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Prospective Resources Audit OML 127, PML 2, PML 3, PML 4 & PPL 261 offshore Nigeria as of 1 January 2024 (Volume 2 of 2)

For Prime Oil & Gas Coöperatief U.A.

12 March 2024

Private and Confidential
Our ref: 220040

1. Executive Summary

Prime Oil & Gas Coöperatief U.A. ("Prime") has retained RISC (UK) Limited ("RISC") to carry out an independent technical review of reserves and contingent resources in offshore Nigeria licences OML 127, Petroleum Mining Leases PML 2, PML 3 & PML 4 and Petroleum Prospecting License PPL 261 (NB: PML 2, PML 3 & PML 4, and PPL 261 were formerly known as OML 130). The audit is reported in two volumes. The 1P, 2P and 3P reserve volumes and 1C, 2C and 3C contingent resource volumes of the Agbami, Akpo and Egina producing fields and the Akpo West, Preowei and Ikija fields are reported another volume (Volume 1) and the prospective resources in this volume (Volume 2).

Prospective resource volumes are assessed without application of an economic limit and are therefore '*technically recoverable volumes*'. Volumes have been assessed using probabilistic methods and are quoted as gross for P90, P50 and P10 outcomes of potential resources after consideration of uncertainty in prospect parameters. The probability of geological success (Pg) is defined as the probability of finding flowable hydrocarbons and has been calculated after considering five separate petroleum system elements. Prospective Resources have not been assessed for the probability of full cycle economic success (Pe), or investment point forward commercial success (Pc).

RISC have reviewed the prospective resources in accordance with the Society of Petroleum Engineers' internationally recognised Petroleum Resources Management System 2018 (SPE-PRMS)[1]. A summary of the gross prospect resources and prospect Pg are summarised in Table 1-2.

RISC have conducted a review of various exploration prospects defined by Prime, TotalEnergies and Chevron on the PML 2, PML 3 & PML 4, and PPL 261 (formerly known as OML 130) and OML 127 Licences. RISC reviewed the in-place volumes, development plans and recovery factors at year end 2020, year-end 2021, year-end 2022 and in this review at year end 2023. RISC relied heavily upon the original 2016 and 2017 operator documents for both licences, supplemented with new reports.

RISC was supplied with 52 files to review for Volume 2, exploration. Only 10 of these files were new and had been created after the year end 2022 audit. The remaining 42 files had been reviewed in the previous audits at year end 2020, year-end 2021 and year-end 2022.

Prime holds net 8% working interest in OML 127 and a net 16% working interest in PML 2, PML 3 & PML 4, and PPL 261 which includes the Akpo, Akpo West, Egina and Preowei fields (Table 1-1).

Table 1-1: New licence names for Prime fields formerly licenced under OML 130

LICENCE	PML 2	PML 3	PML 4	PPL 261
FIELD NAME	**Akpo**	**Egina**	**Preowei**	**Egina South**

[1] SPE/WPC/AAPG/SPEE/SEG/SPWLA 2018 Petroleum Resources Management System.

Key Points

- RISC has reviewed the volumes and probability of geological success of seven prospects in OML 127 & the licence formerly known as OML 130: Ikija Deep, Endi Footwall, Egina South prospective, Akpo Deep, Egina Deep, Egina South Deep and Egina West.
- In general, RISC has found the technical evaluations and resulting volumetric STOIIP / GIIP ranges to be sound.
- RISC has typically adopted the P50 in-place volume to carry forward to estimate EUR, rather than the mean probability volume typically used by Prime in their sales case. This is because oil field volumetric distributions are lognormal which results in the individual mean field volume typically lying at around P30 and closer to a high case than a mid-case.
- RISC view the majority of the prospects as attractive upside options to add volume (e.g.: Akpo Deep and Ikija Deep) but cannot comment on the economics as it is out of scope for this review. Endi Footwall and Egina South prospects are also attractive but will require unitization as the majority of in-place volumes are outside of the OML127 and OML130 licence area, respectively.
- The Endi Hanging Wall prospect lies mainly outside the OML 127 licence and is not considered in this audit.
- An update on Akpo Far East G interpretation status was provided but not enough data was supplied for it to be considered for prospective volumes or risking in this audit.
- The Agbami Gas Blowdown (prospective) is not included in this report since not enough data was supplied for it to be considered for prospective volumes, or risking in this audit. Although reservoir simulations were provided, which according to Prime, result in a range of potential recoverable volumes of 440 Bcf to 2,044 Bcf, RISC has been informed by Prime that additional optimizations are required. The paucity of information about the economic terms and conditions for future commercialization does not exclude the gas blow down project from this audit since by definition, prospective volumes do not require this information. However, an audit trail of the technical work and supporting technical information is required before RISC can include Agbami Gas Blowdown in this Prospective Resource audit.

- Data was received on the following prospects and leads in the OML 127 licence:
    1) Agbami Gas Blowdown (prospective)
    2) Endi FW
    3) Ikija Deep
    4) OML 127 Non-Agbami prospective upside (Agbami deep)

- Data was received on the following prospects and leads in the licence formerly known as OML 130:
    1) Akpo Deep
    2) Akpo Far East
    3) Egina NE
    4) Egina South Deep
    5) Egina Main Deep
    6) Egina South Prospective
    7) Egina West
    8) Preowei R641 Gas

Table 1-2: Prospect volume & risk summary

Prospect	Licence	RISC's Risk (Pg)	P50 GIIP / STOIIP	Recovery Factor	EUR (MMstb / Bcf)	Producer Wells	Injector Wells	EUR / Producer (MMstb / Bcf)	Condensate EUR (MMstb)	Oil EUR MMBoe
Ikija Deep (Oil)	OML 127	17%	106	30%	32	5	5	6	-	-
Endi FW (Oil)	OML 127	14%	95[1]	30%	29	3	3	10	-	-
Egina Deep (Oil)	PML 3	10%	81	25%	20	-	-	-	-	-
Egina South Deep (Oil)	PPL 261	6%	58	25%	15	-	-	-	-	-
Egina South Prospective (Oil)	PPL 261	40%	148[2]	42%	62	5	7	4	-	-
Egina West Prospective (Oil)	PML 3	41%	69	49%	34	2	2	-	-	-
Akpo Deep I,J (Gas)	PML 2	25%	374	48%	180	4	4	45	22	52

NOTE: [1]On block volume. [2]Not reviewed by RISC, but TotalEnergies' STOIIP used by Prime, and recovery factor assumption deemed reasonable.

Four leads have been named in the licence formerly known as OML 130 (2 in PML 2 and 2 in PML 3) and one in OML 127 (Table 1-4) which were low graded by the operator. Little to no information has been available to RISC to make an assessment. They are listed here for completeness.

Table 1-3: Prioritised named Leads/Concepts in OML 127, PML 2, PML 3 and PPL 261

Lead/Concept	Licence
Agbami deep	OML 127
Akpo Far East G	PML 2
Akpo Far West	PML 2
Egina South A West	PPL 261
Egina Ridge	PML 3

Table 1-4: Low graded named Leads/Concepts in OML 127, PML 2, PML 3 and PPL 261

Lead/Concept	Licence
Inji	OML 127
Akpo Central (R1000)	PML 2
Akpo Far East (1A, 3, 4)	PML 2
Akpo Shallow (H930-H950)	PML 2
Egina East	PML 3
Egina South B	PPL 261
Egina Main Deep	PML 3
Egina South Deep	PPL 261
Egina West	PML 3
Egina North East	PML 3

Table of contents

List of figures

List of tables

2. Introduction

2.1. Portfolio description

Prime has an 8% working interest in OML 127. The Agbami Field straddles OML 127 and OML 128, approximately 100 km from the nearest Nigerian shoreline. OML 127 also contains the undeveloped Ikija field discovery, the Ikija Deep and Endi Footwall exploration prospects (Figure 2-1, Figure 2-2).

Prime has a net 16% working interest in the licence formerly known as OML 130 which used to cover Akpo, Akpo West, Egina, Egina South and Preowei fields, and several exploration prospects and leads (Table 1-2, Four leads have been named in the licence formerly known as OML 130 (2 in PML 2 and 2 in PML 3) and one in OML 127 (Table 1-4) which were low graded by the operator. Little to no information has been available to RISC to make an assessment. They are listed here for completeness.

Table 1-3 & Table 1-4), approximately 130 km from the nearest Nigerian shoreline (Figure 2-1, Figure 2-3). Since the year end 2022 review the OML 130 licence has been split into PML 2, PML 3 & PML 4, and PPL 261 licences which includes the Akpo, Akpo West, Egina and Preowei fields (Table 2-1).

Table 2-1: New licence names for Prime fields formerly licenced under OML 130

LICENCE	PML 2	PML 3	PML 4	PPL 261
FIELD NAME	Akpo	Egina	Preowei	Egina South

Water depths for the licences range from 1,100 to 1,700 m.

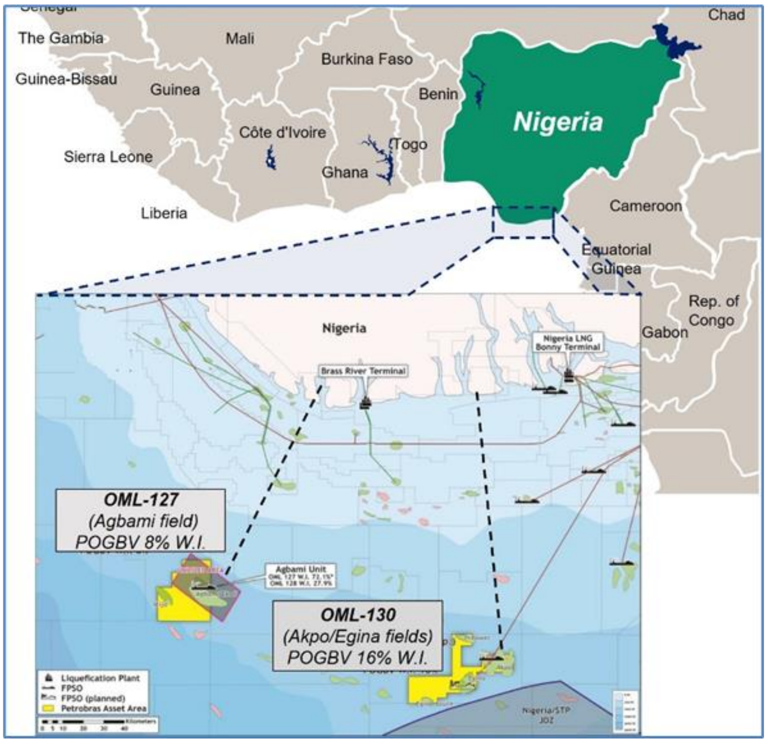


Figure 2-1 Location map

The resource assessment of each licence has been carried out using an effective date of 1 January 2024 and the licence boundaries of the new Nigerian Petroleum Industry Act (PIA) from the conversion dates of 1 March 2023 and 1 June 2023 for OML 127 and OML 130 respectively.

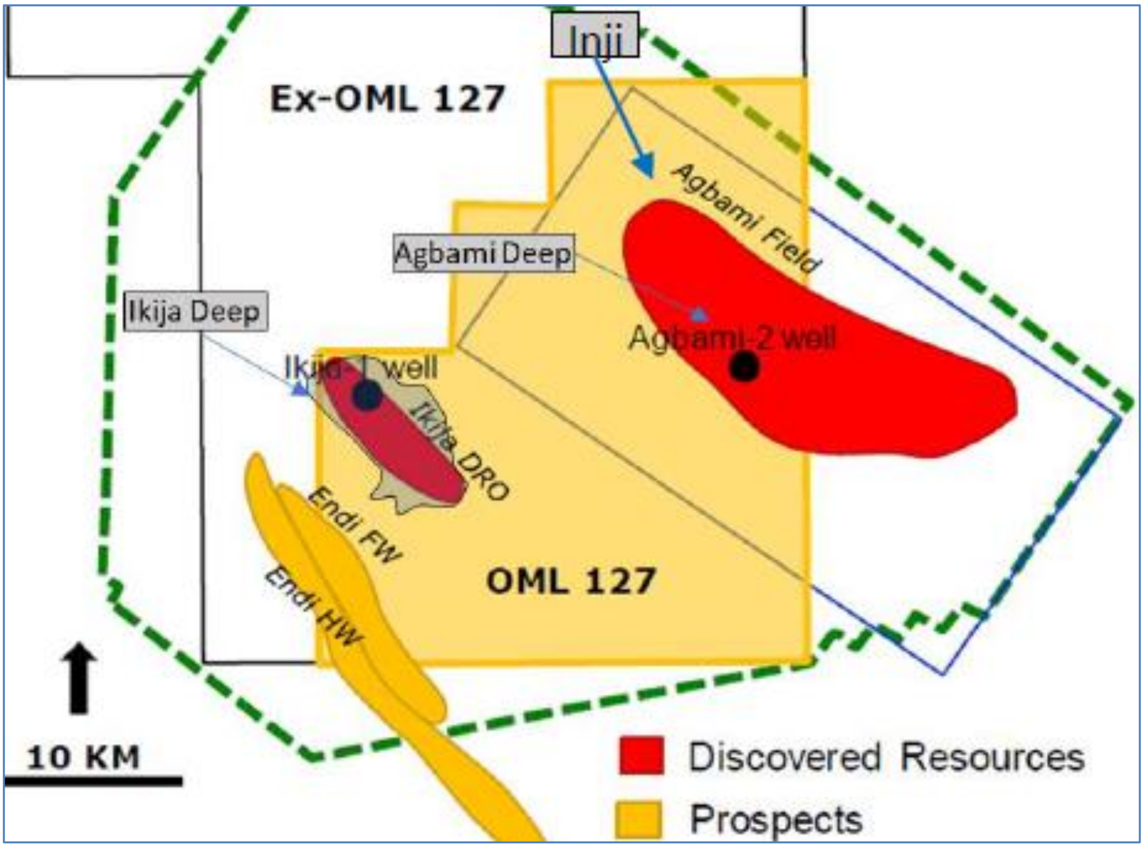


Figure 2-2: Location of prospects in OML 127

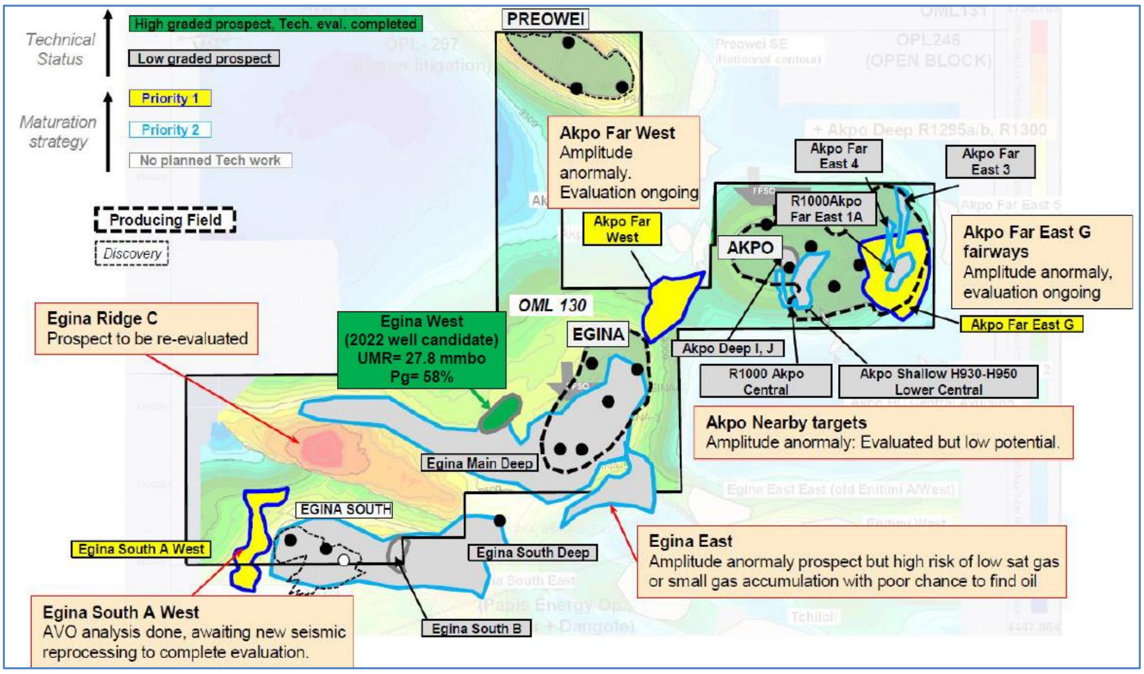


Figure 2-3: Location of prospects in licence formerly known as OML 130 (PML 2, 3, 4 & PPL 261)

A summary of the prospects and leads covered in this report is shown in Table 2-2

Table 2-2: Assets contained in reports

Report	Asset	Block	Resource Type	Status
Contained in this report, (Volume 2)	Ikija Deep	OML 127	Prospective	Prospect
	Endi Foot Wall	OML 127	Prospective	Prospect
	Egina South	PML 3	Prospective	Prospect
	Egina South Deep	PML 3	Prospective	Prospect
	Egina Deep	PML 3	Prospective	Prospect
	Egina West	PML 3	Prospective	Prospect
	Akpo Deep	PML 2	Prospective	Prospect
Contained in separate report, (Volume 1)	Agbami	OML 127	Reserves	Producing
	Preowei	PML 4	Reserves	Discovery
	Akpo	PML 2	Reserves	Producing
	Akpo West	PML 2	Reserves	Discovery
	Egina	PML 3	Reserves	Producing
	Agbami	OML 127	Contingent	Discovery
	Ikija Foot Wall	OML 127	Contingent	Discovery
	Ikija Hanging Wall	OML 127	Contingent	Discovery
	Preowei	PML 4	Contingent	Discovery
	Akpo	PML 2	Contingent	Discovery
	Akpo West	PML 2	Contingent	Discovery
	Egina	PML 3	Contingent	Discovery
	Egina South	PML 3	Contingent	Discovery

2.2. Terms of reference

Prime Oil & Gas Coöperatief U.A. ("Prime") has retained RISC (UK) Limited ("RISC") to carry out an independent technical review of six exploration prospects in offshore Nigeria licences OML 127 and licence formerly known as OML 130, now known as PML 2, PML 3 & PML 4, and PPL 261 licences.

2.3. Basis of assessment

The data and information used in the preparation of this report were provided by Prime, supplemented by public domain information. RISC have relied upon the information provided and have undertaken the evaluation on the basis of a review of existing interpretations and assessments as supplied, making adjustments that in our judgment were necessary. Our assessment for the prospective resources is based on data available at end December 2023.

RISC have reviewed the prospective resources in accordance with the Society of Petroleum Engineers internationally recognised Petroleum Resources Management System (PRMS) 2018. We have not conducted a site visit to the offshore prospects.

2.4. Database

RISC was supplied with 52 files to review for Volume 2, exploration (Table 2-3). Only ten of these files were new and had been created after the year end 2022 audit (Table 2-4). The remaining 42 files had been reviewed in the previous audits at year end 2020, year-end 2021 and year-end 2022 (Table 2-5).

Table 2-3: File types provided for year end 2023 audit

Filetype	PDF	XLS	XLSX	PPTX	LOG	DAT	PET	TOTAL
Number of files	42	1	2	3	1	2	1	52

Table 2-4: New files provided for the year end 2023 review of exploration

DATE	ASSET	FILE	FILE TYPE
2023	Ikija	2023 OML 127 OCM Pre-Read.pdf	pdf
2023	Ikija	2023 OML 127 OCM_Post Mtg.pdf	pdf
2023	Agbami Gas Blowdown (prospective)	OML-127_2P_Agbami Profile_1023_v3.xlsx	xlsx
2023	Akpo Far East and Egina NE	2023 -06-OML130 SSCM Exploration.pdf	pdf
2023	Akpo Far East and Egina NE	2023 -10 SSCM Exploration.pdf	pdf
2023	Egina West	2023 -06-OML130 SSCM Exploration.pdf	pdf
2023	Egina West	2023 -10 SSCM Exploration.pdf	pdf
2023	Egina West	Exploration_SSCM_Q12023.pdf	pdf
2023	Preowei R641 Gas (new)	2023 -10 SSCM Preowei.pdf	pdf
2023	Preowei R641 Gas (new)	Preowei_SSCM_Q12023.pdf	pdf

Table 2-5: Creation date of files provided for Exploration review at year end 2023

DATE	FILE	FILE TYPE
2022	2022 OML 127 OCM pre-read.pdf	pdf
2022	2022 - 10 - SSCM Exploration_As Presented.pdf	pdf
2021	3.0 OML127_Exploration_Activities.pdf	pdf
2021	Agbami - Ikija and Exploration.pptx	pptx
2021	2021-06-16 PML130 SSCM Exploration-Pre-Read.pdf	pdf
2021	Exploration SSCM#25 17Mar2021.pdf	pdf
2021	OML 130 Explo SSCM#27 Pre-read.pdf	pdf
2021	Egina_West_POG_v1.pet	pet
2021	GMS.log	log
2021	POG_V2_1.8.ExportFaultRules.dat	dat
2021	Structural_POG_V2_2.0.ExportFaultRules.dat	dat
2020	4.1. Ikija Project Overview.pdf	pdf
2020	4.2. Ikija_Subsurface_Evaluation.pdf	pdf
2020	4.3 Ikija_Appraisal_Plan.pdf	pdf
2020	4.4. Subsea_Facilities.pdf	pdf
2020	4.5. Wells Presentation.pdf	pdf
2020	Ikija project (3OP 1WI) Questor 2020.xls	xls
2020	Ikija_Chevron_3OP_1WI_102020.xlsx	xlsx
2020	3.0 OML127_Exploration_Activities.pdf	pdf
2020	Akpo & Explo SSCM#23 Preread.pdf	pdf
2020	Egina & Egina South SSCM#23 Preread.pdf	pdf
2020	Egina_EGN South GSR SSCM #22 Pre-read.pdf	pdf
2020	SSCM #21 Pre-read Egina_Explo 17Mar2020.pdf	pdf
2020	Prime - Egina West 2020 short.pptx	pptx
2020	Prime - Egina West 2020.pptx	pptx
2018	02-OML130 Egina South Cretaceous.pdf	pdf
2018	OML130 upsides WKS Summary.pdf	pdf
2018	20181107_OML_130_Explo_Wshop_Egina_West-Other_Upsides_-_As_Presented.pdf	pdf
2017	OML 127 Workshop 11Sept2017_Part1.pdf	pdf
2017	OML 127 Workshop 11Sept2017_Part2.pdf	pdf
2017	PRES-NIGERIA-127-015-EXP-Sep2017 Exp. Workshop L - Copy.pdf	pdf
2017	PRES-NIGERIA-127-015-EXP-Sep2017 Exp. Workshop Lagos - POG View Endi FW.pdf	pdf
2017	OML 127 Workshop 11Sept2017_Part1.pdf	pdf
2017	OML 127 Workshop 11Sept2017_Part2.pdf	pdf
2017	PRES-NIGERIA-127-015-EXP-Sep2017 Exp. Workshop Lagos - POG View Endi FW.pdf	pdf
2017	Akpo Deep - OIP Assessement_POGBV Jun 2017.pdf	pdf
2017	Akpo Deep - Rec Volume Assessment_POGBV Aug 2017.pdf	pdf
2017	Akpo Deep_PPFG FOR PARTNERS.pdf	pdf
2017	Egina Deep Assessment_POGBV May 2017.pdf	pdf
2016	PRES-NIGERIA-127-804-EXP-Ikija Deep Volumetric U - Copy.pdf	pdf
2016	PRES-NIGERIA-127-804-EXP-Ikija Deep Volumetric Update April 2016_lr.pdf	pdf
2016	PRES-NIGERIA-127-804-EXP-Ikija Deep Volumetric Update April 2016_lr.pdf	pdf

3. OML 127: Prospective Resources

OML 127 contains the producing Agbami field, the undeveloped Ikija field discovery, the Ikija Deep and Endi Footwall exploration prospects (Figure 3-1). The Endi Hanging Wall prospect lies mainly outside the licence and is not considered in this audit.

There have been no changes to the Ikija and Endi prospective resource volumes in OML 127 for several years and no new subsurface work appears to have been carried out. The volumes presented at year end 2023 is the same as that presented at year end 2022. However, drilling plans have been updated for Ikija Development Project:

- Appraisal Drilling in 2025
- Phase 3 in 2027; FID in 2Q 2028
- Estimated 1st oil date of 2030

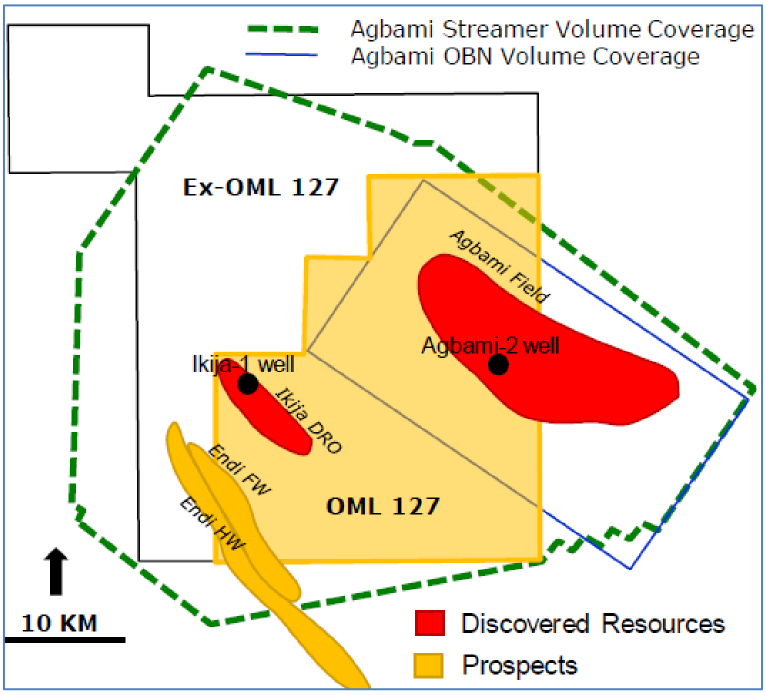


Figure 3-1: Location of prospects in OML 127.

3.1. Ikija Deep Prospect

The 2015 PSTM and PSDM reprocessing of the 3D seismic data has separated the Ikija Deep and Endi Footwall prospects with a saddle in between them, compared to the 2011 seismic data which indicated a potential single accumulation.

3.1.1. Ikija Field

Ikija field is a three-way anticlinal structure and Ikija-1 discovered oil and gas in both the hanging wall and footwall of the Ikija thrust fault (Figure 3-2). In the hanging wall, 91 ft of oil net pay was discovered in the

16.4 Ma sand, plus 114 ft of gas net pay in the 12.7 Ma sand. In the footwall, 48 ft of oil net pay was discovered in the 11.7 Ma sand. The oil samples were circa 45° API.

The 16.4 Ma reservoir has two flow units defined by MDT pressure data. The upper unit (16.4_30) did not encounter an Oil Water Contact (OWC), while the lower unit (16.4_20) has an established OWC. Reservoir area is limited, as defined by the structure and contacts. The oil column is likely limited by fault seal capacity.

The 11.7 Ma reservoir did not encounter an OWC. Contact uncertainty between the Lowest Known Oil (LKO) and spill point defines an upside. Additionally, reservoir extent and structural uncertainty remains high with the well placement at the north-western flank. The relative uncertainty in the contacts is shown in Figure 3-4.

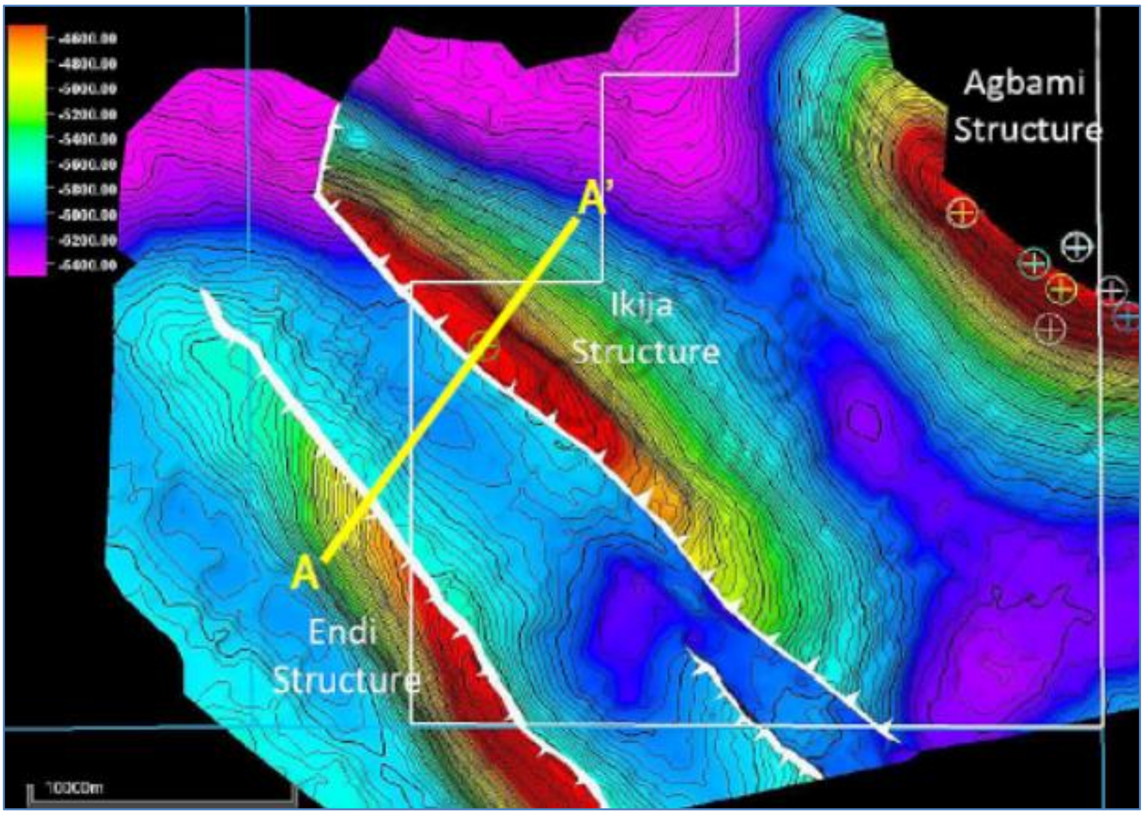


Figure 3-2: Location of Ikija Structure, Relative to Agbami field.

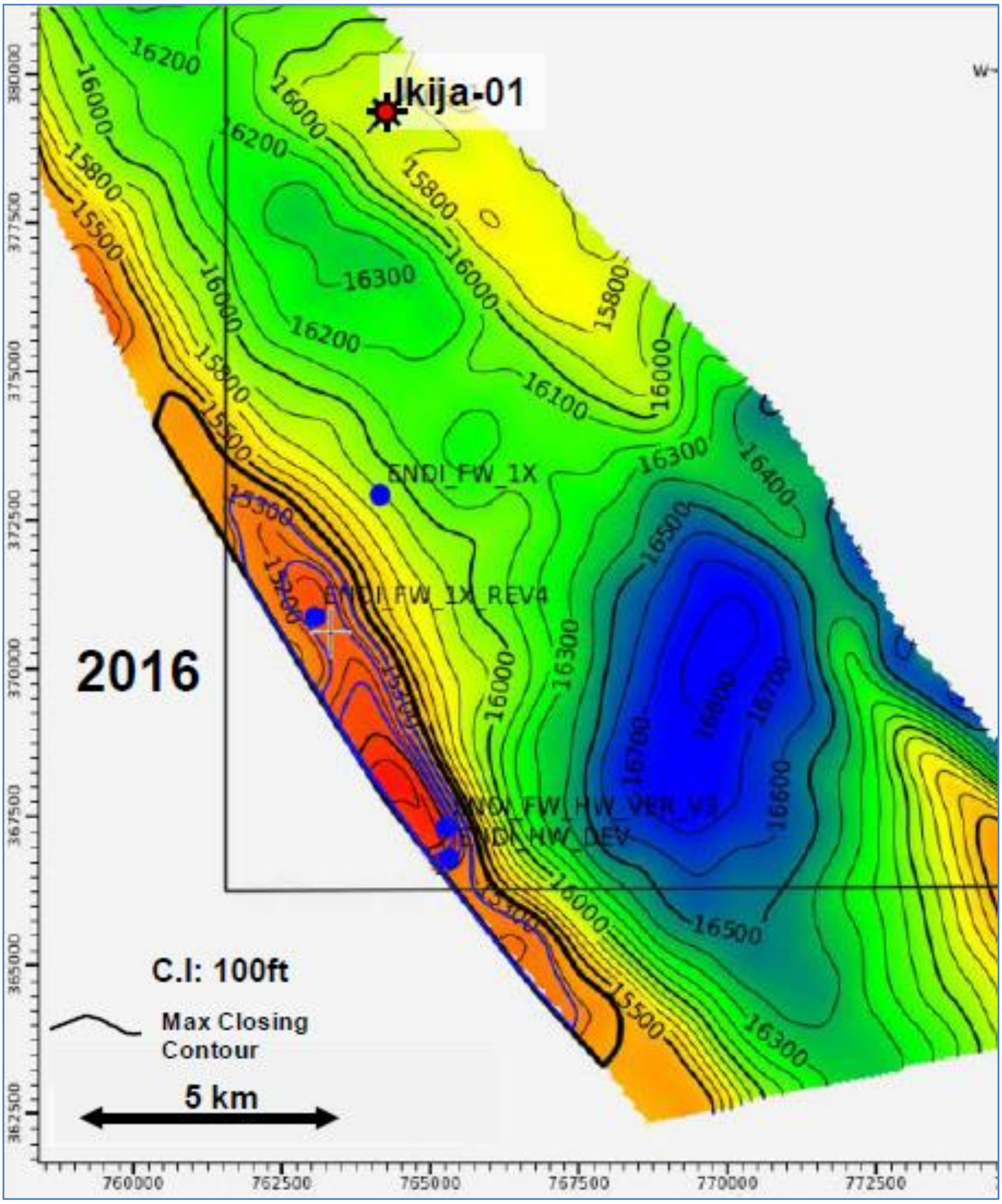


Figure 3-3: Ikija Field discovery well location and depth map.

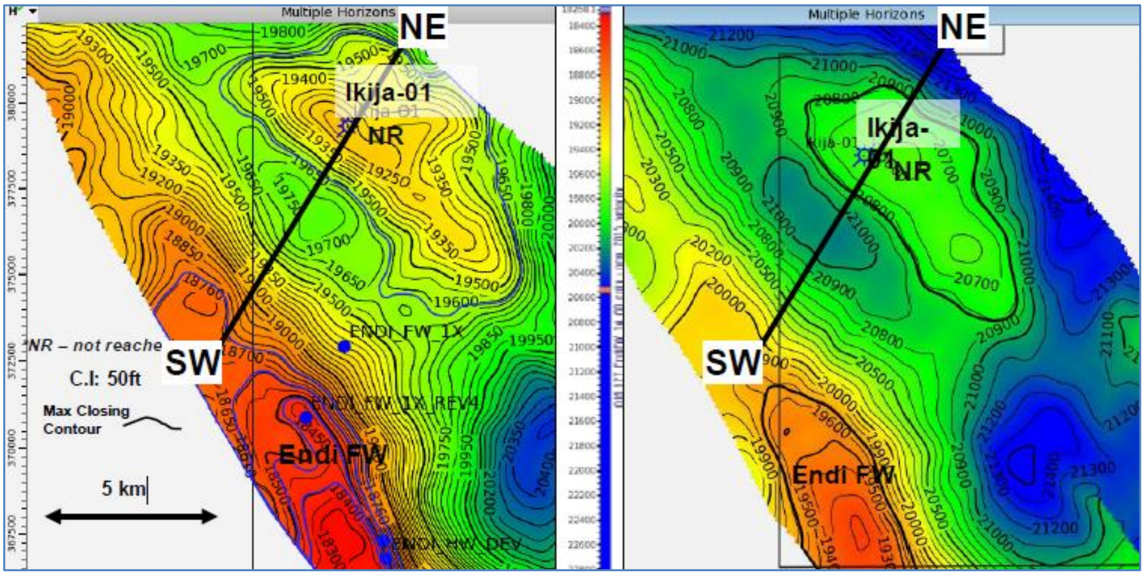


Figure 3-4: Ikija Deep 14.8 Ma & 19.5 Ma Prospective Zones (NR – Not Reached).

An appraisal well has been in planning for several years with a primary objective to appraise the 11.7 Ma hanging wall sand accumulation. However, it is planned to also be drilled deeper to penetrate the 12.7 Ma to 19.5 Ma prospective intervals known as Ikija Deep prospect. It is currently planned to be drilled approximately 4 km SSE along strike of the Ikija-1 discovery well (Figure 3-5).

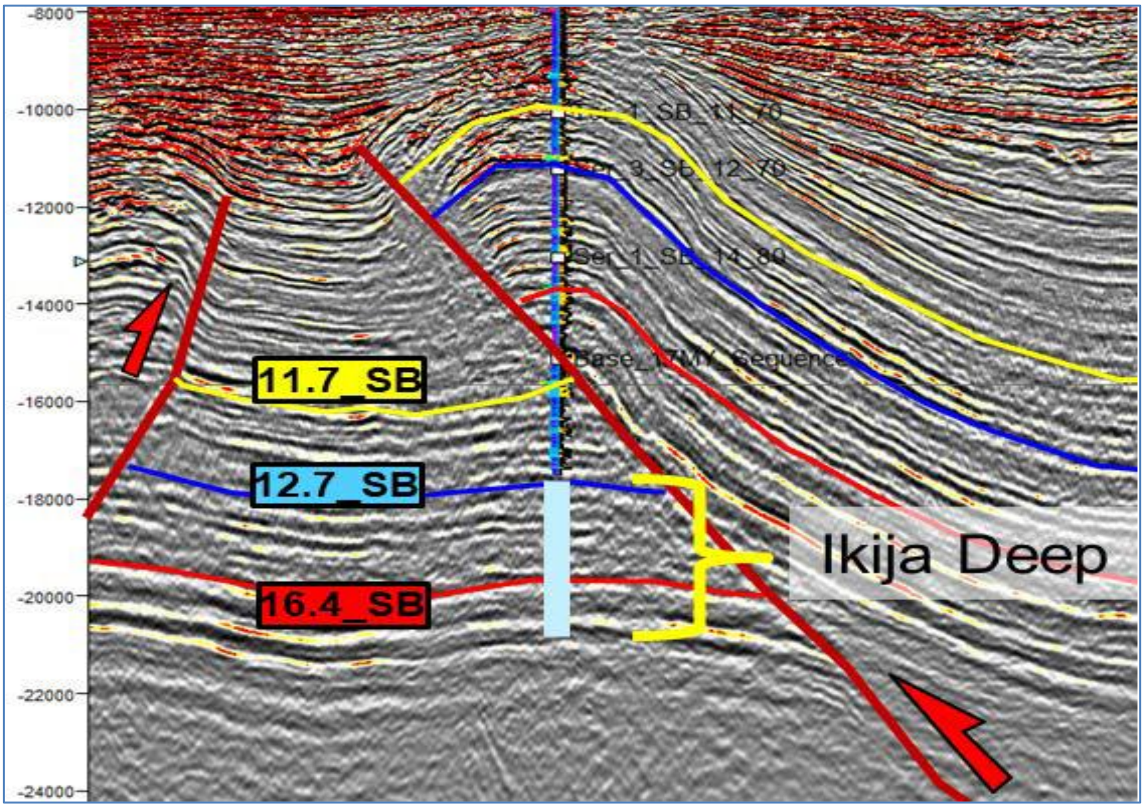


Figure 3-5: Seismic cross section (NE-SW) through Ikija field well location and Ikija Deep prospect.

3.1.2. Ikija Deep Reservoirs

Three main targets have been identified by Prime equivalent to reservoir sands penetrated in the Ikija-1 well:

- TL16A Reservoir (thought to be equivalent to MY14);
- TL16B Reservoir (Equivalent to MY 15.5);
- TM17 Reservoir (equivalent to MY16.5).

In all reservoirs, Ikija Deep is interpreted as a 4-way dip-closed structure beneath a large thrust fault. The structures are relatively flat and are limited in extent by spill points to the SW. There are discovered hydrocarbons in the fault block with Ikija 10.5 MY oil. Prime have assumed oil with associated gas. The estimated volumes of associated gas are significant (P50 of 130 Bcf), but RISC have only considered the oil in this review.

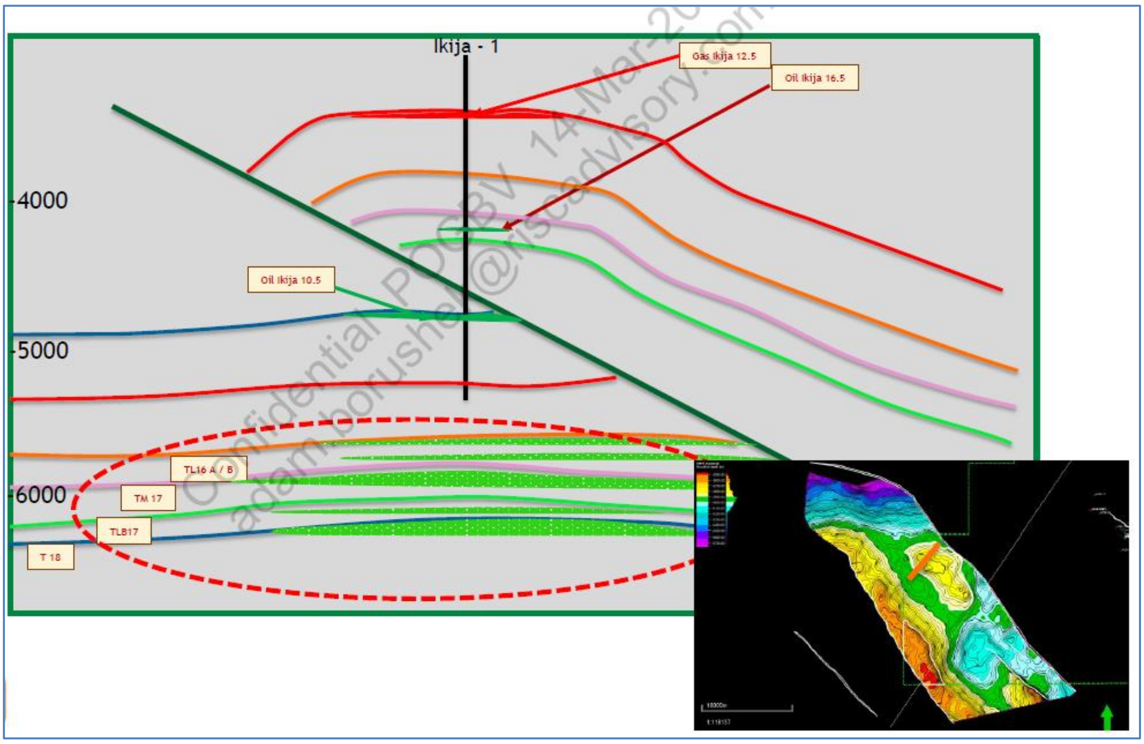


Figure 3-6: NE-SW schematic depth cross section through Ikija-1 well.

3.1.3. Ikija Deep Volumes and Risk

The seismic correlation of horizons across the thrust fault is considered reasonable. Using Ikija-1 as the reservoir analogue is a sensible approach, but the reservoirs are deeper in the footwall (depths of >5500 m TVDSS) which will likely result in poorer reservoir quality. Prime's basic assumptions on P90-P10 areas and reservoir thickness, defining GRVs, are reasonable. Other volumetric parameter ranges are sound apart from NTG where in RISC's view Prime have a narrow range that does not represent the low side appropriately. However, modifying this is unlikely to significantly impact the P50 volume.

Prime have consolidated the individual reservoirs into a single STOIIP range, placing dependencies on Migration, Geometry and Timing which RISC consider to be appropriate.

Table 3-1: Ikija Deep Prime STOIIP (MMstb)

Reservoir	P90	P50	Pmean	P10
TL16A	6	36	83	205
TL16B	18	73	129	300
TM17	16	69	124	289
Consolidation	**19**	**106**	**177**	**416**

RISC support the overall STOIIP range, but favour using the consolidated P50 STOIIP of 106 MMstb as input to estimating EUR (rather than using the mean probability volume of 177 MMstb which Prime have adopted) since P50 is a more likely outcome for a single prospect than the mean outcome.

The Ikija deep re-assessment was based on the OML 127 2015 PSDM. Following a review of the velocity data, RISC have recognised anomalies that result in significant uncertainty in the structural definition of both Ikija Deep and Endi Footwall. As a consequence, RISC define the key prospect risk as trap in our assessment of probability of geological success. RISC Pg estimate is 17%.

Table 3-2: Risking of Ikija Deep Prospect

Petroleum System Element	RISC Probability (%)	RISC Probability (%)	
Trap	50	35	Containment
Seal	70		
Reservoir	60	60	Reservoir
Source	100	80	Charge
Migration / Timing	80		
Probability of Geological Success	**17**	**17**	

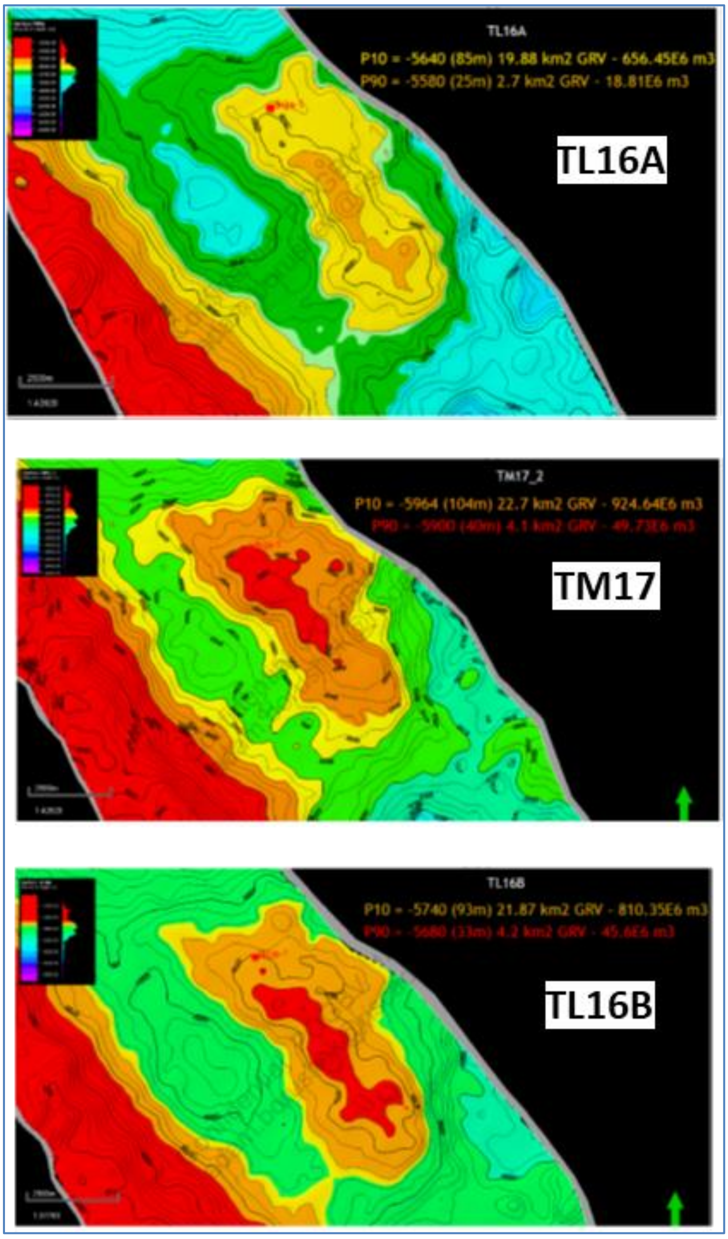


Figure 3-7: NE-SW schematic depth cross section through Ikija-1 well

For each individual reservoir, RISC estimate Pg at 17%, similar to Prime's 19.5%. Prime's consolidated risk is 37.3% (i.e., the probability of discovering some flowable hydrocarbons if all three reservoirs were drilled). RISC consider this to be appropriate.

RISC also note that there is a possible charge risk associated with finding gas rather than oil as in Ikija-1 12.5MY.

Ikija Development Project is a 25-km sub-sea tie-in to Agbami FPSO to recover 80 MMstb. Ikija facilities Capex is approx. USD$700 million (2019 estimate).

3.2. Endi Footwall Prospect

Three main targets are identified by Prime, equivalent to reservoir sands penetrated in the Ikija-1 well. Endi Footwall is only partially contained with OML 127. The prospective target reservoirs are from 11.7 Ma –12.7 Ma to the deeper 14.8 Ma to 19.5 Ma:

In all reservoirs, Endi Footwall is interpreted as a 3-way dip-closed structure against a large thrust fault. However, following seismic reprocessing, significant changes to the geometry from previous ERT interpretation were observed. The structures are relatively steep and elongate following a thrust fault with structural spill to the north and south. There are discovered hydrocarbons in the fault block with Ikija 10.5 MY oil. Prime have assumed oil with associated gas for Endi Footwall. The estimated volumes of associated gas are significant (P50 = 114 Bcf on block), but RISC have only considered the oil in this review.

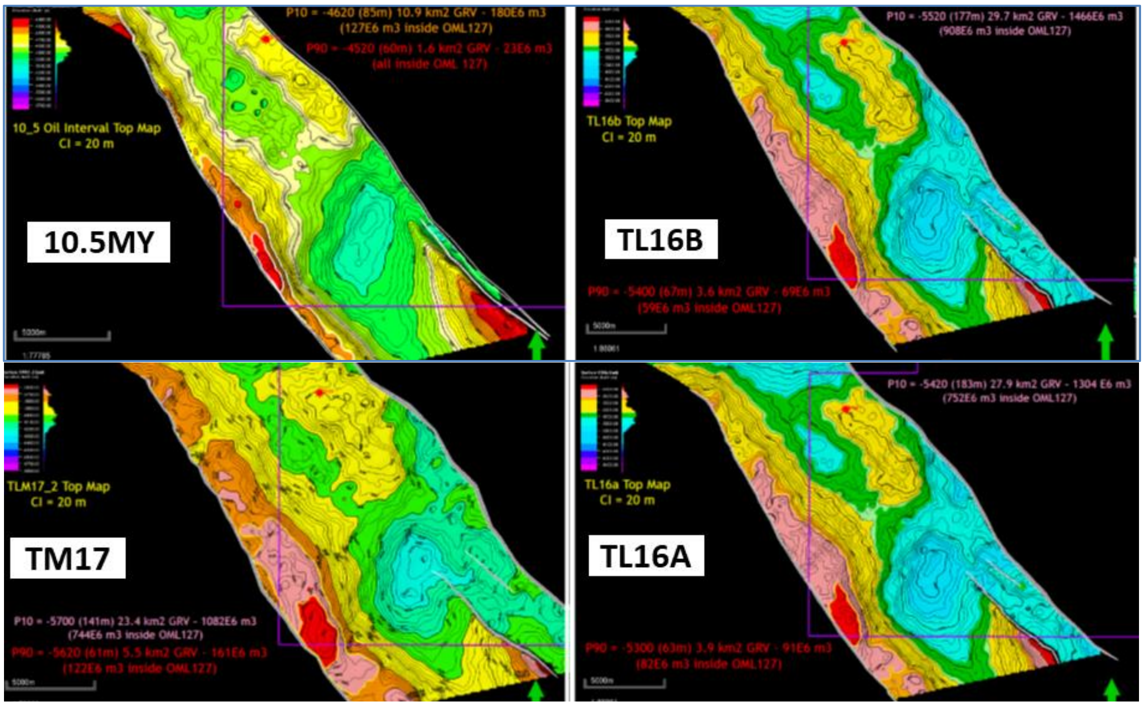


Figure 3-8: Top reservoir depth structure maps (2016/2017)

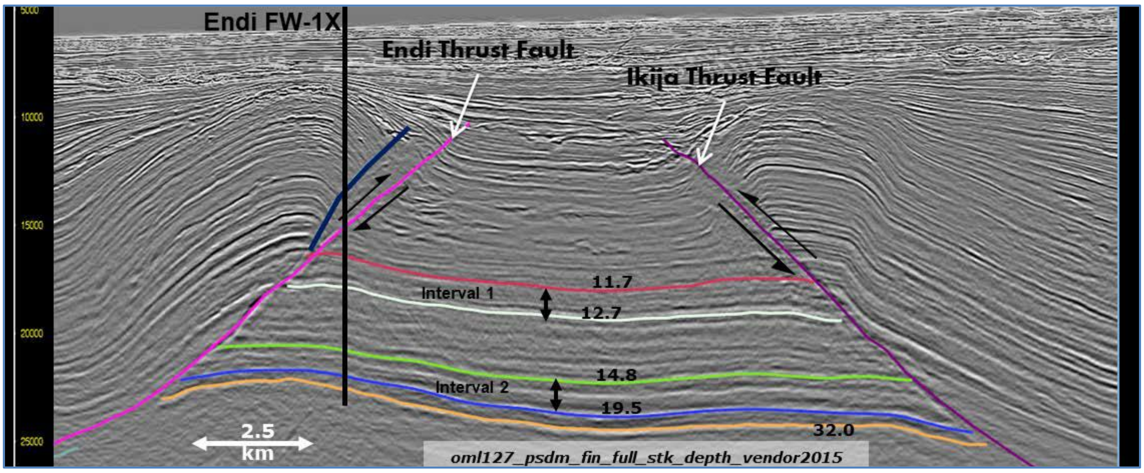


Figure 3-9: NE-SW seismic cross section through the Endi FW and Ikija-1 well

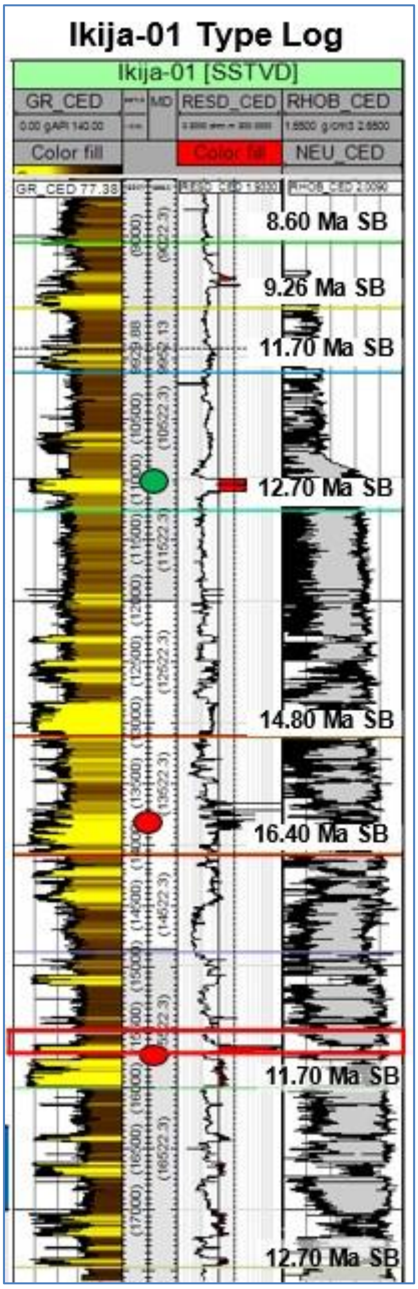


Figure 3-10: Ikija-1 well (gamma ray and resistivity logs)

3.2.1. Endi Footwall Volumes and Risk

The Endi Footwall re-assessment (Figure 3-9) was based on OML 127 2015 PSDM. The seismic horizon correlation across the thrust fault from Ikija-1 and then across to Endi Footwall area is considered reasonable by RISC. It is also reasonable to use Ikija-1 as the reservoir analogue, but the reservoirs are deeper in the Footwall prospect (depths of greater than approximately 5,500 m TVDSS) which will likely result in poorer reservoir quality. RISC consider Prime's basic assumptions on P90 to P10 areas and reservoir thickness, which define the gross rock volume also to be reasonable representations of the uncertainty. Other volumetric parameter ranges are sound apart from NTG where in RISC's view Prime have a narrow range that does not represent the low side appropriately. However, modifying this parameter is unlikely to significantly impact the P50 in place volume.

Prime have consolidated the individual reservoirs into a single STOIIP range. However, it is not clear what dependencies were used.

RISC support the overall On Block STOIIP range but have instead used the consolidated P50 STOIIP of 95 MMstb as input to estimating EUR (rather than using the mean probability volume of 146 MMstb used by Prime) since P50 is a more likely outcome for a single prospect than the mean outcome.

Table 3-3: Prime Endi Footwall STOIIP (MMstb) full prospect and on block

Reservoir	P90	P50	Pmean	P10
MY10.5	9.5	26	35	72
TL16A	30	111	182.8	420
TL16B	27	120	232	553
TM17	51	134	173	350
Prime On Block STOIIP (MMstb)				
	P90	**P50**	**Pmean**	**P10**
Consolidation	19	95	146	335

Following a review of the velocity data, RISC have recognized anomalies that result in significant uncertainty in the structural definition of both Ikija Deep and Endi Footwall. As a consequence, RISC define the key prospect risk as trap in our assessment of probability of geological success. RISC's Pg = 14%.

Table 3-4: Risking of Endi Footwall Prospect

Petroleum System Element	RISC Probability (%)	RISC Probability (%)	
Trap	50	30	Containment
Seal	60		
Reservoir	60	60	Reservoir
Source	100	80	Charge
Migration / Timing	80		
Probability of Geological Success	**14**	**14**	

For each individual reservoir RISC estimate Pg at 14%, similar to Prime's Pg= 13%. Prime's consolidated risk is 37.5% (i.e., the probability of discovering some flowable hydrocarbons if all four reservoirs were drilled). RISC consider this to be reasonable. RISC also note that there is a possible charge risk associated with finding gas rather than oil as in Ikija-1 well, 12.5MY reservoir.

3.3. Agbami Deep

Prime make reference to an Agbami Deep prospect at reservoir intervals 24 57, 26 4 and 50 1 million years based on hydrocarbon shows from the Agb 2 well in the Agbami field (Figure 3-11) but there are reservoir pressure challenges. Spare capacity exists for new opportunities at the Agbami facilities. Chevron estimates resources of 100 MMstb and a Chance of Geological Success of 20% with main risk placed on the reservoir. The operators analysis has not been completed and RISC have not seen any of the work so cannot verify any of the figures for the Agbami Deep prospect.

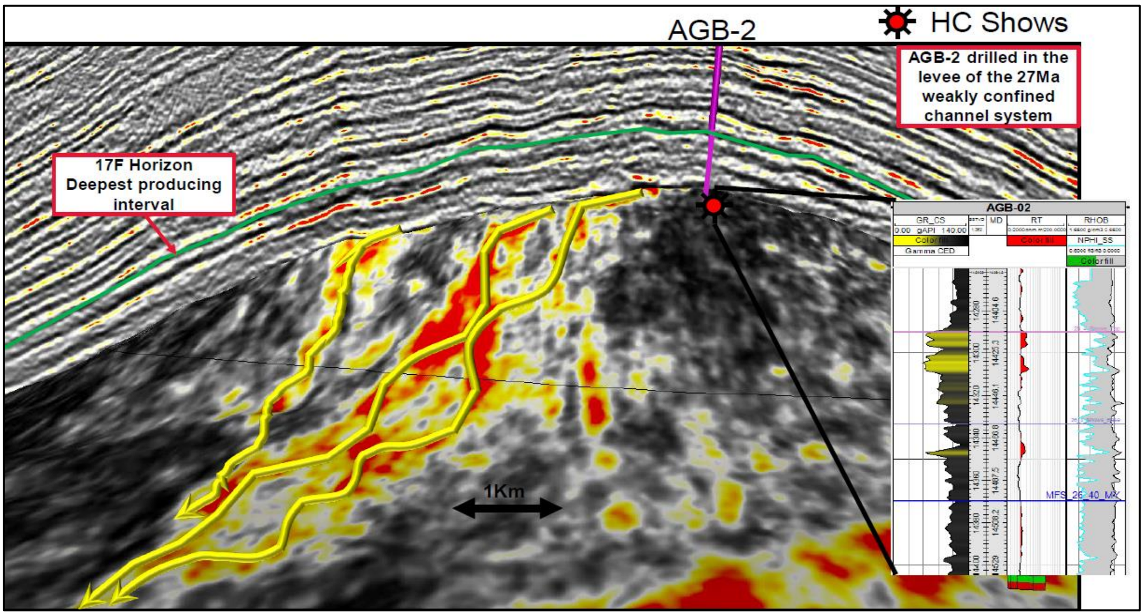


Figure 3-11: Agbami Deep prospect RMS amplitude from full stack

3.4. Inji Lead

Inji is a series of poorly imaged, imbricate thrust fault blocks north of Agbami field (Figure 3-12). The lead is a very immature concept.

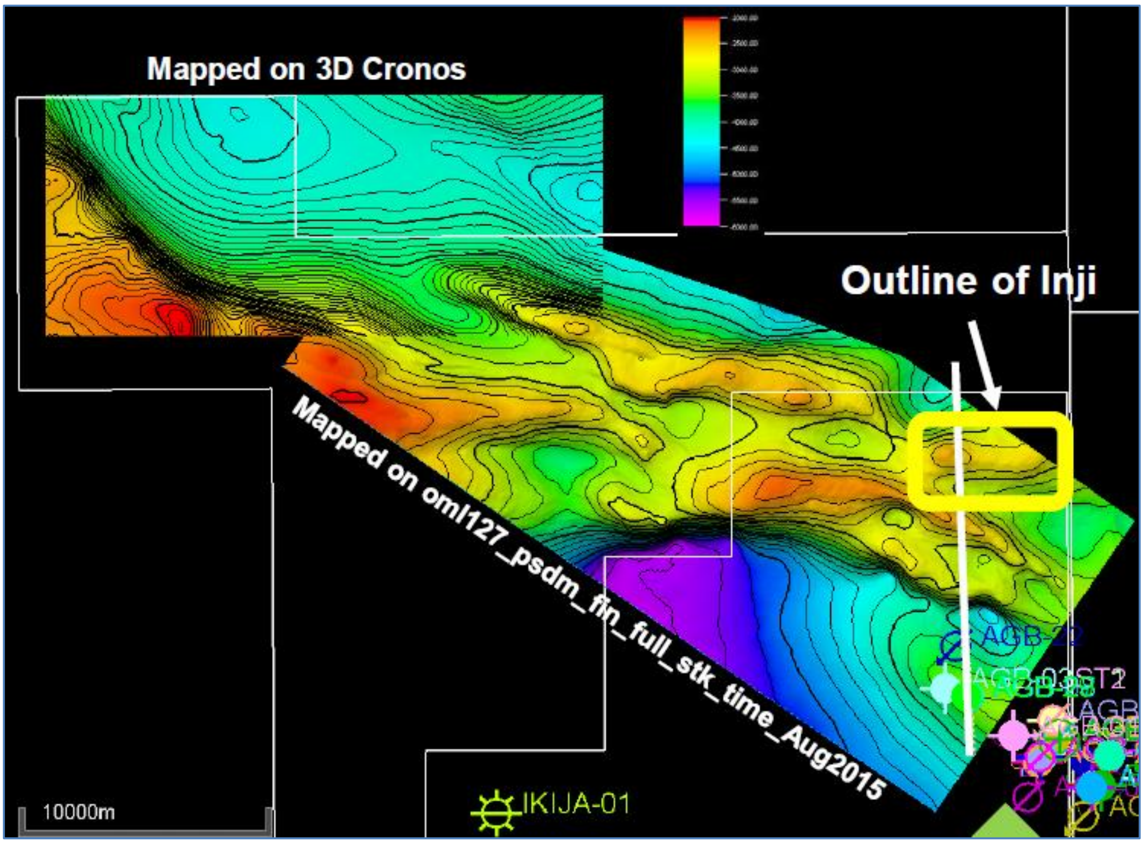


Figure 3-12: :Outline of Inji lead being matured (12.7 Ma SB TWT map)

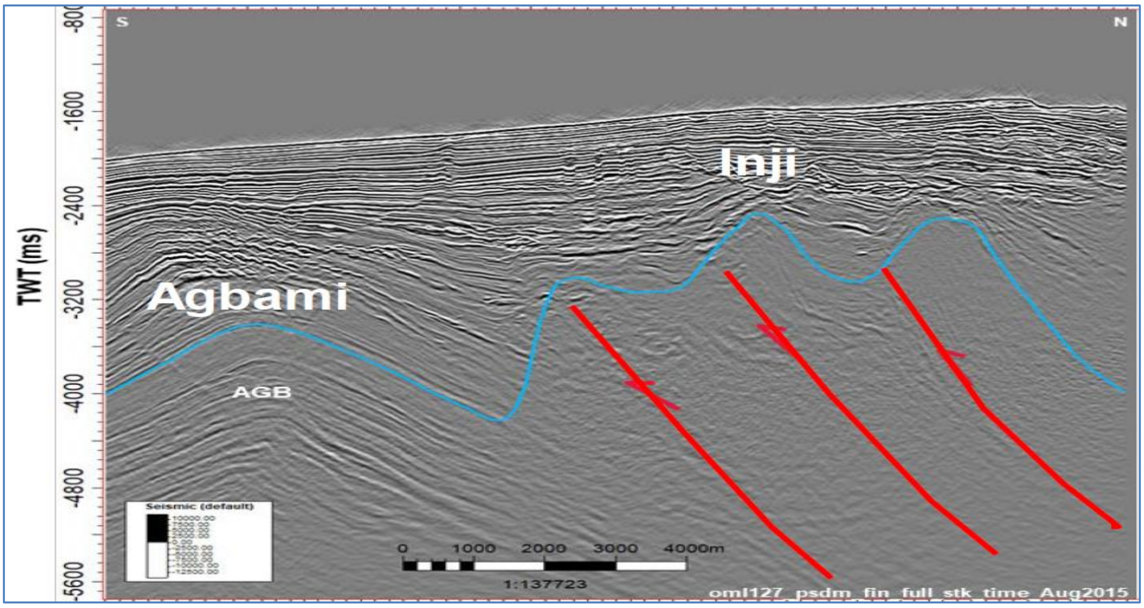


Figure 3-13: Seismic showing imbricate thrust fault blocks of Inji lead

4. PML 2: Prospective Resources

The work programme for operator TotalEnergies is to mature prospects in the key focus areas into drillable status over the next two to three years to incrementally sustain production from Akpo and Egina FPSOs.

4.1. Akpo Deep Prospect

The Akpo Deep prospect lies beneath the Akpo field (**Error! Reference source not found.Error! Reference source not found.**). The Akpo field is located approximately 175 km from Port Harcourt, within OML 130, in water depths ranging from between 1,100 and 1,300 m. TotalEnergies is the operator.

The Akpo Deep prospect is targeting deeper reservoir intervals (I, J, R1300) below the Akpo Field based on analogues from reservoirs penetrated in the Egina South-1 well (Figure 4-2Figure 4-2). All reservoir targets are anticipated to be gas bearing with condensate.

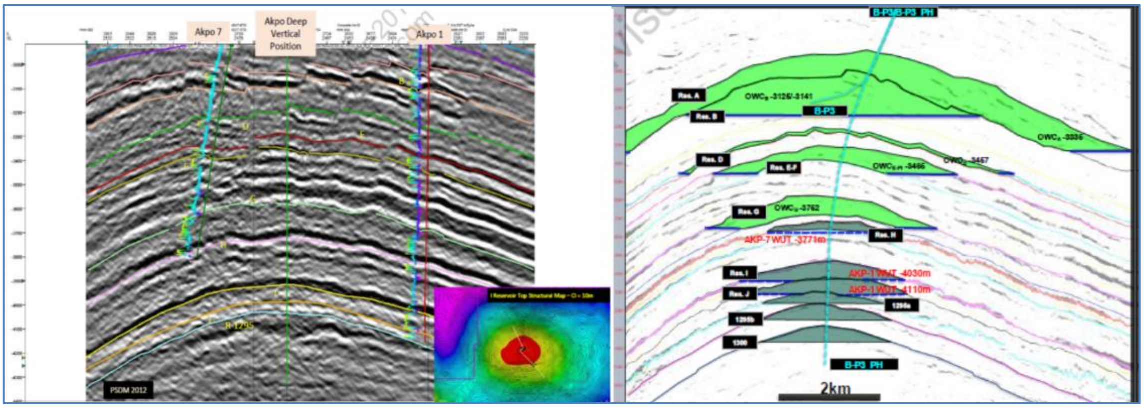


Figure 4-1: NW-SE seismic section and schematic depth cross section through Akpo.

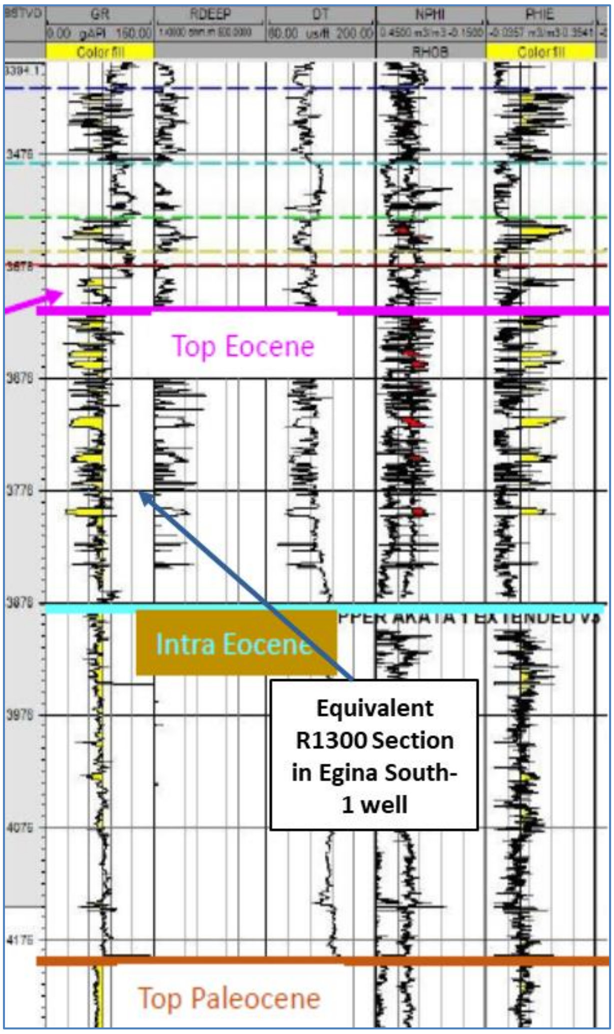


Figure 4-2: Egina South-1 well. Analogue for Akpo deep.

4.1.1. Reservoirs sands I & J

Reservoir sands for I and J are proven by Akpo-1^{ST} well, although those were found to be water bearing. The Akpo-1ST well provides a maximum area constraint for calculating GIIP updip, as well as an indication of reservoir parameters for volumetrics.

Prime GIIP for the I reservoir is P90 =28, P50 = 77 and P10 = 213 Bcf, with P50 = 10 MMstb of associated liquids which gives a P50 total in-place volume of approximately 23 MMboe. RISC's probability of geological success, Pg = 22% for the I reservoir.

Prime GIIP for J reservoir is P90 = 20, P50 = 44, P10 = 99 with P50 = 6 MMstb of associated liquids which gives a P50 total in-place volume of approximately 14 MMboe). RISC's probability of geological success, Pg =22% for the j reservoir.

RISC do not consider the I sands and the J sands to be entirely independent. Dependency exists in the charge category of the petroleum system elements.

Table 4-1: Risking of Akpo Deep, combined I and J reservoirs

Petroleum System Element	RISC Probability (%)	RISC Probability (%)	
Trap	90	54	Containment
Seal	60		
Reservoir	90	90	Reservoir
Source	100	60	Charge
Migration / Timing	60		
Probability of Geological Success	**29**	**29**	

Based on the limited information available, RISC consider the Prime P50 volumes and Pg assessment for the Akpo Deep I/J reservoirs as reasonable. RISC note that Prime have used very narrow parameter input ranges in their volumetrics, particularly for the petrophysical parameters (porosity, water saturation and NTG). RISC recommend widening these ranges as Primes estimates are only based on a single well. However, this would have little impact on the P50 volumes.

4.1.2. Reservoir sands R1300

The equivalent reservoir section to the R1300 was penetrated in the Egina South-1 well providing a calibration point for volumetric input parameters. The well penetrated a relatively low NTG sand / shale section >200 m thick. However, reservoir sands at this level are unproven in the Akpo area.

Prime's GIIP for the R1300 reservoir is P90 = 55, P50 = 253 and P10 = 1181 Bcf with P50 = 34 MMstb of associated liquids which gives a P50 total in-place volume of approximately 78 MMboe. RISC's probability of geological success, Pg = 19%.

Table 4-2: Risking of Akpo Deep, R1300 reservoir

Petroleum System Element	RISC Probability (%)	RISC Probability (%)	
Trap	90	54	Containment
Seal	60		
Reservoir	50	50	Reservoir
Source	100	60	Charge
Migration / Timing	60		
Probability of Geological Success	**16**	**16**	

Based on the limited information available, RISC consider the Prime P50 volumes and Pg assessment for the Akpo Deep R1300 reservoir as reasonable.

Due to lack of available data, RISC are unable to run a probabilistic consolidation on the Prime volumetrics and therefore propose to use the arithmetic summation of the P50 GIIP which results in a value of 374 Bcf with an average Pg of 25%.

Table 4-3: Prime's Akpo Deep In-Place volumes

Reservoir	P90 (Bcf)	P50 (Bcf)	P10 (Bcf)		P50 (MMstb)		P50 (MMboe)[2]
I	28	77	213		10		23
J	20	44	99		6		14
R1300	55	253	1181		34		78
Total		**374**			**50**		**114**

4.2. Akpo Far East-G

Akpo Far East-G prospect located on the eastern flank of the Akpo structure (Figure 4-3). The exploration risk has not been assessed by RISC since too little data has been provided. The June 2021 subsurface committee meeting concluded that an AVO anomaly existed but this has not been fully calibrated or differentiated from the known water trends in the Akpo G reservoir.

The operator is using seismic coherence data to review the Akpo Far East-G anomaly and reviewing the trapping mechanism and sedimentology. AVO studies are ongoing therefore prospect evaluation and risking will be carried out after this work.

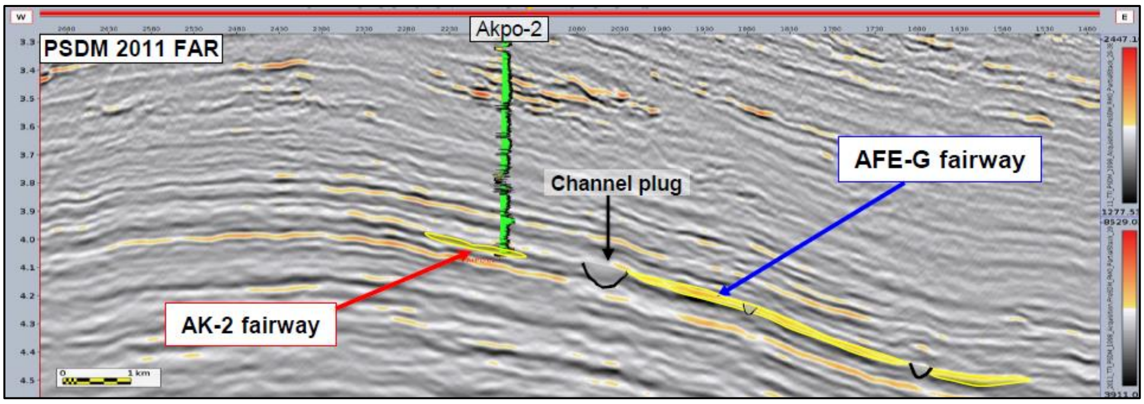


Figure 4-3: Akpo Far East G prospect far offsets

In June 2023 interpretation update it was reported that ongoing sedimentological interpretation suggests that Akpo G main lobe is separated from the Akpo Far East G lobe and that the seismic response shows Class

[2] 1 Boe = 5,800 scf of gas

II-P AVA behaviour consistent with PEM result. The major risk is identifying a seal that justifies a stratigraphic trap at Akpo Far East G.

4.3. Akpo Far West

Akpo Far West is a combined structural-stratigraphic trap with amplitude shut-off dip closure to the north, fault trapped to the east/southeast and bounded by the channel margin in the west/southwest (Figure 4-4). The main risk is therefore containment by the top and lateral seals/channel margins. The prospect therefore would be greatly enhanced with a calibrated amplitude anomaly. AVO studies are ongoing therefore prospect evaluation and risking will be carried out after this work.

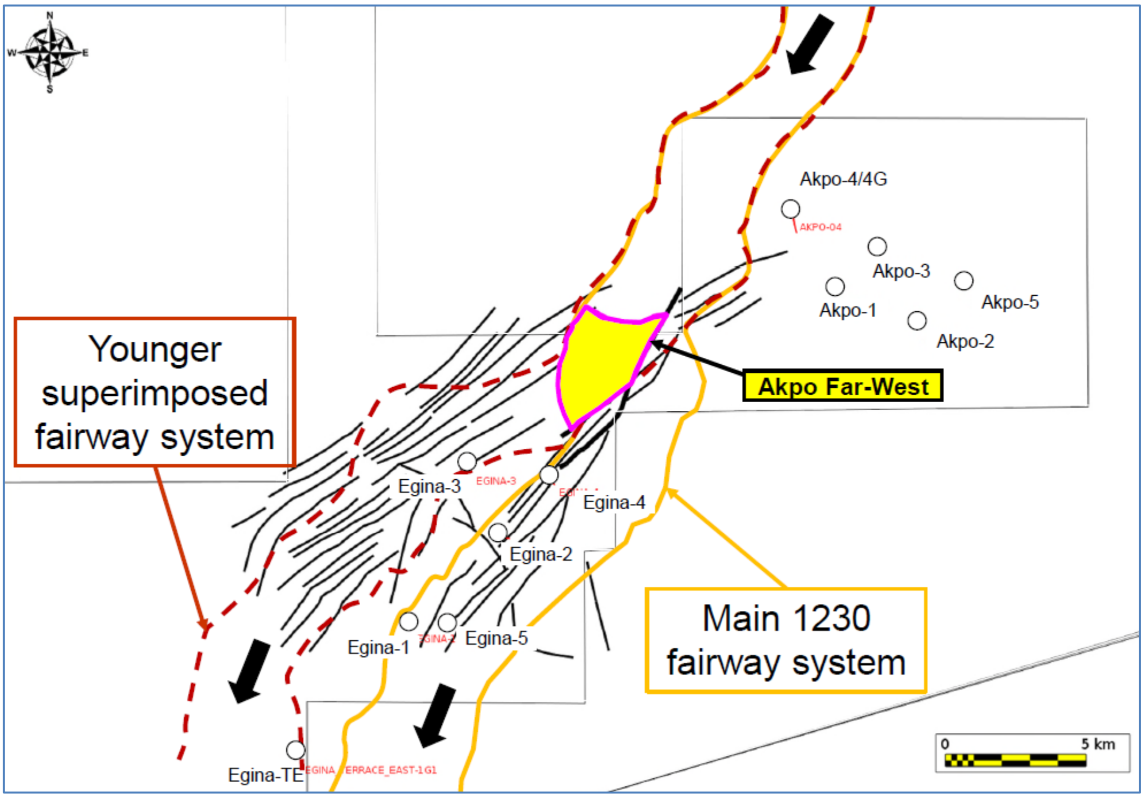


Figure 4-4: Akpo Far West prospect location and trap style

5. PML 3 & PPL 261: Prospective Resources

The work programme for operator TotalEnergies is to mature prospects in the key focus areas into drillable status over the next two to three years to incrementally sustain production from Akpo and Egina FPSOs.

5.1. Egina South Prospect

The Egina South reservoir is divided into the discovered Egina South West block and the largely undiscovered East Blocks. Egina South discovery and Egina South prospect lie 20 km southwest of the Egina Field in PML 3 in approximately 1,650 m water depth (Figure 5-1).

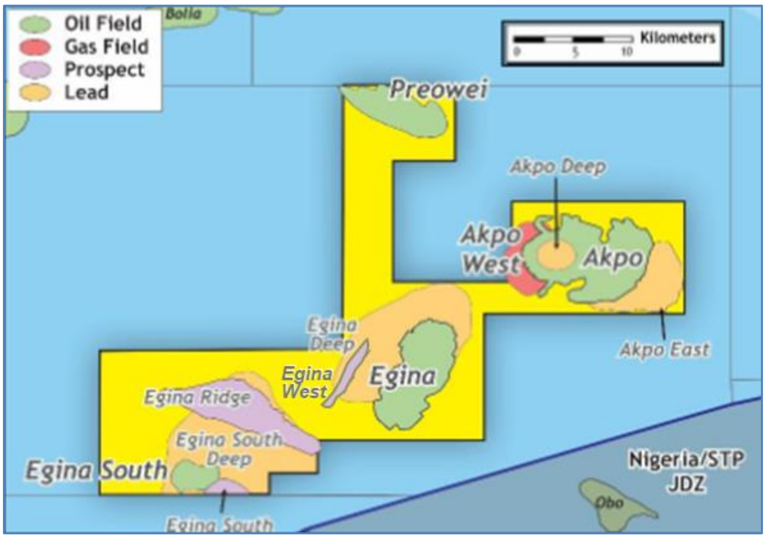


Figure 5-1: Location of Egina South prospect

5.1.1. Geoscience Overview

Two wells, EGS-1 and EGS-2 have been drilled on the discovery in 2003 and 2007 respectively, discovering gas and oil accumulations in the R1180, R1220, R1246 and R1265 reservoirs (Figure 5-2). The two wells discovered only the Western portion of the structure while the Eastern part remains prospective (Egina South Prospective). The proven resource is contained within the PML 3 block with the majority of the prospective resource contained within the adjacent OPL 257 Block.

Table 5-1: Egina South Discovered & Prospective Resources

Reservoir	STOIIP (MMBo)	Gross EUR (MMBo)	EUR Net in PPL 261 (%)	EUR Net in PPL 261 (MMBo)
R1180 (Discovered)	94	28	85%	24
R1230 (Discovered)	23	12	100%	12
Subtotal (Discovered)	**117**	**40**	**89%**	**36**
R1180 (Prospective)	235	86	24%	21
R1230 (Prospective)	117	53	78%	41
Subtotal (Prospective)	**353**	**139**	**45%**	**62**
Total	**470**	**179**	**55%**	**98**

The reservoir intervals are similar to the main Egina field. Egina South reservoir is divided into the discovered Egina South West block and the largely undiscovered East Blocks (Figure 5-2 & Figure 5-3). The prospective resources in Egina South consists of two reservoirs with a general NE-SW orientation. The R1180 reservoir corresponds to a channel-levee system with lateral and vertical gradation of reservoir and non-reservoir parameters.

TotalEnergies performed a comprehensive uncertainty analysis on the Egina South STOIIP, and RISC reviewed and supported the 2C STOIIP quoted by Prime at 169 MMstb in the year end 2021 assessment. New static and dynamic models were supplied by Prime at year end 2022 for R1180 and R1230 reservoirs. TotalEnergies now map a total gross, prospective EUR of 139 MMBo, and 62 MMBo net to PPL 261 (Table 5-1). The discovered Contingent resources are described in Volume 1 of the report (section 8).

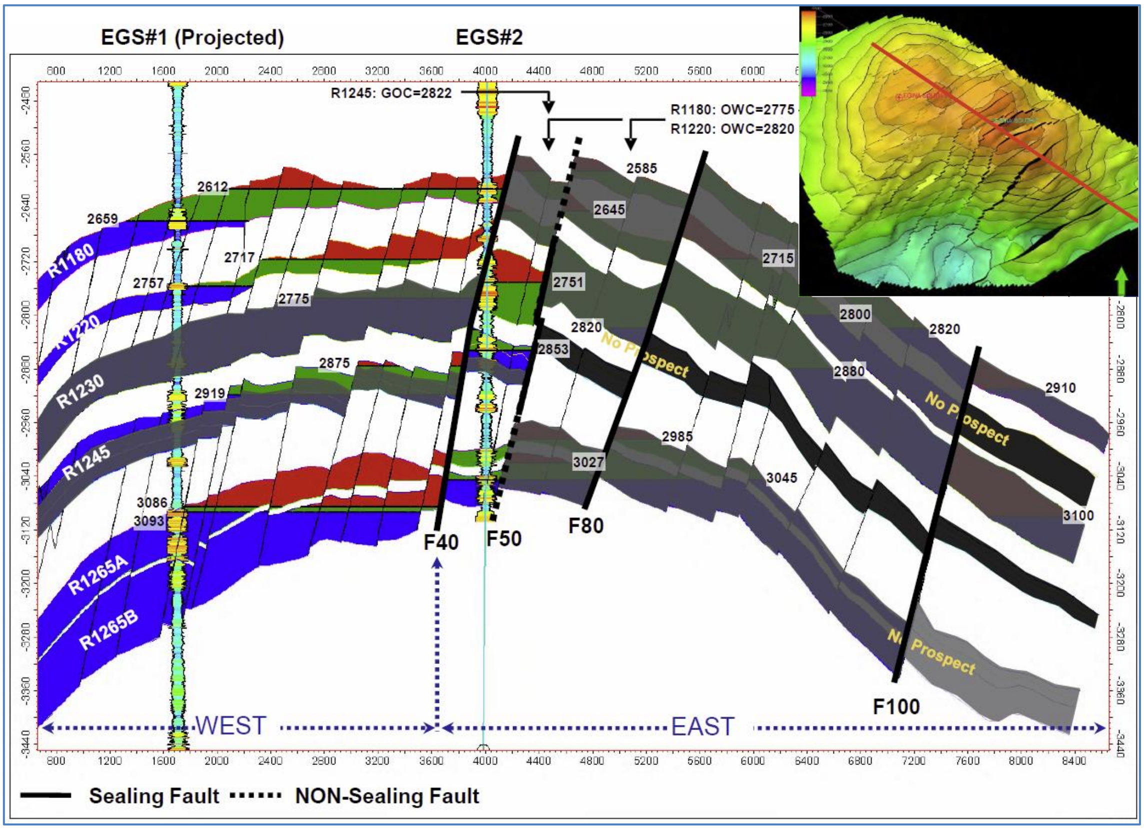
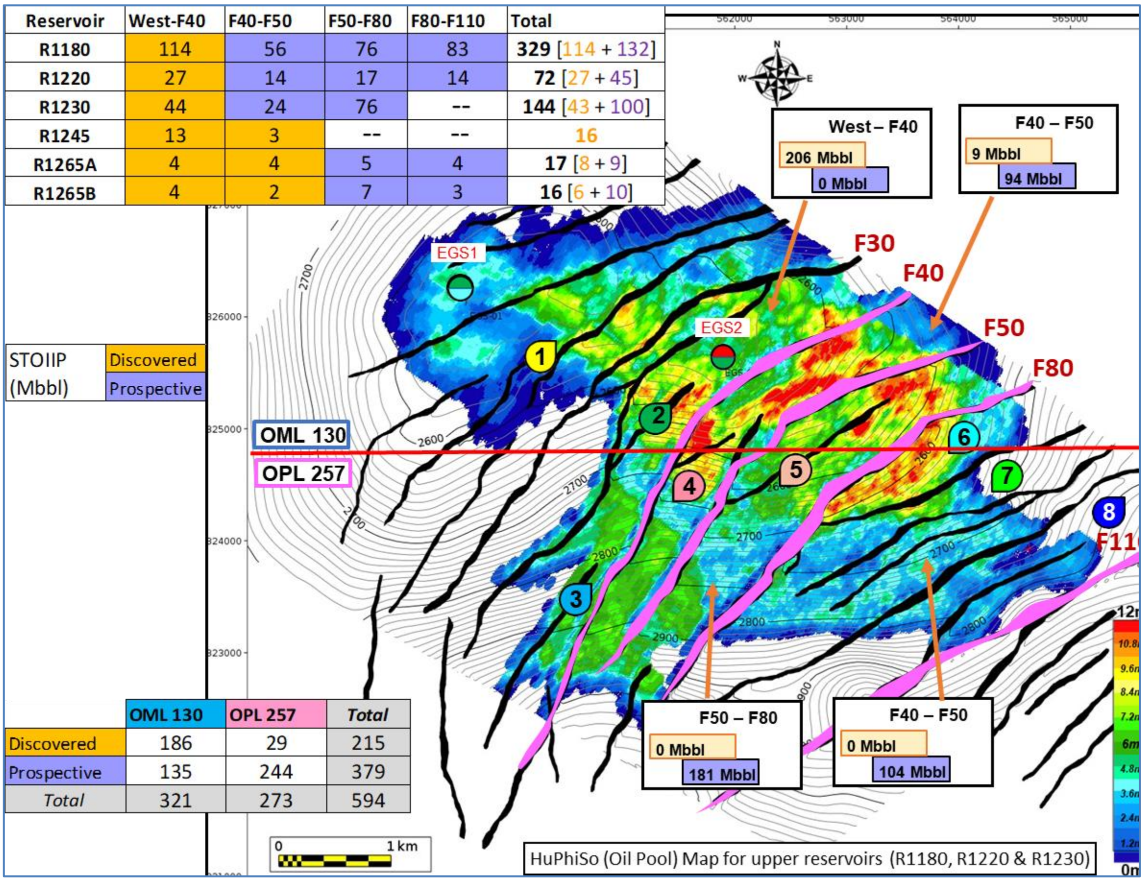


Figure 5-2: Egina South Cross Section

Although not reviewed in detail by RISC, based on our review of TotalEnergies' work on the Contingent Resources, RISC support TotalEnergies' quoted '*on block*' prospective resource STOIIP of 146 MMstb. RISC Pg of 40%.

Prime quote the same prospective STOIIP with 40 MMstb recoverable from 10 wells (recovery factor of 27%) which RISC consider acceptable.

RISC note that more oil is anticipated in prospective areas based on seismic amplitude response, but this is not wholly reliable. In RISC's opinion, there is a reasonable chance of discovering a higher proportion of gas than currently proposed in TotalEnergies' prospective resources. RISC also note that the majority of the prospective STOIIP is contained in OPL 257 to the south of PPL 261.



Reservoir	West-F40	F40-F50	F50-F80	F80-F110	Total
R1180	114	56	76	83	329 [114 + 132]
R1220	27	14	17	14	72 [27 + 45]
R1230	44	24	76	--	144 [43 + 100]
R1245	13	3	--	--	16
R1265A	4	4	5	4	17 [8 + 9]
R1265B	4	2	7	3	16 [6 + 10]

	OML 130	OPL 257	Total
Discovered	186	29	215
Prospective	135	244	379
Total	321	273	594

Figure 5-3: Egina South A Top Reservoir Depth Map, discovered and undiscovered STOIIP.

New models generated by the Operator and supported by Prime in R1180 and R1230 reservoirs based on the 2020/2021 sedimentological model reinterpretation, fluid configuration and DST match, indicates total Egina South STOIIP of 470 MMBo of which 353 MMBo is prospective (Table 5-2). Approximately 80% of the STOIIP is contained within the upper R1180 and R1230 reservoirs. Only 36% of the total STOIIP is within the discovered west blocks (West-F40).

Table 5-2: Total Egina South STOIIP

Classification	STOIIP (MMBo)
Discovered	117
Prospective	353
Total	**470**

Table 5-3: Risking of Egina South prospect

<table>
<tr><th>Petroleum System Element</th><th>RISC Probability (%)</th><th>RISC Probability (%)</th><th></th></tr>
<tr><td>Trap</td><td>80</td><td rowspan="2">56</td><td rowspan="2">Containment</td></tr>
<tr><td>Seal</td><td>70</td></tr>
<tr><td>Reservoir</td><td>90</td><td>90</td><td>Reservoir</td></tr>
<tr><td>Source</td><td>100</td><td rowspan="2">80</td><td rowspan="2">Charge</td></tr>
<tr><td>Migration / Timing</td><td>80</td></tr>
<tr><td>Probability of Geological Success</td><td>40</td><td>40</td><td></td></tr>
</table>

5.2. Egina Deep and Egina South Deep Prospects

Egina Deep and Egina South Deep are deeper targets (Intra-Akata section) below the producing Egina Field and the undeveloped Egina South discovery (Figure 5-4, Figure 5-5). The lithology and reservoir potential is unknown, and this sedimentary section is thought to be unproven offshore.

RISC are unable to verify the validity of the mapped closures due to limited information. Egina Deep is mapped as 4-way dip closure and Egina South Deep is mapped as a 3-way closure, requiring the southern fault to seal to form closure. Hydrocarbon source is proven by the Egina field and Egina South discoveries, but migration and timing for the deeper prospects are uncertain.

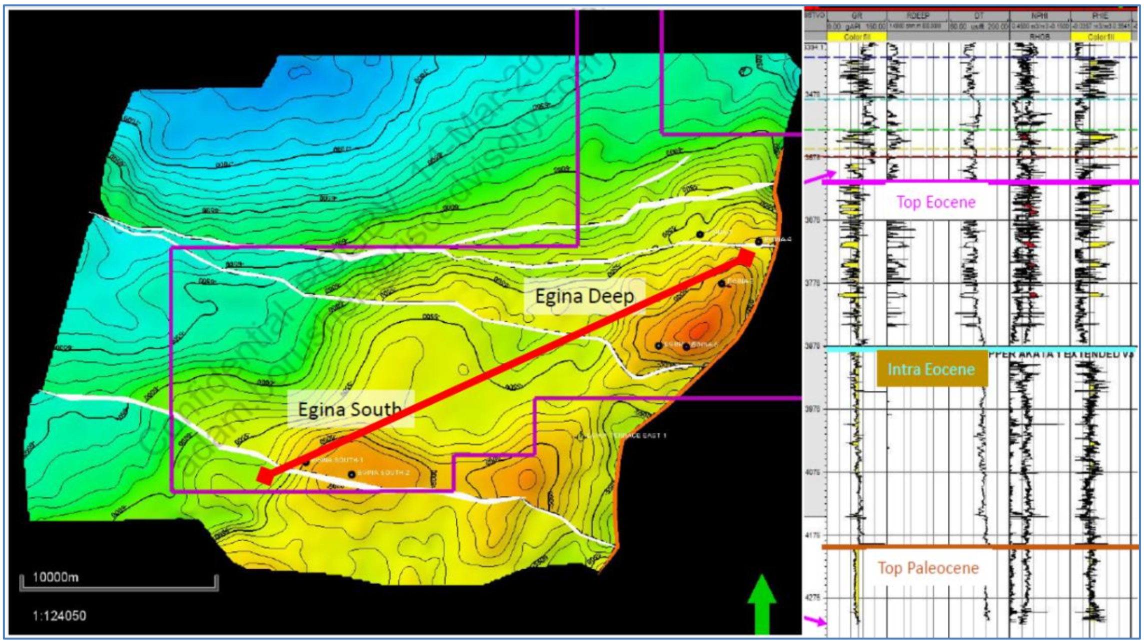


Figure 5-4: Intra Akata depth structure (CI 100m) and Egina South-1 well panel

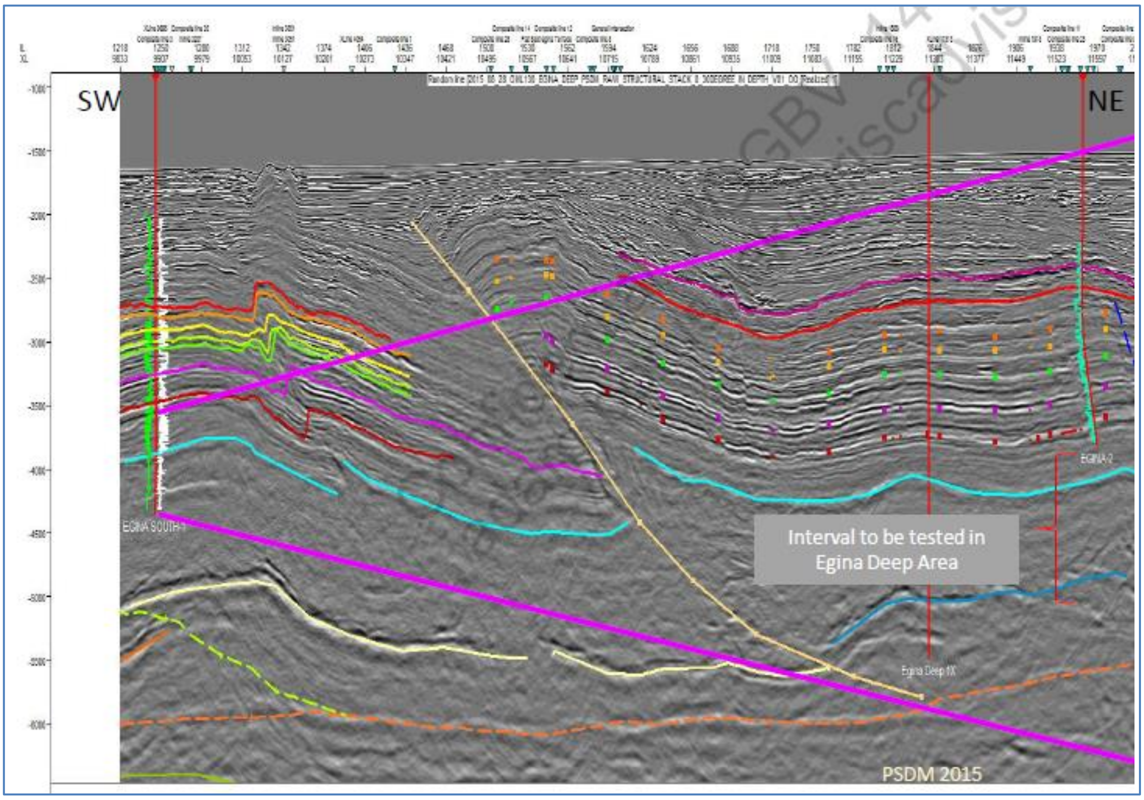


Figure 5-5: SW-NE seismic section from Egina South to Egina

RISC have audited the STOIIP calculations and view the P50 Prime STOIIP as appropriate for the two prospects.

Table 5-4: Prime Egina Deep and Egina South Deep STOIIP (MMstb)

Structure	P90	P50	P10
Egina Deep	27	81	248
Egina South Deep	29	58	111

RISC's estimated probability of geological success for Egina Deep, Pg = 10%.

RISC's estimated probability of geological success for Egina South Deep, Pg = 6%

RISC view of Pg is low for these prospects, principally due to the uncertainty of reservoir presence and quality.

5.3. Egina West Prospect

Egina West is described by the operator as TotalEnergies in it's June 2023 update as the most attractive mature prospect near the Egina field since it is 100% on block, close to the Egina FPSO and is AVO supported with good calibration.

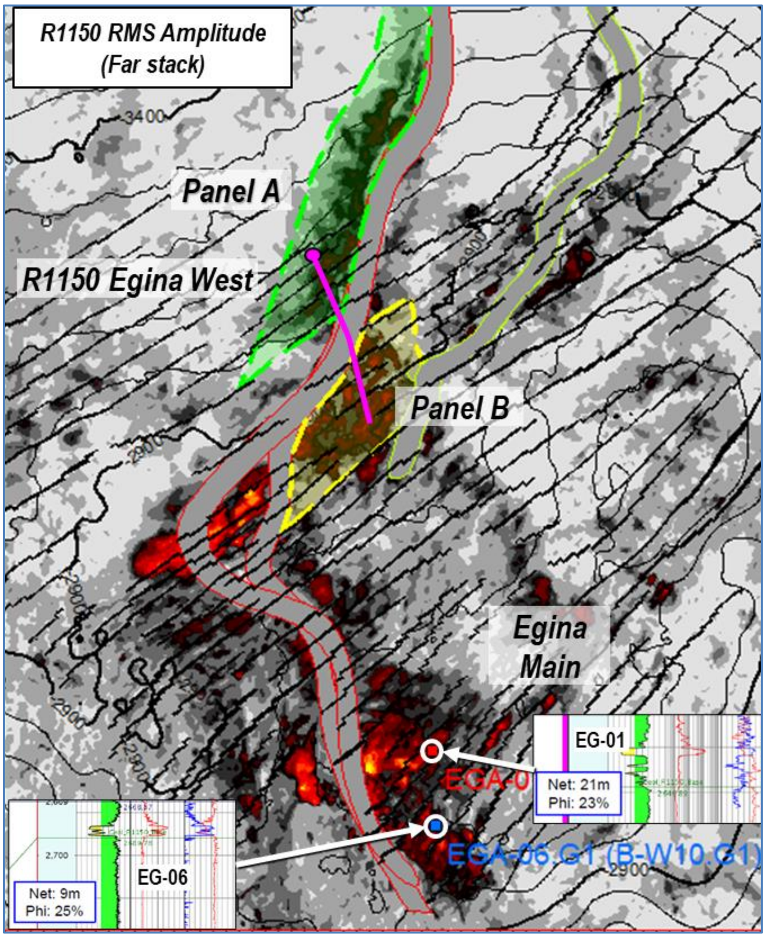


Figure 5-6: Egina West crevasse splay channel (R1150 RMS Far Stack)

Egina West is a stratigraphic channel prospect identified by Type III AVO seismic amplitudes approximately 5 km to the west and down dip of the main Egina field (Figure 5-6). The prospect is divided into three sections: 1) Panel A, 2) Panel B and 3) Panel C with the Egina West AX-1 well planned to test panel A and Panel B in the R1150 and R1120 sands.

The reservoir sandstone units are a series of confined channel-levee complexes deposited in an erosionally confined channel system. The main reservoir target is the R1150 sands at around 3,000 m which encountered hydrocarbons in the EGA 01 and EGA 06 wells of the Egina field. The main channels have been back filled with clays and muds as part of the channel abandonment. The clay plug forms part of the southeastern stratigraphic seal for Panel A and normal faults separate the prospect from the main Egina field along the southern margin. The prospect is dip closed to the northwest and stratigraphically sealed to the west and east otherwise it will spill updip towards the Egina Ridge and Egina field areas respectively.

The amplitudes are reasonably well calibrated with hydrocarbons from the EGA 01 and EGA 06 wells in the Egina main field, but less work has been done on the false positive calibration with the Egina Terrace East-1 well (EGTE-1) which drilled an R1180 amplitude anomaly but encountered wet sands with low saturation gas.

Despite the fact Source rock, Migration, Timing and Reservoir are well known and favourable elements of a proven petroleum system in Nigeria, there are concerns about the integrity of the trap which is mostly stratigraphic, different to the traditional structural style in analogous fields like Egina, Akpo and Preowei.

Amplitude conformance to structure can be explained but is inherently difficult in stratigraphic channel; plays where trapping relies on several geological features such as channel edges rather than structure. The depth cut off at

The key amplitude characteristic in this play type for type III AVO, is not depth conformance but seismic amplitude anomaly in the vertical direction (i.e.: anomaly compared to amplitude strength of reflectors above and below) as well as the AVO response on gathers (i.e.: near versus far offsets). The apparently diffuse nature of the anomaly may indicate degrading reservoir quality and the calibration at the EGA 01 and EGA 06 wells may give the impression of better quality reservoir.

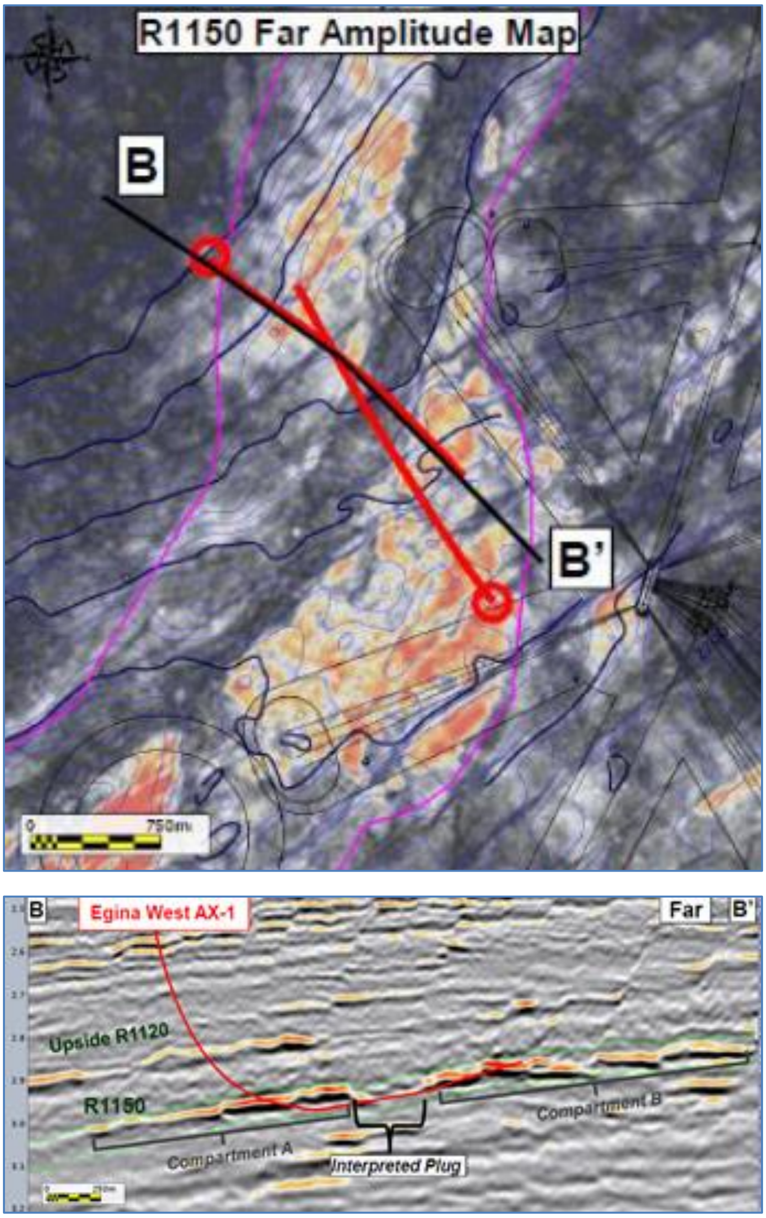


Figure 5-7: Egina West seismic amplitude prospect downdip from Egina field

The postmortem of the EGTE-1 well highlighted that the amplitudes were not conformant with depth contours and the analysis predrill was that it was difficult to understand the EGTE trap at R1180. However, no information was given on the reason for EGTE-1 failure mode.

Prime report P50 STOIIP in Panel A of 37 MMstb and 28 MMstb in Panel B.

One firm budget exploration well was being planned in 2022 during the Egina and Akpo drilling campaign to de risk both Panel A and B. Egina West drilling was been moved to a slot in Q2 2023. Well results could not be found in the data provided to RISC.

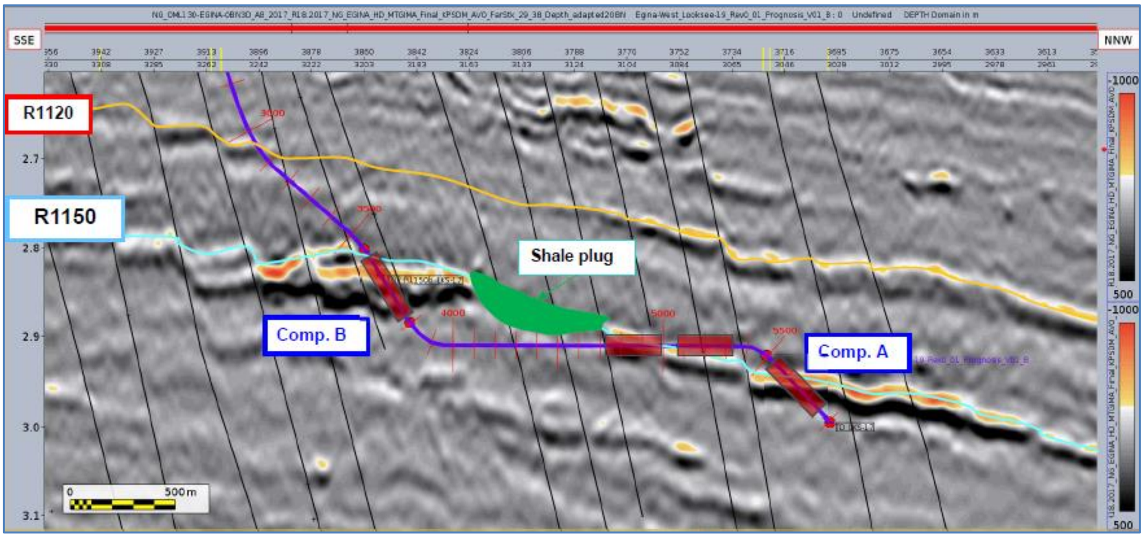


Figure 5-8: Egina West proposed exploration well targets for Q2 2023

The operator risks the R1150 and R1120 reservoirs at Pg=58% and 39% respectively. The operator's overall Egina West pre-drill assessment is that probability of geological success is 70% with an uplift to 73% for the amplitude anomaly. TotalEnergies put the key risk as seal (70%) with the other four risk factors set at 100%. Prime recognize a higher risk on seal (65%) and also recognize a risk of poor reservoir (90%). Prime Pg = 58%.

Table 5-5: Risking of Egina West prospect

Petroleum System Element	RISC Probability (%)	RISC Probability (%)	
Trap	90	54	Containment
Seal	60		
Reservoir	75	75	Reservoir
Source	100	100	Charge
Migration / Timing	100		
Probability of Geological Success	**41**	**41**	

Conceptual development uses four subsea wells (two oil producers, two water injectors) tied back to Egina. More development and economics work is required on Egina West to confirm the materiality of the prospect. The operator maps the following gross unrisked volumes:

- Main Objective (R1150_reservoir): P50 = 52 MMstb, P10 = 80 MMstb
- Secondary Objective (R1120reservoir): P50 = 36 MMstb, P10 = 53 MMstb

5.4. Egina Ridge

The Egina Ridge prospect lies to the west of the Egina field with reservoir intervals which have already been encountered in hydrocarbon bearing sands in the Egina Main area and updip at Egina West (Egina 3 & 20 wells). The sand fairways generally run from NE to SW across Egina field and over the Egina Ridge area. The Egina Ridge is a structural/strati trap which partially (but not fully) closes against a northwest to southeast striking thrust fault.

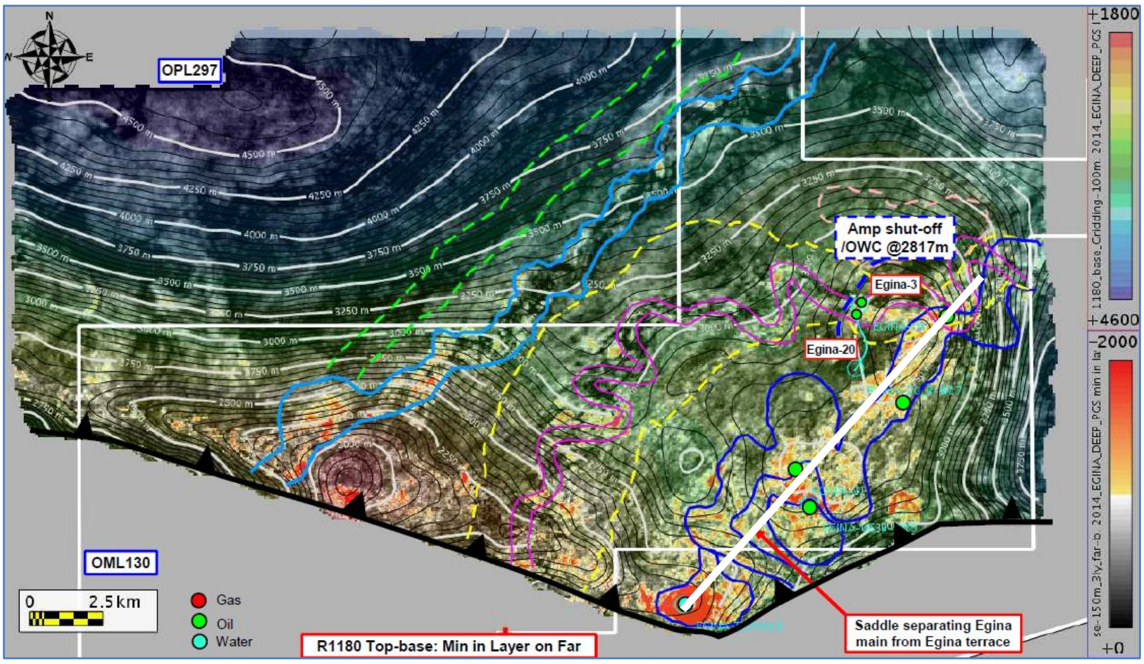


Figure 5-9: Far stack seismic amplitudes draped on depth structure map of R1180 reservoir.

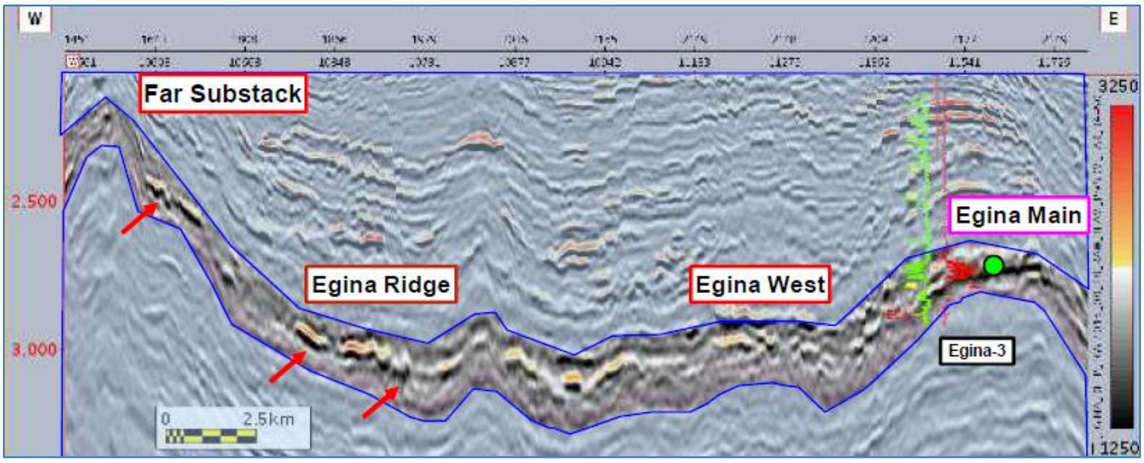


Figure 5-10: Far stack seismic cross section (NE to SW) through Egina and Egina Ridge

There are indications of a seismic flat spot on the western part of the prospect but the operator states the robustness is going to be further investigated. The operator gives the 1230 reservoir a Pg of 39% and unrisked P50, gross resources of approximately 20 MMstb.

The 1246 reservoir is the main reservoir with P50 gross unrisked resources of approximately 380 MMstb and operator's Pg of 22%.

The operator needs to mature the Egina Ridge 1120 & 1180 reservoirs.

6. PML 4: Prospective Resources

6.1. Preowei (R641 Shallow Gas Reservoir)

The gas in the R641 reservoir should only be considered as an immature prospect or a lead at year end 2023. The reservoir is at the margin of AVO window at approximately between 500 m and 750 m depth. The seismic far offset data does not completely discriminate fluid and there is uncertainty in reservoir quality. Operator Total Energies intends to appraise it further with the Preowei development wells.

The operator's in-place volumes are approximately 250 Bcf with estimated recoverable resources of approximately 140 Bcf.

7. Declarations

7.1. Terms of Engagement

This report, any advice, opinions, or other deliverables are provided pursuant to the Engagement Contract agreed to and executed by the Client and RISC.

7.2. Qualifications

RISC is an independent oil and gas advisory firm. All of the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts each with many years of relevant experience and most have in excess of 20 years. RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. RISC has completed over 2,200 assignments in more than 90 countries for over 500 clients. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

The preparation of this report has been managed by Mr. Gavin Ward who is an employee of RISC. Mr. Ward is a member of the Society of Petroleum Evaluation Engineers (SPEE), the Society of Petroleum Engineers (SPE), the Petroleum Exploration Society of Great Britain (PESGB) and is a Fellow of the Association of Chartered Certified Accountants. Mr. Ward holds a B.Sc. (Hons) (Geology & Physics), Aston University, 1988, and an MBA, Cranfield University, 2007. Mr Ward has over 30 years' experience in the sector and meets the requirements of the PRMS and COGEH[3] as a Qualified Reserves Evaluator (QRE) and Qualified Reserves Auditor (QRA). Mr. Ward is independent of the reporting issuer for the purposes of the TSX, FTSE and ASX.

7.3. Standard

Reserves and resources are reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.

[3]COGHE: Canadian Oil and Gas Evaluation Handbook

7.4. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. While every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances or regulations that apply to these assets.

RISC have also not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

We believe our review and conclusions are sound, but no warranty of accuracy or reliability is given to our conclusions.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

7.5. Use of advice or opinion and reliance.

a) The Report is confidential and is for the Sole benefit of the Client. ***It may not be relied upon by any 3rd party.***

b) RISC grants permission for the report to be disclosed, on condition of confidentiality:

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7.8. Authorization for release

Final version authorised for release.

Gavin Ward

Director

RISC (UK) Limited

8. Declarations

8.1. Terms of Engagement

This report, any advice, opinions or other deliverables are provided pursuant to the Engagement Contract agreed to and executed by Prime and RISC.

8.2. Standard

Reserves and resources are reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.

8.3. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from Prime as well as information in the public domain. The information provided to RISC has included both hard copy and electronic information supplemented with discussions between RISC and key Prime staff.

While every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose.

In particular, we have not independently verified property title, encumbrances, regulations that apply to this asset(s). RISC has also not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

8.4. Use of advice or opinion and reliance

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b) RISC grants permission for the report to be disclosed, on condition of confidentiality:

i. to directors, officers, employees and contractors of the Client;

ii. to its professional advisers on a non-reliance basis;

iii. to a party in which the Client has a controlling interest on a non-reliance basis;

iv. to the extent required by law; or

v. as otherwise agreed to in writing by RISC in accordance with the Engagement Contract.

8.5. Independence

RISC has no pecuniary interest, other than to the extent of the professional fees receivable for the preparation of this report, or other interest in the assets evaluated, that could reasonably be regarded as affecting our ability to give an unbiased view of these assets.

RISC makes the following disclosures:

- RISC is independent with respect to Prime and confirms that there is no conflict of interest with any party involved in the assignment;
- Under the terms of engagement between RISC and Prime, RISC will receive a time-based fee, with no part of the fee contingent on the conclusions reached, or the content or future use of this report. Except for these fees, RISC has not received and will not receive any pecuniary or other benefit whether direct or indirect for or in connection with the preparation of this report;
- Neither RISC Directors nor any staff involved in the preparation of this report have any material interest in Prime or in any of the properties described herein.

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9. List of terms

The following lists, along with a brief definition, abbreviated terms that are commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
1P	Equivalent to Proved reserves or Proved in-place quantities, depending on the context.
1Q	1st Quarter
2P	The sum of Proved and Probable reserves or in-place quantities, depending on the context.
2Q	2nd Quarter
2D	Two Dimensional
3D	Three Dimensional
4D	Four Dimensional – time lapsed 3D in relation to seismic
3P	The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context.
3Q	3rd Quarter
4Q	4th Quarter
AFE	Authority for Expenditure
ARO	Asset Retirement Obligation
bbl	US Barrel
bbl/d	US Barrels per day
Bcf	Billion (10^9) cubic feet
Bcm	Billion (10^9) cubic metres
Bfpd	Barrels of fluid per day
bopd	Barrels of oil per day
BTU	British Thermal Units
boepd	US barrels of oil equivalent per day
bwpd	Barrels of water per day
°C	Degrees Celsius
Capex	Capital expenditure
CAPM	Capital asset pricing model
CGR	Condensate Gas Ratio – usually expressed as bbl/MMscf
Contingent Resources	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 are a class of discovered recoverable resources as defined in the SPE-PRMS.
CO_2	Carbon dioxide
cp	Centipoise (measure of viscosity)
CPI	Consumer Price Index
deg	Degrees
DHI	Direct hydrocarbon indicator
Discount Rate	The interest rate used to discount future cash flows into a dollars of a reference date
DST	Drill stem test
E&P	Exploration and Production
Eg	Gas expansion factor. Gas volume at standard (surface) conditions/gas volume at reservoir conditions

Term	Definition
	(pressure and temperature)
EIA	US Energy Information Administration
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
ESMA	European Securities and Markets Authority
ESP	Electric submersible pump
EUR	Expected Ultimate recovery
Expectation	The mean of a probability distribution
°F	Degrees Fahrenheit
FDP	Field Development Plan
FEED	Front End Engineering and design
FID	Final investment decision
FM	Formation
FPSO	Floating Production Storage and offtake unit
FWL	Free Water Level
FVF	Formation volume factor
GCOS	Geological Chance of Success
GIIP	Gas Initially In Place
GJ	Giga (10^9) joules
GOC	Gas-oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GSA	Gas sales agreement
GTL	Gas To Liquid(s)
GWC	Gas water contact
H_2S	Hydrogen sulphide
HHV	Higher heating value
ID	Internal diameter
IRR	Internal Rate of Return is the discount rate that results in the NPV being equal to zero.
JV(P)	Joint Venture (Partners)
Kh	Horizontal permeability
km^2	Square kilometres
Krw	Relative permeability to water
Kv	Vertical permeability
kPa	Kilo (thousand) Pascals
Mstb/d	Thousand Stock tank barrels per day
LIBOR	London inter-bank offered rate
LNG	Liquefied Natural Gas
LTBR	Long-Term Bond Rate
m	Metres
MDT	Modular dynamic (formation) tester
mD	Millidarcies (permeability)

Term	Definition
MJ	Mega (10^6) Joules
MMbbl	Million US barrels
MMscf/d	Million standard cubic feet /per day\
MMboe	Million barrels of oil equivalent
MMstb	Million US stock tank barrels
MOD	Money of the Day (nominal dollars) as opposed to money in real terms
MOU	Memorandum of Understanding
Mscf	Thousand standard cubic feet
Mstb	Thousand US stock tank barrels
MPa	Mega (10^6) pascal (measurement of pressure)
mss	Metres subsea
MSV	Mean Success Volume
mTVDss	Metres true vertical depth subsea
MW	Megawatt
NPV	Net Present Value (of a series of cash flows)
NTG	Net to Gross (ratio)
ODT	Oil down to
OGIP	Original Gas In Place
OOIP	Original Oil in Place
Opex	Operating expenditure
OWC	Oil-water contact
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively.
PBU	Pressure build-up
PJ	Peta (10^{15}) Joules
POS	Probability of Success
Possible Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) 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.
Probable Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that 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.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS.
Proved Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty 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

Term	Definition
	probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as “Proven”.
PSC	Production Sharing Contract
PSDM	Pre-stack depth migration
PSTM	Pre-stack time migration
psia	Pounds per square inch pressure absolute
p.u.	Porosity unit e.g. porosity of 20% +/- 2 p.u. equals a porosity range of 18% to 22%
PVT	Pressure, volume & temperature
QA/QC	Quality Assurance/ Control
rb/stb	Reservoir barrels per stock tank barrel under standard conditions
RFT	Repeat Formation Test
Real Terms (RT)	Real Terms (in the reference date dollars) as opposed to Nominal Terms of Money of the Day
Reserves	RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.
RT	Measured from Rotary Table or Real Terms, depending on context
SC	Service Contract
scf	Standard cubic feet (measured at 60 degrees F and 14.7 psia)
Sg	Gas saturation
Sgr	Residual gas saturation
SRD	Seismic reference datum level
SPE	Society of Petroleum Engineers
SPE-PRMS	Petroleum Resources Management System, prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.
So	Oil Saturation
Sor	Residual Oil Saturation
s.u.	Fluid saturation unit. e.g. saturation of 80% +/- 10 s.u. equals a saturation range of 70% to 90%
stb	Stock tank barrels
STOIIP	Stock Tank Oil Initially In Place
Sw	Water saturation
TCM	Technical committee meeting
Tcf	Trillion (10^{12}) cubic feet
TJ	Tera (10^{12}) Joules
TLP	Tension Leg Platform
TRSSV	Tubing retrievable subsurface safety valve
TVD	True vertical depth
UR	Ultimate recovery
US$	United States dollar
US$ million	Million United States dollars

Term	Definition
WACC	Weighted average cost of capital
WHFP	Well Head Flowing Pressure
Working interest	A company’s equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.
WPC	World Petroleum Council
WTI	West Texas Intermediate Crude Oil