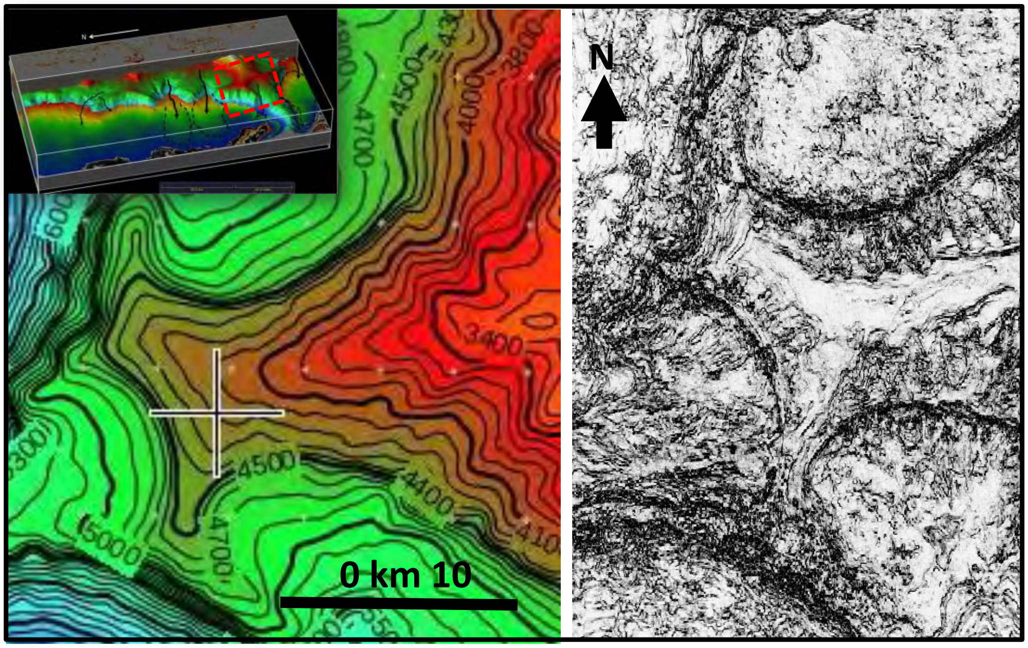

Figure 5.6 Top carbonate depth (m TVDSS) and coherency slice, south SOSP block

6. Appendix 1: SPE PRMS Guidelines

SPE/WPC/AAPG/SPEE Petroleum Reserves and Resources Classification System and Definitions

The Petroleum Resources Management System

Preamble

Petroleum Resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum Resources managements system provides a consistent approach to estimating petroleum quantities, evaluating development projects and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum Resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum Resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing Reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of Resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE-PRMS consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum Resources. It is expected that the SPE-PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, hereinafter referred to as the SPE-PRMS, can be viewed at

www.spe.org/specma/binary/files6859916Petroleum_Resources_Management_System_2007.pdf .

Overview and Summary of Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide and sulphur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "Resources" as used herein 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."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE Resources classification system. The system defines the major recoverable Resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

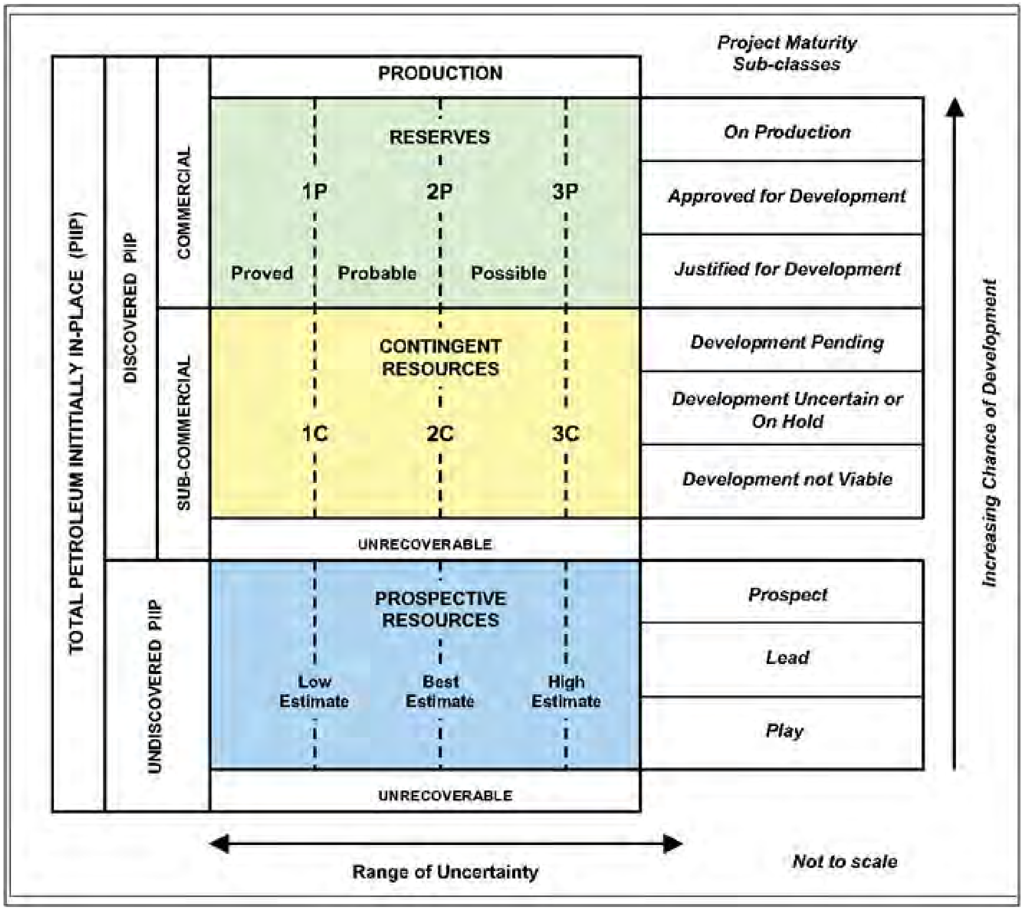

Figure 1-1: SPE/AAPG/WPC/SPEE Resources Classification System

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 Development", that is, the chance that the project that will be developed and reach commercial producing status.

The following definitions apply to the major subdivisions within the Resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE

Total Petroleum Initially in Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations.

It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total Resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE

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

PRODUCTION

Production is the cumulative quantity of petroleum that has been recovered at a given date.

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

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 satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided 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 development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

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% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

the area delineated by drilling and defined by fluid contacts, if any, and adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved Reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive and interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

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% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional Reserves which analysis of geoscience and engineering data indicate 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), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project.

Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.

In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.

Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.

In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable 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.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE

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

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

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

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

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.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

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.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

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% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

• There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

• There should be at least a 10% 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 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.

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. 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. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project.

7. Appendix 2: Nomenclature

7.1. Units

°C	degrees Celsius
°F	degrees Fahrenheit
bbl	barrel
cp	centipoises
ft	feet
ftMDRKB	feet below Kelly Bushing
ftTVDSS	feet subsea
km	kilometres
m	metres
M or MM	thousands and millions respectively
m/s	metres per second
md	millidarcy
mTVDSS	metres subsea
psia	pounds per square inch absolute
psig	pounds per square inch gauge
pu	porosity unit
rb	reservoir barrels
stb	a stock tank barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit

7.2. Reserves and Resources Classifications

Low	Low estimate of Prospective Resources, as defined in SPE PRMS 2007
Best	Best estimate of Prospective Resources, as defined in SPE PRMS 2007
High	High estimate of Prospective Resources, as defined in SPE PRMS 2007
COS	Geological Chance of Success associated with Prospective Resources
P10	10 per cent probability = Proved + Probable + Possible, or 3P
P50	50 per cent probability = Proved + Probable, or 2P
P90	90 per cent probability = Proved, or 1P

7.3. Abbreviations

AvO	amplitude variation with offset
Bo	oil shrinkage factor or formation volume factor, in rb/stb

CPI	computer processed information log
FVF	formation volume factor
FWL	free water level
GRV	gross rock volume
GWC	gas water contact
KB	kelly bushing
kh	permeability thickness
MD	measured depth
MSL	mean sea level
N/G	net to gross ratio
ODT	oil down to
OWC	oil water contact
Phi	porosity
PSC	production sharing contract
PSDM	post stack depth migration
PSTM	post stack time migration
PVT	pressure volume temperature experiment
RFT	repeat formation tester
So	oil saturation
Soi	initial oil saturation
SS	Subsea
STOIIP	stock tank oil initially in place
Sw	water saturation
Swc	connate water saturation
TD	total depth
TOC	total organic carbon
TVD	true vertical depth
TWT	two way time
Vsh	shale volume