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Reserves & Contingent Resources Audit of OML 127, PML 2, PML 3, PML 4 & PPL 261, offshore Nigeria as of Year End 2023 (Volume 1 of 2)

For Prime Oil & Gas Coöperatief U.A

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Private and Confidential

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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 in this volume (Volume 1) and the prospective resources in another volume (Volume 2).

RISC has reviewed the reserves and resources in accordance with the Society of Petroleum Engineers' internationally recognised Petroleum Resources Management System (SPE-PRMS)[1]. A summary of the net oil and gas reserves attributable to Prime are summarised in Table 1-1. The content of this report and RISC's estimates of reserves and contingent resources are based on data provided by Prime to the end of November and some of December 2023.

Table 1-1: Reserves Net to Prime as of 1 January 2024

Net Entitlement Oil/Condensate and Sales Gas	Unit	Reserves		
		1P	2P	3P
Licence OML 127				
Agbami Field Oil	MMstb	19.3	30.7	38.2
Licence PML 2, PML 3 & PML 4 (formerly part of OML 130)				
Akpo Field Oil	MMstb	11.7	18.4	25.2
Akpo Field Sales Gas	Bcf	27.0	60.5	98.2
Akpo West Field Oil	MMstb	1.4	1.9	2.4
Akpo West Field Sales Gas	Bcf	10.6	22.0	39.7
Egina Field Oil	MMstb	18.0	32.2	44.4
Egina Field Sales Gas	Bcf	6.7	11.7	18.1
Preowei Field Oil	MMstb	12.4	18.7	24.1
Preowei Field Sales Gas	Bcf	5.4	8.5	11.2

Notes:

1. Prime Reserves are stated at its net entitlement.
2. Sales Gas resources are adjusted for fuel gas.
3. Volumes are based on conversion of both licences to PIA terms.
4. Agbami has zero sales gas, therefore zero sales gas reserves.

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

The economic analysis of each licence has been carried out using an effective date of 1 January 2024 and the economic terms 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.

All costs quoted are in US dollars US$ in real terms with reference date 1 January 2024.

Prime holds an 8% working interest in OML 127 which covers part of the Agbami field. Agbami has been unitised over OML 127 and OML 128 approximately 62.5% and 37.5% respectively.

Prime holds a net 16% working interest in PML 2, PML 3, PML 4 and PPL 261 (formerly known as OML 130) which covers the Akpo, Akpo West, Egina, Egina South and Preowei fields. Prime is part of a Production Sharing Agreement (PSA) in each licence and therefore net reserves are calculated using net entitlement, not working interest. The method used for calculating Prime net entitlement reserves is described in Section 9.3 of this report.

The Akpo, Egina and Agbami fields are in production. The Preowei field is under development, with first oil expected September 2027. A field development plan has been approved for D-P5 and Akpo West.

RISC's estimates of gross field reserves as of 1 January 2024 are shown in Table 1-2.

Table 1-2: Gross Field Volumes as of 1 January 2024

Gross Field Oil/Condensate and Sales Gas	Unit	Reserves		
		1P	2P	3P
Agbami Field Oil[1]	MMstb	203.9	364.4	477.5
Akpo Field Oil	MMstb	64.9	105.2	152.2
Akpo Field Sales Gas	Bcf	159.5	366.8	608.8
Akpo West Field Oil[2]	MMstb	12.9	18.5	19.7
Akpo West Field Sales Gas[2]	Bcf	75.8	148.6	253.4
Egina Field Oil	MMstb	106.9	194.6	275.4
Egina Field Sales Gas	Bcf	41.6	72.8	113.1
Preowei Field Oil	MMstb	72.3	113.1	148.8
Preowei Field Sales Gas	Bcf	33.8	52.9	69.7

Notes:

1. This Table 1-2 refers to gross field volumes, which is 100% of the field's production. Table 1-3 refers to gross licence volumes (e.g.: Agbami is multiplied by the OML 127 unitization of approx. 62.5%).
2. Akpo West volumes include volumes from Akpo life extension due to presence of Akpo West of 4.8 MMstb & 9.5 Bcf in the 1P case, 6.7 MMstb & 11.2 Bcf in the 2P case, and 4.3 MMstb and 5.1 Bcf in the 3P case.
3. Sales Gas resources are adjusted for fuel gas.
4. Volumes are based on conversion of both licences to PIA terms.
5. Agbami has zero sales gas, therefore zero sales gas reserves.

We have included a reserves reconciliation between the year-end 2022 RISC reserves report and those for this year-end 2023 RISC reserves report (Table 1-3). Both sets of year-end reserves have reported recoverable volumes to the earlier of the field economic cut-off, or the end of the PIA licence periods.

Reserves

RISC has analysed the incremental economics of all undeveloped and contingent projects. We are satisfied that all reserves projects are economically viable in a 1P, 2P and 3P case when using the oil price forecast.

Table 1-3: Reserves reconciliation compared to Year-End 2022 report

Oil/Condensate and Sales Gas	Unit	Reserves		
		1P	2P	3P
Licence OML 127				
Agbami Field Oil Gross at 1 Jan 2023	MMstb	142.3	233.2	322.8
Agbami production, 1 Jan 2023 to 31 Dec 2023	MMstb	22.2		
Revisions (unit share)	MMstb	7.3	16.6	-2.3
Agbami Field Oil Gross on 1 Jan 2024	MMstb	127.4	227.6	298.3
Licences PML 2, PML 3 & PML 4 (formerly known as OML 130)				
Akpo Field Oil Gross at 1 Jan 2023	MMstb	87.4	137.4	197.8
Akpo Field production, 1 Jan 2023 to 31 Dec 2023	MMstb	25.5		
Akpo Field Revisions	MMstb	15.8	11.8	-0.4
Akpo Field Oil Gross on 1 Jan 2024	MMstb	77.8	123.7	171.9
Egina Field Oil Gross at 1 Jan 2023	MMstb	133.0	225.7	324.2
Egina Field production, 1 Jan 2023 to 31 Dec 2023	MMstb	33.9		
Egina Field Revisions	MMstb	7.8	2.8	-14.9
Egina Field Oil Gross on 1 Jan 2024	MMstb	106.9	194.6	275.4
Preowei Field Oil Gross at 1 Jan 2023	MMstb	72.3	113.0	148.8
Preowei Field Revisions	MMstb	0.0	0.1	0.0
Preowei Field Oil Gross on 1 Jan 2024	MMstb	72.3	113.1	148.8
Sales Gas Gross at 1 Jan 2023	Bcf	410.6	617.1	1,140.9
Sales Gas production, 1 Jan 2023 to 31 Dec 2023	Bcf	119.2		
Sales Gas Revisions	Bcf	19.3	143.3	23.3
Sales Gas Gross on 1 Jan 2024	Bcf	310.6	641.2	1,045.0

Notes:

1. For OML 127 “Gross” licence reserves are 62.4619% of total field reserves as of 1 January 2024.
2. For PML 2, PML 3 & PML 4 (formerly known as OML 130) “Gross” licence reserves are 100% of total field reserves.
3. Akpo field reserves include Akpo West.
4. Sales Gas resources are adjusted for fuel gas.
5. Volumes are based on conversion of both licences to PIA terms.

Contingent Resources

In addition, Prime identified potential projects that are classified as contingent resources. The contingent resources are dependent on maturing technical work, further approvals, and ongoing production from the host fields. The net oil and gas contingent resources attributable to Prime are summarised in Table 1-4.

Table 1-4: Contingent resources Net to Prime as of 1 January 2024

Net Entitlement Oil/Condensate and Sales Gas		Unit	Contingent Resources		
			1C	2C	3C
Agbami 6 PAIDP Wells	Prime net oil entitlement	MMstb	2.9	2.9	3.4
	Prime net gas entitlement	Bcf	0.0	0.0	0.0
Ikija (4 wells)	Prime net oil entitlement	MMstb	6.5	10.1	11.8
	Prime net gas entitlement	Bcf	0.0	0.0	0.0
Akpo 5 Infill Wells	Prime net oil entitlement	MMstb	3.3	4.3	5.5
	Prime net gas entitlement	Bcf	6.2	9.6	12.5
Akpo MGI	Prime net oil entitlement	MMstb	5.9	8.0	9.3
	Prime net gas entitlement	Bcf	-21.2	-19.0	4.2
Preowei 8 Infill Wells	Prime net oil entitlement	MMstb	3.3	5.7	6.6
	Prime net gas entitlement	Bcf	1.5	2.7	3.2
Egina South (12 wells)	Prime net oil entitlement	MMstb	3.0	5.6	7.7
	Prime net gas entitlement	Bcf	2.0	3.7	5.1

Notes:

1. Prime resources are stated at its net entitlement.
2. Sales Gas resources are adjusted for fuel gas.
3. Volumes are based on conversion of both licences to PIA terms.
4. OML-127 has zero sales gas, therefore zero sales gas resources from Agbami and Ikija.

Fuel gas reserves

Prime fuel gas reserves are included in Table 1-5.

Table 1-5: Prime Fuel Gas reserves as of 1 January 2024

Gas Consumed in Operations	Unit	Reserves		
		1P	2P	3P
Agbami net entitlement	Bcf	6.7	8.4	8.4
Akpo net entitlement	Bcf	1.9	3.2	4.6
Akpo West net entitlement	Bcf	1.4	2.0	2.6
Egina net entitlement	Bcf	6.5	12.7	16.0
Preowei net entitlement	Bcf	0.2	0.3	0.4

Notes:

1. Prime net entitlement for gas is calculated using the method described in section 9.3 of this report.
2. Volumes are based on conversion of both licences to PIA terms.
3. Fuel gas reserves are not to be added to the sales gas reserves and must be reported separately.

SPE PRMS[2] 2018 states that gas used as fuel for operations may be included as Reserves or Resources but only when these volumes are recorded separately. These are not sales volumes but are gas volumes consumed in the operations (CiO).

The split between Developed and Undeveloped reserves for both oil and gas is shown in Table 1-6.

[2] Society of Petroleum Engineers Petroleum Resources Management System

Table 1-6: Developed and Undeveloped Reserves gross to licence and net to Prime as of 1 January 2024

Oil	Unit	Reserves		
		1P	2P	3P
Developed, gross to licence	MMstb	248.6	452.0	596.6
Undeveloped, gross to licence	MMstb	135.7	207.1	297.7
Total, gross to licence	**MMstb**	**384.3**	**659.0**	**894.4**
Developed, Prime net entitlement	MMstb	39.9	69.1	89.3
Undeveloped, Prime net entitlement	MMstb	22.9	32.8	45.1
Total, Prime net entitlement	**MMstb**	**62.8**	**101.9**	**134.4**
Sales gas				
Developed, gross to licence	Bcf	115.5	228.9	375.5
Undeveloped, gross to licence	Bcf	195.2	412.3	669.5
Total, gross to licence	**Bcf**	**310.6**	**641.2**	**1,045.0**
Developed, Prime net entitlement	Bcf	18.5	36.6	60.1
Undeveloped, Prime net entitlement	Bcf	31.2	66.0	107.1
Total, Prime net entitlement	**Bcf**	**49.7**	**102.6**	**167.2**

Notes:

1. For OML 127 “Gross” licence reserves are 62.4619% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 and PPL 261 (formerly known as OML 130) is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.
6. Additions beyond the field level have all been made arithmetically, as a result RISC cautions that the 1P aggregate quantities may be conservative estimates and the 3P aggregate quantities may be optimistic due to portfolio effects.

Table 1-7: 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**

Key uncertainties: Use of decline curves in Egina Field to forecast production and switch to reservoir model.

Key risks: Government-regulated reduction in production volumes to meet changes in OPEC quotas.

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2. Introduction

2.1. Asset/Portfolio Description

Prime has an 8% working interest in OML 127. The Agbami Field straddles OML 127 and OML 128, approximately 70 miles south-southwest from the nearest Nigerian shoreline and approximately 220 miles southeast of Lagos. OML 127 also contains the undeveloped Ikija field discovery.

Prime has a 16% working interest in PML 2, PML 3 & PML 4 and PPL 261 (formerly known as OML 130). This covers the Akpo, Akpo West, Egina, Egina South and Preowei fields, approximately 130 km from the nearest Nigerian shoreline. Water depths for the licences range from 1,100 to 1,700 m.

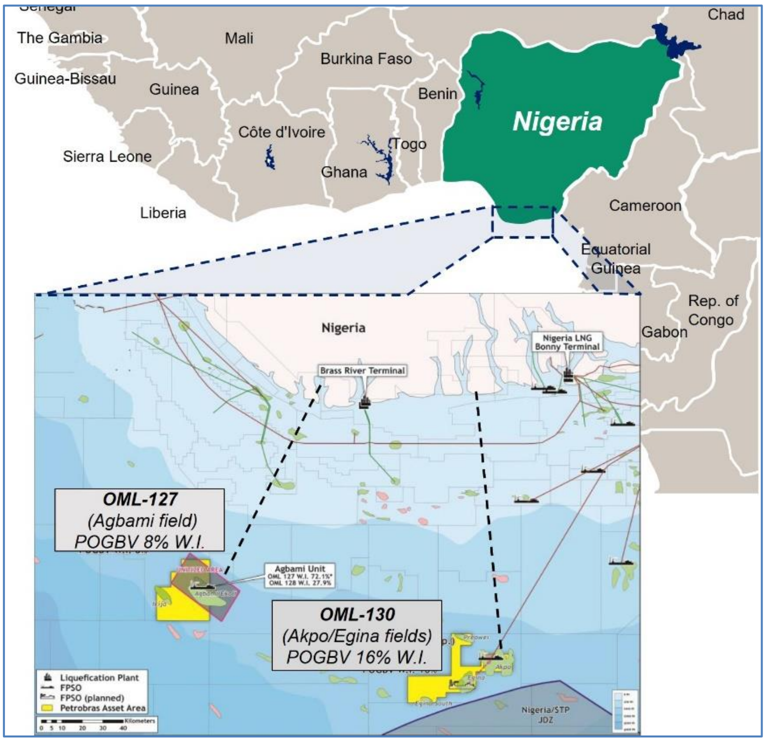

Figure 2-1: Location map

Agbami field commenced production in 2008 and reached a plateau rate of 250,000 bopd in 2009. A total of 30 production wells, 10 water injection wells and 5 gas injection wells have been drilled. Field average oil production rate in 2023 was about 98 Mstb/d. Production is via a dedicated FPSO and there is no gas export. All gas is reinjected, used as fuel, or flared. Undeveloped reserves include 6 wells of the PAIDP (Post Agbami Infill Drilling Project[3]) and a workover. Contingent resources include 6 additional infill wells plus a potential gas blowdown project.

[3] AIDP acronym taken from 2021 Field Development Plan

Akpo field production started in 2009 with a plateau rate of 180,000 bopd reached in 2010. By end 2020, 27 oil producers, 19 water injectors and 2 gas injectors had been drilled, spread across the 5 main reservoirs (A, B+C, D, EF, and G). As of 31 December 2023, there have been 29 oil producers, 18 water injectors and 2 gas injectors spread across the 6 main reservoirs (AU, AL, B+C, D, EF and G). Akpo contains a critical fluid that has also been described as condensate or light oil with an original GOR of approximately 3,500 scf/bbl. There is a significant variation of fluid properties with depth without sharp gas-oil contacts. Pressure maintenance at or near initial pressure is required and is provided by both water and gas injection. Cumulative oil production up to and including 31 December 2023 was 664 MMstb (estimated). Part of the produced gas is re-injected for pressure maintenance and the remaining part is transported via an export line to the Nigeria LNG plant (NLNG) via the Akpo-Amenam pipeline with cumulative gas production of 2.47 Tcf, cumulative injection 0.90 Tcf and cumulative gas export of 1.43 Tcf on 31 December 2023.

Egina production commenced at end 2018 and achieved a plateau rate of 200,000 bopd in 2019. Gas is exported to shore and the NLNG, via the Akpo-Amenam pipeline. Water injection started in February 2019 and reached 300,000 bpd mid 2019 with 14 injectors. Water production started in May 2019 and is currently 95,000 bwpd. The GOR was steady at 650 to 700 scf/stb but increased from 65 MMscf/d in May 2023 to 170 MMscf/d in November 2023 before dropping back to 70MMscf/d in December 2023. Cumulative oil production up to and including 31 December 2023 is 256.1 MMstb. Sixteen injectors have injected 425.7 MMbbl water. Cumulative water production is 59.3 MMbbl, with a field water cut of 51%.

Table 2-1: Asset summary

Asset		Operator	Working Interest	Status	Licence expiry date	PIA Term Effective Date
Country	Licence					
Nigeria	OML 127	Chevron	8% of Licence	Agbami producing	December 2024	1 March 2023
	OML 130	Total	16% of Licence	Akpo and Egina producing; Akpo West and Preowei under development	February 2025	1 June 2023
	PML 2/3/4 & PPL 261 (formerly OML 130)	Total	16% of Licence	Akpo and Egina producing; Akpo West and Preowei under development and Egina South (PPL 261)	February 2045	1 June 2023

Preowei is under development and FID is expected in 2024. Drilling is planned to commence in Q1 2027 leading to first oil in Q3 2027. It will have 8 oil producers and 8 water injectors, tied back to the Egina FPSO for oil and gas export. Plateau production of 60,000 bopd is expected. Further development potential (contingent resources) includes 4 additional producer-injector pairs.

This resource assessment is based on conversion of both licences to the Petroleum Industry Act (PIA). Prime have assumed conversion dates of 1 March 2023 for both OML 130 and OML 127. A summary of the assets and licences is given in Table 2-1 and Table 2-2.

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 reserves and contingent resources in offshore Nigeria licences OML 127 and PML 2, PML 3 & PML 4 and PPL 261 (formerly known as OML 130).

This review included an assessment of three producing fields (Egina, Agbami and Akpo), one field approaching FID (Preowei), one field in development planning (Akpo West) and three undeveloped discoveries (Ikija Hanging Wall, Ikija Foot Wall and Egina South).

Table 2-2: Assets covered in reports

<table>
<tr><th>Report</th><th>Asset</th><th>Block</th><th>Resource Type</th><th>Status</th></tr>
<tr><td rowspan="14">Contained in this Report: Volume 1 – Reserves & Contingent Resources</td><td>Agbami</td><td>OML 127</td><td>Reserves</td><td>Producing</td></tr>
<tr><td>Akpo</td><td>PML 2</td><td>Reserves</td><td>Producing</td></tr>
<tr><td>Egina</td><td>PML 3</td><td>Reserves</td><td>Producing</td></tr>
<tr><td>Akpo West</td><td>PML 2</td><td>Reserves</td><td>Discovery</td></tr>
<tr><td>Preowei</td><td>PML 4</td><td>Reserves</td><td>Discovery</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>Agbami</td><td>OML 127</td><td>Contingent</td><td>Discovery</td></tr>
<tr><td>Ikija Foot Wall</td><td>OML 127</td><td>Contingent</td><td>Discovery</td></tr>
<tr><td>Ikija Hanging Wall</td><td>OML 127</td><td>Contingent</td><td>Discovery</td></tr>
<tr><td>Preowei</td><td>PML 4</td><td>Contingent</td><td>Discovery</td></tr>
<tr><td>Akpo</td><td>PML 2</td><td>Contingent</td><td>Discovery</td></tr>
<tr><td>Akpo West</td><td>PML 2</td><td>Contingent</td><td>Discovery</td></tr>
<tr><td>Egina</td><td>PML 3</td><td>Contingent</td><td>Discovery</td></tr>
<tr><td>Egina South</td><td>PPL 261</td><td>Contingent</td><td>Discovery</td></tr>
<tr><td colspan="5"></td></tr>
<tr><td rowspan="7">Volume 2 - Exploration (Prospective Resources)</td><td>Ikija Deep</td><td>OML 127</td><td>Prospective</td><td>Prospect</td></tr>
<tr><td>Endi Foot Wall</td><td>OML 127</td><td>Prospective</td><td>Prospect</td></tr>
<tr><td>Egina Deep</td><td>PML 2</td><td>Prospective</td><td>Prospect</td></tr>
<tr><td>Egina South Deep</td><td>PPL 261</td><td>Prospective</td><td>Prospect</td></tr>
<tr><td>Egina West</td><td>PML 3</td><td>Prospective</td><td>Prospect</td></tr>
<tr><td>Akpo Deep</td><td>PML 2</td><td>Prospective</td><td>Prospect</td></tr>
<tr><td>Egina South</td><td>PPL 261</td><td>Prospective</td><td>Prospect</td></tr>
</table>

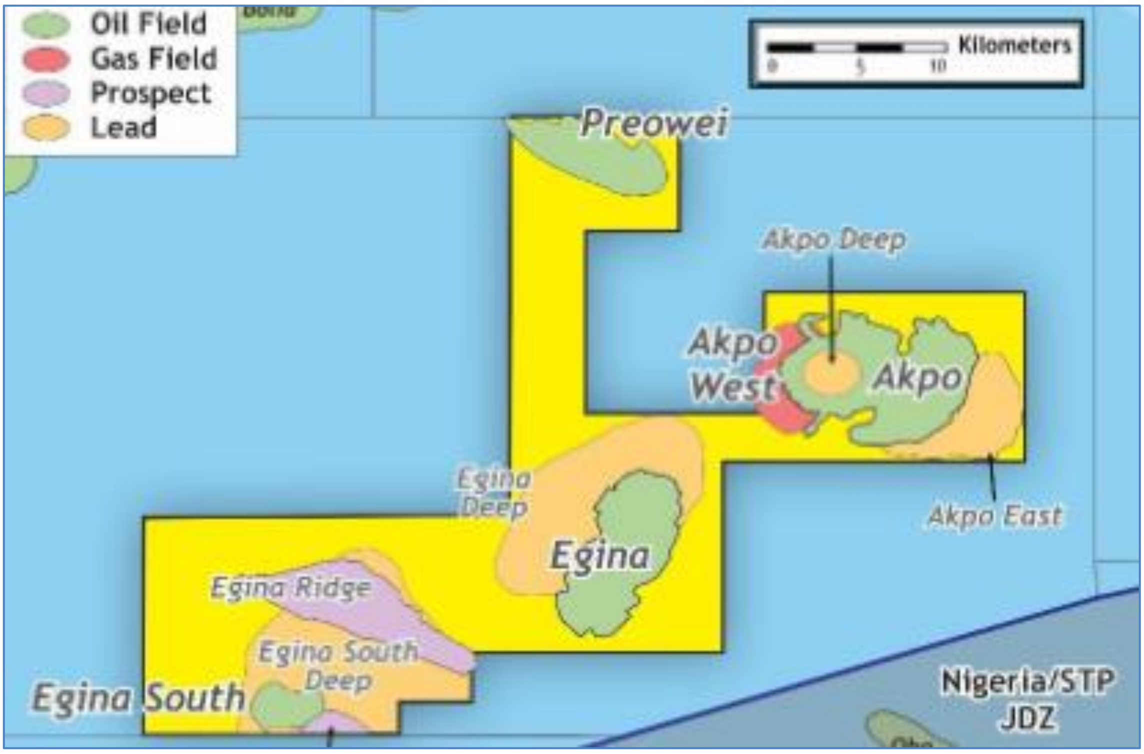

Figure 2-2: Location of Assets in PML 2, PML 3, PML 4 and PPL 261 (formerly known as OML 130)

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 has relied upon the information provided and has 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 producing assets is based on production data to end November 2023.

RISC has reviewed the reserves/resources in accordance with the Society of Petroleum Engineers internationally recognised Petroleum Resources Management System (PRMS) 2018.

We have reviewed the production forecasts, development plans and costs prepared by Prime. The reserves presented in this report are based on Brent quality oil price projections of US$75/bbl (RT2024[4]), long term and reflecting the macroeconomics of demand and Opec's management of oil price.

The economic model for these assets was provided by Prime for RISC's use in this review. RISC has traced and checked the flow of calculations in the economic model as part of its quality control of outputs.

Unless otherwise stated, all resources presented in this report are gross (100%) quantities with an effective date of 1 January 2024. All costs are in US$ real terms with a reference date of 1 January 2024 (RT2024).

We have not conducted a site visit to the offshore discoveries and prospects.

OPEC quotas that were imposed in previous years are no longer applicable and the fields can produce at full capacity.

[4]Real Terms 2024

3. OML 127 – Agbami Field Reserves

3.1. Field Description

The Agbami Field is located in the OML 127/128 Blocks approximately 70 miles south-southwest from the nearest Nigerian shoreline and approximately 220 miles southeast of Lagos in water depths between 1,280 and 1,650 m (4,200 ft and 5,410 ft). The Agbami-1 discovery well was spudded on 15 July 1998 and encountered 420 net feet of pay, in multiple oil zones from 8,200 ft to the total depth of 12,400 ft-TVDSS. A further five wells and one side-track were drilled between 1999 and 2001 to appraise the field. A second phase of delineation and development began in 2003 with 15 additional wells drilled before first oil. The project received FID in June 2004.

The field straddles OML 127 and OML 128. The Equity Determination in 2010 apportioned resources between block OML 127 and OML 128 approximately 62.5% and 37.5% respectively. The 2012 Final Redetermination was referred to an Expert who determined an OML 127 equity of 72.064%. This final equity revision is pending implementation and for this report RISC has retained the 2010 determination.

In June 2023, OML127 licence was converted to the PIA terms with the new terms effective 1st March 2023 and the producing area within OML127 is now known as Agbami PML. An application for licence renewal post December 2024 was submitted in November 2023. As per previous audit, RISC considers there is a reasonable expectation that an extension/renewal of 20 years will be granted (Section 9.2).

The field commenced production on 28 July 2008 at an initial production rate of approximately 95,000 bopd from five wells. The field reached peak (plateau) production of 250,000 bopd on 13 August 2009. The field was developed in three main Phases with drilling of additional infill wells planned to take part in two stages (part of the AIDP –Agbami Infill Drilling Project). AIDP Stage 1 commenced in 2016. A total of 30 production wells, 10 water injection wells and 5 gas injection wells have been drilled. Agbami Field gross oil production averaged 98 Mstb/d in 2023.

Production is via a dedicated FPSO and there is no gas export. All gas is reinjected, used as fuel, or flared.

Undeveloped reserves include 6 infill oil wells of the Post-AIDP programme plus 1 subsea well intervention (SSWI) planned to be drilled in 2026/7. An ongoing programme of 3 acid stimulations/year is assumed to maintain well productivity.

Contingent resources include 4 further infill oil production wells and 2 water injectors to be drilled in 2027/8 plus a potential gas blowdown starting 2037.

3.1.1. Geoscience Overview

The following section represents a summary of the geological evaluation of the field described in the Agbami Field Development Plan (Agbami FDP Revision 5, November 2021, in addition to other presentation material and reports provided by Prime.

Regionally the Agbami field lies in the Niger Delta front and is associated with compressional tectonics, such as toe thrusts and folds, at the transition between the oceanic and continental crusts (Figure 3-1).

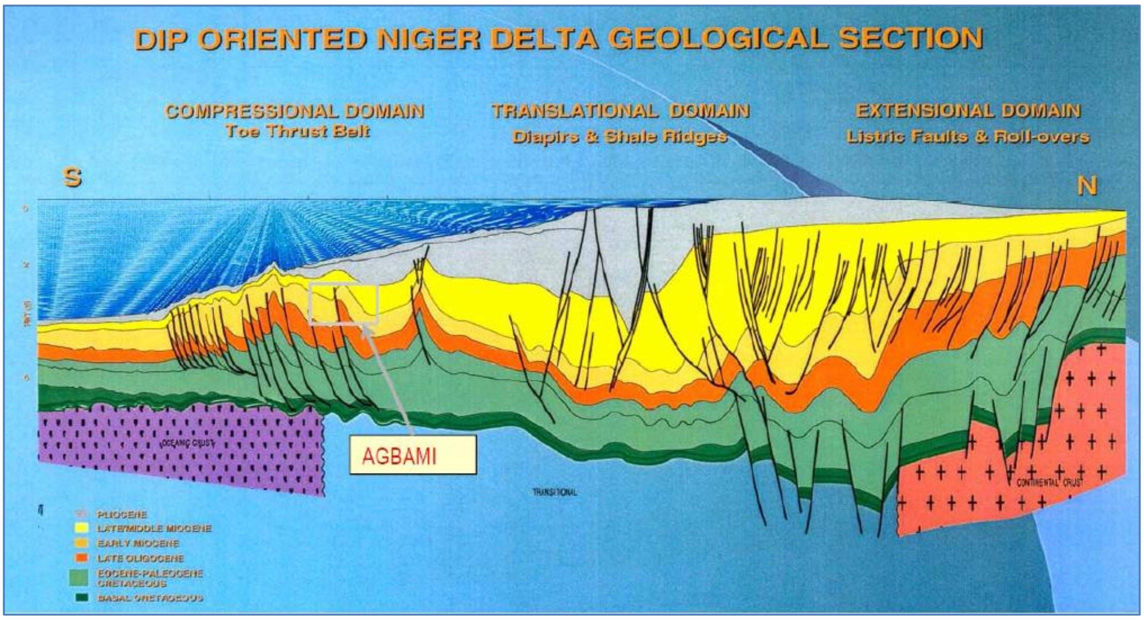

Figure 3-1: Regional Cross Section Across the Niger Delta

The Agbami structure is a double-plunging anticline, spanning approximately 14 km, forming a large 4-way dip closure which is cut by a significant NE-SW thrust fault along the crestal axis (often referred to as the 'Main Thrust Fault' Figure 3-2 and Figure 3-3). The field is comprised of four major stacked reservoir units of Miocene age named 13 MY (Million Years), 14 MY, 16 MY, and 17 MY. Each reservoir is vertically subdivided into multiple stratigraphic units. The field subdivided into three main areas by the main NW-SE thrust fault and a NE-SW trending fault. The hanging wall/up-thrown block is referred to as the "Inboard block" and comprises of two areas (Area 1 and 2) while the foot wall/down-thrown block is referred to as "Outboard block" and has one area (Area 3). The reservoirs are considered to be largely in pressure communication both vertically and laterally across the three main areas on a geological timescale, supported by interference testing and production data analysis, but this still remains an uncertainty particularly when considering the lateral variability of the main reservoir facies.

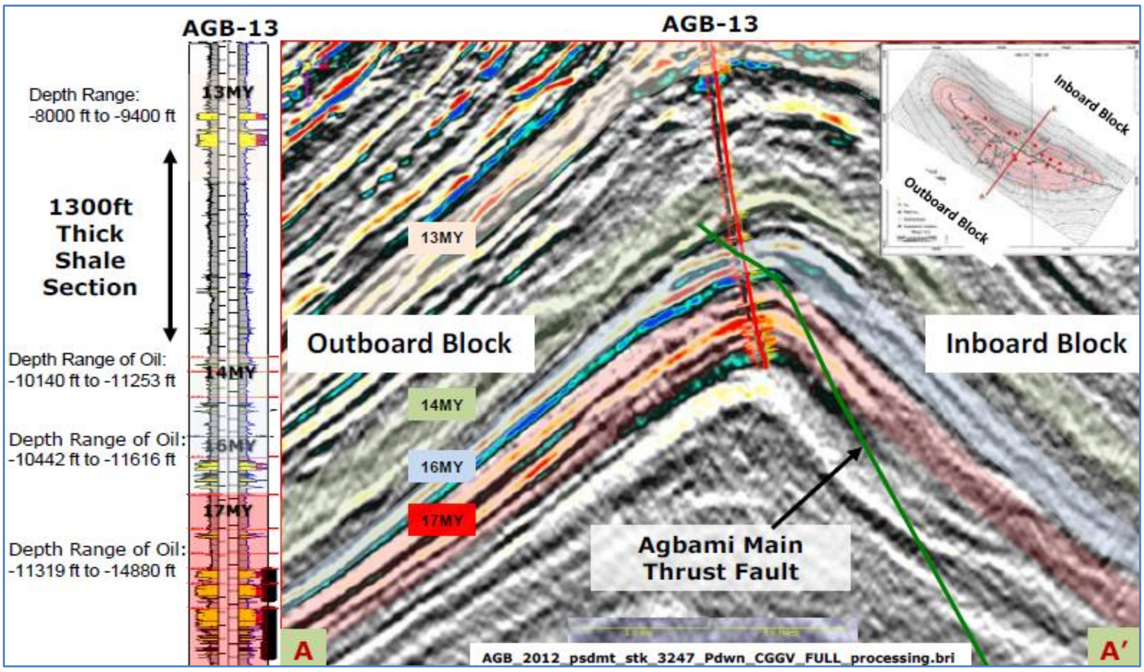

Figure 3-2: Agbami Main Structural configuration and Agbami 13 Type well

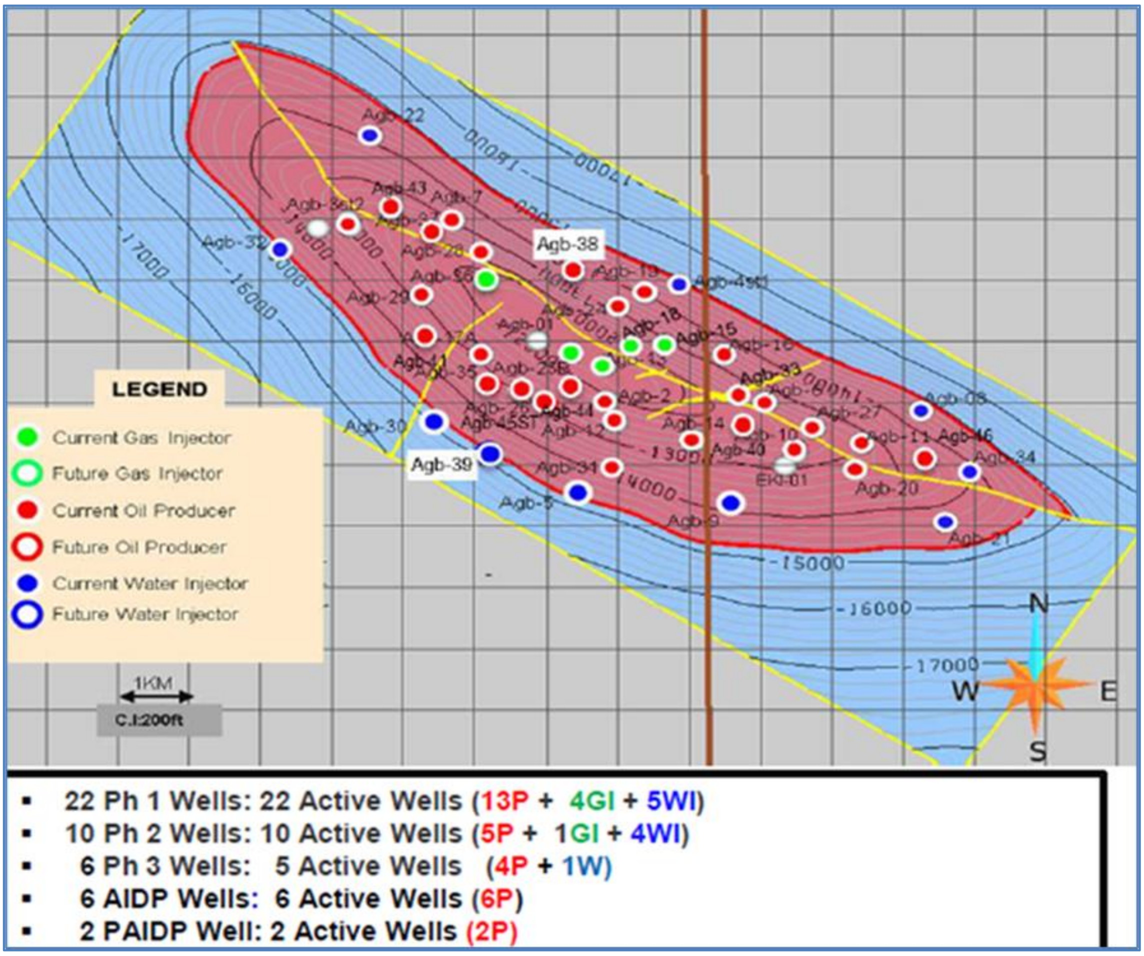

Figure 3-3: Agbami Field 17 MY Depth Structure Map

Several 4D seismic surveys have been acquired over the Agbami Field. The 4D baseline survey was acquired in 2010 with the first 4D Monitor survey (M1) acquired in 2012-2013. Another monitor survey (M2) was acquired in 2017 and has been used in the preparation of FDP Rev5. A third 4D monitor survey (M3) is planned for April 2024.

The monitor surveys have been successful in enhancing the seismic data quality and understanding of the Agbami field and in particular in helping to identify water movement and swept/unswept areas of the field. Seismic resolution is not sufficient to identify individual sands, but on a gross reservoir basis there is good correlation between seismic and wells with seismic amplitudes highlighting the major reservoir intervals and hydrocarbon contacts.

Depth conversion and velocity uncertainty has been extensively studied by the operator and with an excess of 40 well penetrations are not seen as a major uncertainty by RISC.

The four main reservoir units (13 MY, 14 MY, 16 MY and 17 MY) are Lower to Middle Miocene age of the Agbada Formation. The reservoirs form a series of stacked sandstones within a background of shales with sandstones deposited from high and low energy turbidity currents within sub-marine channel and lobe complexes (Figure 3-4). Accumulations of sand bearing intervals appears to have occurred near the toe-of-slope where depositional systems tend to range from confined to weakly confined deposits. The reservoirs are well characterised and correlated due to over 40 well penetrations and a significant core and log database. OBMI dipmeter analysis from several wells suggests the main depositional fairway for the Agbami reservoirs originates from the Northeast and is focused primarily within the main development area. In general, the Agbami reservoirs exhibit good sand development over the crest and South-eastern area, with deterioration in reservoir thickness and quality observed towards the North-west across the channel complexes. The exception to this general trend is the 14B and 17B sands which are essentially mainly confined to the Northwest and poorly developed to absent in the Southeast.

The 17 MY reservoir (which accounts for approximately 80% of developed field STOIIP) is comprised of weakly confined channel complexes as defined by well logs, seismic, core and OBMI data. The sands are mostly present as organized, stacked, amalgamated channels over the field extent; with debris flows and mudstones representing the non-reservoir facies within this section.

The 16 MY sandstone units are mostly non-erosive sheet and channel deposits interpreted to have been deposited in a confined to weakly confined system. The sands generally extend laterally over the entire length of the field (approximately 14 KM) suggesting a high rate of sedimentation, accumulation and amalgamation. The lower 16MY reservoirs generally range from broad, organized channels to restricted proximal sheets.

The 14 MY sandstone units are a series of confined channels opening up into a splay deposit over the folded structure. Seismic geomorphology suggests the sands most likely broke the pre-existing overbank/levee resulting in abandonment of the sands over the 14 structure. Four facies have been identified based on AGB-28 core description: Debris flow/MTC, Massive Channel Axis, Mud rich Channel Margin and Mudstone facies.

The 13 MY sandstone units are a series of confined channel-levee complexes deposited in an erosionally confined channel system and are mostly present over the crest of the structure as imaged from seismic and well logs. There is evidence for a high degree of compartmentalization (more than 10 blocks), with different fluid contacts. This unit is minor volumetrically and is not included in this audit.

In general, the Agbami reservoir sandstones exhibit excellent reservoir properties with average porosities typically in the range of 17-25% and permeabilities in the range 150-2000 mD. Reservoir units are typically shale dominated on a gross basis and can be highly variable in terms of net to gross and reservoir thickness, although the main reservoir sand packages can be correlated across the field with a high degree of confidence. The lateral variability is a function of the depositional system and variation between depositional facies (e.g., channel vs overbank) which can make reservoir distribution difficult to predict despite the large number of well penetrations. Seismic data are not typically of sufficient quality / resolution to accurately map individual sand bodies within each reservoir.

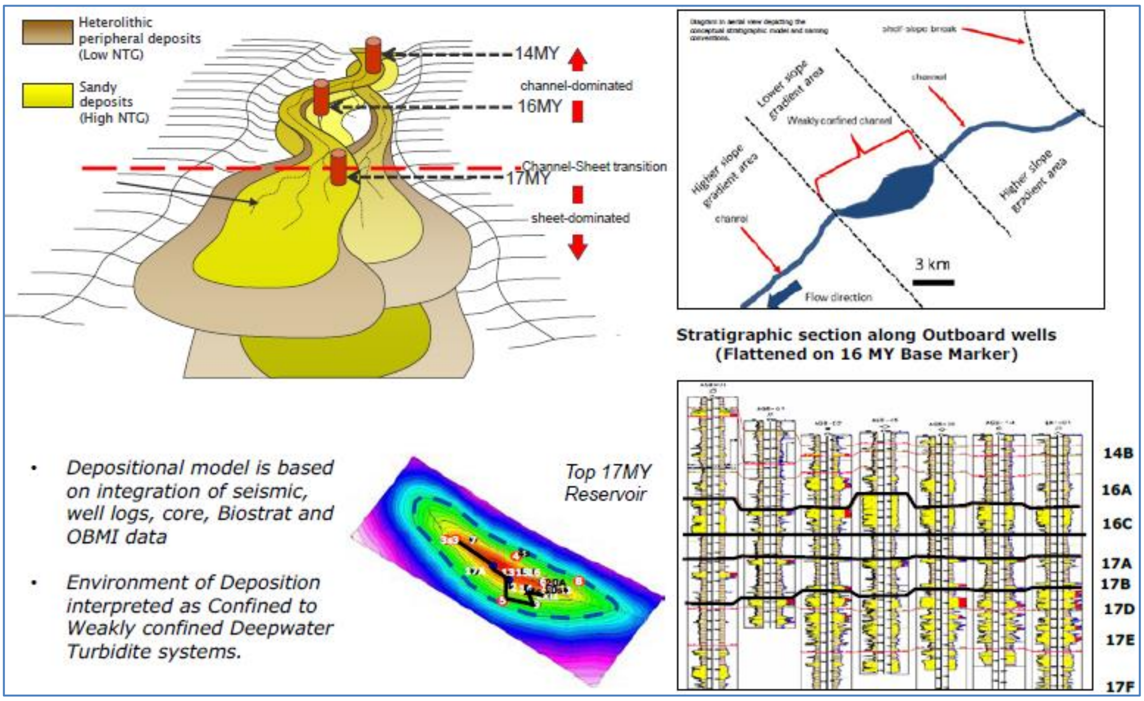

Figure 3-4: Agbami Reservoirs Deposition Model

A range of STOIIP was provided in the FDP. RISC considers Prime's modelled STOIIP used in the simulation to be a reasonable representation of the field volumes with the full uncertainty range displayed in the table below (Table 3-1).

Table 3-1: Agbami Field Gross STOIIP (MMstb) from the 2021 FDP

Field	P90	P50	P10
Agbami (14 MY, 16 MY and 17 MY)	2,372	2,685	3,189

RISC was provided with results from Prime's modified versions of the operator's Agbami v6B static and dynamic models. There have been minor changes since the last report in January 2023. The Prime version contained local pore volume/permeability multipliers adjustments to better match the water cut and gas-oil ratios though 2023. The gross field STOIIP value in the history matched model is 2,638 MMstb. This value is close to the P50 value indicated in the revised FDP (2,685 MMstb).

3.1.2. Reservoir Fluid properties

The fluid properties for the main 17MY reservoir (with circa 80% of the STOIIP) are given in the table below. Agbami oil is light, high GOR, with a bubble point circa 3,000 psi below initial reservoir pressure. Both water injection and gas reinjection are used to maintain reservoir pressure and the operator targets a voidage replacement ratio of about 1.0.

Table 3-2: Reservoir fluid properties for 17MY reservoir (from 2015 FDP)

Property	Unit	Oil column
Pressure	psig	3,971
Temperature	deg C	100
Formation volume factor (Boi)	rb/stb	1.6
Gas oil ratio (Rsi)	scf/stb	1,146
Oil viscosity	cP	0.23
Stock tank oil gravity	deg API	50

Although significant volumes of gas are produced, there are no gas sales and therefore zero sales gas reserves.

3.1.3. Production Facilities

The Agbami subsea wells are tied back to a dedicated FPSO in water depth of approximately 1,400 m. The facilities can process 250,000 bopd oil and 450 MMscf/d gas. Water injection and gas injection are limited to 450,000 bwpd and 415 MMscf/d respectively. The gas injection is at full capacity and with facility optimizations has reached 440 MMscf/d. However, water injection has not exceeded 270,000 bwpd and availability has been relatively poor (only 66% in 2023). At year end 2023 only 1 out of the 4 seawater injection pumps are operational and there have been a number of riser leaks.

There is currently no gas export, so all gas is reinjected, used as fuel, or flared. Fuel gas has been circa 22 MMscf/d since 2019. Prime has requested that the fuel gas used at Agbami be considered as reserves, which is allowable under PRMS (Section 3.6).

A total of 30 production wells, 10 water injection wells and 5 gas injection wells have been drilled. At December 2023, 21 wells were producing. Several wells have intelligent completions, enabling selective zonal control, and down hole gauges.

The wells are tied back to the FPSO through a subsea network. The oil production system has 4 production loops, each with two manifolds connected in series to two flowlines/risers. Each manifold is for 4 wells. The water injection system has 4 x 4 well manifolds each connected to the FPSO with a single flowline and riser. The gas injection system consists of 2 manifolds each with a flowline and riser.

The FPSO consists of 2 x 50% parallel crude oil gathering, processing and treatment trains in addition to produced water and gas processing. Crude oil is exported through an offloading buoy. An overview of the design capacities of the FPSO can be seen in Table 3-3.

Table 3-3: Agbami FPSO capacities

Specification	Capacity
Oil production	250,000 stb/d
Liquid production	450,000 bbl/d
Water injection	450,000 bbl/d
Gas production[1]	450 MMscf/d
Gas injection[2]	415 MMscf/d at 7,000 psi injection pressure
Gas lift	50 MMscf/d
Oil storage	2.15 MMbbl
Notes: 1. Gas production rates of 460- 480 MMscf/d are regularly achieved. 2. Gas injection rates of up to 440 MMscf/d have been achieved.	

3.1.4. Production History

Agbami started production on 29 June 2008 and the oil rate plateau of 250,000 bopd was reached in August 2009. Agbami Field gross oil production averaged 98 Mstb/d in 2023. The estimated gross cumulative oil production to end December 2023 is 1089 MMstb.

Water injection commenced in March 2009 and ramped up to above 200,000 bwpd by 2011. Water injection efficiency has been poor in 2023 and the average rate for 2023 is expected to be about 110 Mbbl/d. Gas reinjection commenced in October 2008 and is currently at the facilities capacity. Gas injection rate is expected to average 400 MMscf/d in 2023.

Injection efficiency of water and gas has improved in recent years however water injection efficiency was poor in 2023 (66% injection efficiency). This was due to a combination of injection riser leaks and availability of seawater pumps. These issues are expected to be remediated in early 2024. The relatively short-term period of voidage replacement ratio less than 1.0 is not expected to materially impact future oil recovery.

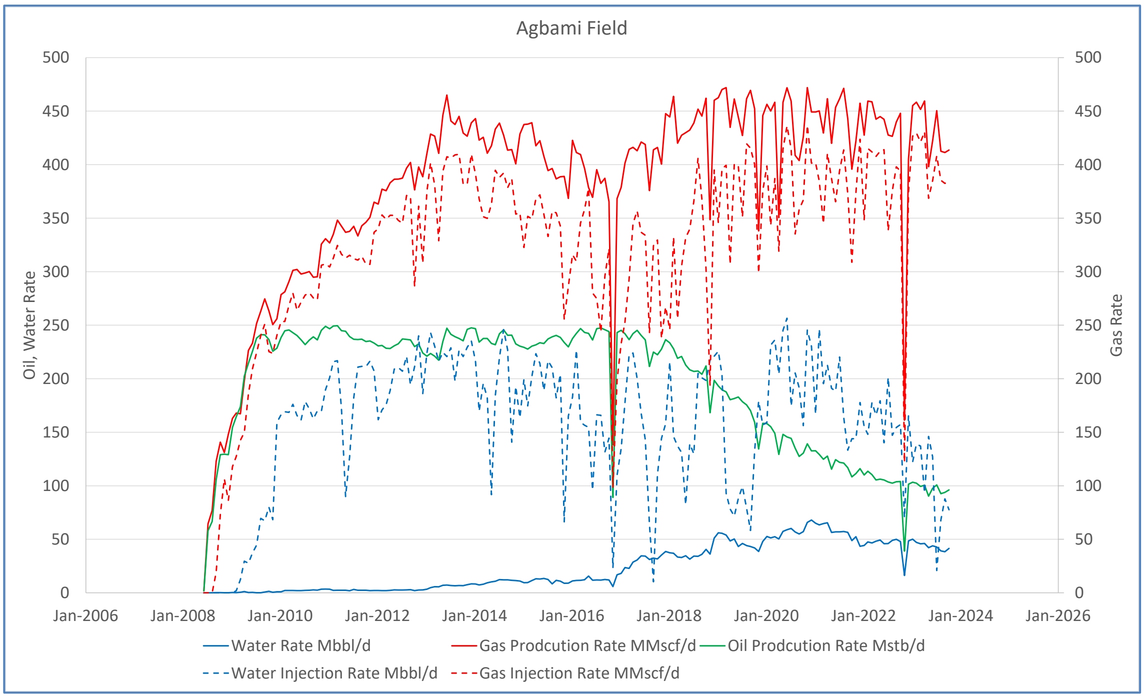

Figure 3-5: Agbami production and injection history

Fieldwide GOR was reasonably stable and averaged about 4,400 scf/stb in 2023, which is well above the initial value of circa 1,100 scf/stb. Gas production is at the processing capacity and flaring limited so expected further rises in gas production will be managed by choking back high-GOR wells to reduce overall field production.

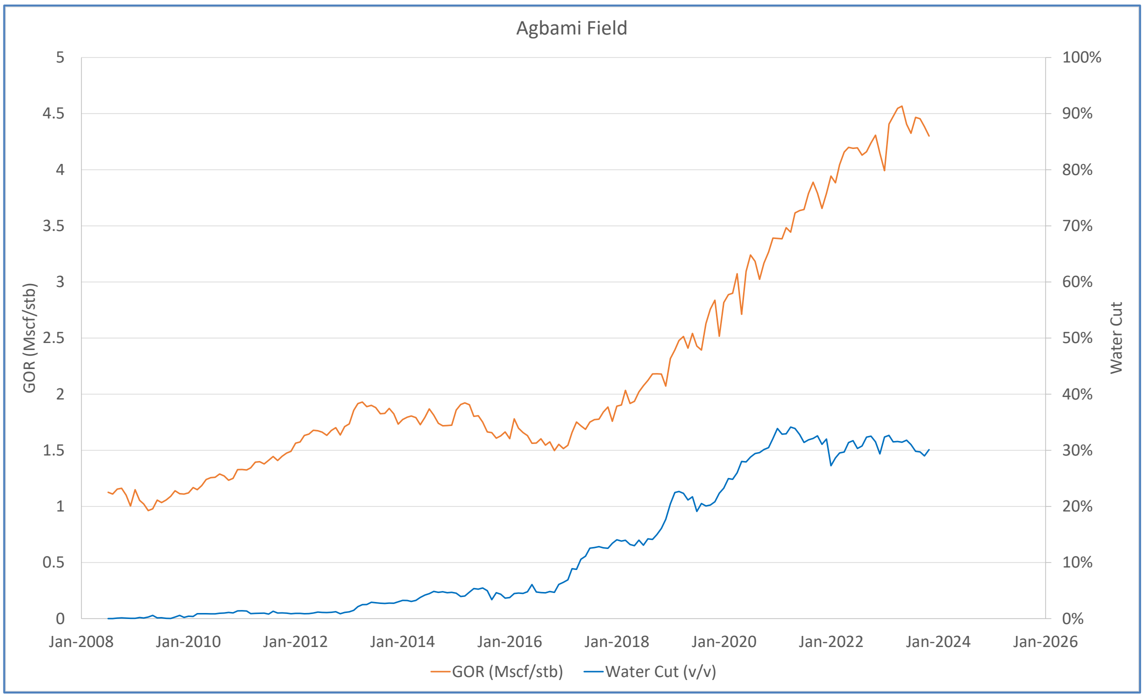

Figure 3-6: Agbami Water cut and Gas-Oil Ratio history.

Water cut has risen since 2017 and has stabilised at about 30% in late 2023. Water cut has remained reasonably stable since late 2020.

Gas flaring continues to be significantly reduced and averaged 9 MMscf/d in 2023.

The 17MY reservoir has produced most of the oil to date (circa 80% of cumulative oil).

3.2. Further Development Plans

The 2021 FDP (Rev 5) update is based on forecasts from the Operator's 6B static and dynamic model. The field development plan has also been revised to include 5 additional infill opportunities over the 2017 FDP Update (Rev4). This is aimed at optimizing field recovery and the infills will utilize existing facilities in the field. Following further work in 2022, additional infill opportunities were identified, and the Operator selected 14 infill opportunities (11 oil producers and 3 water injectors) delivering gross unrisked incremental oil recovery of 74 MMstb. Prime have informed RISC that the FDP (Rev 5) submitted to the authorities in 2022 includes the 14 potential locations.

3.3. Reserves Production Forecasts

3.3.1. Developed

RISC conducted a high-level review of the Prime's reservoir simulation model and reviewed the history matches of the Agbami wells in late 2021. The history match was then updated by Prime to August 2022. Reasonable matches were achieved to water cut, GOR and reservoir pressures for the wells and for the field totals, although we noted that the model water cut is lower than current actual data in the 16 MY reservoir and the model GOR is lower than actual in the 17 MY reservoir. In 2023, Prime has not fully updated the history match but has made minor adjustments to local/well pore volume/permeabilities multipliers in order to better match well test results. As at end 2023, the model predicted field GOR, and water cut are close to actuals.

Prime's 2P Developed forecast is based on this simulation model. Prime's 1P and 3P developed forecasts were based on their fieldwide DCA.

Production efficiencies applied to the model forecasts vary in future years. For 2024, the model assumes production efficiencies of 95.4%, 89.5% and 94.8% for oil production, water injection and gas injection respectively. Actual efficiencies achieved in 2023 compare well apart from water injection where only 66% was achieved at end 2023. Remedial actions are in progress and 2024 Business Plan forecasts water injection efficiency of 89.5%.

In addition, the model includes a Full Field Shut Downs (FFSD) in November 2025 for 18 days and November 2028 for 48 days. Partial Field Shut Downs (PFSD) for 11 days are assumed every 3 years from 2031.

RISC has compared Prime's 2P simulation oil rate forecasts assuming no further development activity with our Decline Curve Analysis (DCA). We selected data in the period from January 2020 onwards since water injection rates have been reasonably stable since then. We note that the oil rate decline is currently controlled by the rising GOR and over time. Increasing water cut is expected to become the constraining factor on oil production. Our comparison indicated good agreement between the reservoir simulation model and DCA.

RISC also generated 1P and 3P Developed oil rate forecasts using DCA and noted reasonable agreement with the Prime 1P and 3P forecasts. As oil production is limited by gas handling capacity, RISC also checked Prime's 1P, 2P and 3P forecasts for their implied gas-oil ratio trends and found these to be plausible. RISC considers Prime's developed forecasts to be reasonable.

The gross ultimate oil recoveries for Prime's developed reserves cases are shown below. These volumes are based on forecasts to 2044 before application of an economic limit.

Table 3-4: EUR of Agbami Developed Reserves Cases

Agbami Field EUR, MMstb (Gross)	Low	Mid	High
Recovery to End 2044	1278	1402	1482

3.3.2. Infill Wells and Workover

Prime has proposed 6 infill wells to be drilled during 2026/2027 and a subsea workover in the Agb-35 well be included in the undeveloped reserves. All these locations are planned to be matured using the new 4D seismic to be acquired in 2024. These wells are selected from the Operator's 2021 FDP (Rev 5) update.

Three of the infill drilling locations target the 16C MY reservoir zone, one well targets production from the western segment of 17B MY reservoir and a further two wells target the 17E MY reservoir. Typically, the locations have been selected from simulation derived remaining oil thickness maps – see below example from the 16C reservoir.

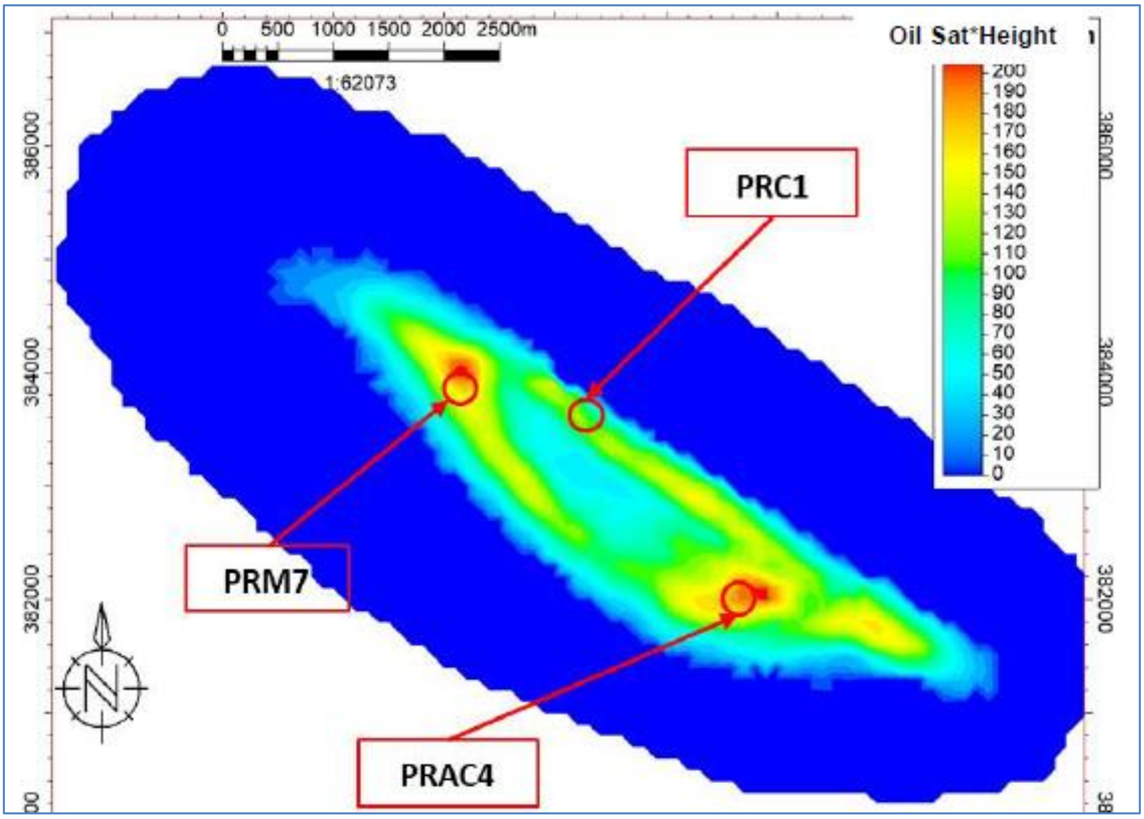

Figure 3-7: Location of 3 infill wells in 16C reservoir

Prime's incremental oil recovery estimates were calculated by taking the difference between two simulation cases (Base vs Base with 6 AIDP wells plus AGB35 workover). The total incremental oil production is forecast to be 44 MMstb to YE2044 in the 2P case.

RISC has benchmarked the model predicted incremental recovery for each infill well (average 7.4 MMstb/well) against the trend in incremental oil volumes achieved by previous infill drilling campaigns at Agbami (Figure 3-8) which indicates that the predictions are on trend with previous results.

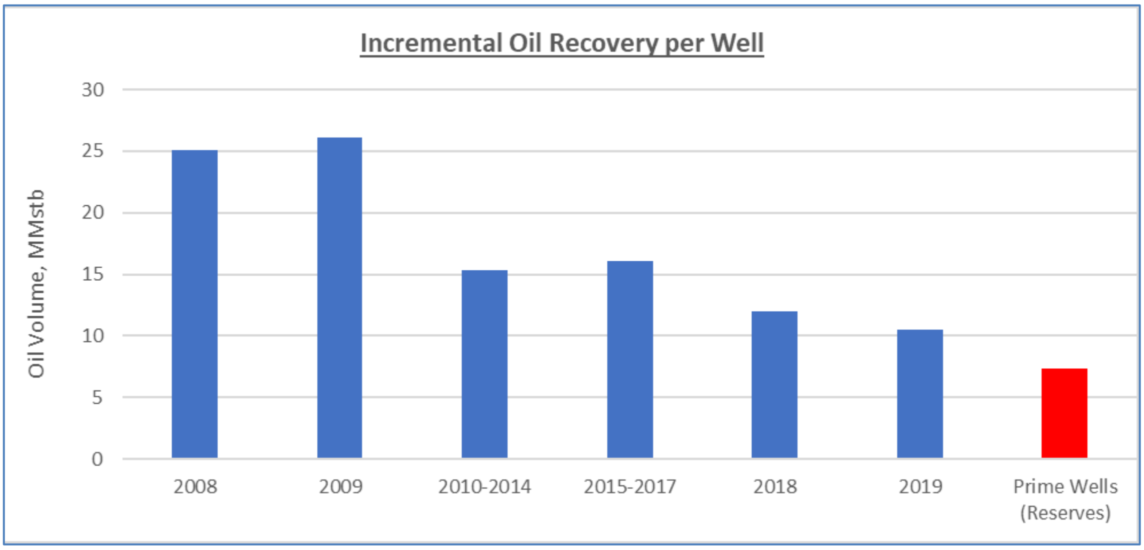

Figure 3-8: Incremental oil volumes per well

All of the planned infill wells are subject to a range of risks generally associated with the difficulty in predicting gas and water encroachment.

A key finding from previous infill drilling associated with FDP Rev 4 was that some zones were swept by water which resulted in lower than predicted recovery in some wells. In particular, well AGB43 has produced at low rates and currently produces intermittently (cumulative production to date is < 1 MMstb oil). RISC has compared the predicted oil recovery of the FDP rev4 AIDP wells with their outcomes. On an incremental oil recovery/well basis, the Operator's analysis (in FDP rev5) indicates that the FDP rev4 AIDP wells achieved about 75% of the predicted results and one of the wells was an economic failure. However, the 4DM2 seismic was not used to confirm well locations in this drilling campaign since the seismic processing was completed after the wells were drilled.

The FDP Rev 5 wells are planned to be validated/adjusted on the basis of high resolution 4DM3 seismic data which is planned to be acquired in 2024. We expect this will reduce the risks and consider Prime's estimates of incremental recovery associated with the planned infill drilling to be reasonable.

Prime's estimated incremental ultimate recoveries for the 6 AIDP wells plus AGB35 workover are given in Table 3-5. These volumes are based on forecasts to 2044 and before application of an economic limit.

Table 3-5: Incremental EUR of 6 infill wells + 1 workover

Oil, MMstb (Gross)	Low	Mid	High
Incremental Recovery to End 2044	30	44	85

The 2024 Firm Capex Budget forecasts Wells capex of US$616 million in the period 2024-7. Prime advised that this corresponds to the Operator's plan to drill 6 PAIDPs (Chevron is considering 3 sidetracks and 3 new wells). The evidence to support the Operator's intention to conduct the AGB-35 workover is not so clear, however RISC has elected to retain this activity in the undeveloped reservoir category since the ultimate recovery impact is modest (about 1 MMstb).

Based on the STOIIP range above, the recovery factors for the 1P, 2P and 3P Developed+Undeveloped forecasts are 55%, 54% and 49% respectively. This range represents values that are appropriate for a large, good permeability, waterflooded field with many wells.

3.4. Contingent Resources Production Forecasts

3.4.1. Infill Wells

Prime has proposed 6 further infill wells (4 oil producers and 2 water injectors) to be drilled in 2027/8 be included in contingent resources. All these locations are planned to be matured using the new 4DM3 seismic to be acquired in 2024. These wells are selected from the Operator's 2021 FDP (Rev 5) update.

Prime's incremental oil recovery estimates were calculated by taking the difference between two simulation cases. The total incremental oil production is forecast to be 35 MMstb to YE2044 in Prime's 2C simulation model.

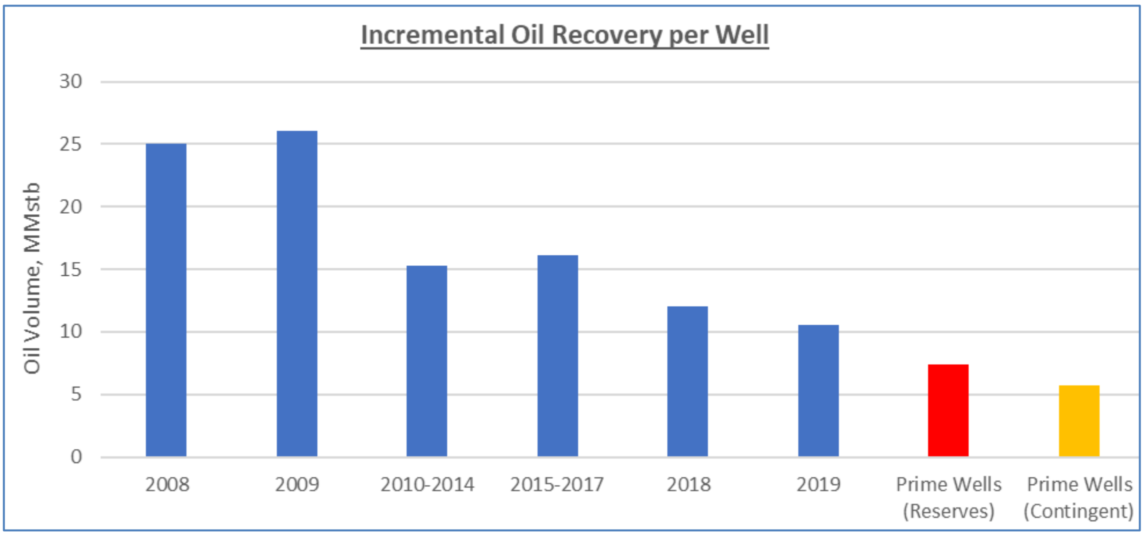

Figure 3-9: Incremental oil volumes per well (including contingent).

RISC has benchmarked the model predicted incremental recovery for each well (average 5.8 MMstb) against the trend in incremental oil volumes achieved by previous infill drilling at Agbami (Figure 3-9) and considers Prime's estimates to be reasonable.

The incremental ultimate recoveries for the additional 6 wells are given in Table 3-5. RISC scaled Prime's 2C forecast by -50%/+50% to estimate 1C and 3C production profiles to account for the uncertainty in rates and incremental recovery of the new wells. These volumes are based on forecasts to 2044 instead of at the economic limit.

Table 3-6: Incremental EUR of 6 infill wells

Oil, MMstb (Gross)	Low	Mid	High
Incremental Recovery to End 2044	17	35	52

3.4.2. Agbami Gas Blowdown

Prime has presented modelling results for a gas blowdown scenario. This scenario envisaged gas export commencing 2037 at a gas rate of 150 MMscf/d resulting in a cumulative exported volume of 438 Bcf to YE44. The modelling indicates that the impact on oil recovery was very minor (-0.5 MMstb).

For year-end 2023, RISC has included this potential project in contingent resources.

Table 3-7: Incremental EUR of Gas Blowdown

Gas, Bcf (Gross)	Low	Mid	High
Incremental Recovery to End 2044	219	438	657

3.4.3. Agbami Gas Project

The Agbami Gas Project (AGP) to increase gas handling capacity of the Agbami FPSO from the existing 450 MMscf/d to 600 MMscf/d, has previously been evaluated. Prime has advised that they no longer consider this project to be potentially commercial and, for year-end 2023, RISC has not included this project in contingent resources.

3.4.4. 13MY Reservoir

At Prime's request, RISC has retained this section on 13MY Reservoir to document the estimates oil recovery from this reservoir. However, given that there is no reasonable expectation of economic viability, these volumes are no longer classified as Contingent Resources. RISC's views and forecasts of the 13MY reservoir are unchanged since the YE2020 report.

Very little technical work on the development of the 13MY reservoir has been undertaken by the operator, or Prime. Although the reservoirs have been penetrated by Agbami wells, mapped, and samples taken, there is very little information available about the potential for development. The FDPs from 2013, 2015 and 2021 include basic reservoir descriptions but do not provide any detailed development of the 13MY reservoir. The key source of data was a slide pack '*13MY Reservoir Study Update'*, created by Chevron and dated 2012.

The development plan is notional at this stage and has little detail. It consists of one oil producer and one water injector but well locations and completions have not been determined. Both wells will use the Agbami FPSO facilities.

The Chevron study stated the 13MY reservoir is interpreted as highly compartmentalized and broken into 10 fault blocks. These are likely sealing faults as the appraisal wells were interpreted with different OWC's on either side of the faults. Two fault blocks were interpreted as 'wet sands'. Although the total STOIIP is estimated at circa 35 MMstb (Mid case), the risks related to compartmentalization and contacts mean only three of these fault blocks can be called 'Discovered'. Figure 3-10Figure 3-10 shows the Upper Sand Interval (the 13B), with discovered blocks labelled with red circles. The second reservoir (13C sands) has a similar structure and additional volumes.

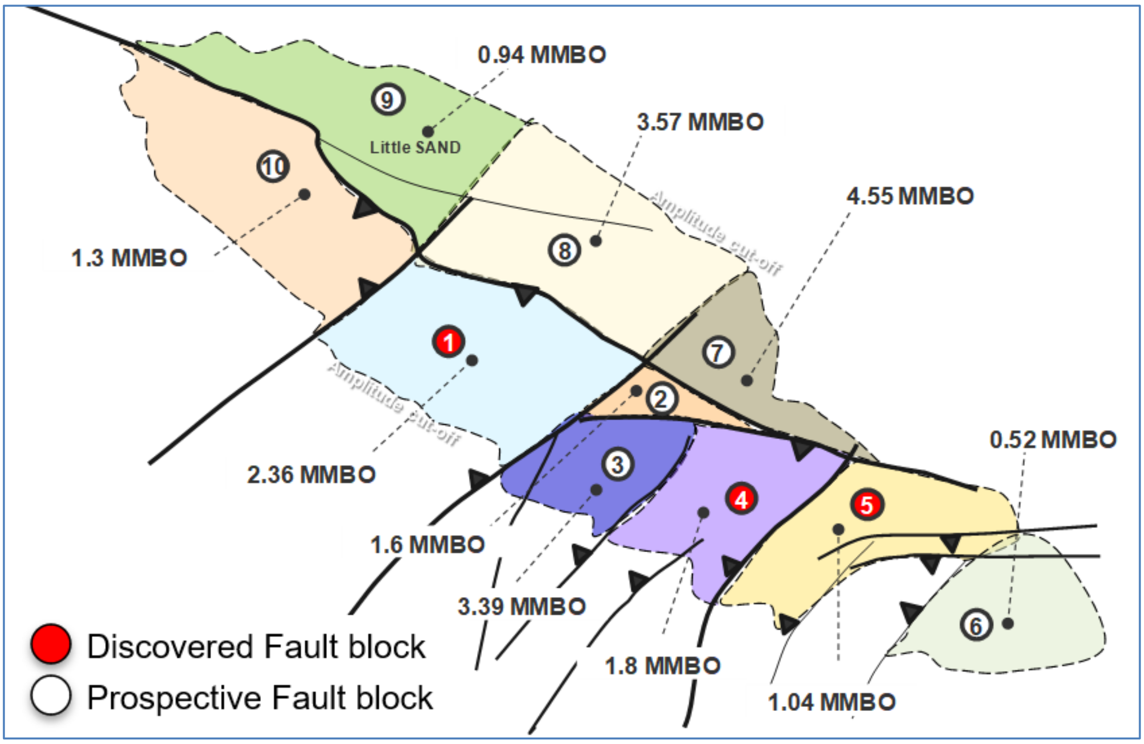

Figure 3-10: Agbami 13MY Reservoir, Upper Sand Interval. Discovered blocks labelled with red circles.

These blocks are not adjacent nor in communication, and the reservoir sands occur at two intervals. The stated development plan of a single producer-injector pair can therefore only drain a STOIIP of circa 7 MMstb between the two reservoirs. This is planned with a vertical well in the largest discovered fault block (Block 1 in Figure 3-10) draining both sand intervals. RISC considered an alternative plan with horizontal wells through multiple (discovered) fault blocks. However, these were either lower in recovery, or required unfeasibly long and complex geo-steered wells.

Table 3-8: Agbami 13MY STOIIP – discovered blocks only

Field	Low	Best	High
13 B Sand - Blocks 1, 4 and 5	5.2	12.0	13.3
13C Sand - Blocks 1 and 4	1.7	1.9	2.2
Agbami 13 MY Total	6.9	13.9	15.5

Given there will be only 2 wells drilled and the 13MY reservoir has not been produced before, RISC has allowed for a wide range of recovery factors (30%, 40%, 50%) in estimating the ultimate recovery. Exponential trends were used to forecast the annual rates and due to the low volumes the project life is short (5-8 years).

Based on the limited data set, RISC expects high quality sands with permeability and porosity similar to the 17MY reservoir, albeit with far smaller volumes in 13MY. Initial oil rates are based on analogues from the producing 17MY reservoir, scaling initial rates using Boi and net pay. Prime chose a conservative initial rate of the analogous Agbami 17MY wells, which was scaled down to circa 3,000 bopd for the 13MY reservoir to represent a Mid case. Low and High cases represent a range of uncertainty around this, starting at 1,000 and 5,000 bopd respectively.

The ultimate recoveries for the Low, Mid and High cases are given in Table 3-9. These volumes are based on a final rate of 200 bopd instead of ceasing at the economic limits.

Table 3-9: EUR of 13MY Reservoir

13MY Reservoir, EUR, MMstb	Low	Mid	High
Recovery to End 2044	0.8	2.7	3.7

3.5. Cost Forecasts

RISC has reviewed the costs in the economic model supplied by Prime. We have compared these with costs in the budget, Field Development Plans, cost models provided by Prime and RISC's own tools and benchmarks. We have made modifications where we consider appropriate. All costs are reported on 100% basis in US$, 2023 real terms.

3.5.1. Capital Costs

The Operator total reserves and contingent capital costs of US$2.1 billion (excluding abandonment) are forecast to 2029. The breakdown of the Operators costs is shown in the table below and estimated phasing can be seen in Figure 3-11[5]. In general RISC see them as reasonable and appropriate for the development.

[5] 'Agbami Main' includes geology and geophysics for the field.

Table 3-10 Agbami future development capex to 2029

$ million	Agbami Main	Agbami 6 PAIDP I	Agbami 6 PAIDP II	FPSO Life Extension	Total
D&C	0	501	535	0	**1,036**
Facilities	406	99	147	446	**1,099**
Total	**406**	**601**	**682**	**446**	**2,135**

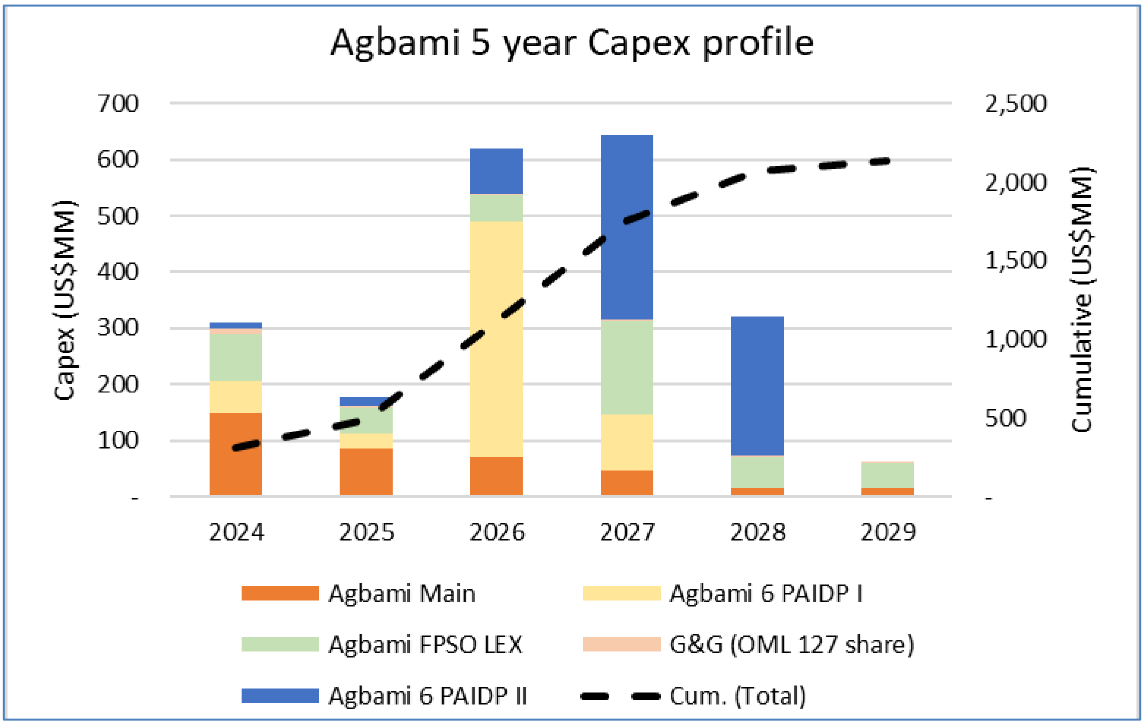

Figure 3-11: Agbami capex forecast by project to 2029[16].

The Phase I 'firm' 6 wells in the Agbami Infill Drilling Plan (PAIDP) wells are estimated to cost US$501 million in total, which includes hook-up costs. Three of the wells are side-tracks and therefore no subsea or facilities costs are included. Each side track well is estimated to involve 22 days of de-completing and partially abandoning the existing wells and then 47 days of drilling the side-track and recompleting. This results in a total time per well of 69 days and costs are estimated using an average spread rate of US$1,100,000/day. RISC note the spread rate is based on the current rig spread rate for the rig contracted on the OML-130 licence. An additional US$99 million is forecast for facilities to tie-in the wells to the existing facilities.

The remaining 3 infill wells are forecast to take 79 days to drill and complete which RISC views as reasonable and note that this is slightly longer than the wells on Egina and Akpo. The costs have been calculated using

[6] 'Agbami Main' includes geology and geophysics for the field.

a spread rate of US$1,100,000/day. The PAIDPII, second 6 well set of potential wells in the Agbami Infill Drilling Plan will start in Q2 2027 but no firm decision has been made as yet to go ahead with these wells (Capex has been included in the Capex profile for reference). Each well has also been estimated to take 79 days to drill and has an average spread rate of US$1,100,000/day. An additional US$147 million is forecast for facilities to tie-in the wells to the existing facilities.

The facilities Capex until 2029 is US$1,099 million which includes the tie-in costs for tying in the PAIDPI and PAIDPII wells mentioned above. The Agbami FPSO facilities are designed for a 20-year life and will achieve this milestone in 2027 when the ABS Class notation expires. The Life Extension (LEX) project will extend the design life of the facilities for an additional 20-years until 2047. The facilities Capex includes US$446 million for this as well as US$ 406 on the existing facility upgrades which includes flare gas recovery system, upgrades to asset integrity, reliability improvements (water and gas injection systems, tank inspections, cooler replacements, sand management), capital spares and exploration seismic.

Prime’s ongoing facilities costs until 2029 are based on the operator’s outlook. These costs then reduce to US$15 million in 2030 until the end of field life. RISC note that these costs are in addition to the non-recurrent Opex facilities intervention costs and are an allowance for facility upgrades to the FPSO and field shutdowns. RISC would normally expect to see an allowance every 3-5 years for full field shutdowns which is in line with the Akpo and Egina FPSO units but accepts the costs as reasonable.

3.5.2. Operating Costs

The Operator forecast total operating costs to be US$338 million in 2024 (excluding HCDT and community development funding totalling approximately US$10 million), which includes US$297 million and US$41 million in recurrent and non-recurrent costs, respectively. This compares to actual costs of US$366 million in 2020, US$388 million in 2021 and US$376 million in 2022. In 2023 the LE 10 + 2 estimate was US$306 million, US$11 million under budget. Excluding these the 2023 Opex was approximately in line with the initial budget. Since 2021 the Opex budget has shown a downward trend indicating that the Operators cost reduction initiatives have had some impact. Prime have forecast an Opex budget for 2024 of US$324 million which is US$14 million less than the Operators and takes in to account the Operators proposed cost saving initiatives. RISC view the cost saving initiatives as reasonable and note that they are spread out over a number of cost items including logistics, optimised maintenance, marine systems and procurement.

Going forward until 2027 the Prime recurrent costs are based on the operator’s forecasts as presented in the September 2023 Agbami Unit CUOA FINCOM 2nd Meeting but have taken credit for the cost savings to be implemented. RISC views this as reasonable thus accepts Prime’s Opex budget. The long-term recurrent forecast is then based on the 2027 cost and split between fixed (87%) and variable (13%). In addition, Prime add non-recurrent costs of US$2.0 million p.a. for well intervention for the Agbami existing well (increases to US$15 million every 4 years) and US$0.8 million p.a. for the 6 PAIDP infill wells as well as US$7.6 million for the facilities maintenance fees (increases to US$13.6 million every 4 years). Gas flaring fees of US$3.5/Mcf have also been accounted for, up from US$2/Mcf last year. Recurrent Opex for the 12 future wells, 6 PAIDP infill wells confirmed and 6 contingent Phase II wells described in section 3.5.1 is accounted for via the variable component in the long-term baseline, equal to US$0.97/bbl. Non-recurrent costs for the 6 PAIDP infill wells confirmed are estimated at US$0.8 million p.a.

In the 2P case, RISC's operating costs forecast averages US$271 million pa with Opex dropping from US$324 million in 2024 to US$243 million in 2044 (Figure 3-12). It should be noted that the Opex in the plot includes gas flaring fees.

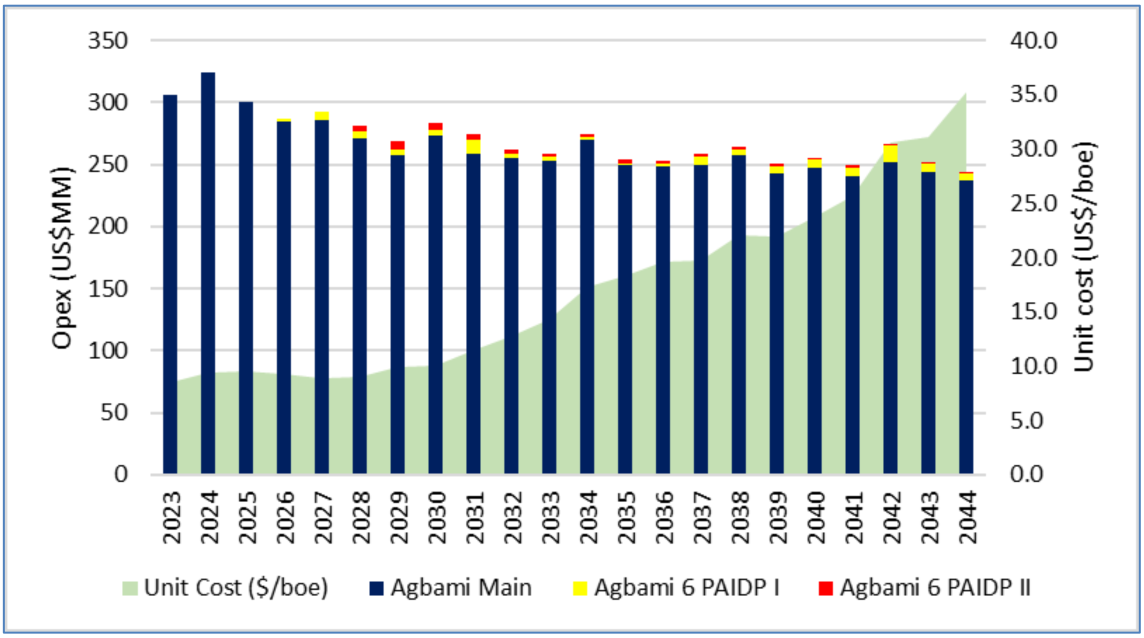

Figure 3-12: Agbami RISC Opex.

3.5.3. Abandonment Costs

Decommissioning costs have been estimated by Prime to be approximately US$623 million, which RISC view as reasonable, comprised of US$425 million in well P&A and US$198 million in facilities decommissioning for the main Agbami wells and facilities plus US$55 million each for the first and second series of infill wells. Well P&A costs are estimated to be approximately US$9 million per well based on 22.5 days and a spread rate of US$410,000 per day (US$250,000 for rig and US$160,000 for support services). In addition to this, mobilization and demobilization costs are estimated to be US$10 million in total.

Although discussions are ongoing with respect to provisioning the abandonment costs, Prime has assumed a linear annual distribution approach with expenditure from 2025 to end of Agbami field life. RISC considers this as appropriate.

3.6. Agbami Field Reserves and Contingent Resources Summary

The developed and undeveloped reserves are shown in Table 3-11 and Table 3-12. The contingent resources associated with a potential 6 further PAIDP wells and life extension are shown in Table 3-13.

Table 3-11: Agbami Field developed reserves as of 1 January 2024

Oil	Unit	Reserves		
		1P	2P	3P
Agbami oil, gross to OML 127	MMstb	109.5	202.3	245.0
Prime net entitlement	MMstb	16.9	27.7	32.2

Notes:
1. OML 127 share of total field reserves are 62.4619% as per the 2010 Equity Determination.
2. Prime net entitlement is calculated using the method described in Section 9.3 of this report.
3. Volumes are based on conversion of both licences to PIA terms.
4. Agbami has zero sales gas, therefore zero sales gas reserves.

Table 3-12: Agbami Field undeveloped reserves as of 1 January 2024

Oil	Unit	Reserves		
		1P	2P	3P
6 PAIDP wells, gross to OML 127	MMstb	17.9	25.3	53.3
6 PAIDP wells, Prime net entitlement	MMstb	2.4	3.0	6.0
Agbami base life extension, gross to OML 127	MMstb	2.6	0.0	0.0
Agbami base life extension, Prime net entitlement	MMstb	0.5	0.0	0.0

Notes:
1. The undeveloped projects extend the Agbami base field life in the 1P case, but do not change the field life in 2P and 3P cases.
2. OML 127 share of total field reserves are 62.4619% as per the 2010 Equity Determination.
3. Prime net entitlement is calculated using the method described in section 9.3 of this report.
4. Volumes are based on conversion of both licences to PIA terms.
5. Agbami has zero sales gas, therefore zero sales gas reserves.

Table 3-13: Agbami contingent resources for 6 PAIDP wells as of 1 January 2024

Oil	Unit	Contingent Resources		
		1C	2C	3C
6 PAIDP wells, gross to OML 127	MMstb	18.4	23.9	32.3
6 PAIDP wells, Prime net entitlement	MMstb	2.9	2.9	3.4
Agbami base life extension, gross to OML 127	MMstb	0.0	0.0	0.0
Agbami base life extension, Prime net entitlement	MMstb	0.0	0.0	0.0

Notes:

1. The contingent project does not result in any base life extension.
2. OML 127 share of total field reserves are 62.4619% as per the 2010 Equity Determination.
3. Prime net entitlement is calculated using the method described in section 9.3 of this report.
4. Volumes are based on conversion of both licences to PIA terms.
5. Agbami has zero sales gas, therefore zero sales gas reserves.

Table 3-14 shows a comparison of the Year-End 2022 Agbami developed and undeveloped reserves with the Year-End 2023 estimates.

Oil reserves in the Agbami field have increased at the 1P and 2P level mainly reflecting increasing confidence in the developed reserves.

Table 3-14: Agbami Reserves Reconciliation Compared to Year-End 2022 Report

Oil	Unit	Reserves		
		1P	2P	3P
Agbami Licence Oil Gross at 1 Jan 2023	MMstb	142.3	233.2	322.8
Agbami production, 1 Jan 2023 to 31 Dec 2023	MMstb	22.2		
Revisions	MMstb	7.3	16.6	-2.3
Agbami Licence Gross on 1 Jan 2024	MMstb	127.4	227.6	298.3

Notes:

1. OML 127 share of total field reserves are 62.4619% as per the 2010 Equity Determination.
2. Prime net entitlement is calculated using the method described in section 9.3 of this report.
3. Volumes are based on conversion of both licences to PIA terms.
4. Agbami has zero sales gas, therefore zero sales gas reserves.

Prime requested RISC to include a separate table for fuel gas reserves, which can be seen in Table 3-15. These are not sales volumes but are gas volumes consumed in the operations. Under some jurisdictions these volumes can be included in reserves.

Table 3-15: Agbami Fuel Gas reserves as of 1 January 2024

Gas Consumed in Operations	Unit	Reserves		
		1P	2P	3P
Fuel gas used at Agbami, gross to OML 127	Bcf	84.1	105.4	105.4
Prime net entitlement	Bcf	6.7	8.4	8.4

Notes:

1. OML 127 share of total field reserves are 62.4619% as per the 2010 Equity Determination.
2. Prime net entitlement for gas in OML 127 is 8%.
3. Volumes are based on conversion of both licences to PIA terms.
4. These are not to be added to the sales gas reserves and must be reported separately as per the PRMS 2018 standard of reporting.

4. OML 127 - Ikija Field Contingent Resources

The Ikija field is an oil and gas accumulation on both sides of a thrust fault that was discovered in January 2000. The field is approximately 20 km SW of the Agbami Field, and development is under consideration as a tie-back to the Agbami FPSO as gas ullage becomes available. An appraisal well to better define the resources is under consideration for drilling in 2027. First oil is expected in 2032.

RISC's views and forecasts of the Ikija field are unchanged since the YE2020 report. There has been no change in 2C resources between YE2022 and YE2023.

4.1. Geoscience Overview

Ikija is a 3-way anticlinal structure and the Ikija-1 well discovered oil and gas in both the hanging wall (HW) and footwall (FW) of the Ikija thrust fault. In the HW, 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 FW, 48 ft of oil net pay was discovered in the 11.7 Ma sand. The oil samples were circa 45 degrees API.

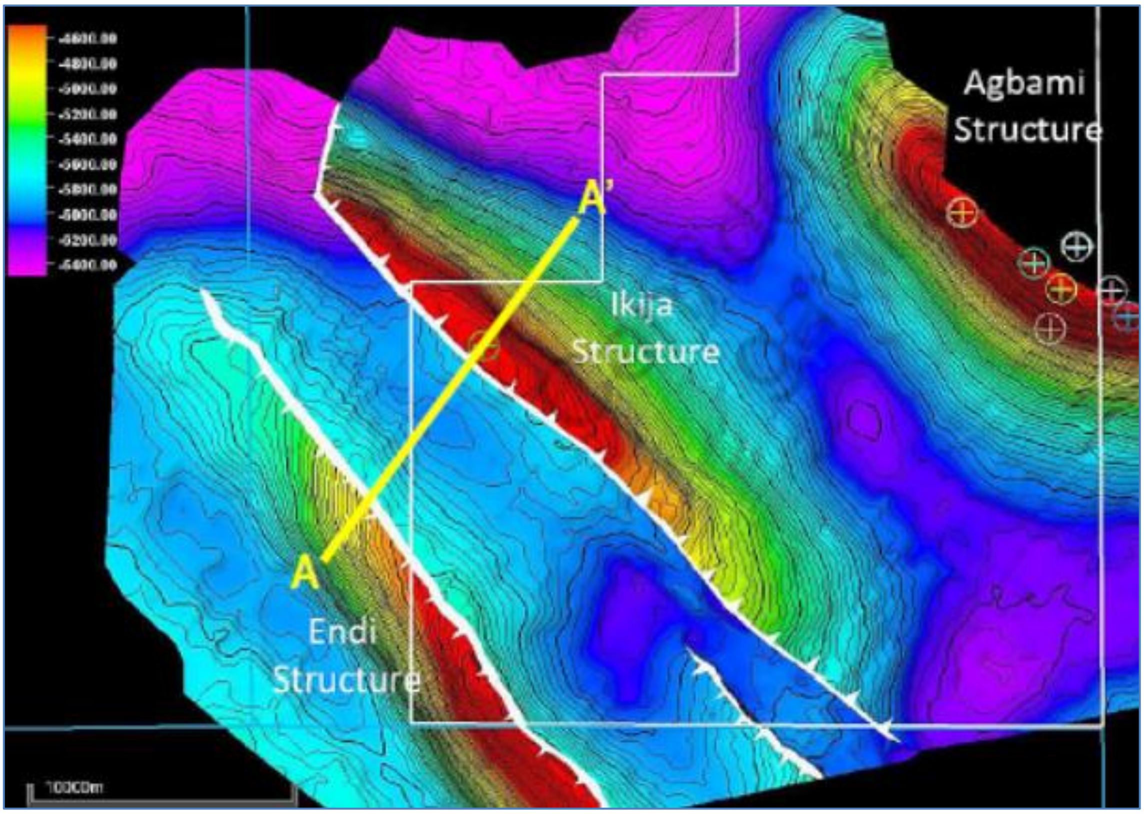

Figure 4-1: Ikija top reservoir depth map

The 16.4 Ma has two flow units defined by MDT pressure data. The upper unit (16.4_30) did not encounter an 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 did not encounter an OWC. Contact uncertainty between the LKO and Spill defines an upside range of 214'. 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 4-2 below.

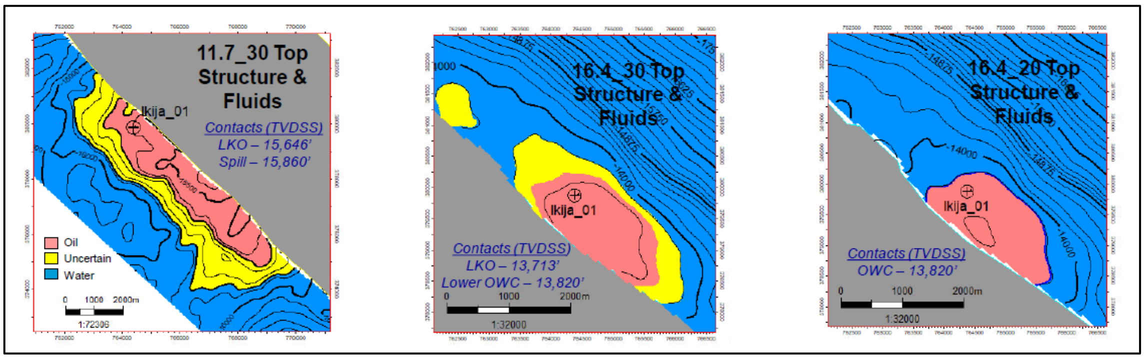

Figure 4-2: Ikija Field Fluid Contact Uncertainty

Table 4-1 below shows the uncertainty range estimated for Ikija STOIIP, presented by Chevron in the Ikija Development Plan (2020). Based on the data set available, RISC considers the volumes and the uncertainty range to be reasonable.

Table 4-1: Ikija STOIIP Range

STOIIP, MMstb	P90	P50	P10
16.4_30 Ma sands	15	21	29
16.4_20 Ma sands	12	16	21
Total 16.4 Ma sands	27	37	50
11.7_30 Ma	74	134	217
Total Ikija	**101**	**171**	**267**

There are key subsurface uncertainties that remain (structure, reservoir extent, rock properties, etc) and an appraisal well is planned in 2027 to expand the discovered area of the field and accomplish the subsurface objectives:

- Reduce the uncertainty range in resource size;
- Test for variability in reservoir quality, connectivity, and extent;
- Amplitude and depth control/calibration; and
- Robust data acquisition.

The appraisal well is designed as a keeper (future production/injection well or kept for side-tracking). It's primary objective is to appraise the 11.7 Ma hanging wall (HW) sand accumulation but will also be drilled deeper to penetrate the 12.7 Ma to 19.5 Ma prospective intervals. It is currently planned to be drilled approximately 4 km SSE along strike of the Ikija-1 discovery well (see Figure 4-3).

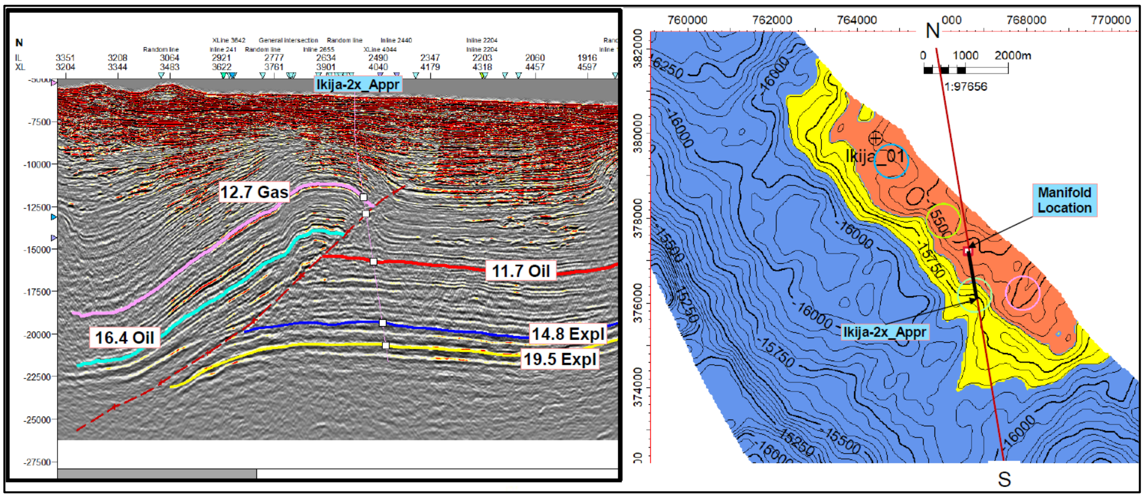

Figure 4-3: Ikija appraisal well location

4.2. Ikija Development and Production Forecast

Development consists of three oil production wells targeting the larger 11.7Ma reservoir, with one as a dual completion also targeting the 16.4Ma reservoir. There will be a single water injector targeting both reservoirs. Water injection will maximize oil recovery where aquifer pressure support is insufficient. The gas is not planned for development.

RISC modelled the 11.7 Ma structure in Rubis software. This structure accounts for circa 80% of the STOIIP. An additional well was scaled down to represent production from the single 16.4 Ma reservoir well. The Rubis model included the contact ranges, STOIIP range, likely well locations, rock, and fluid properties, etc. It also accounted for the peak rates and minimum wellhead pressures stated in the Operator's plan. RISC's Mid case forecast was very similar to the operator's forecast, with RISC's production plateau ending a few months earlier.

Chevron identified 17 close analogue fields with an average P50 recovery factor of 51%. This is close to the RISC Mid Case results of circa 50%.

As the Agbami FPSO has no gas export, sales gas volumes are zero. The relatively low rates of Ikija associated gas will be used as fuel and injected into the Agbami field.

First oil is assumed to be in 2032. The maximum field oil rate has been set at 20,000 bopd for the first year as wells are drilled, stepping up to 40,000 bopd for a plateau period in the 2C and 3C cases. Annual average rates are lower after accounting for downtime.

The Expected Ultimate Recoveries (EUR) associated with the Ikija forecasts to end 2044 are shown below (Table 4-2).

Table 4-2: EUR of Ikija Cases

Ikija Discovery	Low	Mid	High
Ikija recovery to End 2044, Oil, MMstb	48	82	103

4.3. Cost Forecasts

Ikija total capital costs are forecast to be US$1,011 million (excluding abandonment) and are similar to the YE 2023 reserves review with first oil scheduled for 2032.

The project capital costs include:

- US$103 million for an appraisal well and initial studies (Appraisal well drilled in 2027);
- US$403 million for 4 development wells in 2030-2031, and;
- US$505 million for facilities.

The appraisal well is planned to involve 58 days of drilling and 27 days of special logging and other activities, at an average spread rate of US$1.1 million/day. This results in a cost of US$94 million. The first two production wells, Ikija-3 and 4, are also estimated to cost US$94 million each, taking 58 days to drill and 27 days to complete at spread rates of US$1.1 million/day. The third production well, Ikija-5, is estimated to cost US$112 million due to a longer completion time of 46 days at the same spread rate. Finally, the water injection well, Ikija-6, is estimated to cost US$91 million and will take 83 days to drill and complete. US$13 million is also estimated for mob/de-mob costs. RISC consider these estimates to be reasonable based on the latest drilling schedule and costs associated drilling campaigns already underway on Egina.

Prime estimate the facilities costs to be US$505 million and include a subsea manifold, water injection and a single flowline with electrical heating to the Agbami FPSO. This estimate from Prime was developed using an industry standard cost estimating tool in 2020. RISC notes that facilities costs have increased considerably since 2020 and have allowed for an increase of 15%, taking the total facilities costs to US$581 million and the overall development cost to US$1,087 million. RISC recommend that the estimation be updated for next year's reserves report. The planned development schematic is shown in Figure 4-5 and RISC's Capex forecast, reflecting the operators well costs and our revised facilities costs, is shown in Figure 4-4.

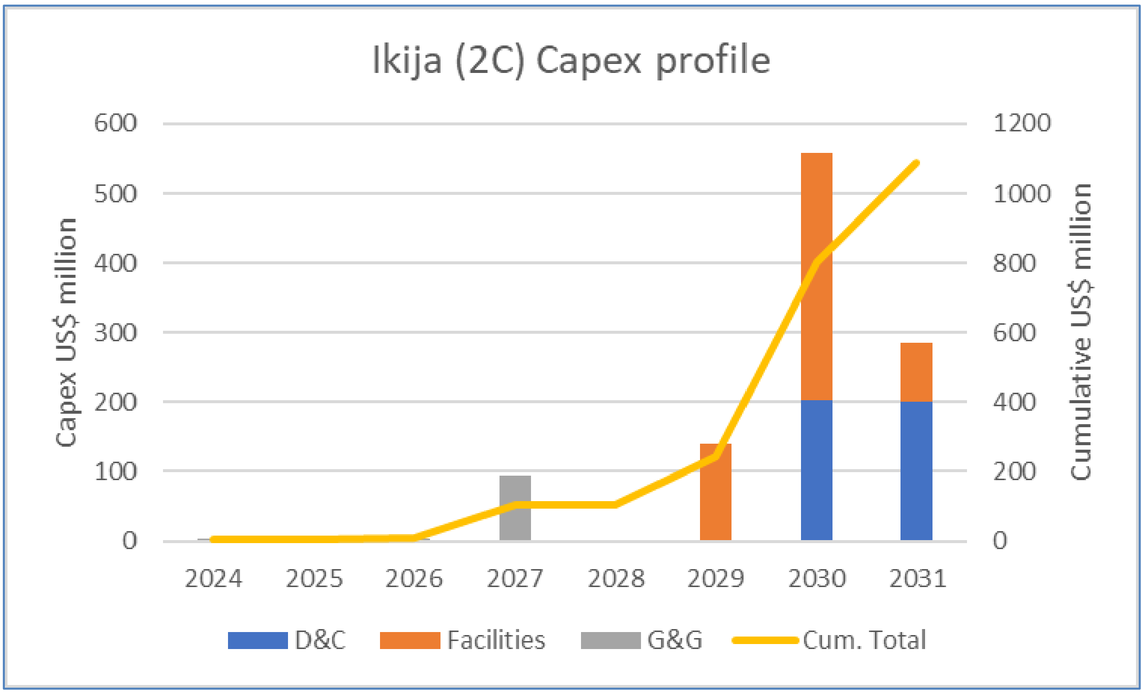

Figure 4-4: RISC's Ikija development Capex forecast.

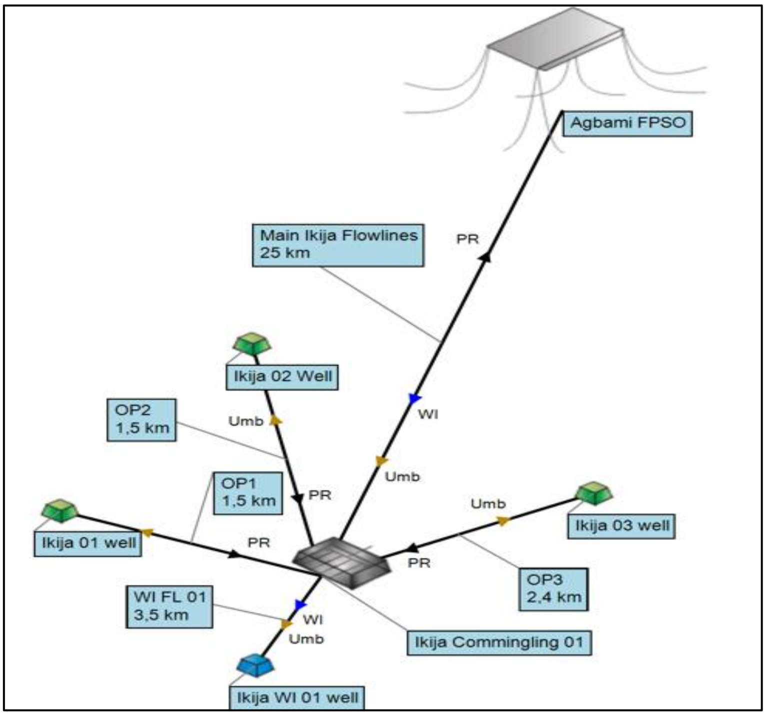

Figure 4-5: Ikija development schematic

The Operator has forecast USD$14 million per annum Opex in the first 3 years of operation before reducing to USD$1.3million over the life of the field. Overall RISC considers the variable component of Opex to be on the high side but RISC views the Opex towards the end of field life to be reasonable and not that different to the other nearby developments. The unit Opex is below US$1.5/boe and is quite low due to the fact that the development is tied in to the Agbami project, which absorbs most of the costs. The Opex forecast is shown in Figure 4-6.

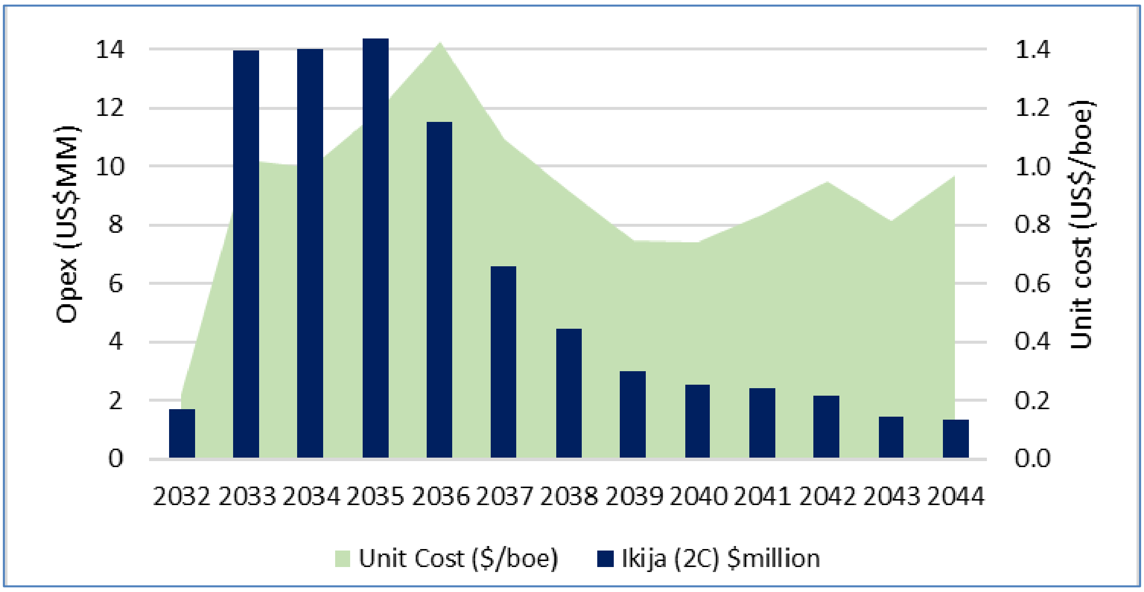

Figure 4-6: Ikija opex in comparison to unit cost

The Operator's total abandonment costs are unchanged from the YE2021 review and are estimated to be USD$99 million, comprised of USD$37 million in well P&A and USD$64 million in facilities decommissioning which RISC views as reasonable. An allowance has been made for selling scrap material for USD$3 million. In line with Agbami, linear provisioning has been assumed for and begins in 2025.

4.4. Ikija Contingent Resources

The contingent resources associated with the Ikija development are shown in Table 4-3.

Table 4-3: Ikija contingent resources as of 1 January 2024

Oil	Unit	Resources		
		1C	2C	3C
Ikija (4 wells), gross to OML 127	MMstb	46.9	82.2	102.6
Prime net entitlement	MMstb	6.5	10.1	11.8

Notes:
1. OML 127 share of total Ikija field resources is 100%.
2. Prime net entitlement is calculated using the method described in section 9.3 of this report.
3. Volumes are based on conversion of both licences to PIA terms.
4. Ikija has zero sales gas, therefore zero sales gas reserves.

5. PML 2 – Akpo Field Reserves

5.1. Field Description

The Akpo oil field is located approximately 175 km from Port Harcourt, within the Oil Mining Lease 130, in water depths ranging from 1,100-1,300 m. TotalEnergies is the operator.

Akpo was discovered by the Akpo-1 exploration well in April 2000 and appraised by four additional wells between June 2000 and July 2002. The initial FDP was submitted and approved in 2003 based on the development of 44 subsea wells: 22 producer wells, 20 water injector wells and 2 gas injector wells. However, based on improved understanding of the field and in agreement with the Nigerian Authorities, 2 redundant water injector wells were swapped to 2 producer wells in 2014 and 2015. Akpo field production started in March 2009 with a plateau of 180,000 bopd reached in June 2010. Field average oil production in 2023 was approximately 69,500 bopd with 58% water cut.

As of 31 December 2023, there have been 29 oil producers, 20 water injectors and 2 gas injectors spread across the 6 main reservoirs (AU, AL, B+C, D, EF and G). Akpo contains a critical fluid that has also been described as condensate or light oil with an original GOR of approximately 3,500 scf/bbl. There is a significant variation of fluid properties with depth without sharp gas-oil contacts. Pressure maintenance at or near initial pressure is required and is provided by either water or gas injection. Cumulative oil production up to and including 31 December 2023 was 664 MMstb (estimated). Part of the produced gas is re-injected for pressure maintenance and the remaining part is transported via an export line to the Nigeria LNG plant (NLNG) via the Amenam field with cumulative gas production of 2.61 Tcf (estimated), cumulative injection 0.94 Tcf (estimated) and cumulative gas export of 1.52 Tcf (estimated) on 31 December 2023.

Akpo FDP Revision 2 update was issued in April 2020 and subsequently approved; Akpo FDP Revision 3 was issued for NAPIMS approval in February 2021. It included the 3 well development of Akpo West gas field, Akpo D gas-condensate reservoir blowdown, one firm Akpo well D-P5 and a contingent Akpo well AU4-P4 (now drilled). Since then, the scheduled timing has changed, and 5 new infill wells have been proposed.

Prime’s estimated start-up dates in its forecasts are a shown in Table 5-1**.**

Table 5-1: Akpo Field Best Case STOIIP by reservoir (MMstb)

Project	Resource Classification	FDP (Rev 3) Estimated Date	Current Prime Estimate
AU4-P4	Reserve	Nov-21	Actual: 26 November 2021
Akpo West	Reserve	Aug-23	Dec-23
D-P5	Reserve	Dec-23	Apr-24
B-W4	Reserve	Dec-25	Dec-24
5 Infill wells	Contingent	Not included	Dec-25 (1 AU well) Jan-26 (1 AL well) Mar-26 (1 AL well) Apr-26 (1 AL well) Jun-26 (1 B well)
Miscible gas injection	Contingent	Dec-25 (2 AU wells & 1 B well) Dec-28 (1 EF well & 1 G well)	Jul-26 (1 AU well) Mar-29 (1 AL well) Dec-29 (1 B well) Dec-33 (1 EF well)

5.1.1. Geoscience Overview

The following section represents a summary of the geological evaluation of the field described in the latest Akpo Field Development Plan (Akpo FDP Revision 2 Update, April 2020), in addition to other presentation material and reports provided by Prime.

The Akpo field is a large anticlinal 4-way dip closed structure (approximately 50 km²) induced by shale diapirism within the translational structural zone of the West African Passive Margin (Figure 5-1).

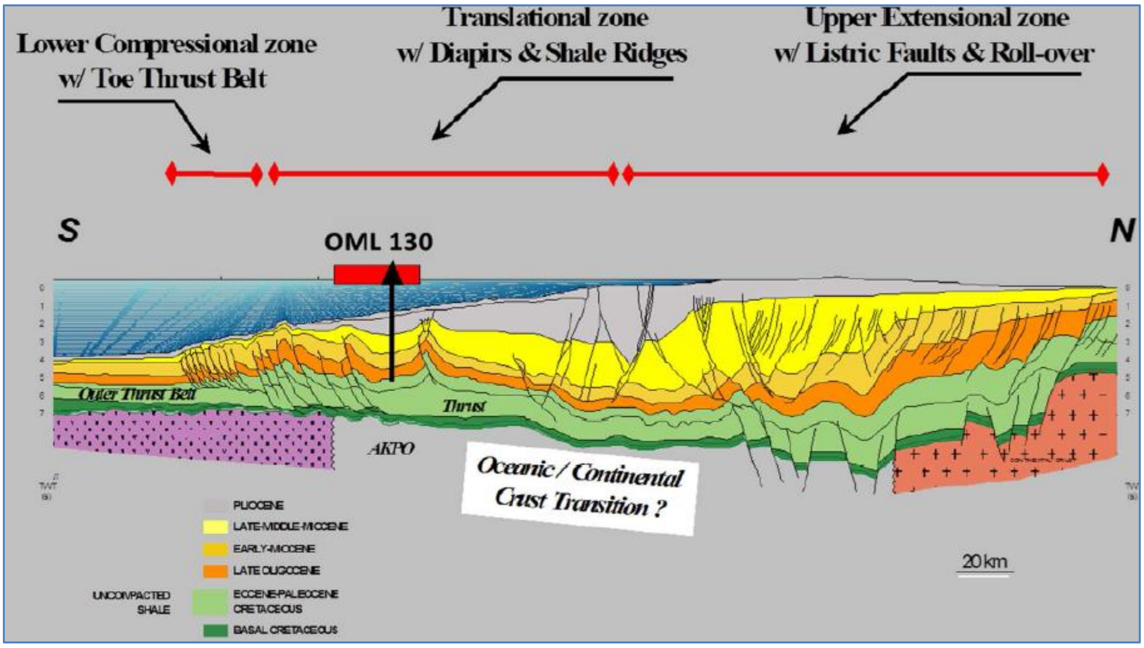

Figure 5-1: Niger Delta, North-South Regional Cross Section

The field is heavily faulted with predominant SW-NE orientation, many of which are sealing, which has caused significant compartmentalisation with various oil water contacts present in the field. The reservoir succession is shale dominated with five (5) main reservoir accumulations (A, B+C, D, EF and G) identified based on seismic interpretation, well correlation (sequence stratigraphy) and exploration/appraisal and development drilling (Figure 5-2). Furthermore, the identified reservoir is not present over the entire Akpo structure and are restricted to certain areas that can be split into three distinct accumulations (Figure 5-3):

1. An eastern accumulation comprising the A-Lower and A-Upper reservoirs defined by a mixture of structural closure and stratigraphic components;
2. A central accumulation comprising the B, D, EF, and G reservoirs within a faulted 4-way dip closed anticlinal structure;
3. A western accumulation comprising the currently undeveloped Akpo West reservoirs defined by a mixture of structural closure and stratigraphic components.

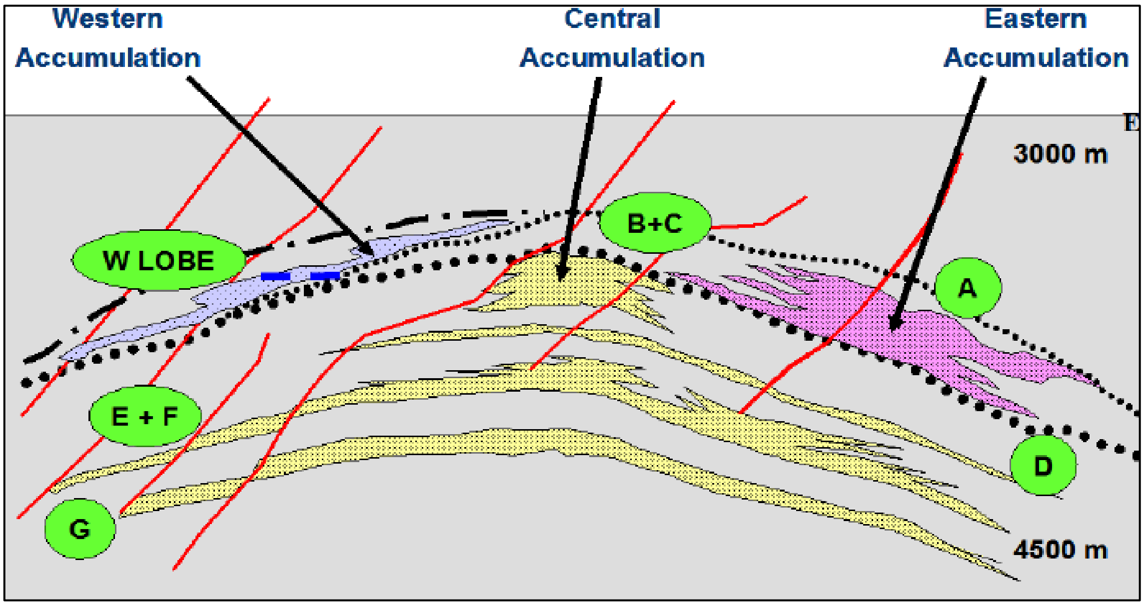

Figure 5-2: Schematic W-E cross section through Akpo Field.

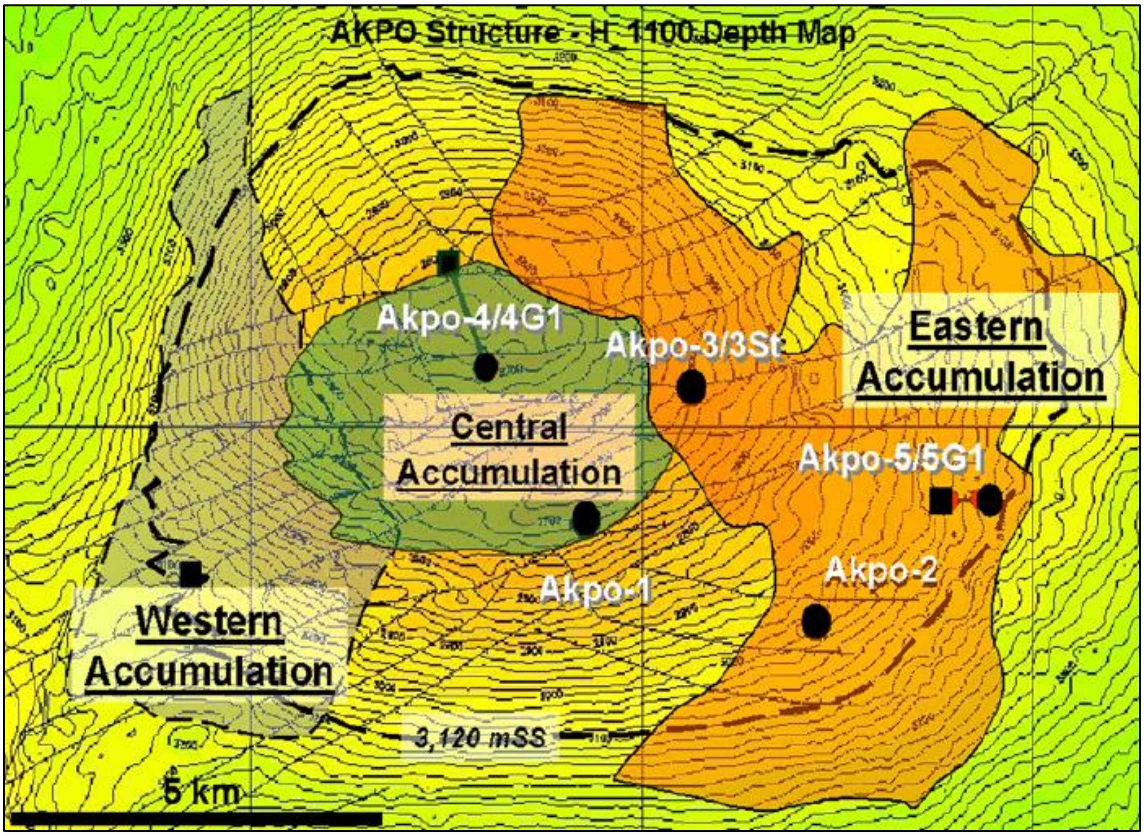

Figure 5-3: Overview of Akpo accumulations.

Akpo Field is covered by 1998/99 3D seismic data that was acquired by GecoPrakla with a total coverage area of 1,800 km². This was reprocessed in 2003 following field discovery which improved the imaging of deeper targets and frequency content. This survey was reprocessed again in 2010 to take advantage of advances in seismic processing which resulted in a significantly improved product. The current Akpo field reservoir models are based on the 2010 reprocessed seismic and 2011 seismic inversion. Subsequently, three 4D seismic monitors have been acquired in 2011 (M1), 2015 (M2) and 2018 (M3), with results incorporated into the reservoir model. Significant improvement of the image at reservoir level from the 4D M2 and 4D M3 has helped to recognize additional potentials in un-swept areas. A new 4D-M4 was acquired in December 2023 through to January 2024 and is currently being processed.

Akpo Reservoirs are deep water fans of distal turbiditic origin deposited in submarine channels and lobes during two main depositional episodes:

1. Prograding “basin-floor fan” episode during Late Oligocene to Early Miocene times. This phase corresponds to the deposition of Lower Akpo reservoirs G, EF & D (Figure 5-4). Reservoirs are distributed through complex often highly sinuous channel networks forming broad sand-rich channelized lobes. Unconfined sheet sands become more common at the margin of these systems. The location of the channelised lobes is largely controlled by basin-floor topography, and compensational (lateral) stacking is common.
2. Aggrading "slope fan" episode during Middle Miocene times, corresponding to the channel-levee complexes of the Upper AKPO reservoirs A & B, mainly confined to the eastern and central parts of

the field (Figure 5-4). The channelised Lobe System for Lower Akpo reservoirs G, E,F and D is shown on the left in the figure and channel-levee complexes for Upper Akpo reservoirs B and A on the right. Overall grain size is more variable compared to the lobe complexes, resulting in constructive channel-levee complexes, as illustrated by reservoir B with periodic evolution of erosive features as illustrated in reservoir A Lower. As these complexes evolve, lateral and downslope migration of individual highly sinuous channel fills is common (e.g., in the B and A Upper reservoirs).

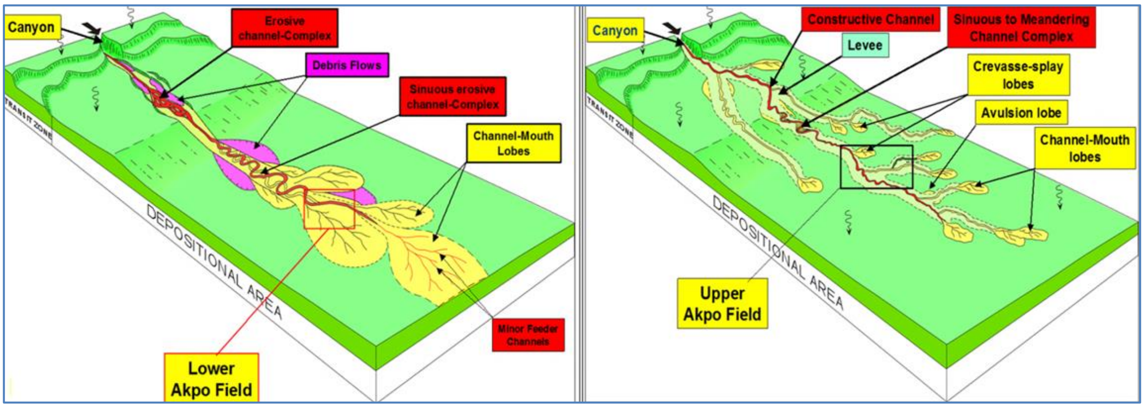

Figure 5-4: Depositional Models: Lower Akpo reservoirs G, E, F, D (left). Upper Akpo reservoirs A, B (right).

Akpo West is a potential upside located on the western flank of the AKPO Main structure which is planned as a tie-back to the Akpo Main development. Two reservoir intervals are identified on seismic data: Akpo West Upper A & B units and Akpo West Lower A, B & C units. The main target is the Akpo West Lower B unit, which is interpreted as a hydrocarbon bearing, channelized lobe reservoir with a combined structural and stratigraphic trapping. Akpo West is essentially a gas accumulation with minor condensate and a GWC at 3,260 m TVDss.

In general, the Akpo reservoir sandstones exhibit excellent reservoir properties with average porosities typically in the range of 15-27% and permeabilities in the range 150-3,000 mD with better quality observed in channel facies vs lobes. Reservoir units are typically shale dominated on a gross basis and can be highly variable in terms of net to gross and reservoir thickness, although the main reservoir sand packages can be correlated across the field with a high degree of confidence. The lateral variability is a function of the depositional system and variation between depositional facies (e.g., channel vs overbank vs lobe) which can make reservoir distribution difficult to predict despite the large number of well penetrations. Seismic data are not typically of sufficient quality / resolution to accurately map individual sand bodies within each reservoir.

RISC have reviewed the reports and information provided by Prime regarding Akpo STOIIP and note reasonable consistency in STOIIP through time and between the operator and Prime with some small exceptions. RISC note that the operators STOIIP values are derived from a series of different static models and model updates. STOIIP is now based on the history match and performance methods. Prime history matched simulation model provides an indication of field STOIIP (Table 5-2). RISC has conducted independent decline analysis to estimate reserves and checked consistency with Prime STOIIP estimates.

Recent reported updates to STOIIP by the operator include an increase in STOIIP in reservoir D between the old model RM3.0 (168 MMstb) and RM4.0 (177 MMstb). A 16 MMstb increase in reservoir G has also been included in RM4.0.

The main field has been developed with 49 development wells. The 2021 STOIIP estimates are shown in Table 5-2, although our reserve assessment is based on decline analysis.

Table 5-2: Akpo Field Best Case STOIIP by reservoir (MMstb)

Evaluation	A Upper	A Lower	BC	D	EF	G	Total
Operator (TotalEnergies) 2021 STOIIP[7] (MMstb)	397	310	147	168	153	161	1,336
Prime 2020 Simulation STOIIP (MMstb)[8]	678		130	166	154	172	1,300
Operator (Total) 2021 STOIIP[9] (MMstb)	387	310	147	177	153	177	1,351
Prime Aug 2023 Simulation STOIIP (MMstb)[10]	397	310	148	177	154	195	1,381

Akpo West is a discovered but undeveloped western lobe. Exploration upside exists in deeper horizons (Akpo Deep) and the far East (Akpo Far East).

The operator reports a Best Case GIIP volume for Akpo West based on recent static modelling as shown in the latest FDP (April 2020), Table 5-3 with an implied condensate liquid volume of 25.7 MMstb (CGR 129 stb/MMscf). RISC was provided with the dynamic model in 2021 but not static model to allow a full audit of this estimate. There was no update in 2022 or 2023.

Table 5-3: Akpo West GIIP

Reservoir	Low	Best	High
Akpo West GIIP (Bcf)	-	200	-

5.1.2. Reservoir Fluid Properties

Table 5-4 summaries the Akpo reservoir fluid properties. The oil is light, gassy and low viscosity (condensate like) which results in favourable water displacement and high oil recovery factors (RFs). The bubble point is only a few hundred psi below initial reservoir pressure. Therefore, water or gas injection to supplement the aquifer and provide full voidage replacement is important to limit gas coming out of solution and limiting oil recovery.

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7 Values from Annual Reserves Meeting (ARM Dec 9, 2021):
8 POGBV Technical Update RISC Jan21 v14.pdf
9 Values from Annual Reserves Meeting (ARM Dec 8, 2022):
10 POGBV Reserves Audit 2024 v4 postmeeting.pdf

Table 5-4: Akpo reservoir and fluid properties[11]

Environment	Turbiditic Channel			Middle Miocene		
Reservoirs	A Upper	A Lower	B	D	EF	G
Average Depth (m)	3,100	3,100	3,050	3,434	3,434	3,660
Average Permeability (mD)	1,200	1,200	1,000	1,000	600	400
Average Swi (%)	25	20	15	10	13	15
Average Porosity (%)	20	20	17	25	20	20
Average NTG (%)	40	40	40	80	65	66
Average Net Pay (m)	60	60	50	17	50	66
API Gravity	44.4	47	45.1	44.6	49.9	48
Viscosity (cp)	0.15	0.12	0.13	0.12	0.06	0.08
Boi (rb/stb)	2.0	2.4	2.1	2.3	4.2	3.3
Initial GOR (scf/stb)	1,965	2,527	2,145	2,611	5,615	4,183
Saturation Pressure (psi)	4,482	4,482	4,438	5,308	5,323	5,642
Initial Reservoir Pressure (psi)	4,772	4,772	4,743	5,439	5,453	6,048
Current FDP and Mechanism	Aquifer Support	Aquifer Support	Aquifer Support	Gas Injection	Aquifer Support	Aquifer Support

5.1.3. Production Facilities

The field has been developed with 49 subsea wells tied back to an FPSO. An offloading buoy moored nearby exports condensate to a tanker, the buoy is connected to the FPSO via two 16” inner diameter (ID) flexible lines. The 16” gas export pipeline has a capacity of 320 MMscf/d and transports gas 150 km to the Amenam complex. From there it is transported to the Nigeria LNG plant (NLNG).

The breakdown of wells within each reservoir unit as YE2023 can be seen in Table 5-5.

Table 5-5: Akpo number of wells as at 31 December 2023

Reservoir Unit	Producers	Injectors
Reservoir AU	6	5 water
Reservoir AL	8	6 water
Reservoir B	3	3 water
Reservoir D	4	2 gas
Reservoir EF	3	3 water
Reservoir G	4	2 water
Total	**28**	**21**

[11] AKPO FDP Rev.2 Update (April 2020)

Wells are a mixture of deviated, highly deviated and horizontal wells with Frac-pack, ESS (Expanded Sand Screens) and SAS (Stand Alone Screens) for sand control.

The subsea system has four production loops, four water injection risers and two gas injection risers, as follows:

- 4 x 10” ID production flow loops and risers (60 km total length);
- 1 x 8” nominal diameter (ND) gas injection line and riser (6 km total length);
- 4 x 10” ND water injection line and riser (40 km total length);
- 4 x production umbilicals (30 km total length);
- 4 x injection umbilicals (50 km total length).

In addition, there are manifolds to facilitate tie-in of individual production wells to the flowlines, multiphase flow meters for measure of individual well rates and a monitoring and control system.

The FPSO has the capacity limits summarized in Table 5-6.

Table 5-6: Akpo facility production constraints

Specification	Capacity[12]
Oil production	185,000 bbl/d
Liquid production	235,000 bbl/d
Water disposal at sea	150,000 bbl/d
Water injection	420,000 bbl/d (3 pumps), 280,000 bbl/d (2 pumps)
Gas production	607 MMscf/d
Gas injection	230 MMscf/d
Gas export	406 MMscf/d (increased from 396)

The FPSO fluid handling limits are shown schematically in Figure 5-5.

[12] Based on 95% availability.

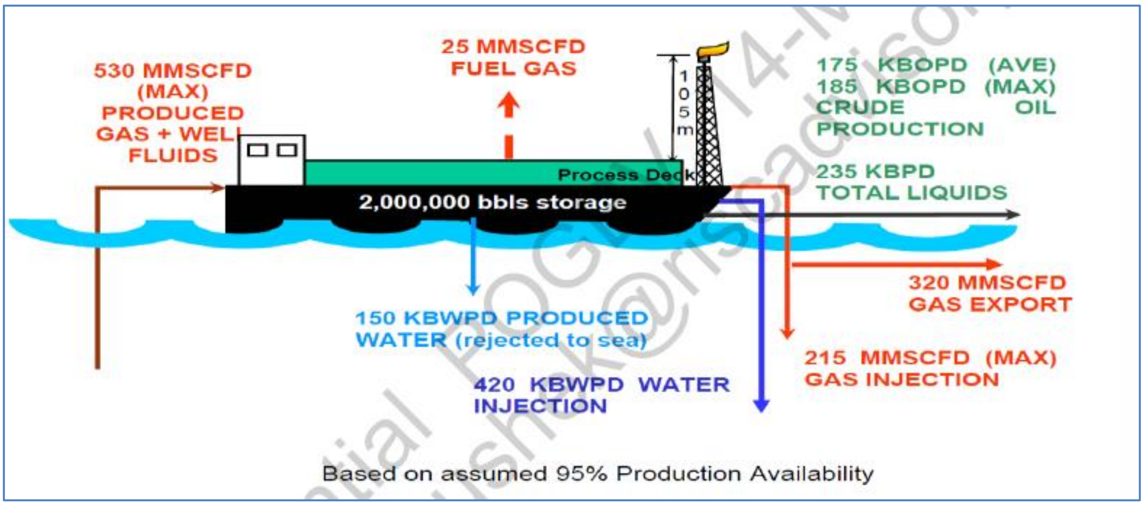

Figure 5-5: Akpo FPSO design flowrates.

There are seawater injection facilities. Artificial lift is not required due to the high GOR. The facility is estimated to use 25 MMscf/d of gas as fuel, and this has been used by RISC as a Fuel & Flare estimate (NB: The current average is approximately 17 MMcf/d).

5.1.4. Production History

Akpo started production in March 2009 and reached a plateau oil rate of 180,000 bopd in 2010. Figure 5-6 shows the historical oil, water, and gas production rates from 2018. The current (early December 2023) daily oil production is approximately 64,500 bbl/d, water production is approximately 115,900 bbl/d and gas production 384 MMcf/d.

RISC notes that, in the last 12 months:

- Oil production has decreased from 80,000 bbl/d to 64,500 bbl/d;
- Water production has increased from 80,000 bbl/d to 115,900 bbl/d. This has been enabled by an increase in the water handling capacity; and
- Gas production has decreased from 420 MMcf/d to 384 MMcf/d.

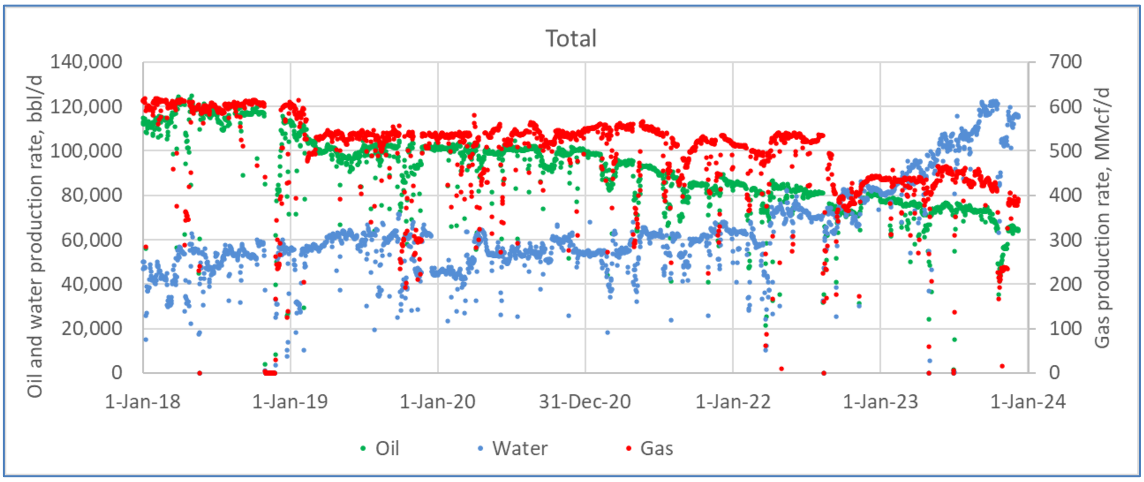

Figure 5-6: Akpo oil, water and gas production rate history from 2018.

With respect to facility capacities:

- Plateau oil production was close to the facility capacity (175,000 bbl/d) but has subsequently declined;
- Water production is only slightly below the facility capacity (now increased to 120,000 bbl).
- Gas production has been at or near the facility capacity (607 MMcf/d) since 2014. It is currently below the facility capacity.
- Water injection has been below full capacity (420,000 bbl/d) since 2016 and is currently operating at slightly below the facility capacity on 2 pumps (currently 280,000 bbl/d).
- Gas injection had been near capacity since start-up until the last 4 months of 2022. The gas injection capacity remained low in 2023 due to the valve issues at Akpo 22 and production was curtailed to maintain a voidage balance.

Historically, production had been generally constrained by facility gas capacity, which mainly affects reservoir D production, prior to OPEC quota restrictions since 2019. Reservoir D is producing 175 MMscf/d of the total YE2023 field gas production (385 MMscf/d). As the field's decline continues the relevance of production constraints will reduce.

Figure 5-7 shows the development of water cut and GOR. The impact on the GOR of curtailing production from the D reservoir since August 2022 due to the Akpo 22 valve issue is clearly shown.

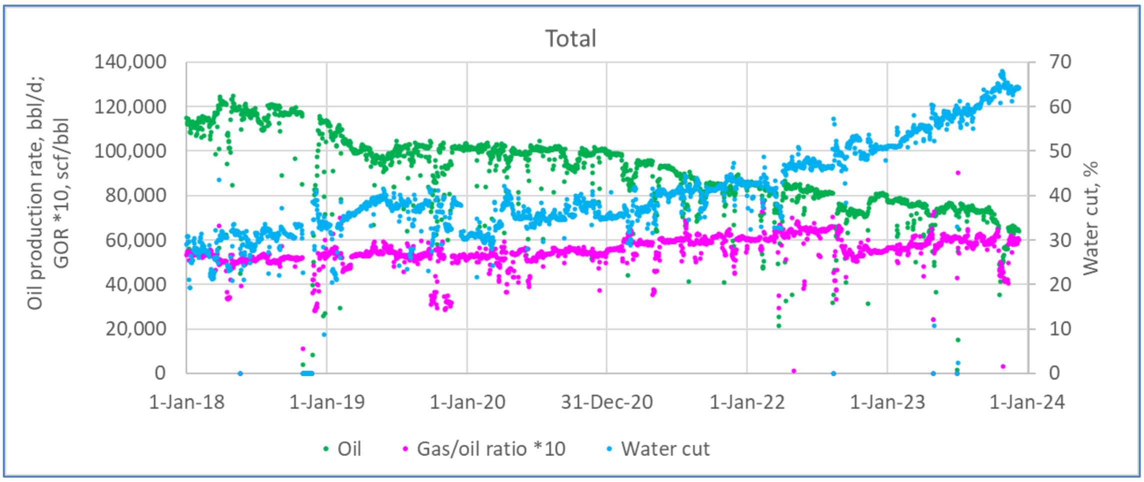

Figure 5-7: Akpo Field oil production rate, GOR and water cut history from 2018.

Water injection started in 2009 with peak injection rates of 420,000 bwpd. The D reservoir has had gas injection since 2009 increasing to 240 MMscf/d and no water injection. The constraint on gas injection due to Akpo 22 is evident (Figure 5-8).

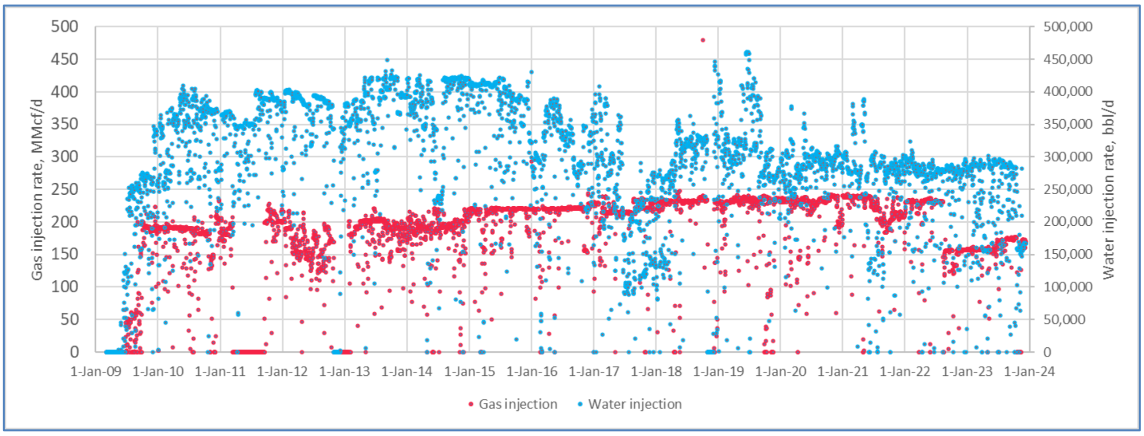

Figure 5-8: Akpo Field water and gas injection history.

The AL reservoir provides the largest contribution (circa 16,000 bopd) to field oil production rate. The G reservoir is the next highest contribution (circa 15,000 bopd) but has been on decline since late 2021. The EF reservoirs are the third highest contribution (circa 12,500 bopd) and have been relatively stable over 2023.

There were a number of interruptions to production during the last year for operational matters, including the 3-day Full Field Shut Down (FFSD) for cooling water header repair in July and the GEC-B electrical motor replacement and TG-C gas generator exchange in November.

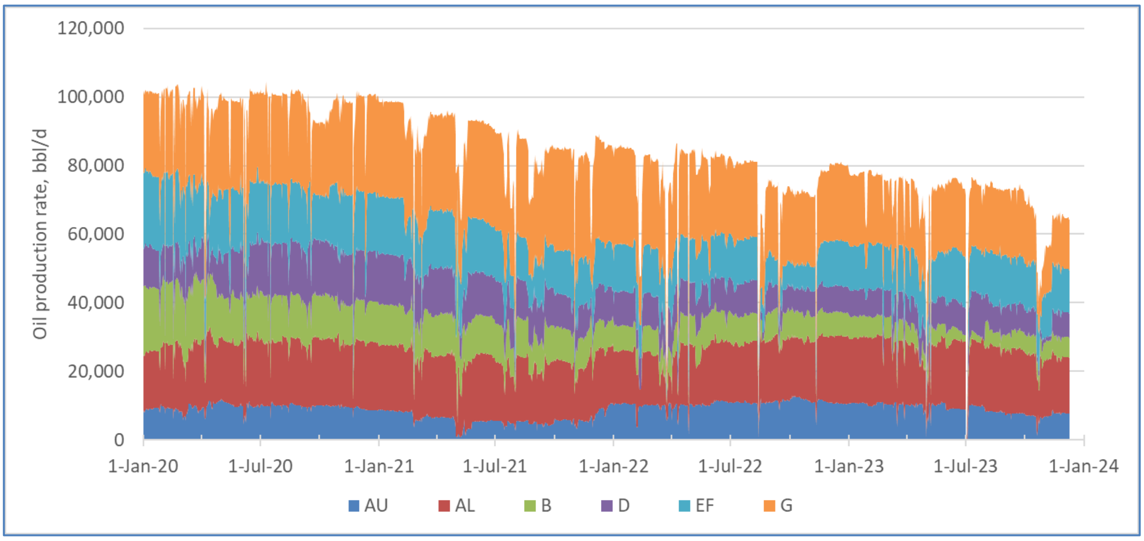

Figure 5-9: Akpo Field recent oil production history by reservoir.

5.1.5. Reservoir Simulation

Both Prime and the operator (TotalEnergies) use simulation models to identify and optimize infill well opportunities and forecast future well performance. Prime's model history matches were updated for production to August 2023, the operator's to April/May 2023.

4D seismic is used to identify fluid movement and unswept areas.

Table 5-7 identifies the key findings in the latest simulation update.

Table 5-7: Akpo simulation results by reservoir (TotalEnergies)

Reservoir	Model Version	Type	TotalEnergies HM Date	PRIME HM Date	PRIME Remarks
A Upper	RMV 3.2	E300 / INTERSECT	30-Apr-23	31-Aug-23	Update historical performance. Reviewing the WCT Match and re evaluation of stakes, infill and MGI opportunities
A Lower	RMV 4.0	E300 / INTERSECT	30-Apr-23	31-Aug-23	Update historical performance. WCT adjustments. Evaluating additional infills opportunity in A Lower North (LS2) - Production Acceleration, as A-43 is not well supported and A Lower East (LS3/LS0) - Crestal Oil. Re-assessment of stakes, infill and MGI opportunities
B	RMV 3.2	E300	30-Apr-23	31-Aug-23	Update historical performance. Evaluating the Akpo 45 bridging via Akpo 54 opportunity to support Akpo 41. BW4 Infill Studies. Re-assessment of stakes and . Conversion to INTERSECT. Operator working on RMV4.
D	RMV 4.0	E300 / INTERSECT	31-May-23	31-Aug-23	Update historical performance. Reviewing the GOR Match. D-P5 Infill studies consolidation. Akpo West impact sensitivities studies. Reservoir D recovery optimization – condensate and gas focus. And stake re-evaluation
EF	RM 2.3 V4	E300 / INTERSECT	31-May-23	31-Aug-23	Update historical performance. Converted to INTERSECT. Re-assessments of stakes and MGI opportunities.
G	RMV3.0	E300	30-Apr-23	31-Aug-23	Update historical performance. Reviewing the WCT Match and re-evaluation of stakes. Conversion to INTERSECT. Monitoring WCT evolution in all wells. Operator working on New Model.
Akpo West	RM V2	E300 / INTERSECT	-	-	Reservoir: Two intervals: Upper (units A and B) and Lower (Units A,B,C). Main target - Lower B. Development: 2 Producers and 1 Gas Injector. Converted to Intersect. Model update or rebuild in 2024.

The simulation models and analytical analysis appear reasonable and are used by Prime for forecasting. The simulated ultimate recovery is generally similar to Prime's various decline-estimated UR (see Figure 5-14). As there is extensive production history available with most wells producing at significant water cut, RISC has used decline analysis to review Prime's production forecasts.

5.1.6. Decline Analysis

5.1.6.1. Method

In order to audit Prime's developed reserves, RISC has conducted independent decline analysis by well on the oil production, and the decline is the basis for our oil forecasts and developed reserve assessment. We have also analysed and created forecasts for gas and water production, comparing the GOR and the water-cut history to ensure compatibility between the oil, gas, and water forecasts.

We note that, for its developed reserves estimates, Prime has used several methods to cross-check its estimates including reservoir simulation and decline analysis. We acknowledge that there are several features associated with the Akpo wells and reservoirs that are not ideally suited to decline analysis. However, we consider that overall, the method provides a reasonable check on the performance. Overall, Prime's estimates are contained within the bounds of our low to high, oil and gas recovery estimates from decline analysis, and therefore we accept Prime's forecasts of developed reserves.

Some observed features that are not ideal for decline analysis included:

- Unstable production conditions; e.g.: frequent production interruptions in 2023 noted earlier, especially the GEC interruption late in the year.
- In general, the well head pressure (WHP) has been declining consistently for most wells and some of these wells are produced using the Test Separator. We also noted that often the late-2023 production had changing choke sizes and WHP (Figure 5-10).

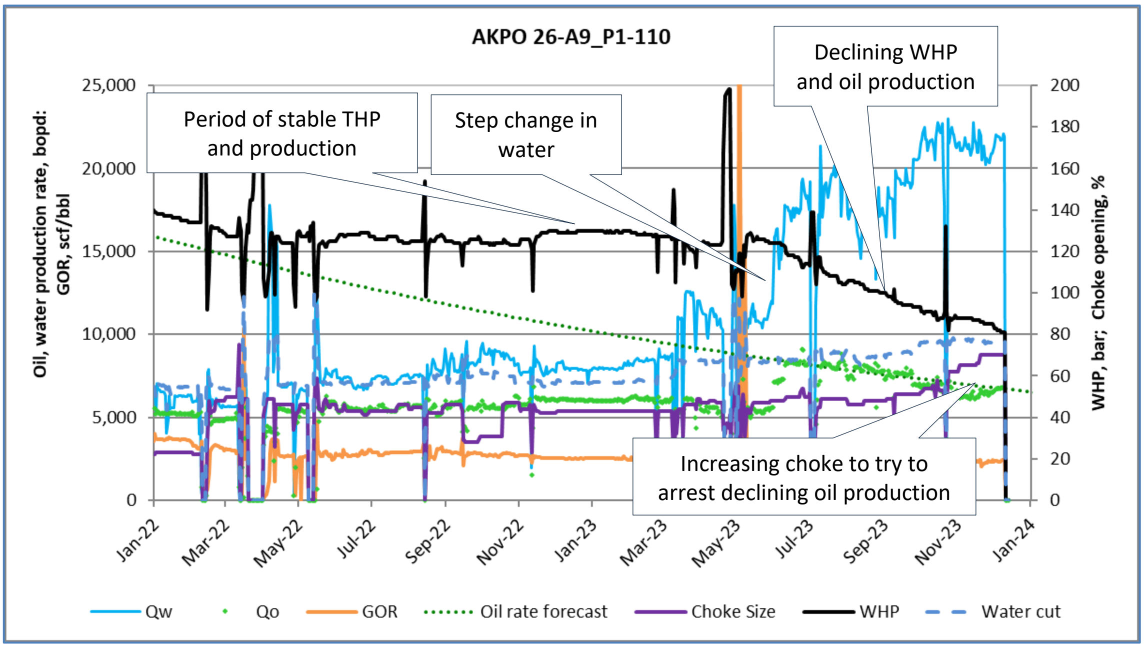

Figure 5-10: Akpo 26 recent oil and water production changes with THP and choke sizes.

- The gas injection in the D reservoir leads to changing compositional and relative permeability effects. This is exacerbated by historical (e.g. Akpo 22) and forecast (with AW start-up) changes to the gas injection forecast;
- We have noted two general patterns of water production behaviour:
  1) Gradual increase, accompanied by a gradual decrease in oil production, e.g. Akpo 20 between Jan-12 and Jan-16.

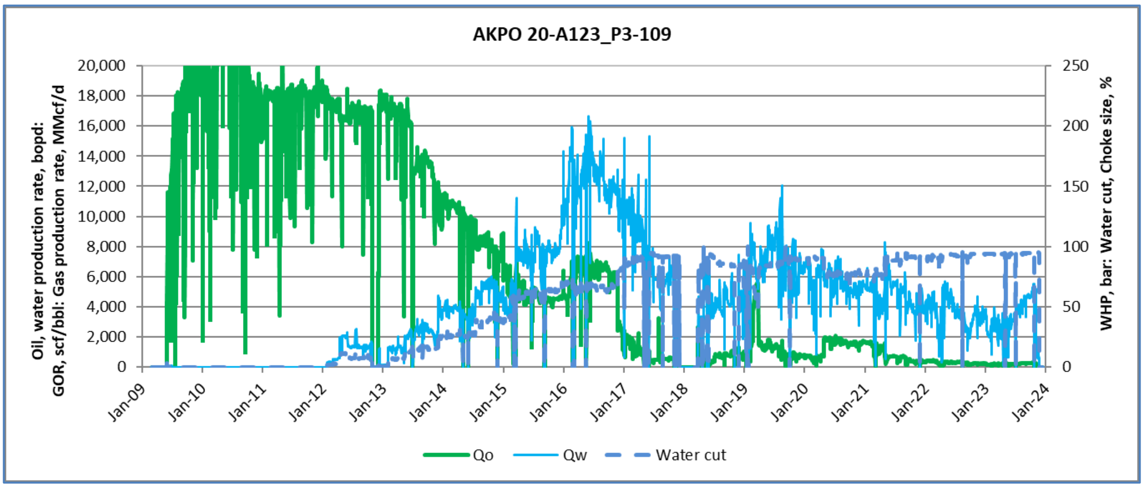

Figure 5-11: Akpo 20 gradual increase in water rate and water-cut.

2) Step increase in water rate, accompanied by a step decrease in oil production, e.g. Akpo 26 in mid-2014.

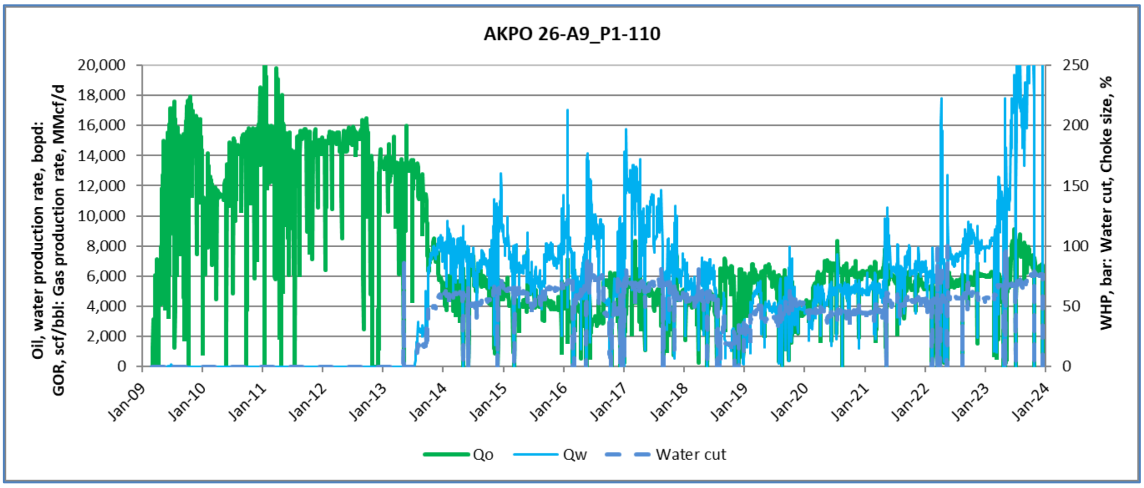

Figure 5-12: Akpo 26 step change in water production and water-cut.

Whilst both appear to start without warning, the rate at which the latter occurs places considerable uncertainty in the DCA forecasts for lower water-cut wells.

5.1.6.2. Results

Figure 5-13 illustrates the last two years of Akpo production history and RISC's forecast for two years. Although RISC forecasts a decrease in production for oil, gas and water, the steeper decline in oil rate than water rate results in an increase in water cut consistent with recent history. Similarly, the GOR is forecast to remain almost constant, consistent with recent history. Note that the forecast does not include the FFSD planned for February 2024 and that RISC's decline ignores the production interruption in November 2023[13] which largely seems to have impacted the D and G reservoir wells. The minor step change down in gas rate and GOR in December 2023 and step change up in late December 2023 is a result of RISC incorporating the shut-in of Akpo 24 during 2024 to accommodate the Akpo West 2 well[14].

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[13] GEC B electrical motor replacement and TG C gas generator exchange. WIP C tripped, Prime Oil & Gas B.V., Reserves Audit 2023, December 13th, 2023, p51
[14] PML 2_3_4 & PPL 261 TCM June 2023 Pre-read, p51

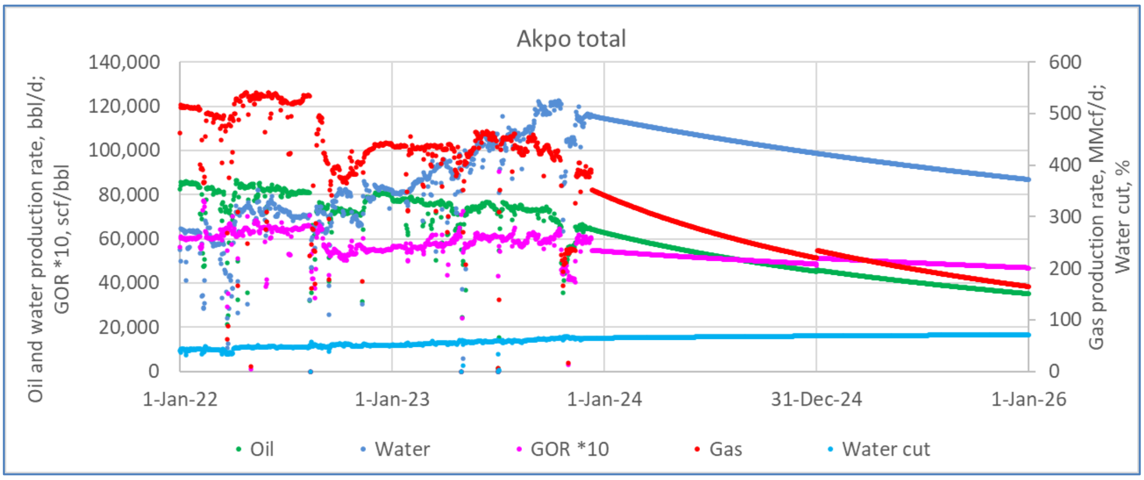


Figure 5-13: Akpo Field recent production history and RISC's forecast production.

Table 5-8 details RISC's estimated oil ultimate recovery to January 2046 (as used by Prime) by reservoir for developed wells. (Note actual data were available to 10 December 2023 with an estimate made to YE2023). The forecast is based on the decline and has not been adjusted for FFSD, nor have they been truncated by economic or other considerations. RISC's low case estimates are based on exponential decline, the mid case estimates incorporate some hyperbolic behaviour and a comparison of Prime's 1P and 2P cases (Base forecasts).

Table 5-8: Developed UR estimates by RISC for Akpo

Reservoir	Cum. Prod. to 10/12/2023	F'cast 11 to 31 Dec	Estimated cum. Prod. at 31/12/2023	Dev prod 1/1/2024 to 1/1/2046	RISC's estimated UR		Prime's estimated UR	
					Low	Mid	Low	Mid
	MMbbl	MMbbl	MMbbl	MMbbl	MMbbl	MMbbl	MMbbl	MMbbl
AU	156.3	0.2	156.5	18.8	170.8	175.3	n/a	186.7
AL	157.7	0.3	158.0	22.5	176.6	180.5	n/a	173.2
B	42.7	0.1	42.8	8.4	46.7	51.2	n/a	53.9
D	116.9	0.1	117.0	9.6	122.9	126.6	n/a	132.4
EF	80.8	0.3	81.1	21.1	100.1	102.1	n/a	101.1
G	108.0	0.3	108.3	28.5	128.4	136.8	n/a	125.2
All	662.4	1.3	663.7	108.8	745.5	772.5	728.0	772.5

Figure 5-14 illustrates Prime's range of developed oil ultimate recoverable estimates for various estimation techniques with RISC's mid case estimates overlain in red. For the field as a whole RISC's estimates are the same as Prime's and by individual reservoir, RISC's estimates lie within the range of Prime's estimates. The largest discrepancies between Prime's estimate and RISC's estimate are for the AU reservoir for which RISC's estimate is 11.4 MMbbl lower than Prime's and the G reservoir for which RISC's estimate is 11.4 MMbbl higher than Prime's estimate.

More detailed discussion of RISC's findings, by reservoir, follows.

Figure 5-14: Comparison between Prime's and RISC's UR estimates for Akpo Field, YE2023.

For the **A Upper (AU) reservoirs** RISC's (best estimate) developed ultimate recovery (ca. 175 MMbbl) is at the lower end of Prime's range of estimates, and 11 MMbbl below Prime's estimate. RISC has concerns regarding the production from this reservoir as:

- Two wells of the five wells producing at the start of the year were shut-in in mid and late 2023.
  1. Akpo 20 was shut in for production optimization and can be reopened when required.
  2. Akpo 6 was shut in to investigate abnormal annulus pressure and investigation is still ongoing.
- The three currently producing wells show declining WHP.
- Economic truncation, FFSD or FPSO life considerations may further reduce recovery.

The A Upper reservoirs have been developed with 6 oil production wells (Akpo 6, 10, 20, 33, 35, and 58) and 5 water injectors (Akpo 13T1, 15, 18, 28 and 48). Oil production was relatively stable at 8,000 to 10,000 bbl/d between 2018 and early 2021 when Akpo 10 was shut in. The addition of Akpo 58 in late 2021 saw the oil rate again return to ca. 10,000 bbl/d until mid-2023. Akpo 6 and Akpo 20 were shut-in in mid and late 2023, respectively, and the current (mid Dec 23) oil production rate is ca. 7,500 bbl/d.

Between early 2020 and mid-2021 water production was approximately 20,000 bbl/d. This dropped to 10,000 bbl/d with the shut-in of Akpo 10 and remained between 10,000 and 15,000 bbl/d until late 2023. The current water rate is 9,500 bbl/d.

Between 2018 and late 2021 the gas rate gradually declined from about 16-25 MMcf/d to ca. 12,000 bbl/d. The addition of the Akpo 58 well in late 2021 increased the gas rate to about 26 MMcf/d. Since then, the gas rate has steadily declined and is currently ca. 13 MMcf/d (Figure 5-15).

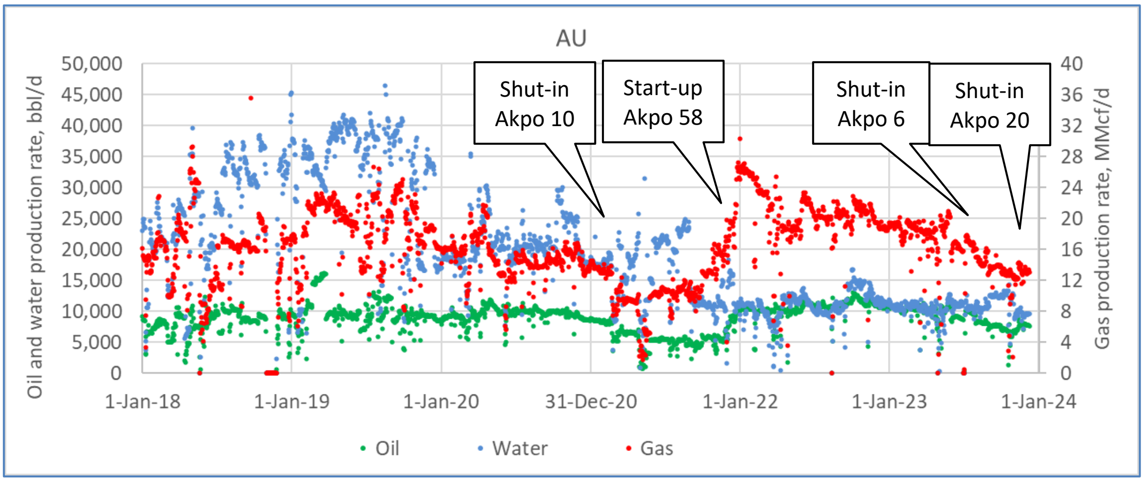


Figure 5-15: Annotated Akpo A Upper production history.

Of the six wells that have produced from the AU reservoir, three are shut-in. Regarding the shut-in wells RISC notes:

- Akpo 10 has not produced since 2021. The well is considered a “Potential water shut-off candidate” in the September SSCM notes (p28) and discussed in detail (p30-33 SSCM). The project is under consideration but yet to be sanctioned, considered as a CR (not a reserve) for this exercise.
- Akpo 6 has not produced since July 2023 (apart from a few days in Oct.). The well is noted to have an integrity issue. Repair considered “unfeasible” in SSCM PPT (p28 and p38).
- Akpo 20 has not produced since Nov. 2023. This is a recent change and post-dates the SSCM. Status unknown.

Figure 5-16 shows the AU reservoir oil gas and water production from 2022 and RISC’s consolidated well forecasts to 2026 along with Prime’s Base case forecasts.

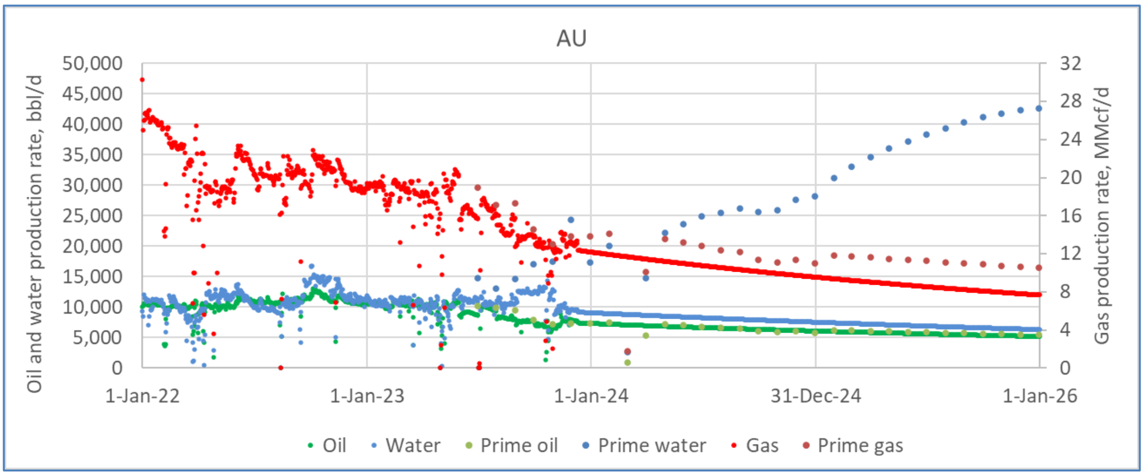


Figure 5-16: Akpo A Upper history and forecast versus time.

Whilst RISC's and Prime's oil forecasts are similar, Prime's gas forecast is slightly greater than that of RISC and appears to come off a higher history in late 2023. Similarly, Prime's water forecast is above RISC's and has a higher history. We note that Prime's forecast has been adjusted for the February 2023 FFSD whereas RISC's has not.

Figure 5-10 illustrates the oil production forecast since January 2022 as a function of cumulative oil production. We have identified the production rate and cumulative production as at YE 2022 (10,500 bbl/d and 153.3 MMbbl) and note relatively steep decline that has occurred since then.

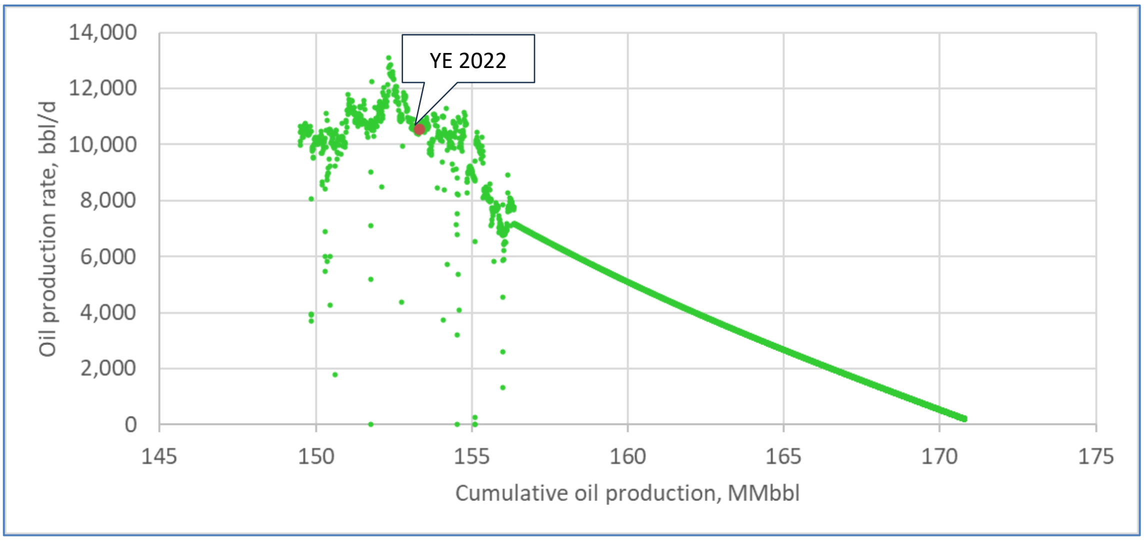


Figure 5-17: Akpo A Upper history and forecast versus cumulative oil production.

Figure 5-18, Figure 5-19 and Figure 5-20 illustrate the last two years of production and the matched oil production rates for the three producing wells on the AU reservoir, Akpo 33, Akpo 35 and Akpo 58, respectively, and makes the following observations:

- During 2023 the WHP in Akpo 33 was relatively constant until November with oil and water relatively constant at 600 bbl/d and 2,700 bbl/d respectively. Since November 2023 the WHP has started to decline. This decline appears to have started with an increase in the choke size from 25% to 40% and has been accompanied by an increase in both the oil and water rate. The later behaviour, (possibly a response to the shut-in of Akpo 20 although the completed sand seems inconsistent), appears transient and we have not attempted to fit the decline to this period;

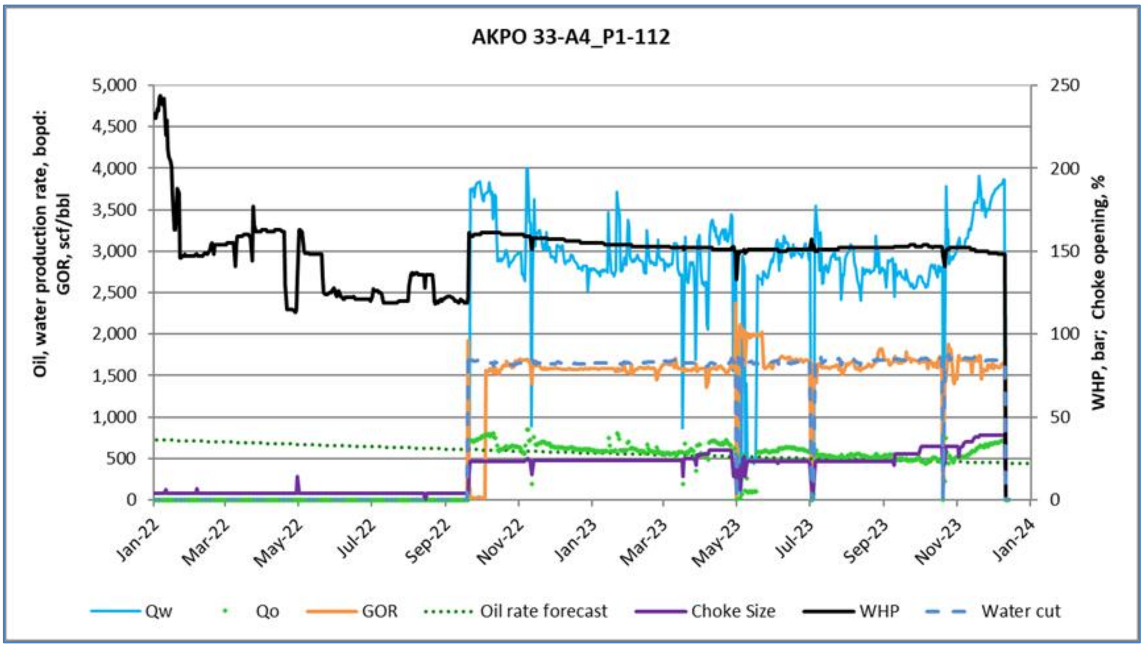


Figure 5-18: Akpo 33 (AU) history and matched oil forecast versus time.

For Akpo 35, after a step-change in oil and water rates in November 2022 (reason unknown) there was a period of stable WHP to March 2023 during which both oil and water rates declined, however, the water cut was stable. Between March and May 2023 choke sizes fluctuated and there were accompanying fluctuations in production. In May 2023 the choke size was increased from 50% to 75% and this was accompanied by an increase in both oil and water rates and the WHP began to fall. The choke size was reduced in late May 2023 to about 40-45% and maintained until late October. During this period the WHP continued to decline, the oil rate declined also (from 1,700 bbl/d to 1,100 bbl/d) and the water rate initially declined but then increased from 3,000 bbl/d to 3,500 bbl/d. In December the choke has been at about 50% with a decline in oil rate and WHP.

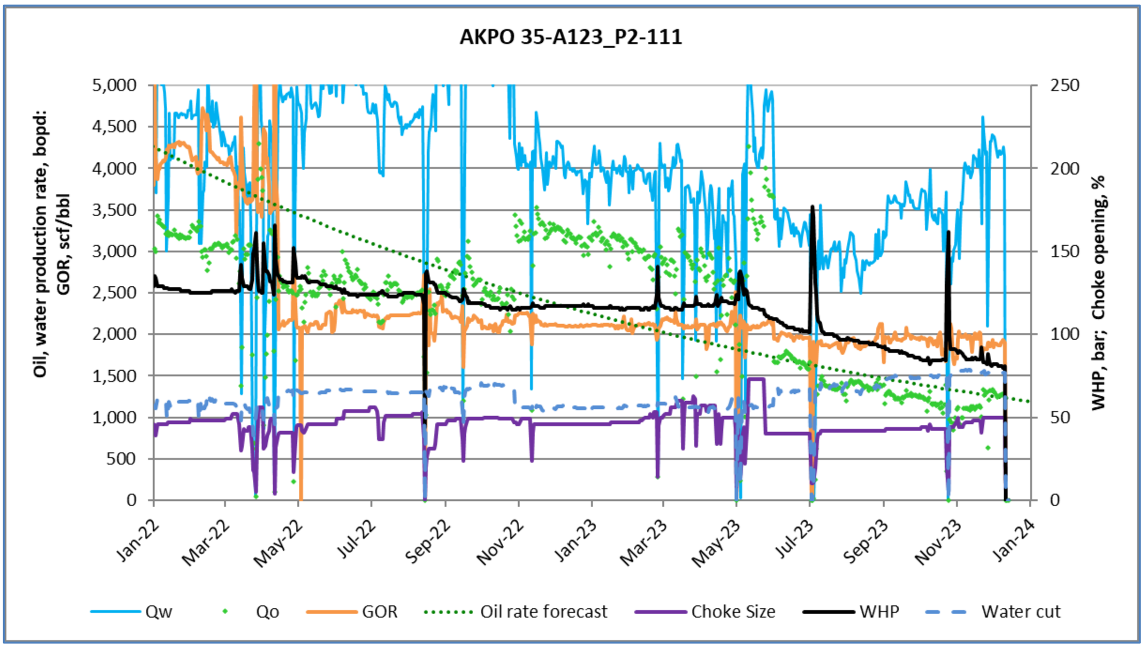


Figure 5-19: Akpo 35 (AU) history and matched oil forecast versus time.

The WHP for Akpo 58 has fallen continuously, and at increasing rate, for the last two years, from about 240 bar to 170 bar. After an initial increase in oil production to June 2022 (reason unknown) the oil rate has decreased relatively constantly from 7,000 bbl/d to 5,700 bbl/d. Water production has been relatively low but increased from zero to 300 bbl/d in November 2022, and to 1,300 bbl/d in September 2023, bringing the water cut to 20%-25%.

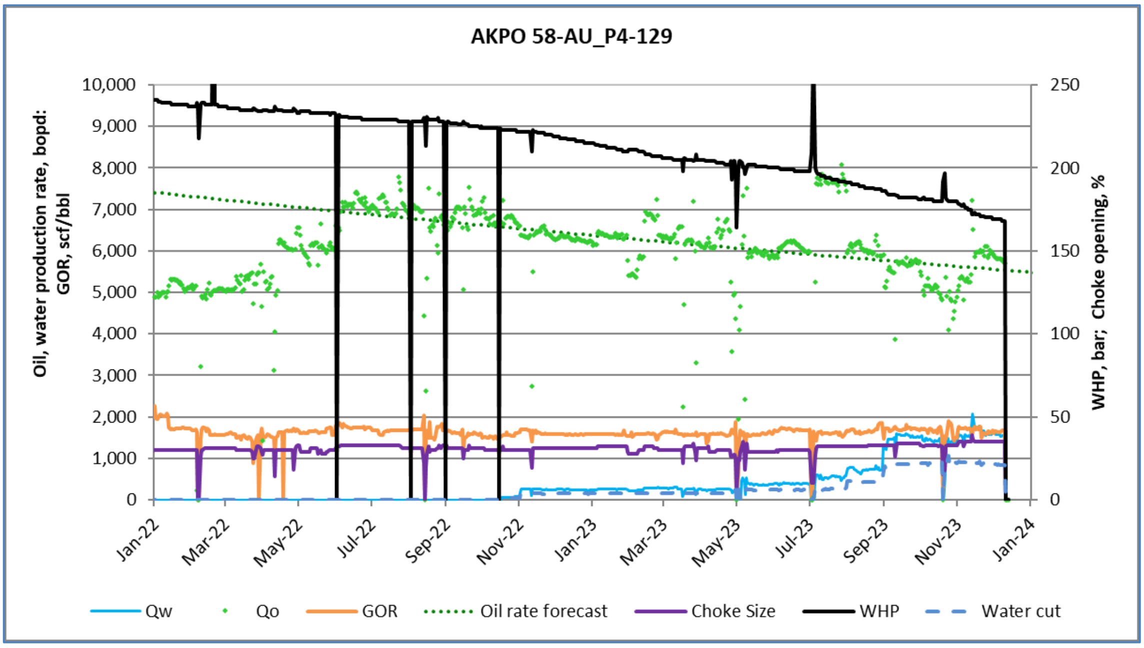


Figure 5-20: Akpo 58 (AU) history and match oil forecast versus time.

RISC understands that, with decreasing WHP across the field, several wells are producing to the test separator as a way of enabling them to produce at low pressure. RISC is concerned that with the three wells showing decreasing WHP that more wells will require this approach which may not be possible. Overall, RISC is concerned that the rapidly decreasing WHP is not sustainable and there is a risk that the forecast production rates will not be achieved.

STOIIP in the AU reservoirs is estimated at 388 MMstb[15]. Cumulative oil production to date represents an oil recovery factor (RF) of 40%.

For the **A Lower (AL) reservoirs** RISC's (best estimate) developed ultimate recovery (ca. 177 MMbbl) is slightly above Prime's range of estimate (173 MMbbl).

The A Lower reservoirs have been developed with 8 oil production wells (Akpo 16, 26, 29, 30, 32, 37, 42, 43) and 5 water injectors (Akpo 19, 27, 31, 34, 52). Two producers are currently shut-in (Akpo 29 and 42). Between mid-2019 and mid-2023 the oil production rate was relatively steady at about 20,000 bbl/d but has subsequently declined to about 16,000 bbl/d (Figure 5-21).

Water production was relatively constant at 15,000 to 20,000 bbl/d between 2020 and early 2022 when it made a step change to 27,000 bbl/d and has subsequently increased exponentially to 57,000 bbl/d.

Gas production has been relatively constant at 45-55 MMcf/d since mid-2019.

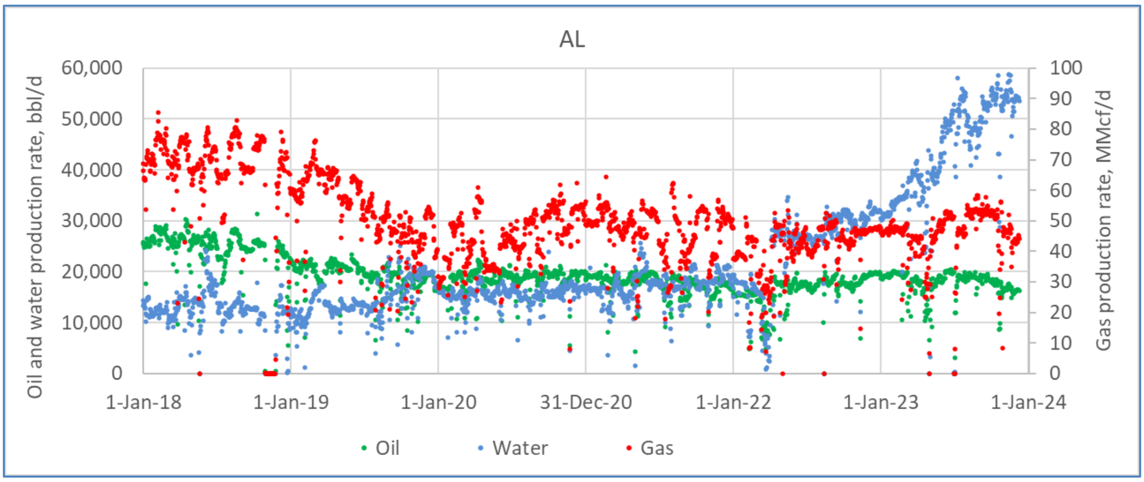


Figure 5-21: Akpo A Lower production history.

[15] SSCM Sept 2023, p10

Figure 5-22 shows the AL reservoir oil, gas and water production from 2022 and RISC's consolidated well forecasts to 2026. The figure also shows Prime's Base forecast.

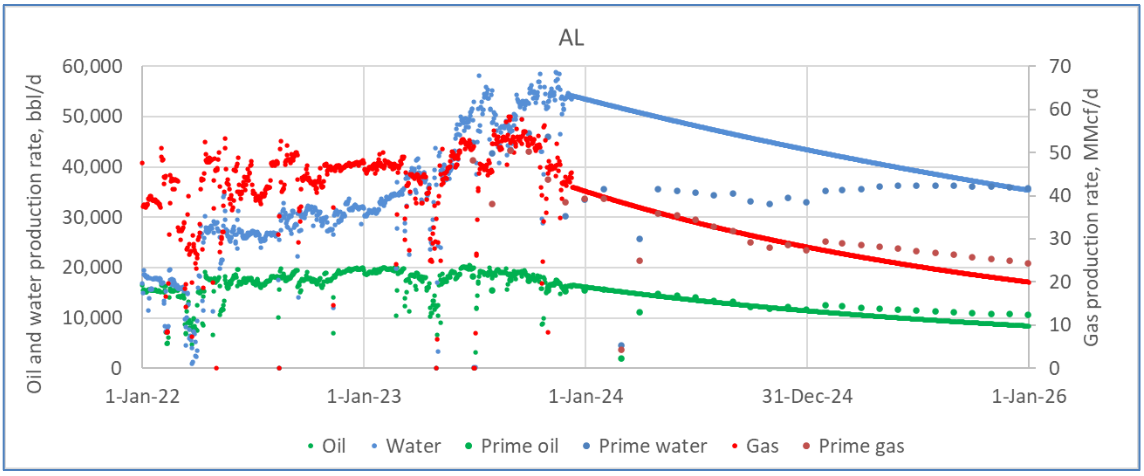


Figure 5-22: Akpo A Lower history and forecast versus time.

Overall, RISC's and Prime's oil and gas forecasts appear similar. Prime's water forecast falls below RISC's forecast and appears to come off a lower historical production.

Figure 5-23 illustrates the oil production forecast since January 2022 as a function of cumulative oil production. We have identified the production rate and cumulative production as at YE 2022 (19,800 bbl/d and 151.6 MMbbl) and note the change in character of the performance since then with a relatively steep decline commencing at about 155 MMbbl.

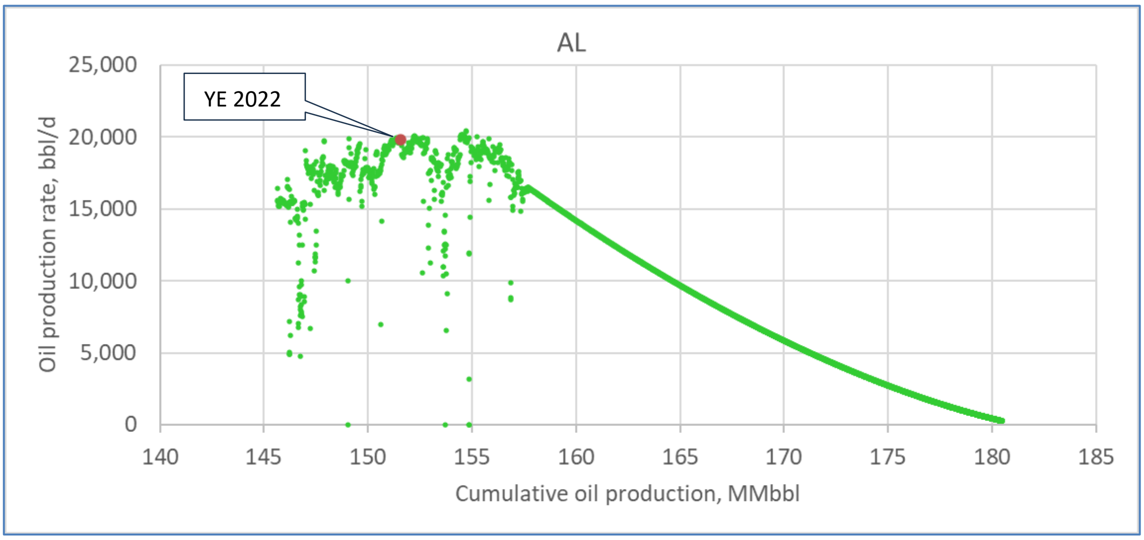


Figure 5-23: Akpo A Lower history and forecast versus cumulative oil production.

STOIIP in the AL reservoirs is estimated at 336 MMstb[16]. Cumulative oil production to date represents an oil recovery factor (RF) of 47%.

For the B reservoir, RISC's developed UR estimate (51.2 MMbbl) is 2.7 MMbbl below Prime's estimate (53.9 MMbbl) and is in the middle of Prime's range of estimates (Figure 5-14).

The B reservoir has been developed with 3 oil production wells (Akpo 41, 46B and 54) and 3 water injectors (Akpo 45, 50 and 55). Two of the producers are shut-in (Akpo 46B S/I June 2023, Akpo 54 S/I February 2022), Akpo 41 is producing at approximately 6,000 bbl/d. Akpo 41 oil production has increased since Akpo 41 was shut-in and water injection support increased through the Akpo 54 bridge (Figure 5-24).

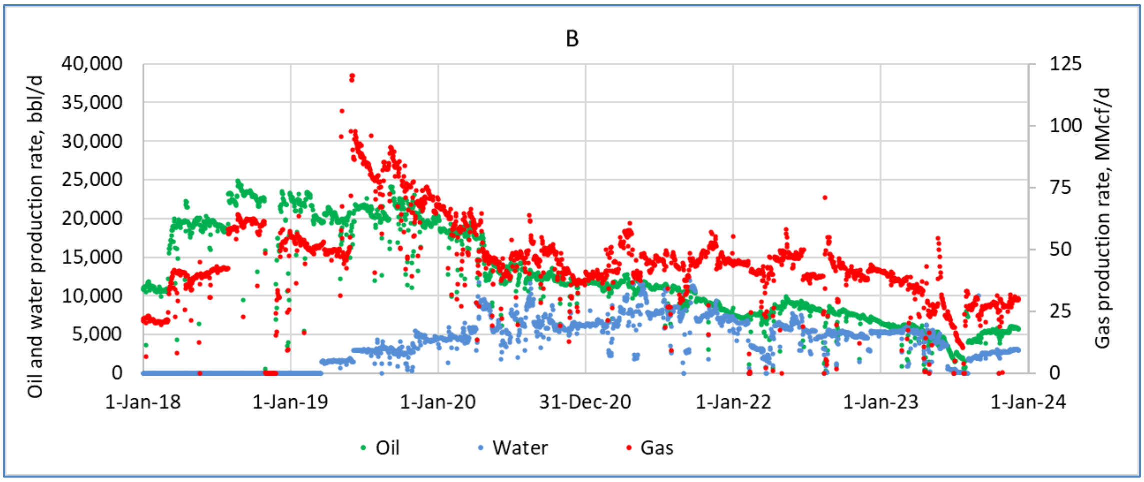


Figure 5-24: Akpo B production history.

[16] SSCM Sept 2023, p13

Figure 5-25 shows the B reservoir oil, gas and water production from 2022 and RISC's consolidated well forecasts to 2026. The figure also illustrates Prime's forecasts.

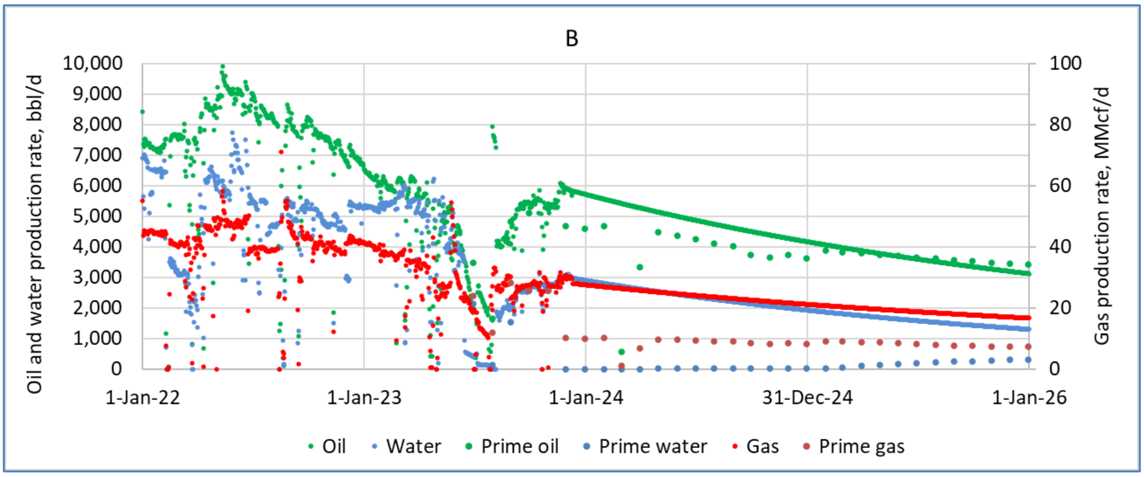


Figure 5-25: Akpo B history and forecast versus time.

Whilst, RISC's and Prime's oil forecasts are comparable, Prime's gas and water forecasts appear low. Figure 5-26 shows RISC's consolidated well decline analysis versus time for the B reservoir. RISC's decline curve honour's the recent production rates and has a decline rate consistent with the earlier period.

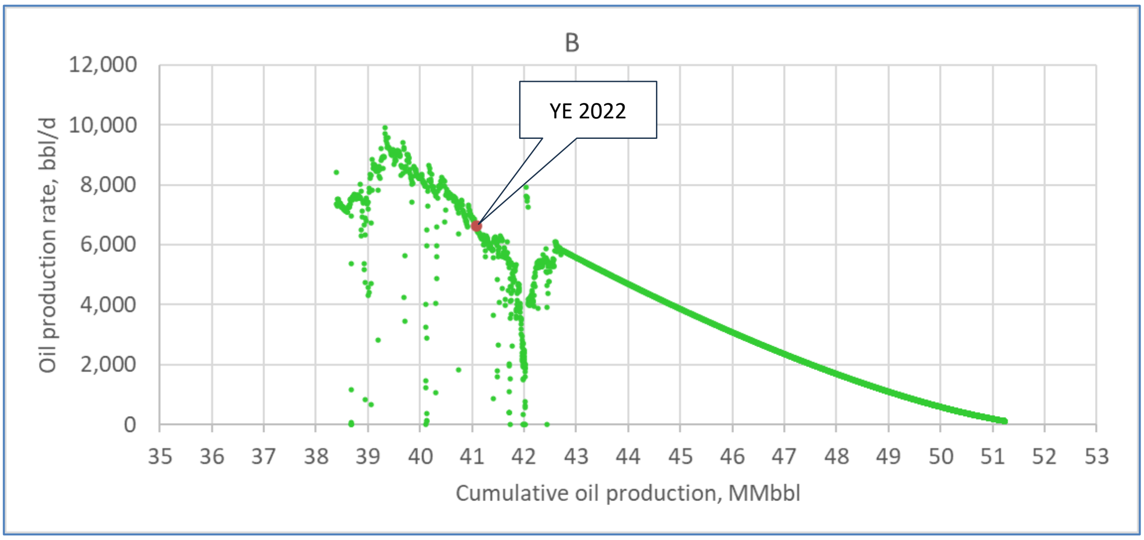


Figure 5-26: RISC's Akpo B developed well decline and forecast versus cumulative production.

Figure 5-27 illustrates Akpo 41 historical performance since 2022 and shows RISC's fitted decline. The decline rate has been matched to the latest production (November- early December 2023) where the choke has been increased to ca. 55%. Although the period is short a consistent decline appears to have been established and is consistent with prior decline rates seen.

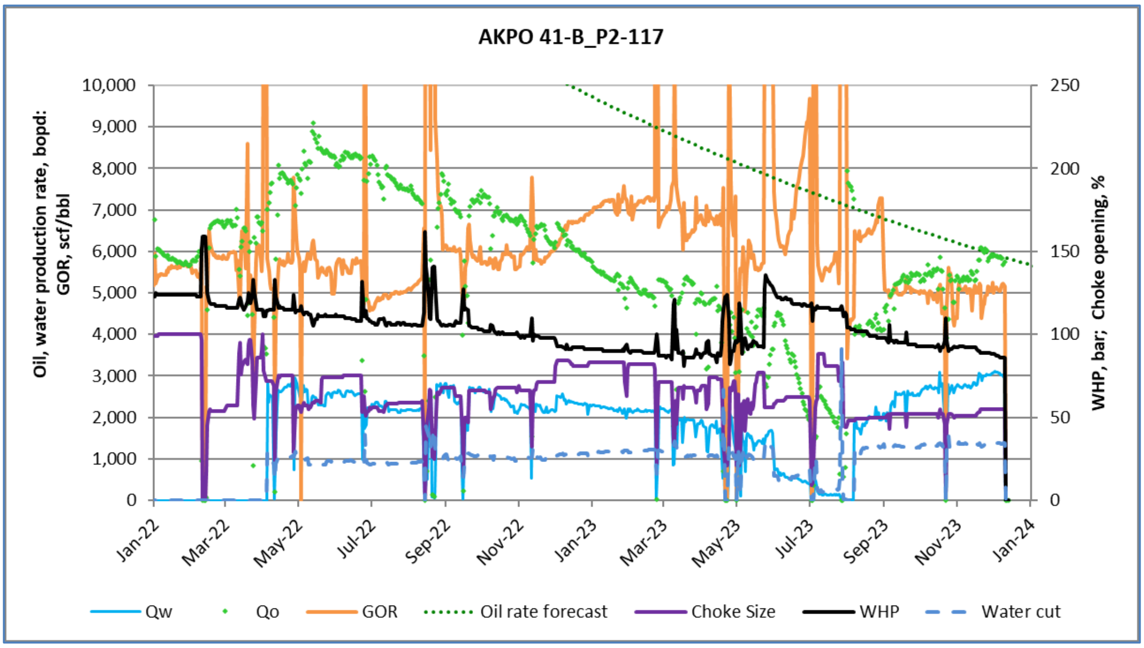


Figure 5-27: Akpo 41 well historical production versus time showing RISC's fitted oil rate decline.

STOIIP in the B reservoir is estimated at 171 MMstb[17]. Cumulative oil production to date represents an oil RF of 25%.

For the D reservoir, RISC's developed UR estimate (123.0 MMbbl) is 9.4 MMbbl below Prime's estimate (132.4 MMbbl) and is slightly lower than the lower end of Prime's range of estimates (Figure 5-14).

The D reservoir differs from the other reservoir in that it is a single layer turbiditic lobe that has been developed with gas injection (rather than water injection). It has been developed with 4 oil production wells (Akpo 14, 17, 24 and 49), all of which remain on production, and 2 gas injectors (Akpo 21, 22), of which Akpo 22 was out of service from August 2022 due to a stuck valve. This was due to be repaired in late 2023.

In general, over the last six years the oil production rate has declined, although, over the last 12 months the rate has been stable at about 7,500 bbl/d (Figure 5-28). The water cut has increased in a few step changes and over the last 12 months has increased from about 3,000 bbl/d to 6,000 bbl/d. Surprisingly, given the gas injection, gas rates have decreased in general over the past five years, however, in the last 12 months gas production rates have averaged 185 MMcf/d. As a result of the temporary shut in of Akpo 22, there's been

[17] SSCM Sept 2023, p15

a need to control the amount of gas produced for the purposes of gas balance and limitations on gas import/gas export (i.e.: production management).

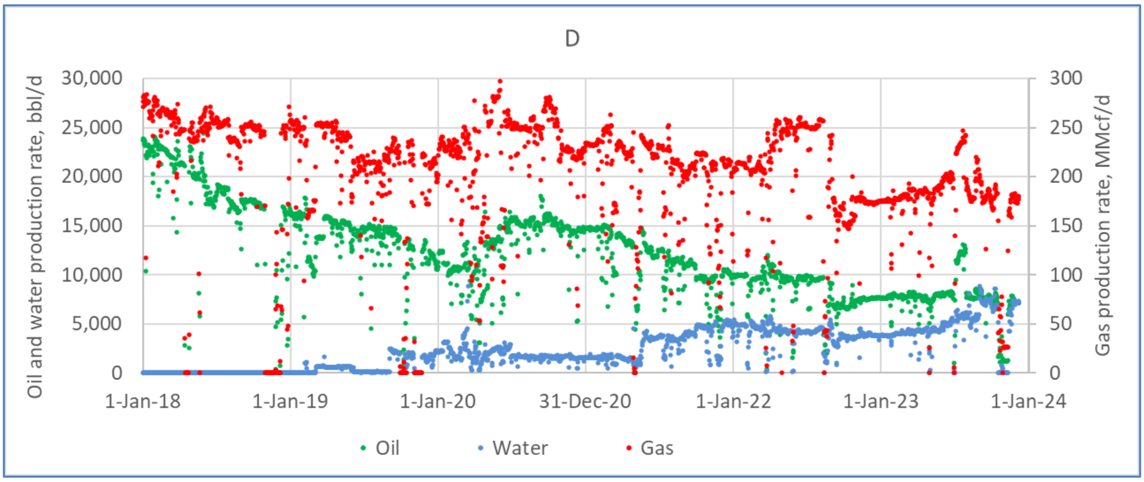


Figure 5-28: Akpo D production history.

Figure 5-29 illustrates The D reservoir historical production since 2022 and RISC's consolidated well forecasts to 2026 for oil gas and water.

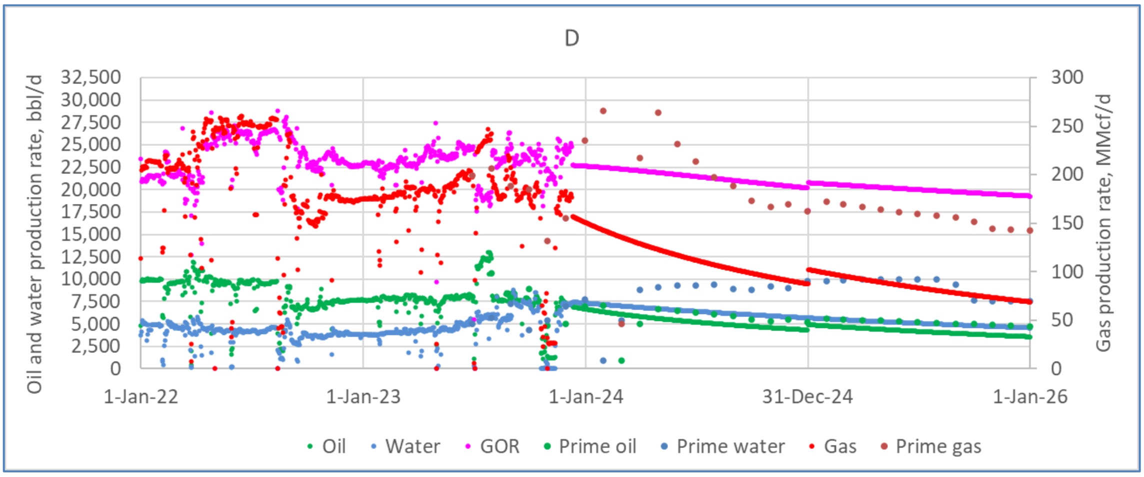


Figure 5-29: Akpo D consolidated well oil, gas and water production history and forecasts versus time.

Both RISC's and Prime's oil and water forecasts are similar. However, Prime's gas forecast is significantly greater than RISC's. RISC notes that Prime's Base forecast assumes gas injection in the period of over 200 MMcf/d which is not consistent with planned injection after the start-up of Akpo West.

Figure 5-30 illustrates the oil production history and forecast versus cumulative production. This figure illustrates the match of the decline to the last 1 MMbbl (approx.) of production.

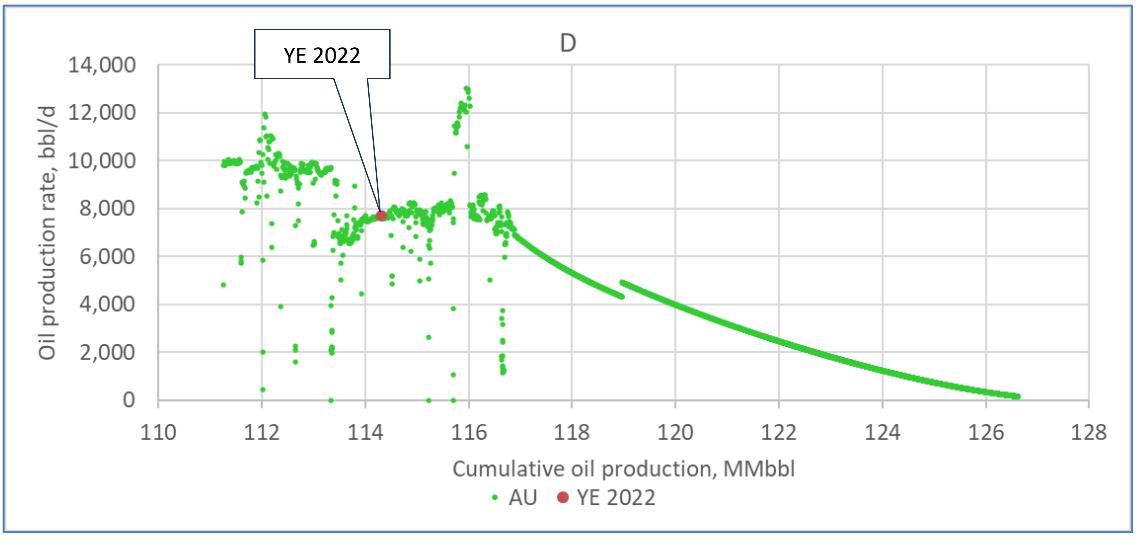


Figure 5-30: Akpo D reservoir consolidated well decline forecast versus cumulative oil production.

The D reservoir is a rich gas-condensate reservoir with dry gas re-injection to provide voidage replacement. Reinjecting gas can lead to a declining condensate rate (CGR drop, or GOR rise) due to dry gas breakthrough (as opposed to water production in the other oil reservoirs) but can be impacted by other factors such as changing pressure leading to changed PVT properties and changing relative permeabilities. The reduced volume of gas injection brought on by the shut-in of Akpo 22 may have also changed flow paths of the reservoir and injected fluids. We note also that, since about 2015 the reservoir pressure has been below the saturation pressure (Psat) of the reservoir fluid (Figure 5-31) which is conducive to gas liberation in the reservoir and can lead to GOR increases. Despite this, the operator has noted a lower than anticipated growth in GOR[18].

[18] SSCM, September 2023, p18.

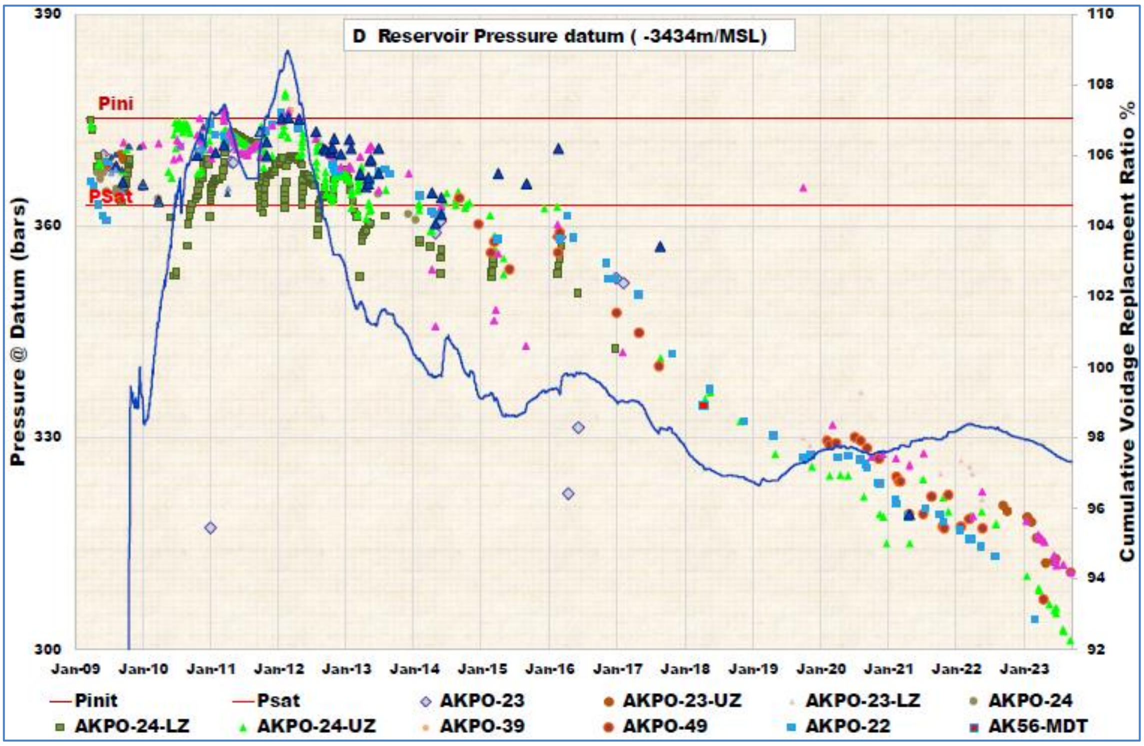


Figure 5-31: Reservoir pressure for Akpo D reservoir and cumulative voidage replacement.

Figure 5-32 illustrates the change in gas/oil ratio (GOR) with time for the Akpo D reservoir. To 2022 the predominant behaviour was a gradual increase in the GOR, however, since then the GOR has been stable to trending lower. This is reflected in RISC's forecasts.

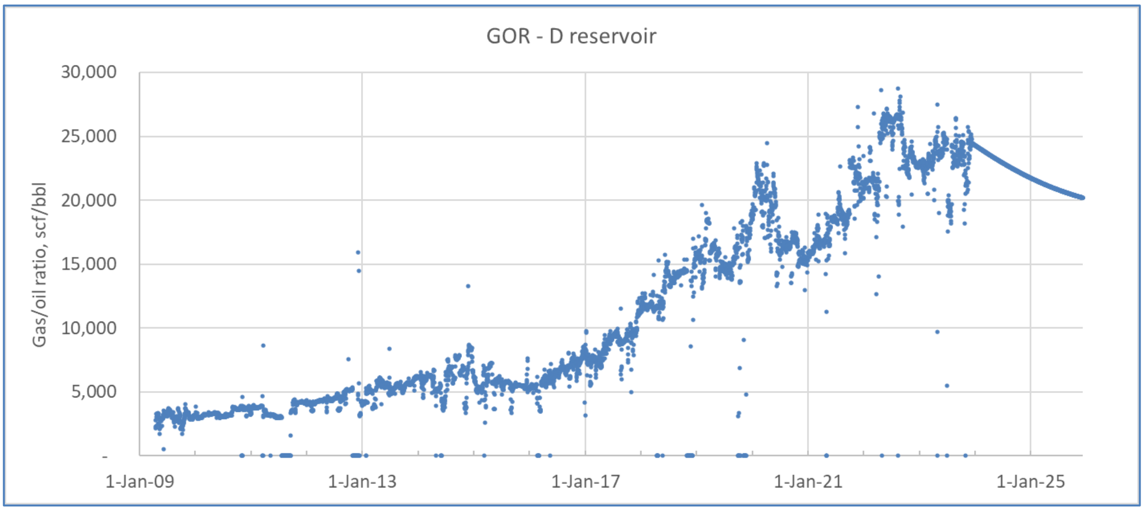


Figure 5-32: Akpo D reservoir gas/oil ratio versus time.

We caution, however, that implicit in forecasts made from DCA is an assumption that production conditions remain (relatively) constant. We note that with the repair, and restart of production from Akpo 22, plus the concern of the operator regarding “optimisation of gas injection with Akpo West”, this assumption may not be achievable.

STOIIP in the D reservoir is estimated at 166 MMstb[19]. Cumulative oil production to date represents an oil RF of 70%.

We note that the forecasts are stated for decline as an oil reservoir, however, gas blowdown is likely prior to the end of field oil production. Whilst this will truncate oil production it will maximise gas recovery. This recovery is currently considered a contingent resource.

For the EF reservoir, RISC’s developed UR estimate (101.1 MMbbl) is 1.0 MMbbl below Prime’s estimate (101.1 MMbbl) and within Prime’s range of estimates (Figure 5-14).

The EF reservoir has been developed with 3 oil production wells (Akpo 38, 44 and 53) all of which are still in production, and 3 water injectors (Akpo 39,40 and 56). In the last 6 years the oil production rate has steadily declined, and the water production increased (Figure 5-33). During 2023 the oil production rate has been reasonably constant at approximately 12,500 bbl/d, water has increased substantially, from 20,000 bbl/d to 35,000 bbl/d, and gas has decreased slightly, from 65 MMcf/d to 52 MMcf/d.

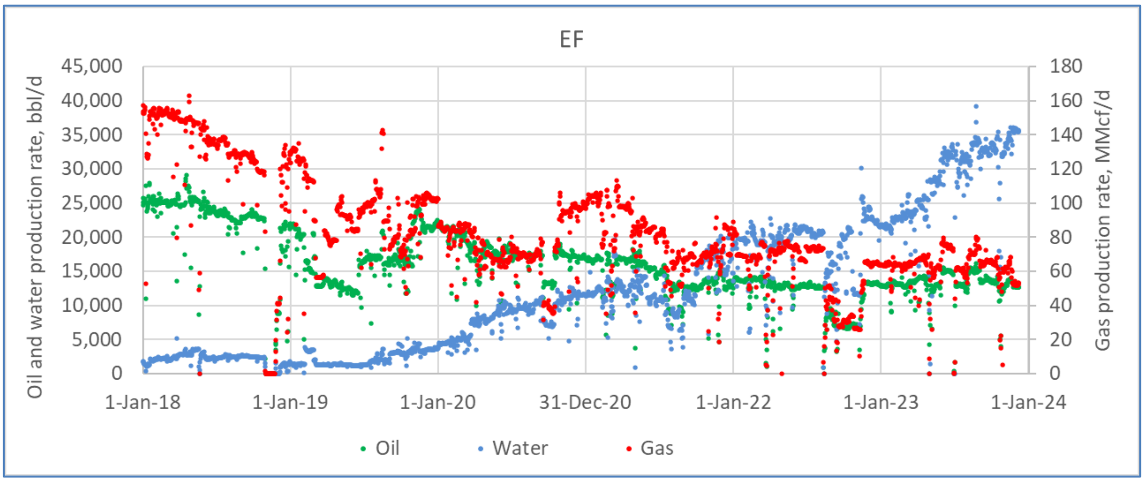


Figure 5-33: Akpo EF production history.

The recent increase in water production was facilitated by increased water handling and increased water injection into the reservoir. This was considered necessary as the reservoir has a cumulative voidage replacement ratio of 70%. Water injection has varied been between 50,000 and 105,000 bwpd since the start of production. Akpo 53 and Akpo 38 have water cuts exceeding 70%, Akpo 44 has a water cut of 33%. Figure 5-34 shows RISC’s developed well decline analysis by consolidated well.

[19] SSCM Sept 2023, p17

Although the water production is forecast to flatten at about 35,000 bbl/d this provides a slight increase in water cut and is consistent with a fall in total liquid rate. We consider the flattening of the rate is consistent with the facility water production limit (current rate 118,000 bbl/d with capacity 120,000 bbl/d) and the declining WHP in the wells.

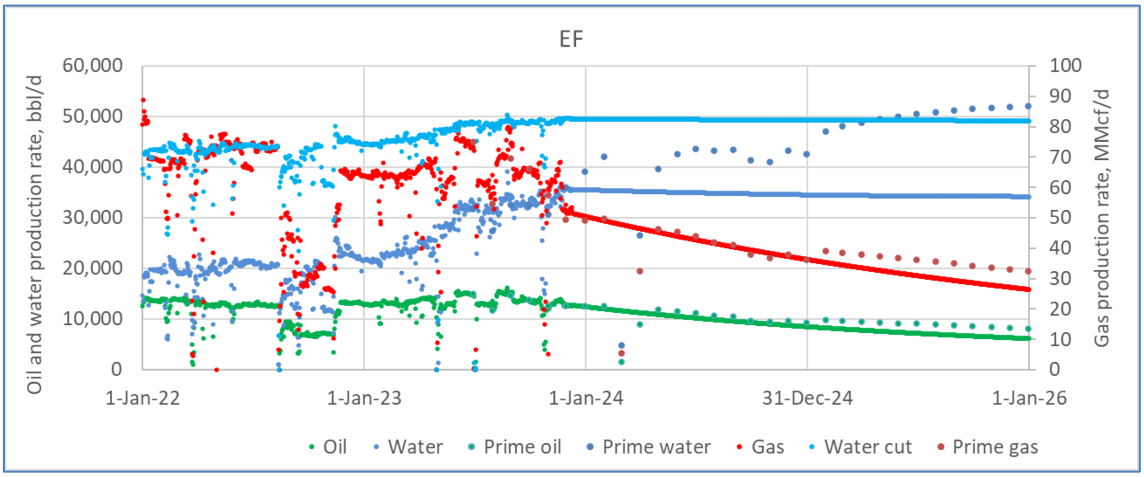


Figure 5-34: Akpo EF consolidated well decline and forecast versus time.

RISC's oil and gas forecasts are similar to those of Prime, however water production continues to increase compared with RISC's forecast.

Figure 5-35 illustrates the oil decline history and RISC's forecast.

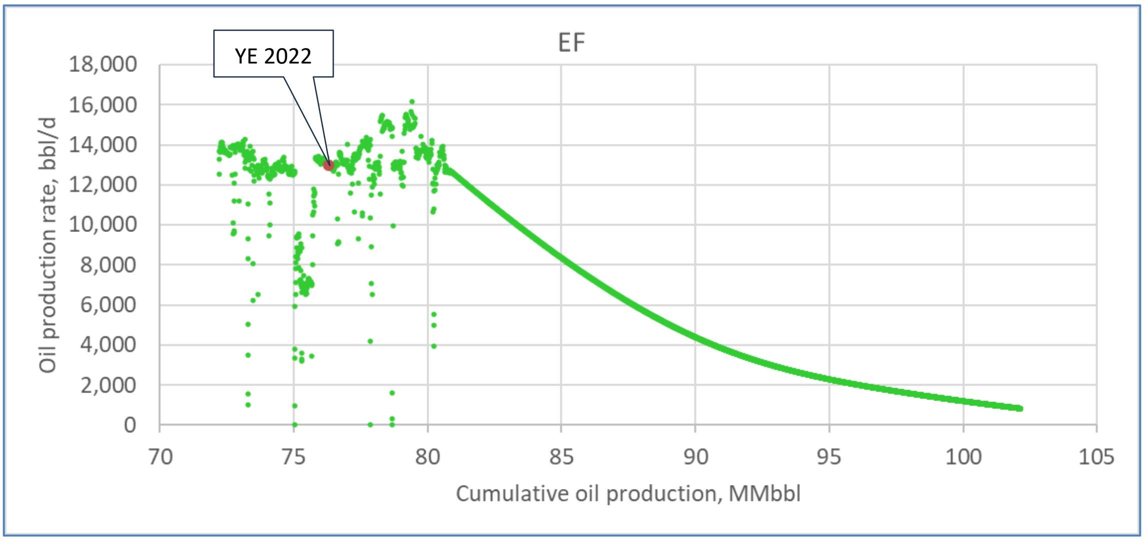


Figure 5-35: Akpo EF consolidated well decline and forecast versus cumulative oil production.

Figure 5-36 illustrates one example of the well performance from the EF reservoir over the last two years, Akpo 44. We note:

- Increasing choke size (from <50% to 75-80%) and declining WHP (125 to 110 bar).
- Declining oil production rate (4,000 bbl/d to 2,300 bbl/d).
- Almost constant GOR (4,000 scf/bbl).
- Increasing water production rate (zero to 1,200 bbl/d) and water cut (zero to 33%).

- STOIIP in the EF reservoir is estimated at 146 MMstb[20]. Cumulative oil production to date represents an oil RF of 56%.

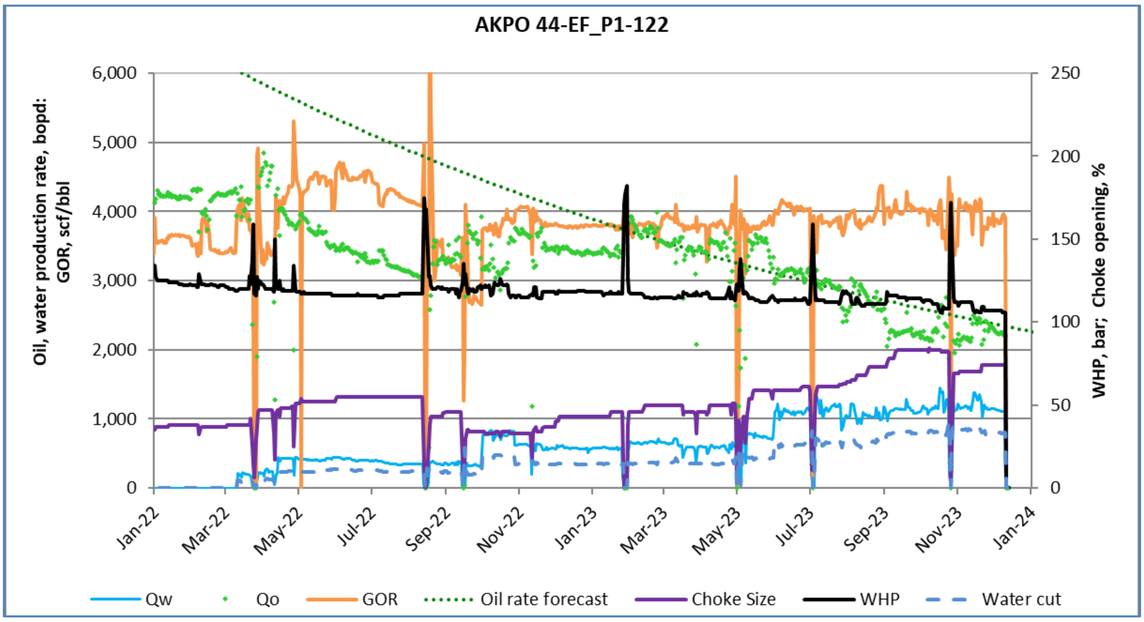


Figure 5-36: Akpo 44 performance and oil decline and forecast versus time.

For the G reservoir, RISC's developed UR estimate (128.8 MMbbl) is 3.6 MMbbl above Prime's estimate (125.2 MMbbl) and within Prime's range of estimates (Figure 5-14).

The G reservoir has been developed with 4 oil production wells (Akpo 7, 9, 51 and 57) and 2 water injectors (Akpo 11 and 25). Production wells Akpo 7 and 9 have been shut-in with high water production, Akpo 7 in August 2019 and Akpo 9 very recently, on 19 October 2023. Figure 5-37 illustrates the last six years production from the G reservoir.

[20] SSCM Sept 2023, p19

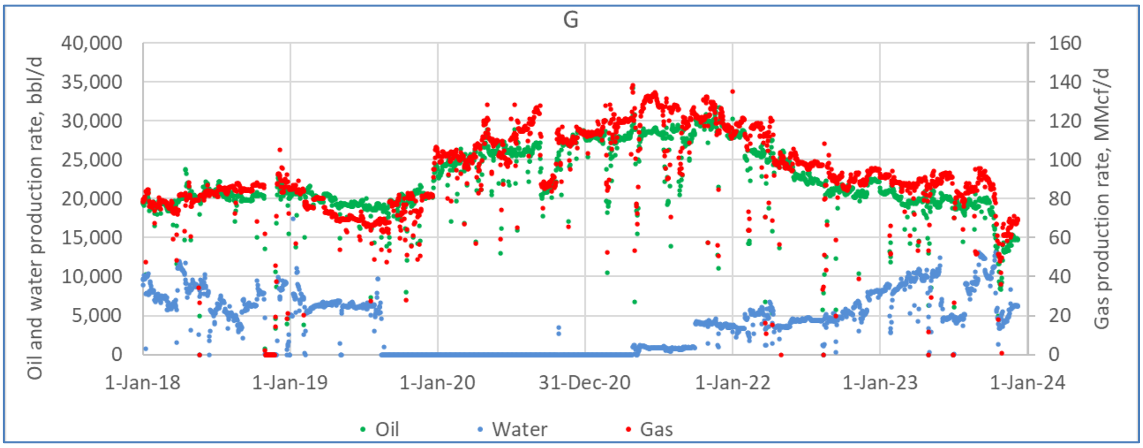


Figure 5-37: Akpo G production history.

Water injection had maintained the cumulative voidage replacement ratio at above 80% until 2022, however both injectors have now been shut-in to attempt to reduce water cut development at the producers. The remaining two producing wells are producing at a water cut of 36% (Akpo 51) and 27% (Akpo 57).

Figure 5-38 shows RISC's consolidated well decline analysis and 2 year forecast for the G reservoir. Also shown are Prime's Base forecasts for oil, gas and water.

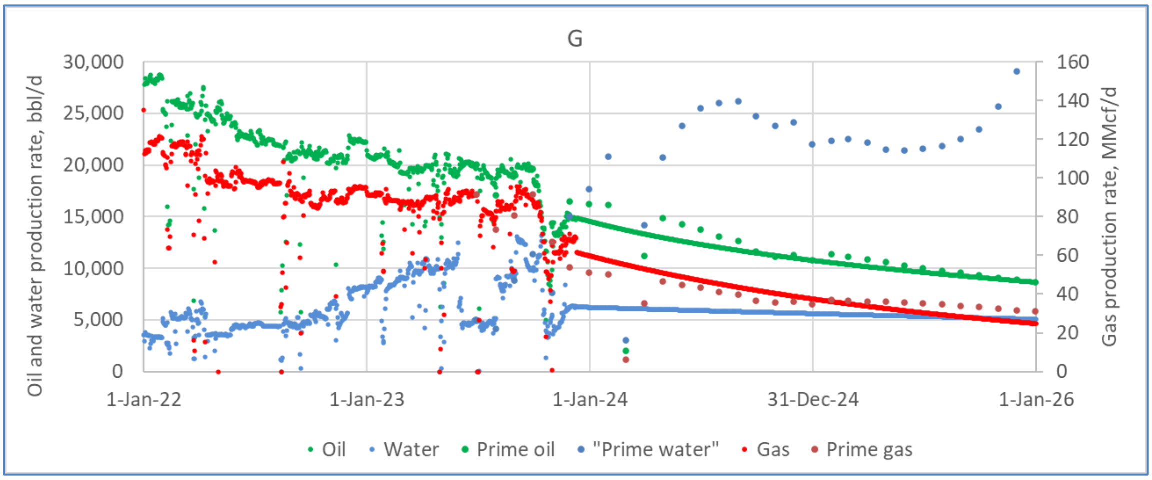


Figure 5-38: Akpo G consolidated well decline and forecast versus time.

Whilst RISC and Prime's oil and gas forecasts are similar Prime's water forecast is higher than RISC's forecast.

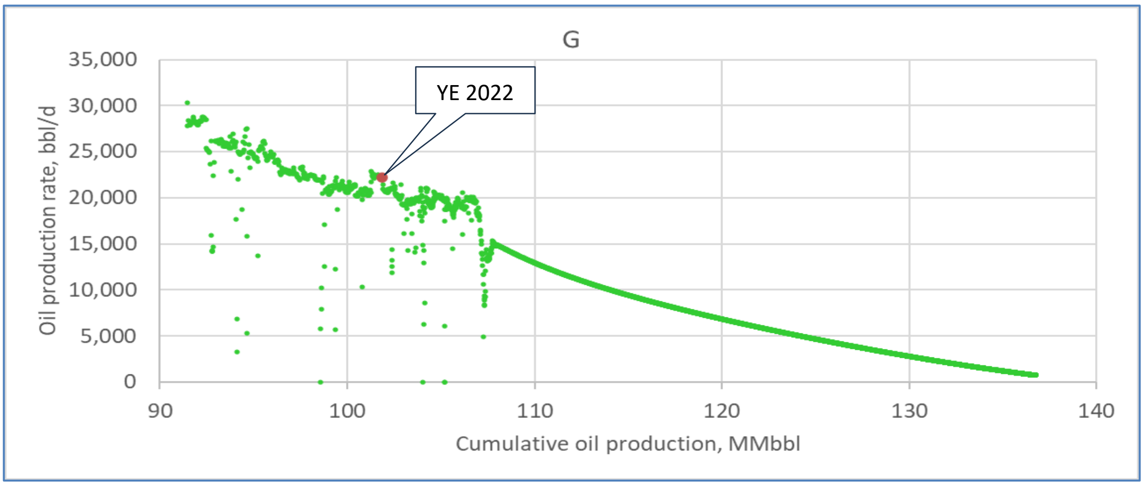


Figure 5-39: Akpo G consolidated well oil rate decline and forecast versus cumulative oil production.

Figure 5-40 and Figure 5-41 illustrate two years of historical production and the fitted oil decline for the two producing wells, Akpo 51 and Akpo 57, respectively. We note that, due to the changing production conditions (shut-in of the injection wells) we have fitted the decline to the production after that time. The length of the period of production is short and conditions may be transient which is not ideal, however, no other period of production was considered appropriate.

For Akpo 51 the choke size was reduced in October 2023 with a corresponding increase in the WHP. The oil and water production were also significantly reduced with the water cut stabilising at about 35%.

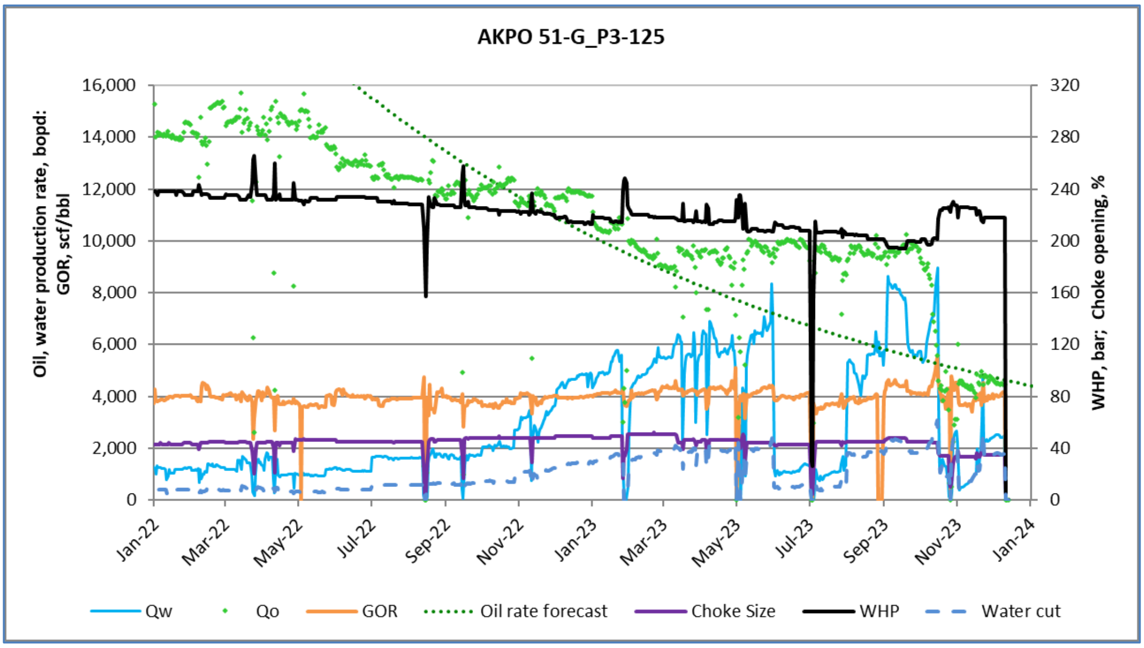


Figure 5-40: Akpo 51 G reservoir well decline and forecast versus time.

For Akpo 57 the choke size has been constant throughout the period, however, the WHP has declined steadily. The fitted period corresponds to the lowest WHP and shows relatively consistent oil decline and constant water production with a small decline in water cut as a result.

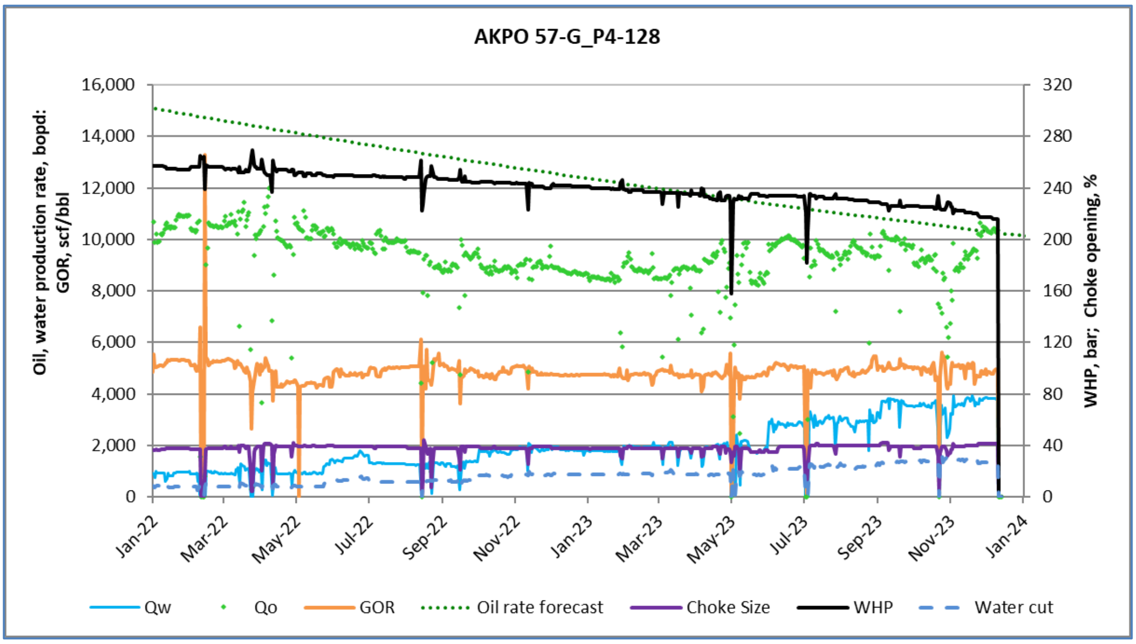


Figure 5-41: Akpo 57 G reservoir well decline and forecast versus time.

STOIIP in the G reservoir is estimated at 164 MMstb[21]. Cumulative oil production to date represents an oil RF of 66%.

Whilst we consider our oil rate declines are reasonable, the calculated recovery factors for the reservoirs appears too high assuming the 164 MMstb STOIIP is correct. STOIIP estimates would have to be higher to support the 2P forecasts (estimated STOIIP from simulation decreased in 2022 and 2023). RISC assumes that there is some uncertainty in the STOIIP estimate and retains its decline forecasts. We note also that the forecast UR is dependent on water cut development at the remaining two producers.

Note that 949 Bcf of re-injected gas has been subtracted from cumulative gas production at YE2023 so as to represent net gas production. As with the oil, the total UR estimated by RISC is very similar to Prime's estimate.

[21] SSCM Sept 2023, p21

Table 5-9: Gas developed UR estimates for Akpo

Reservoir	Cum. Prod. to 10/12/2023	F'cast 11 to 31 Dec	Estimated cum. Prod. at 31/12/2023	Dev prod 1/1/2024 to 1/1/2046	RISC's estimated UR		Prime's estimated UR	
					Low	Mid	Low	Mid
	Bcf	Bcf	Bcf	Bcf	Bcf	Bcf	Bcf	Bcf
AU	297.2	0.3	297.5	22.5	n/a	319.9	n/a	355.2
AL	386.2	0.9	387.1	51.1	n/a	438.2	n/a	425.4
B	133.5	0.6	134.1	51.0	n/a	185.1	n/a	158.3
D	926.5	3.2	-19.6	172.0	n/a	151.8	n/a	134.5
EF	425.0	1.1	426.0	63.8	n/a	489.8	n/a	496.1
G	437.4	1.3	438.7	57.5	n/a	496.2	n/a	495.1
All	2,606	7.3	1,664	417.9	n/a	2,081	1942	2,065

5.2. Further Development Projects

Development plans under consideration consist of:

Reserve projects

- Development of **Akpo West** (two oil producers and one gas injector). First producer drilled and completed (online in February 2024) and second producer to be concluded in Q1 2024. .
- One infill producer: **D-P5** development well in the D reservoir due to be drilled in February-March 2024.
- **Gas blowdown of Akpo D** reservoir is implicit in the base forecasts, in particular D-P5.One infill water injector: **B-W4** in the B reservoir scheduled to be drilled late-September to November 2024.

Contingent resource projects

- **5 infill wells**, under consideration for drilling, one in 2025 and four in 2026.
- **Miscible gas injection** (MGI) in the A Upper from July 2026, A Lower reservoirs from March 2029, B from December 2029 and, EF reservoir from December 2033 by converting water injectors to gas injectors in each reservoir.

Several other minor activities (water shut-off, etc.) are considered routine maintenance and not separately addressed or forecast.

5.3. Production Forecasts

5.3.1. General

RISC has reviewed the production forecasts and other data for these projects provided by Prime. We have also reviewed the data provided in prior years and sought to understand any differences. Based on our findings we have generated 1P, 2P and 3P production forecasts for oil and gas for the above six projects, and for developed wells, i.e. a No Further Activity (NFA) Case.

In preparing the forecasts the following general assumptions have been made:

- 30-day FFSD in February-March 2025;
- 30-day FFSD for Akpo FPSO ever 3rd year thereafter;
- 95% uptime in the intervening periods;
- Fuel of 6.76 MMscf/d plus 2.1% of produced gas[22];
- Constraints:
    1. Gas injection: 230 MMcf/d;
    2. Gas export: 406 MMcf/d;
    3. Water production: 120,000 bbl/d;
    4. Water injection: 2 pumps – 280,000 bbl/d; 3 pumps – 420,000 bbl/d;
- No FPSO life period has been imposed, however, the FPSO will reach its 20-year design life in 2029. RISC has requested further details on lifetime extension considerations;
- No WHP constraints or test separator constraints have been applied although RISC notes that a number of lower pressure wells are being produced through the test separator and WHP is dropping at most wells;
- No well or field production rate cutoffs have been added to raw forecasts, economic truncation to be applied independently;
- For the developed wells the 1P and 3P forecasts have assumed a -/+30% variation in gas and oil production volumes and water production rates a +/-30% variation, without additional time delay/acceleration. Rates assumed a +/-5% variation for the initial production, increasing with time to +/-45% after two years;
- For the undeveloped projects the rate variation was assumed to be +/-30% to +/-50% from the start.

RISC notes that all the wells and projects for which forecasts are made produce through the Akpo FPSO and are therefore inherently linked in many ways:

- Production constraints (oil, gas, water, total fluids);
- Injection constraints (gas, water);
- Export constraints (gas); and
- Manifold pressures.

There are also time considerations that should be accounted for in generating the forecasts (e.g. a gas injection shortfall could impact the time of start-up of gas blowdown). Such a timing change would also impact the starting conditions, e.g. reservoir pressure and production rates, therefore some projects cannot simply be slipped in time. These subtle changes are not within the scope of RISC's review.

5.3.2. Developed Wells

Figure 5-42 shows RISC's 1P, 2P and 3P no further activity (NFA) oil forecasts (without downtime).

[22] Averaged 17 MMcf/d in 2023

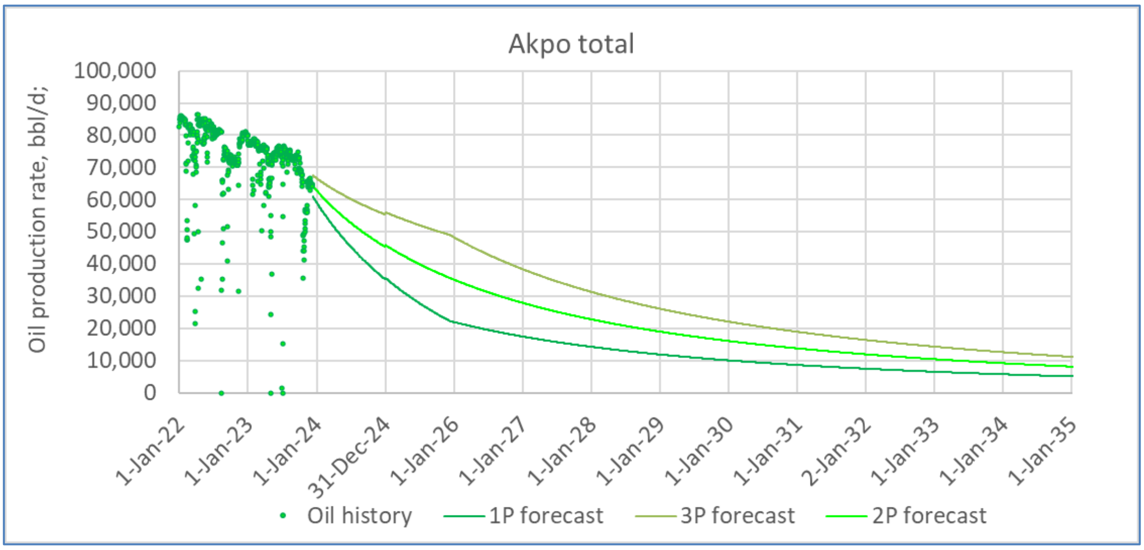


Figure 5-42: RISC's Akpo NFA oil forecast (without downtime considerations).

Note that the forecasts do not include downtime considerations or blowdown of the B reservoir.

Figure 5-43 shows RISC's 1P, 2P and 3P no further activity (NFA) gas forecasts (without downtime).

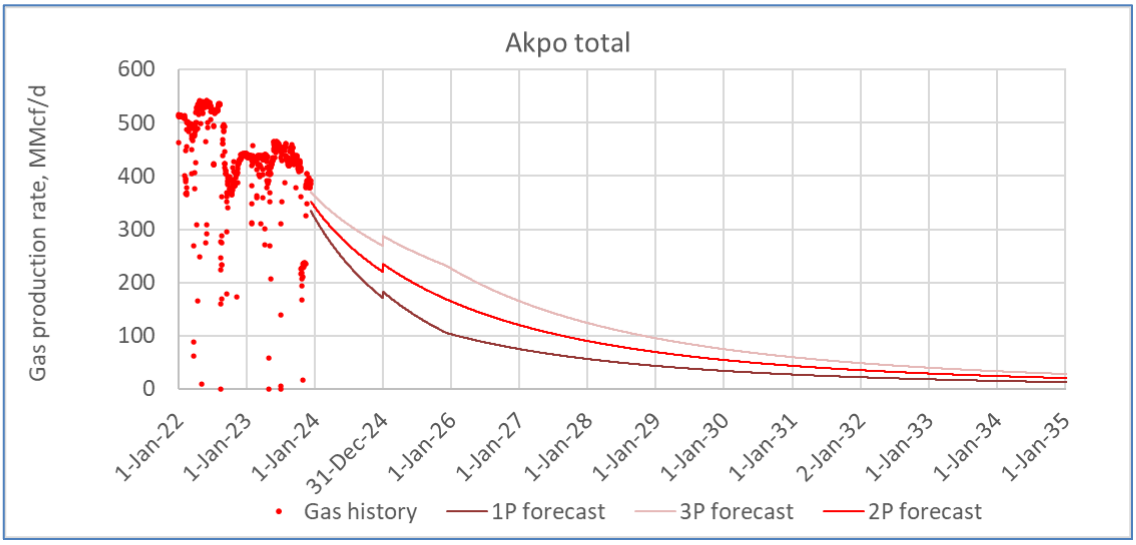


Figure 5-43: RISC's Akpo NFA gas forecast (without downtime considerations).

5.3.3. Development Projects - Reserves

5.3.3.1. Akpo West

Tie back of the Akpo West gas-condensate (critical fluid) discovery through the Akpo FPSO was scheduled for start-up in 4Q 2021 when gas handling capacity on Akpo was due to become available. By YE2022 development had been deferred with first production expected in August 2023. Due to drilling delays the wells were still being drilled at YE 2023 and at time of production forecasting, RISC assumed startup in June 2024 but note that the first production well was connected in February 2024 and is ramping up with production at approximately 4,000 bopd at time of writing this report. Whilst initial production has been reported[23], RISC expects full production will require the completion of all three wells are on line and the FFSD in February 2023 is completed, RISC has assumed startup in March 2024, after the FFSD.

Prime's YE2022 2P Akpo West condensate and gas UR estimates (13.8 MMstb and 140 Bcf) were similar to the volumes presented in the Apr-2020 FDP update (13.9 MMstb, 113 Bcf at 15/12/2029)[11]. Prime's YE2023 condensate recovery estimate[24] of 14.1 MMbbl and gas recovery of 140 Bcf is also similar.

The field reviewed in detail by RISC for YE2021 and, as the recovery estimates have not changed materially and we have not been advised of any changes to the evaluation that have become necessary due to drilling data, we have retained our YE2022 estimates for YE2023.

Development consists of two subsea horizontal production wells and one subsea horizontal gas injector on the crest of the field. Gas re-injection will maximize condensate recovery and delay aquifer encroachment.

Table 5-10 shows the uncertainty range estimated for Akpo West Condensate In Place, presented at the March-2020 Sub-Surface Committee Meeting[25]. RISC considers the uncertainty range to be reasonable for a field of this complexity and maturity. The condensate recovery uncertainty will be larger; RISC estimate +/- 30%.

Table 5-10: Akpo West CIIP range

	Base Case	P90	P50	P10
CIIP (MMstb)	25.7	19.7	25.5	32.6
Difference from P50	1%	-23%	-	28%

Figure 5-44 shows RISC's base case (2P) production forecast for Akpo West. RISC's forecast is a based on of Prime's forecast but has been delayed to account for the current timing of the drilling activities.

- Gas is produced at 141 MMscf/d (4 MMm^3/d) and fully re-injected for the first five years, to mid-2029;
- Gas injection then stops, and the produced gas is exported;
- RISC has assumed start-up in March 2024[26].

[23] TotalEnergies starts production at Akpo West field, boosting Nigeria's output , GlobalData 10 Feb 2024
[24] Prime Oil & Gas B.V., Reserves Audit 2023, December 13th, 2023, PPT
[25] OML130 Akpo Development FDP (Revision 2 Update), Apr 2020
[26] TotalEnergies press release (7 February 2024) announcing first production was too late to include a revision to the start-up of Akpo West for this report.

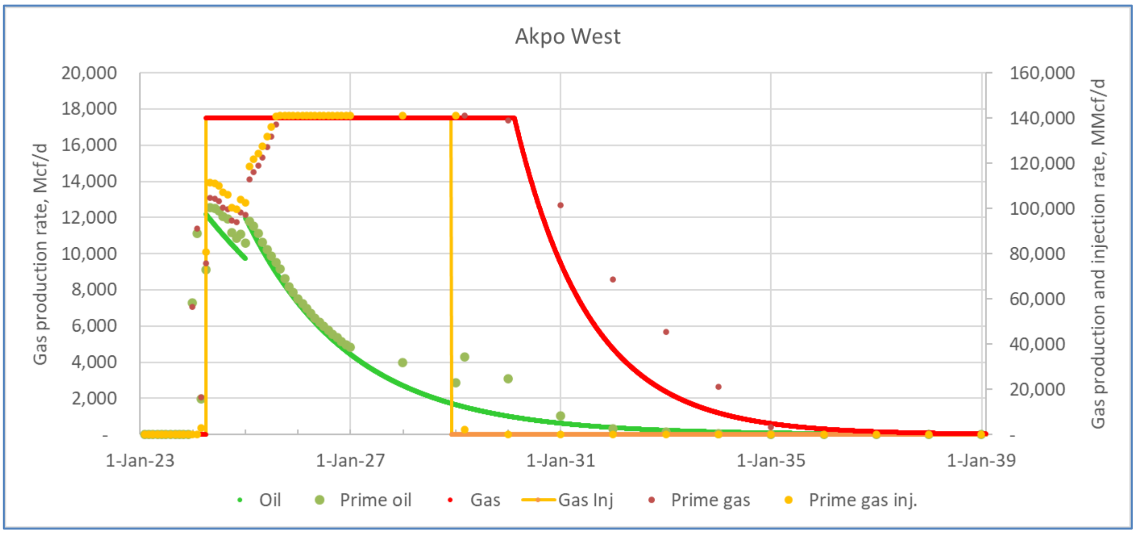


Figure 5-44: RISC's Akpo West production forecasts.

Note that the forecast has not been adjusted for FFSD or fuel, and the injection rates are the target rates, not subject to any limits on available gas. RISC has assumed that water production at Akpo West commences early 2028 and develops as production continues.

Overall, RISC accepts Prime's 2P gas forecast for Akpo West, however, the resource uncertainty range forecast by Prime (+/-10%) is narrow and not consistent with the CIIP range (Table 5-10). RISC has adjusted the 1P and 3P forecasts to incorporate an estimated +/-30% uncertainty, as mentioned above.

In late 2023, prior to the repair of Akpo 22 (gas injection well) gas injection was limited to 173 MMcf/d into the D reservoir through Akpo 23. Akpo West will require 140 MMcf/d for gas injection. The combined gas injection target for Akpo D reservoir and Akpo West is greater than the total Akpo gas injection capacity, 229 MMcf/d.

It is anticipated that Akpo West production will equal its gas injection requirements, thus preserving the available gas for injection into the D reservoir. If Akpo West does not produce the 140 MMcf/d targeted for gas injection, operational decisions will be required as to how the available gas is divided between Akpo West and the Akpo D reservoir. However, we have assumed blowdown of the Akpo D reservoir commences in July 2025 and that Akpo West rapidly achieves and maintains the required gas production rate, so do not anticipate this to become an issue.

5.3.3.2. Akpo D-P5

D-P5 is an infill well on the D reservoir currently scheduled for drilling in February-March 2024. For this exercise RISC has assumed production commences in May 2024.

In 2022, Prime has simulated the planned oil producer in the D reservoir (D-P5) to produce 10.1 MMstb incremental oil and 99 Bcf of gas by end 2044. RISC reviewed Prime's forecast in detail and compared the performance of the existing producers with the D-P5 forecast and concluded that the simulated recovery appeared reasonable.

The region targeted by the D-P5 well is predicted to have high condensate volumes and does not appear to have been impacted by the gas injection to date, Figure 5-45. RISC has assumed that, when the D reservoir blowdown commences, that the area drained by D-P5 will continue its decline.

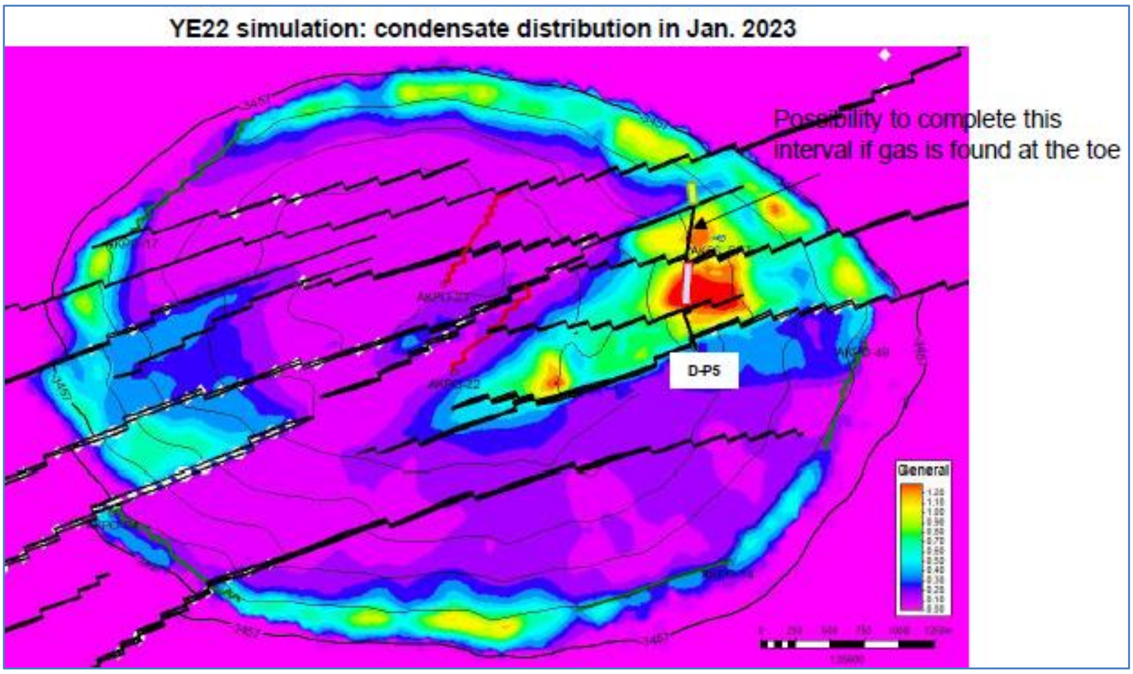
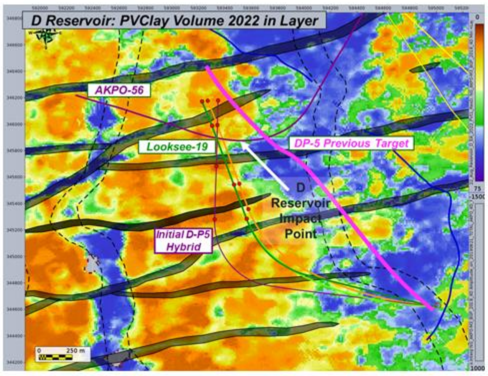


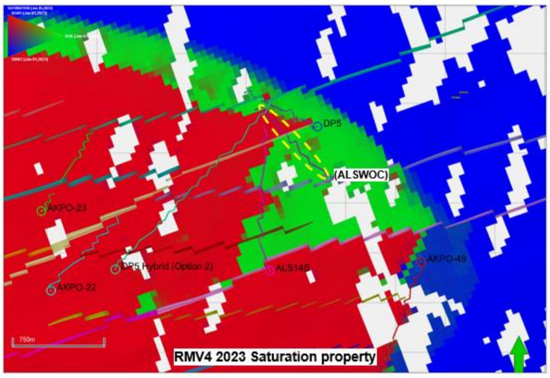
Figure 5-45: Akpo infill well D-P5 simulated condensate distribution.

Prime has advised that the well trajectory has been altered to present a well that has hybrid character with a downdip toe, suitable for oil recovery, and an updip heel, suitable for gas recovery and blowdown. Prime has also indicated that the operator, TotalEnergies, communicated in January 2024 that it has similar expectations for the revised well trajectory (Figure 5-46).

OML-130 Akpo Field

Res. D – D-P5, New Trajectory (Looksee-19) in line with Prime view.





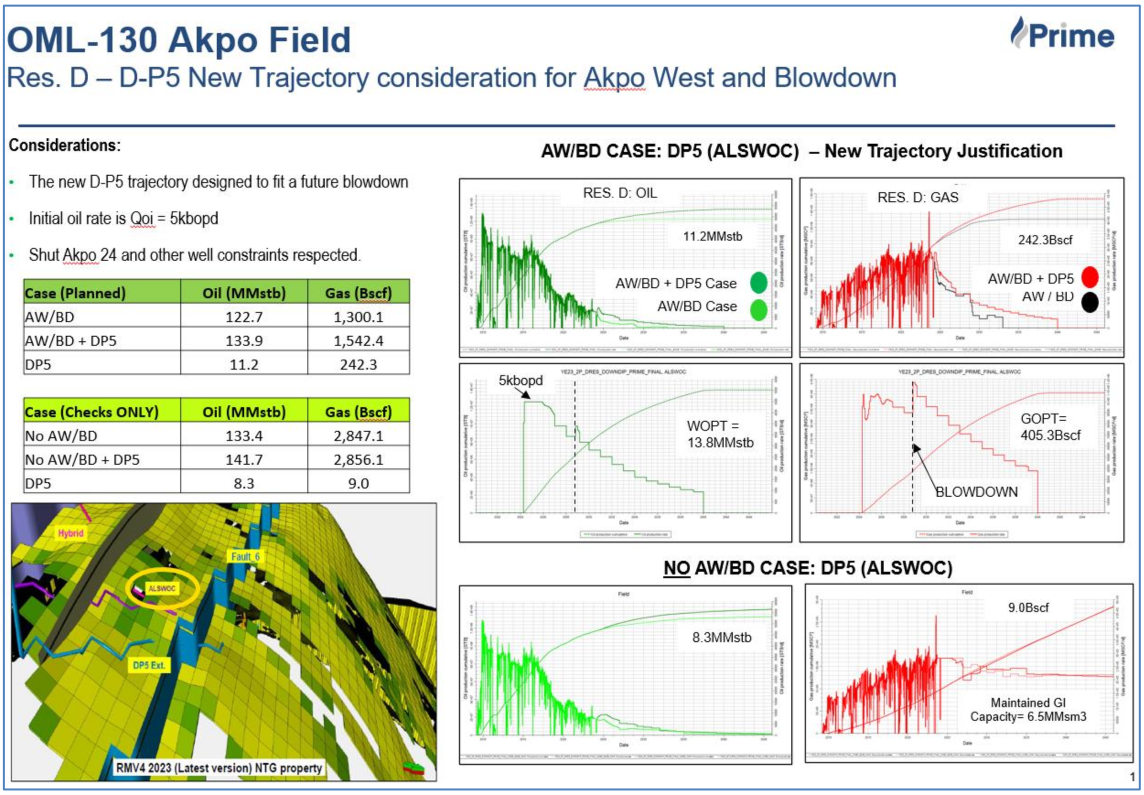
From TotalEnergies (communication to partners, January 2024): *"A Hybrid D-P5 trajectory was proposed up-dip (purple on map), to produce the downdip condensate and the gas at the crest of the D reservoir. Following this Hybrid proposition and based on recommendation from Partners, the initial hybrid D-P5 trajectory has been modified to looksee-19 (dark green on map), which is down-dip of the initial D-P5 trajectory and more aligned to ALSWOC".*

	Oil Produced - MMstb	DP5 - MMstb	Gas Produced, Bscf	DP5 - Bscf
Base	122.7		1,297.5	
(Initial D-P5 Hybrid / ALS14B)	128.9	6.3	1,570.8	273.4
(ALSWOC / Looksee-19)	133.9	11.3	1,542.4	245.0

D-P5 considered the new HM(08/2023) model and new trajectory that maximizes gas blowdown (Oct 2028)

Figure 5-46: TotalEnergies' D-P5 revised well trajectory and expected recovery

Prime has provided its reservoir simulation output supporting the recovery as 11.2 MMbbl and 242 Bcf net (Figure 5-45).



Case (Planned)	Oil (MMstb)	Gas (Bscf)
AW/BD	122.7	1,300.1
AW/BD + DP5	133.9	1,542.4
DP5	11.2	242.3

Case (Checks ONLY)	Oil (MMstb)	Gas (Bscf)
No AW/BD	133.4	2,847.1
No AW/BD + DP5	141.7	2,856.1
DP5	8.3	9.0

Figure 5-47: D-P5 revised well trajectory and expected recovery

Given the matching estimates of both the operator and Prime, RISC considers this revision is reasonable and has prepared a stylized production model to match the revised oil and gas production estimate (Figure 5-48).

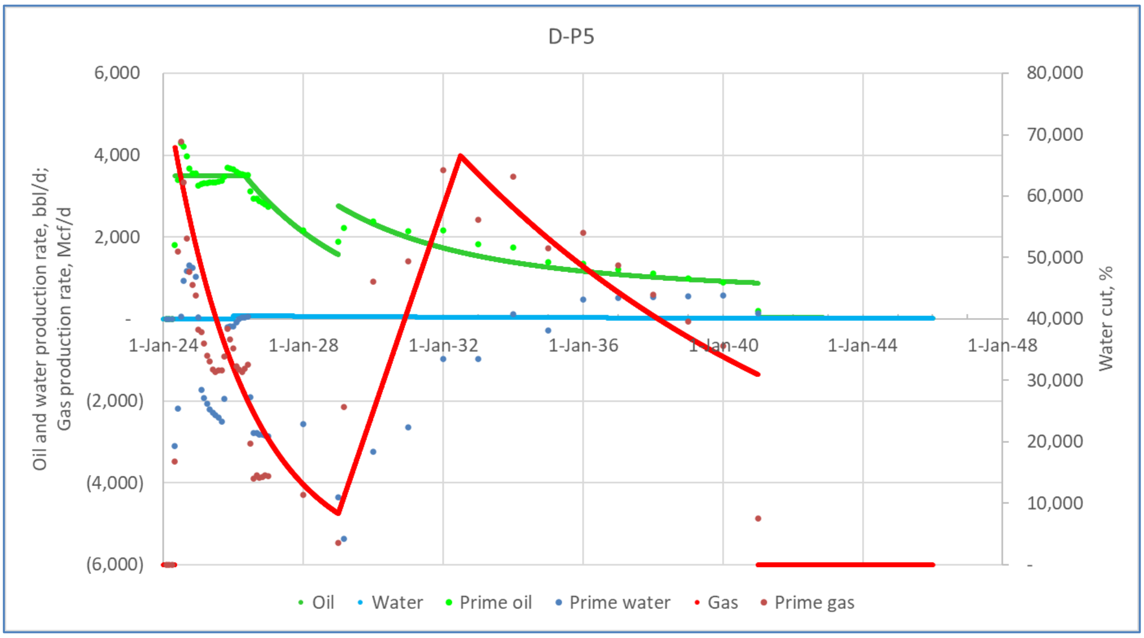


Figure 5-48: Akpo infill well D-P5 production forecasts.

RISC notes that the current net (after injection) production from the D reservoir is estimated at 135 Bcf. With Prime's incremental production from D-P5 of 240 Bcf, this increases to 375 Bcf. Based on the estimated GIIP of 433 bcf this represents an 87% gas recovery factor. This seems high, even after years of dry gas injection.

5.3.3.3. Akpo B-W4

B-W4 is a water injection well on the B reservoir currently scheduled for drilling in late September to mid November 2024. For this exercise RISC has assumed production commences in January 2025.

Prime's YE2022 simulation of the planned infill water injector in B reservoir (B-W4) indicated an oil recovery of 8.3 MMstb incremental oil by the end of 2044.

RISC reviewed this in detail for YE2022 and, after comparison with existing wells, concluded that this appeared potentially high. RISC therefore used the B-W4 simulated forecast as a high case (3P) and applied a 66% and 33% factor to the 2P and 1P, respectively.

Prime's YE2023 condensate recovery estimate[27] of 7.6 MMbbl has come closer to RISC's 2P estimate (5.5 MMbbl). In the absence of additional data RISC has retained its YE2022 estimates, preparing forecasts that also account for the delay in the start of injection compared with YE2022.

The project is carried by Prime as a reserve. RISC notes that the well is contingent on the results of the 4D seismic, and potentially could be considered a contingent resource.

RISC applies a wider uncertainty range of +/-50% to the infill well D-P4, rather than Prime's +/-10%.

5.3.4. Development Projects – Contingent Resources

5.3.4.1. 5 infill wells

The operator is currently evaluating 5 infill wells to be drilled in 2025. The wells are contingent on the 4DM4 seismic currently underway. The operator's and Prime's estimated recovery for the wells currently under consideration have recoveries of approximately 5 MMbbl and 10 Bcf per well. We note, however, that the wells themselves are not yet firm as this list differs from the wells mentioned (without recovery estimates) in the September 2023 SSCM.

[27] Prime Oil & Gas B.V., Reserves Audit 2023, December 13th, 2023, PPT

Classifications	Infill (Contingent)					
Target	A Upper (AU-P8)	A Lower (LS0+1)	A Lower (LS2)	A Lower (LS3)	B (Upper + Mid+Lower)	TOTAL
Estimated Oil (MMbbl) - TE	5.9	5.1	5.0	2.3	8.0	26.3
Estimated Gas (Bscf) - TE	14.5	12.2	12.2	5.8	19.1	63.8
MMBOE - TE	8.4	7.2	7.1	3.3	11.3	**37.3**
Estimated Oil (MMbbl) - PRIME	5.6	5.0	4.4	4.2	6.6	25.6
Estimated Gas (Bscf) - PRIME	10.8	11.2	9.8	9.4	15.6	56.7
MMBOE - PRIME	7.4	6.9	6.0	5.8	9.2	**35.4**
Considerations	Preliminary Volumes associated to the infill targets and contingent on 4DM4. Evaluation to be consolidated post 4DM4.					

Figure 5-49: Akpo preliminary 5 infill well candidates and expected recovery.[24]

As the wells have not been firmly identified and proposed RISC has not attempted to verify the estimate, although we do note the similarity between the operator's and Prime's figures, in general. We are also encouraged by the results of the infill wells drilled to date, as summarised by the operator[28], Figure 5-50, which indicates that, on average, the infill wells drilled to date have recovered more than 2.5 times the sanctioned oil recovery estimate.

Review of Akpo Infill wells performance

Recently Drilled Producers: Sanctioned vs Current Reserves

Type	Well	Reservoir	Start-up Date	Sanctioned 2P (Mbbl)	Np @ Aug 2023 (Mbbl)	2P UR (Mbbl)	Current potential (kbopd)
FDP replacement	Akpo-49	**D**	Dec-14	8.3	20.2	21.4	1.9
FDP replacement	Akpo-51	**G**	Mar-16	4.9	29.8	33.7	9.2
			Sum	**13.2**	**50.0**	**55.1**	**11.1**
Infill	Akpo-53	**EF**	Dec-16	4.6	15.2	17.5	4.8
Infill	Akpo-54	**B**	Mar-18	9.3	4.2	4.2	Shut
Infill	Akpo-57	**G**	Dec-19	3.8	10.3	13.3	9.5
Infill	Akpo-58	**AU**	Nov-21	5.7	3.8	6.6	5.2
			Sum	**23.4**	**33.5**	**41.6**	**19.5**
			TOTAL	**36.6**	**83.5**	**96.7**	**30.6**

Figure 5-50: Summary of Akpo infill well performance versus expected performance.

[28] September SSCM, p26

RISC has prepared conceptual forecasts with recovery of 5 MMbbl and 10 Bcf per well in the 2P case based on Prime's forecasts. Drilling is currently scheduled for 4Q2025/1Q2026, RISC has assumed startup in mid-2026, and assumed water production starting after 1.5 year's production. The 1P and 3P estimates have been given a +/-50% range.

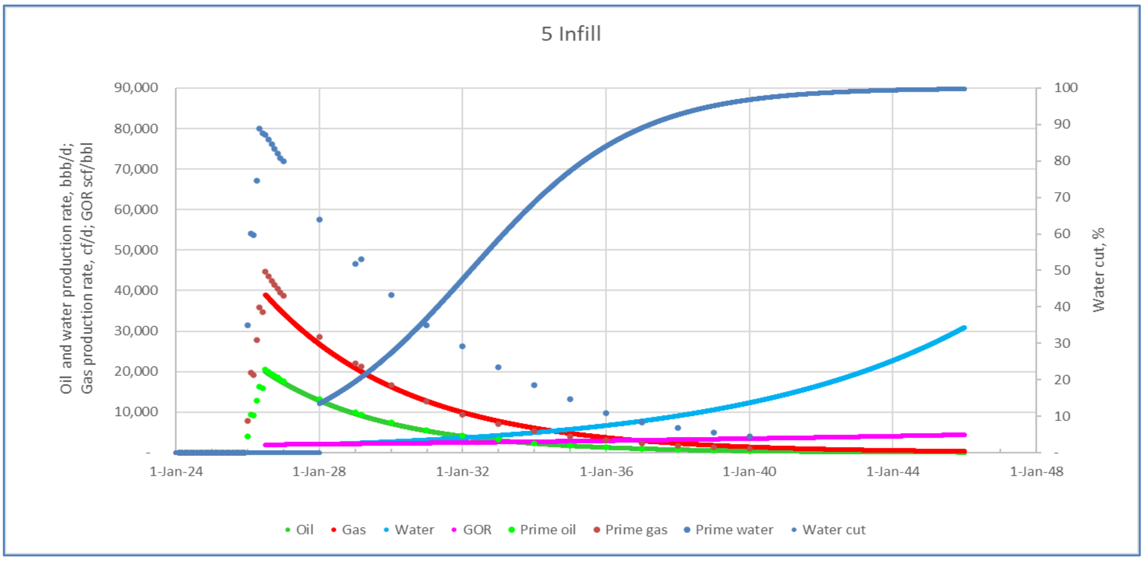


Figure 5-51: RISC's conceptual forecasts for the Akpo 5 infill well contingent activity.

5.3.4.2. Miscible Gas Injection (MGI)

Prime carries contingent resources from wells being considered for miscible gas injection (MGI) to enhance oil recovery. For YE2022 injection was estimated to have 5 wells (A28 (Upper A), A19 (Lower A) in 2025 and A40 (EF reservoir), A45 (B reservoir), A11 (G reservoir)) in 2029. Prime's YE2023 forecast, however, has one well in 2026, two wells in 2029 and one well commencing production in 2033.

For YE 2022 RISC reviewed and accept Prime's simulated contingent resources as reasonable but has used the schedule as shown in Figure 5-52. Overall, the MGI is estimated to recover and additional 43 MMbbl, but will lose 6 Bcf of gas, as considerable volumes of gas are injected and not all is recovered.. The miscible gas injection in Upper A, Lower A and EF are simulated to create a reasonable incremental oil recovery factor of 4 to 5%.

For YE2023 Prime's incremental oil recovery for MGI is forecast at 43.3 MMbbl, Figure 5-52 (note that the 32.6 MMstb does not reconcile with the individual well recoveries).

Prime

Akpo Field

Miscible Gas Project: Potential to bring 32.6 MMstb incremental (Prime)

Classifications	Miscible Gas Injection (Contingent)			
Well Name	A28MGI	A31MGI	A39MGI	A45MGI
Reservoir	A Upper	A Lower	EF	B
Well Type	Gas Injector	Gas Injector	Gas Injector	Gas Injector
Online Date	Q3 2026	Q1 2029	Q1 2029	Q1 2029
Initial Prod. / Inj. Rates	60.0 MMscf/d	60.0 MMscf/d	60.0 MMscf/d	49.5 MMscf/d
Incremental - MMstb (31st Dec 2045)	9.5	17.9	10.5	5.4
Considerations	Well Work over – POOH Water Injection completion and Run Gas Injection Completion			

Figure 5-52: Akpo Miscible Gas Injection - incremental production (2C).

Figure 5-55 illustrates Prime's YE2023 MGI production and injection forecasts. Whilst recognizing the forecasts are contingent resource projects we note that:

- Gas injection at 160 MMcf/d is forecast to be ongoing in 2046;
- Water injection is also forecast to be ongoing in 2046;
- Cumulative net (production – injection) gas to 2046 is -215 Bcf (i.e. more gas injected than recovered).
- Cumulative oil production is estimated at 43 MMbbl;
- The design life of the FPSO is 20 years and production commenced in 2009. With an estimated 5 additional year's certification this would reach 2034.

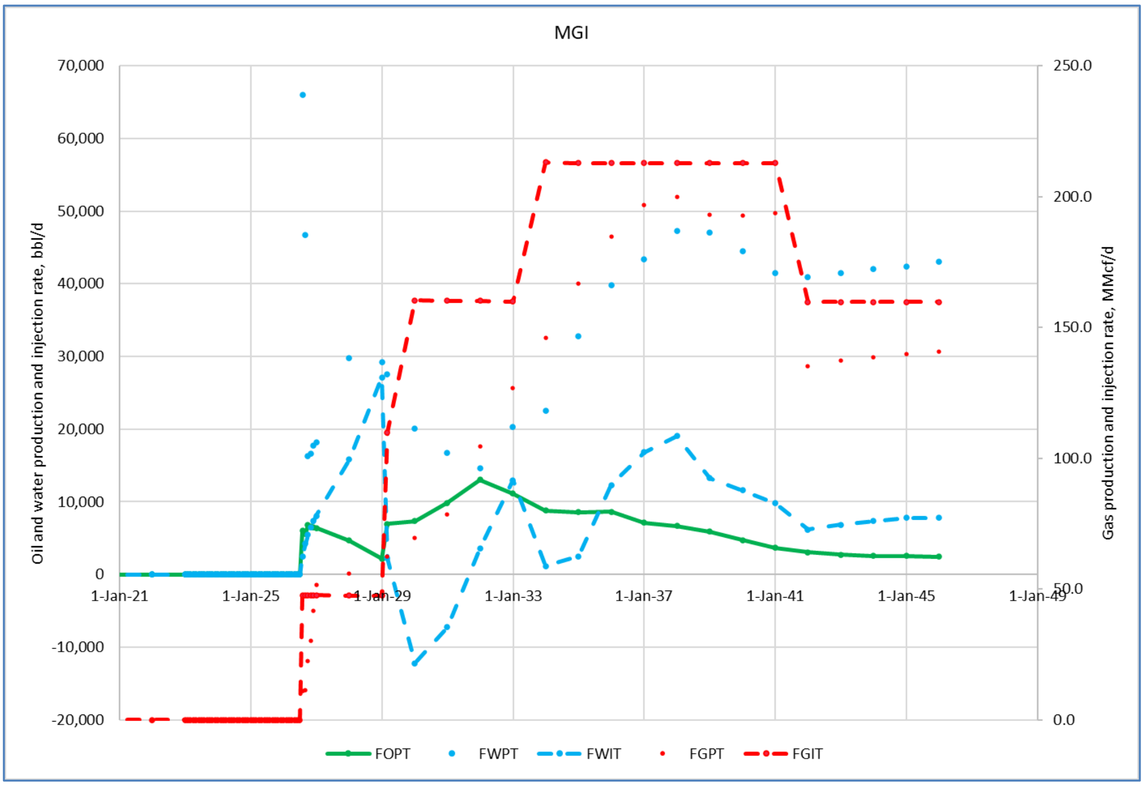


Figure 5-53: Prime's Akpo Miscible Gas Injection (MGI) production forecasts

Despite RISC's misgivings regarding the length of the project relative to the design life of the FPSO, it is a valid contingent resource in that it targets a discovered resource. Ultimately, it is likely that the performance of the pilot, scheduled for 2026, will determine whether the MGI projects on the other reservoirs proceed.

RISC has created production forecasts that honour the gas injection rates, incremental recovery and start-up dates currently foreseen.

Figure 5-54 shows production and injection forecast for Akpo MGI.

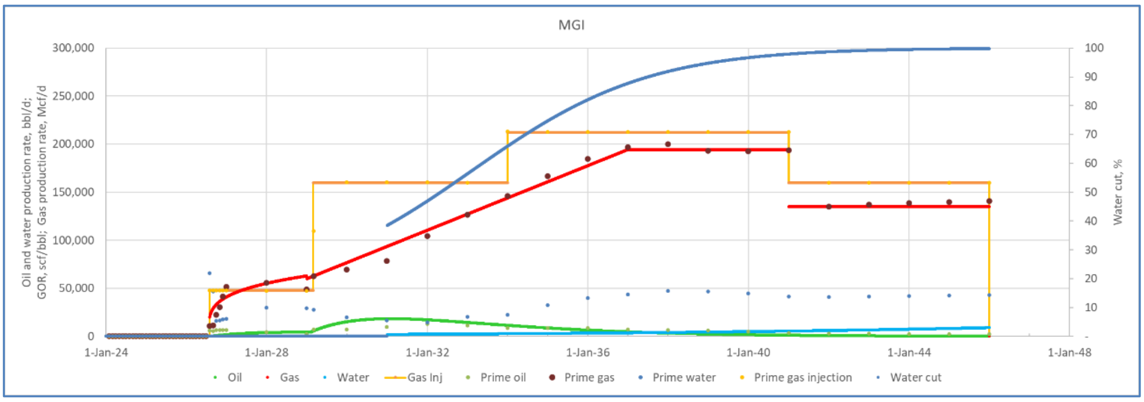


Figure 5-54: Akpo Miscible Gas Injection - incremental production (2C).

Note that RISC's forecast has not been adjusted for FFSD or fuel. The injection rates shown are Prime's target rates, however, RISC's modelling confirms that sufficient gas should be available.

5.3.4.3. D reservoir Blowdown

The D reservoir in Akpo differs from the other reservoirs in that the mechanism applied for pressure maintenance is gas injection, rather than water injection in the other reservoirs. Cumulative gas injection to YE2023 is approximately 945 Bcf, the cumulative gas production is 925 Bcf.

The aim of the gas injection into the D reservoir was essentially to maximise oil recovery, the aim of the gas blowdown is to maximise the gas recovery. Gas for injection will be required for the MGI project and Akpo West. Whilst Akpo West is forecast to provide an internal balance between gas production and injection, the MGI project will require gas from other reservoirs.

Blowdown of the D gas-condensate reservoir has previously been considered a contingent project, however, the production forecasts for D-P5 assume blowdown of the D reservoir. Thus, the D reservoir blowdown should be considered a Base activity. This would slightly alter Prime's base forecast, but not materially.

Prime's forecast Base gas net production from the D reservoir is 135 Bcf, D-P5 is forecast to recover a further 242 Bcf for a cumulative 377 Bcf. The D reservoir GIIP is approximately 433 Bscf, so the estimated net gas recovered gives a recovery factor of 87%. Whilst high, this is to be expected given the quantity of dry gas re-injected over the lifetime of the field. No further blowdown activities are foreseen.

5.3.5. Field Forecasts with all Development

5.3.5.1. 2P plus 2C Case

Figure 5-55 illustrates RISC's consolidated 2P plus 2C production forecast for Akpo Field, incorporating all projects described above and adjusted for FFSD, but not truncated by economic or FSPO life considerations. Total production is 206 MMbbl.

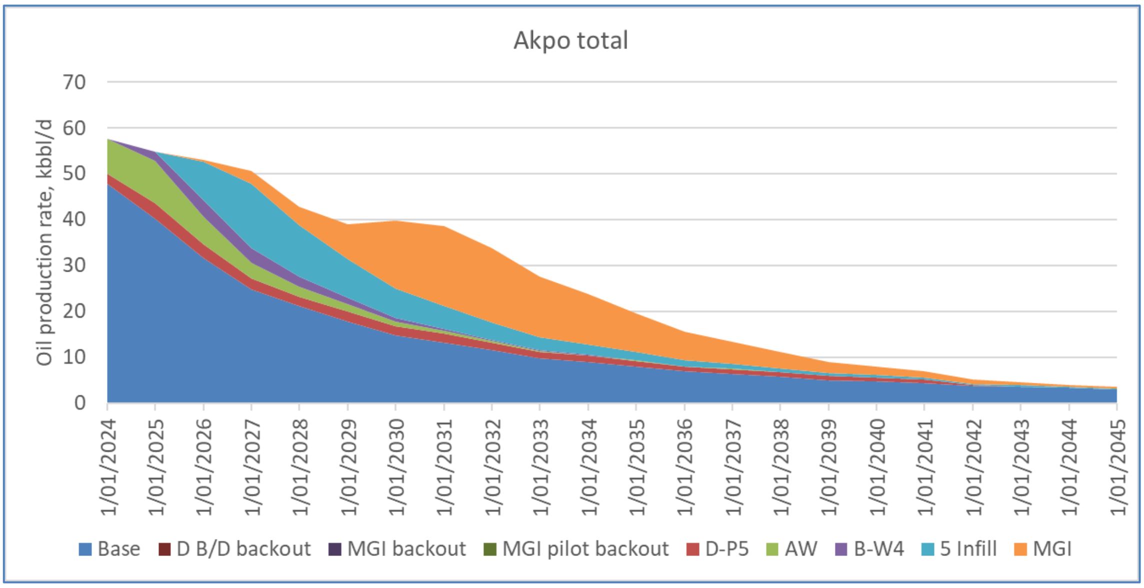


Figure 5-55 RISC's consolidated 2P plus 2C Akpo oil production forecast.

RISC's 2P plus 2C gas production is shown in Figure 5-56. The figures have been adjusted for FFSD.

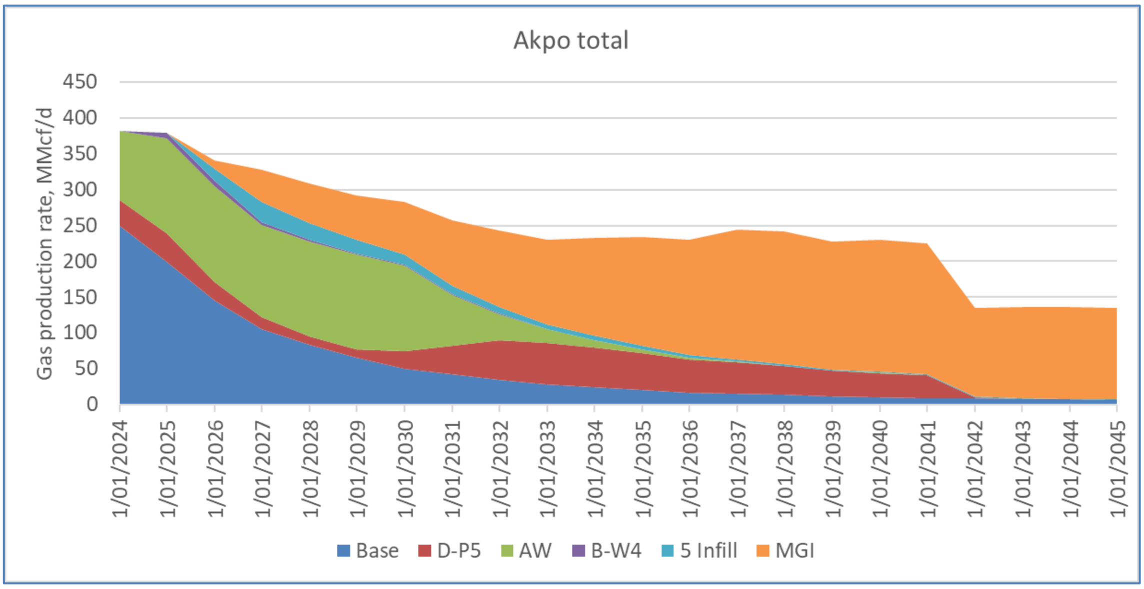


Figure 5-56 RISC's consolidated 2P plus 2C Akpo gas production forecast.

RISC's 2P plus 2C gas utilisation is shown below (Figure 5-57). The figures are also consistent with the start and end dates for the various projects discussed above, however, we note that these may differ in practice. The increase in gas sales in 2030 is due to gas injection stopping in Akpo West and the D reservoir. We note a small overestimate of injected gas in 2027/28. This could be accommodated by limiting injection, or by a delay to the start of the MGI project.

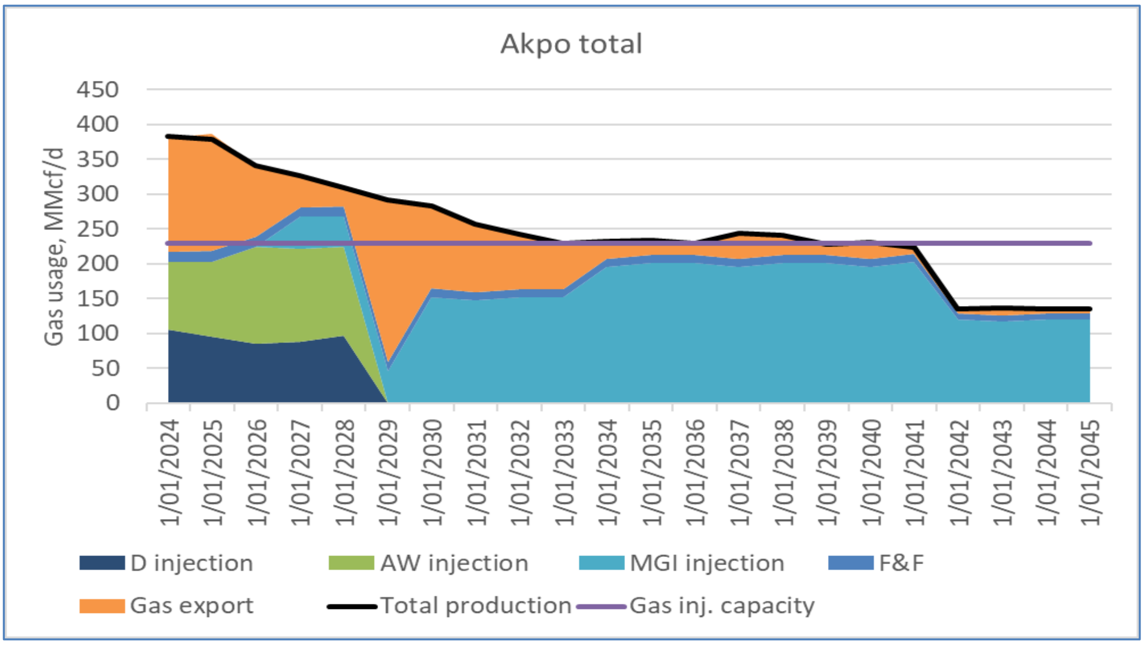


Figure 5-57 RISC's consolidated 2P plus 2C Akpo gas utilisation forecast.

At present RISC has not generated a water production forecast to verify any liquid production constraints are met.

5.3.5.2. Material Balance

In Table 5-11 we have shown Prime's oil recovery for the various projects by reservoir and determined the recovery factor for the total oil recovery estimate. Current oil production of 663 MMbbl represents a recovery factor of 47%. The base (developed) recovery will increase the overall recovery to 55%, whilst the projects will further increase recovery to 62% of STOIIP.

The high recovery factor in the D reservoir is attributed to the dry gas injection for many years, and whilst high, is supported by the high recovery to date. The EF and G reservoirs have a higher recovery than the AU, AL and B reservoirs. This may be attributable to favourable PVT properties (lower viscosity, higher GOR, more volatile oil) in the EF and G reservoirs but may also be related to geological factors. On aggregate, RISC considers that the oil recoveries are reasonable.

Table 5-12 details the forecast gas recovery (net) for the base (developed) wells and the projects. Current gas production represents an average 40% recovery factor, with the Base forecasts targeting a 50% overall recovery factor. Other projects will bring the average recovery factor to 56%.

Table 5-11: Oil UR and recovery factors for Prime's Akpo forecasts

Reservoir	STOIIP	Prime Base	RF	D-P5	AW	B-W4	Infill	MGI	Total oil recov.	RF
	MMbbl	MMbbl	fraction	MMbbl	MMbbl	MMbbl	MMbbl	MMbbl	MMbbl	fraction
AU	388	187	0.48				5.6	9.5	202	0.52
AL	336	173	0.52				13.5	17.9	205	0.61
B	171	54	0.32			7.6	6.6	5.4	73	0.43
D	166	132	0.80	11					144	0.86
EF	146	101	0.69					10.5	112	0.76
G	164	125	0.76						125	0.76
AW	25.4				11				11	0.45
Total	**1,396**	**773**	**0.55**	**11**	**11**	**8**	**26**	**43**	**872**	**0.62**
Net prod.		663	0.47						663	
Reserve		110							209	

Table 5-12: Gas UR and recovery factors for Prime's Akpo forecasts

Reservoir	GIIP	Prime Base	RF	D-P5	AW	B-W4	Infill	MGI	Total gas recov.	RF
	Bcf	Bcf	fraction	Bcf	Bcf	Bcf	Bcf	Bcf	Bcf	fraction
AU	762	355	0.47				10.8	-1.3	365	0.48
AL	849	425	0.50				30.3	-35.1	421	0.50
B	367	158	0.43			17	15.6	-43.1	148	0.40
D	433	135	0.31	241					375	0.87
EF	820	496	0.61					-136	360	0.44
G	686	495	0.72						495	0.72
AW incl B/d	195				139				139	0.71
Total	**4,113**	**2,065**	**0.50**	**241**	**139**	**17**	**57**	**-215**	**2304**	**0.56**
Net prod.		1,666	0.40						1666	
Reserve		399							638	

On an individual reservoir basis, the D reservoir recovery factor is very high, as with the oil, and the G reservoirs are also high. The MGI project has a negative impact on gas recovery due to the large volume of injected gas, however, we do note that the continued gas injection to 2046 for this project precludes any future blowdown.

RISC considers that the forecast gas recoveries are, on aggregate, reasonable.

5.3.5.3. *1P plus 1C and 3P plus 3C Cases*

For the developed wells, RISC has provided 1P and 3P oil and gas forecasts with uncertainty increasing from 5% to 30% with time. For the reserve projects (AW, D-P5 and B-W4) we suggest an uncertainty range of +/-30% and for the contingent resources +/-50%, on an individual project case.

For a combined forecast it is extremely unlikely that all low or high outcomes will occur, and a lower ranges is more appropriate. Further, in the event that a low or high case outcome was encountered, the dependencies between the projects would likely lead to alternative decisions regarding timing of later activities. Thus, low gas production from Akpo West may lead to a decision to accelerate D blowdown, or a high case outcome will trigger facility constraints necessitating shutting-in or beaning-back of wells.

For the low (1P plus 1C) and high (3P plus 3C) forecasts shown below we have assumed the developed reserves have the uncertainty assigned, and that the other projects have a narrower uncertainty, due to the combined forecast. Thus, although the projects are identified separately, the uncertainty shown for each should not be used for individual project evaluation. We consider the overall uncertainty range to be reasonable. We also note that we have not altered the dates of the projects from the 2P plus 2C case and we have honored the same facility constraints as used for the 2P plus 2C.

Figure 5-58, Figure 5-59 & Figure 5-60 illustrates RISC's 1P plus 1C, 2P plus 2C and 3P plus 3C Akpo oil, gas and gas export forecasts, respectively based on the consolidated production.

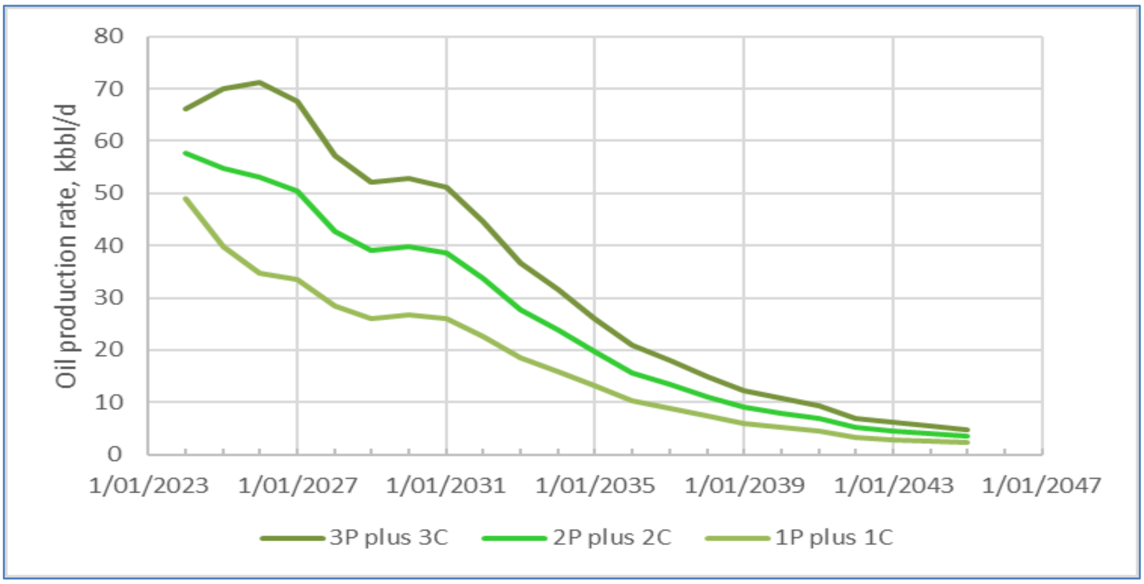


Figure 5-58 RISC's consolidated 1P plus 1C, 2P plus 2C and 3P plus 3C Akpo oil production forecast.

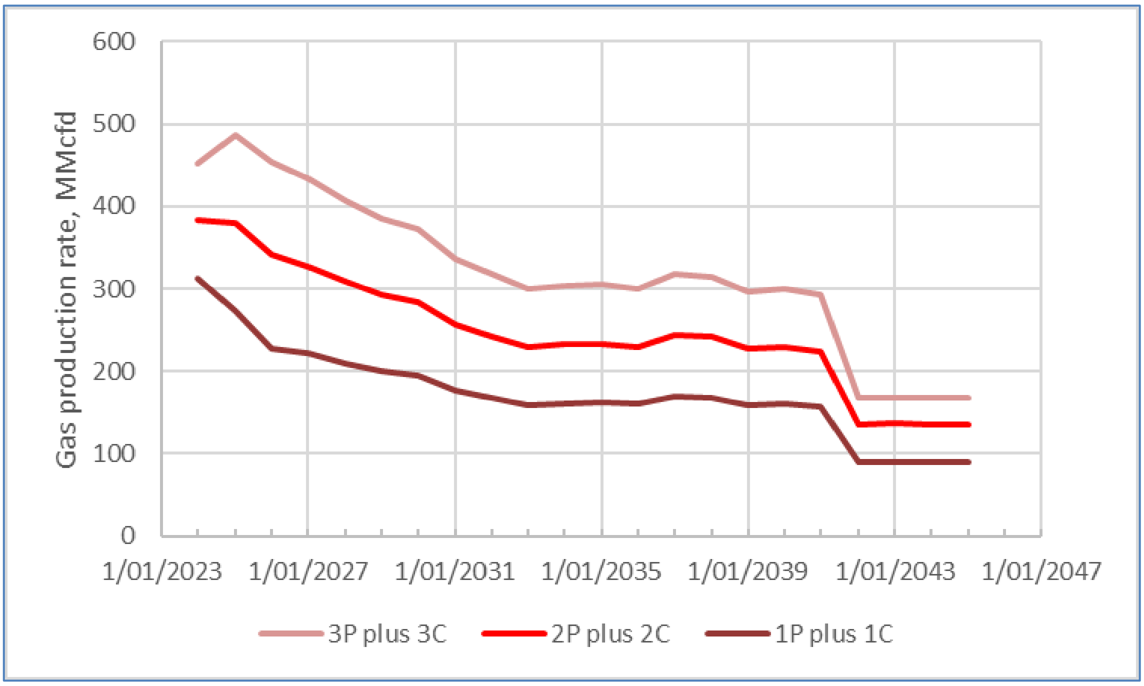


Figure 5-59 RISC's consolidated 1P plus 1C, 2P plus 2C and 3P plus 3C Akpo gas production forecast.

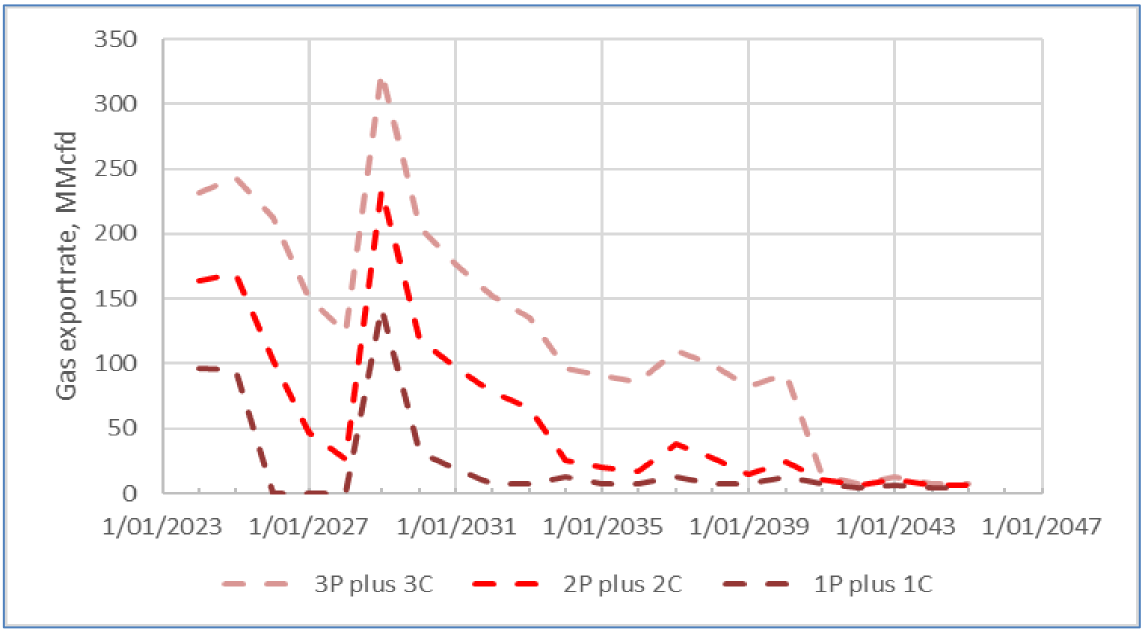


Figure 5-60 RISC's consolidated 1P plus 1C, 2P plus 2C and 3P plus 3C Akpo gas export forecast.

5.4. Recoverable Quantities

The forecast ultimate recoveries for the Akpo reserves activities are given in Table 5-13. These are equivalent to the extended profiles for the 1P, 2P and 3P forecasts, but carried through to end-2045 instead of ending at the economic limits. Note, as UR figures, the Akpo Main volumes include historical production. Note also that the values are incremental, taking into account any backout.

Table 5-13 UR of Akpo reserves models

Akpo Field UR	Low	Mid	High
Akpo Main oil, MMstb	738.3	773.2	808.1
Akpo Main sales gas, Bcf	1,545	1,592	1,639
D-P5 recovery Oil, MMstb	7.9	11.2	14.6
D-P5 sales gas, Bcf	132	191	249
B-W4 oil, MMstb	3.8	5.4	7.0
B-W4 sales gas, Bcf	1	6	9
Akpo West oil, MMstb	8.3	11.9	15.4
Alpo West sales gas, Bcf	103	179	313
Cum Oil and Gas sales at 31/12/2023 were663.7 MMstb and 1,500 Bscf			

The forecast incremental ultimate recoveries for the Akpo contingent project are given in Table 5-14.

Table 5-14: UR for Akpo contingent resource projects

Akpo Field UR	Low	Mid	High
Akpo 5 infill wells oil, MMstb	17.9	25.6	33.2
Akpo 5 infill wells sales gas, Bcf	21	53	71
MGI Oil, MMstb	30.2	43.1	56.1
MGI sales gas, Bcf	-187	-155	33

5.5. Cost Forecasts

RISC has reviewed the costs in the economic model supplied by Prime. We have compared these with costs in the budget, Field Development Plans, cost models provided by Prime and our own tools and benchmarks. We have made modifications where we consider appropriate. All costs are reported on 100% basis in US$ 2024, real terms.

5.5.1. Capital Costs

Total forward capital costs for the project are forecast to be US$983 million to 2029 (half of the costs are attributable to Prime) a summary of which can be seen in Table 5-15, with Figure 5-61[29] showing capex phasing. The cost phasing reflects 3 Akpo West wells that are currently being drilled with the campaign due to finish in Q1 2024, one Akpo D-P5 well in 2024, one Akpo B-W4 well in 2024, 5 Akpo infill wells starting in Q4 2025 and ending in mid-2026 and the conversion of 4 wells from water injection to gas injection; one in in 2026 and the other 3 in 2028 (Akpo – MGI).

Table 5-15: Akpo future development capex to 2029 (total project costs)

$ million	Akpo	Akpo 5 Infills	Akpo Field DP-5	Akpo field West	Akpo B-W4	Akpo - MGI	Total
D&C	0	264	71	48	68	110	561
Facilities	193	68	14	14	14	120	422
Total	**193**	**333**	**85**	**62**	**81**	**230**	**983**
1. Numbers may not add due to rounding.							

The well costs are predicated on a spread rate of US$1.2 million/d in 2024 which has increased from last year's estimate which was US$1.1 million/d. Prime have considered that the rig rate will drop back to US$1.1 million/d in 2025 in line with the Brent forward curve. RISC views this as slightly optimistic but has accepted the assumption.

The DP-5 well cost estimate has increased from US$52 million last year to US$71 million due to the increase in rig rates and the estimated time taken to drill has increased from 47 days to 58 in line with recent drilling experience. The drilling of the well is now scheduled for Q1 2024 and has been delayed due to previous wells taking longer than expected to drill.

There is one well remaining on Akpo West to drill which is estimated to cost US$48 million to drill & complete, approximately the same as last year's estimate. The spread rate has gone up but the estimated time for drilling has decreased slightly taking account the learning curve of drilling the previous wells, which RISC views as reasonable.

The Akpo-MGI well cost estimate is US$110 million for the 4 well conversions (water injection to gas injection) and has remained the same as last year as Prime predicts rig spread rates to fall again.

[29] 'Does not include on-going facilities Capex costs after 2028, USD$22 million p.a.

The Akpo BW-4 well has been moved forward from Q1 2025 to Q4 2024 and the estimated cost has increased from US$51 to $68 million as the spread rate has increased and the drill time has increased from 46 to 55 days.

The drilling of the 5 Akpo infill wells have been added to the drilling schedule and will start in Q4 2025 and finish at the end of Q2 2025 costing US$264 million. Prime have considered 46days for the drilling of each well which RISC view as reasonable and a US$1.1 million rig spread rate.

RISC views the costs associated with tying back of the wells in the facilities costs in Table 5-15 to be reasonable.

Prime has forecast US$193 million to be spend on Capex for the Akpo main facilities with the majority to be spent in 2024 (US$73 million) and 2025 (US$28 million). Subsequently US$21 million has been allowed per annum. The main Capex in 2024 and 2025 is to be spent on facilities upgrades, purchase of valves/capital spares. RISC has reviewed the Operator 2024 Work program and budget and view the costs as reasonable and the work in line with what would be expected for an FPSO of Akpo's age. RISC note that a 31-day Full field shut down planned for 2024.

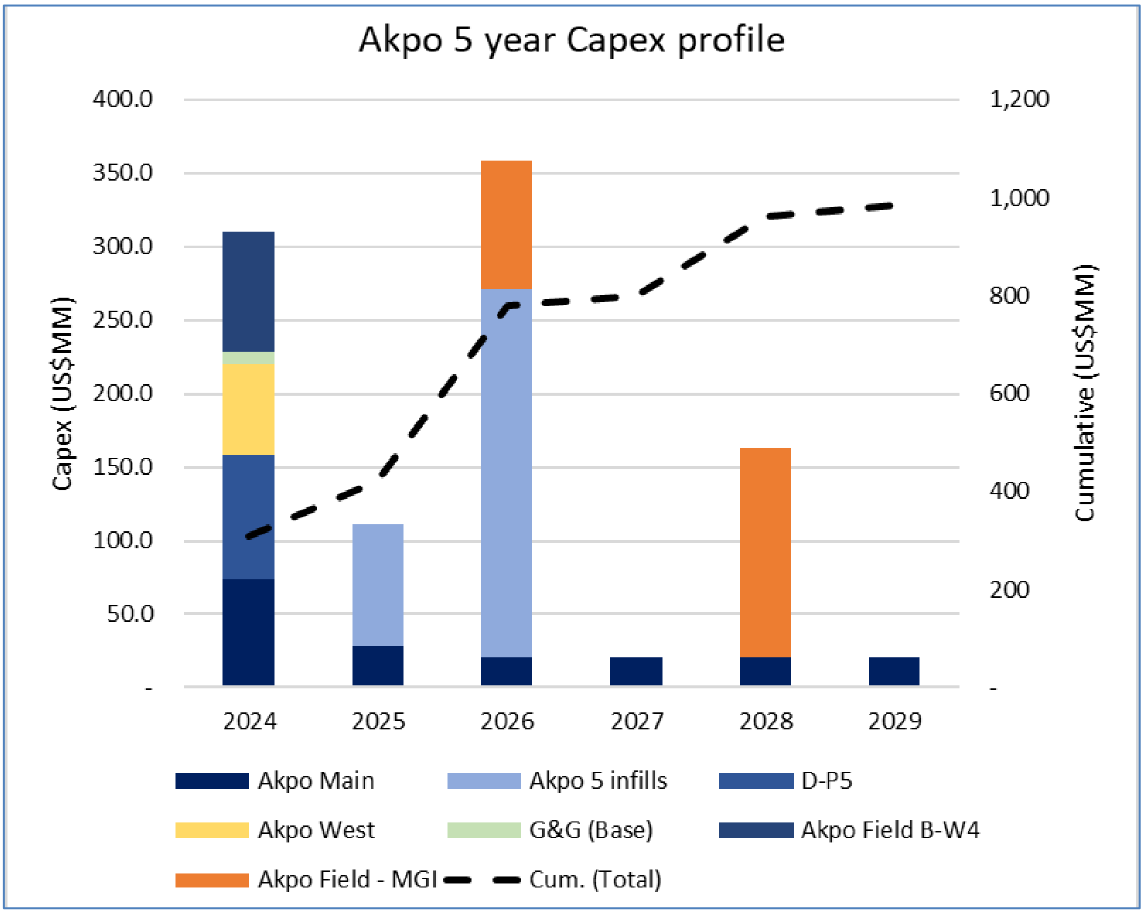


Figure 5-61: Akpo capex forecast by project (Total project cost).

5.5.2. Operating Costs

Operating costs in 2023 were US$246 million (Figure 5-62), US$22 million less than the initial US$268 million which was mainly due to the full field shut down being much shorter than planned. The Operator's budget for 2024 is US$245 million. Prime have budgeted US$233 million as historically the Operator has overestimated Opex (the Operator includes a contingency, which RISC views as reasonable as it avoids having to go back to the joint venture group requesting a budget increase if costs overrun). Prime's assumption also includes a 5% reduction on the WP&B to account for the Naira devaluation not yet factored in the Operators figures. RISC accepts Prime's view on the budget as being reasonable (Operator historical over estimation of Opex can be seen in the historical data in Figure 5-62).

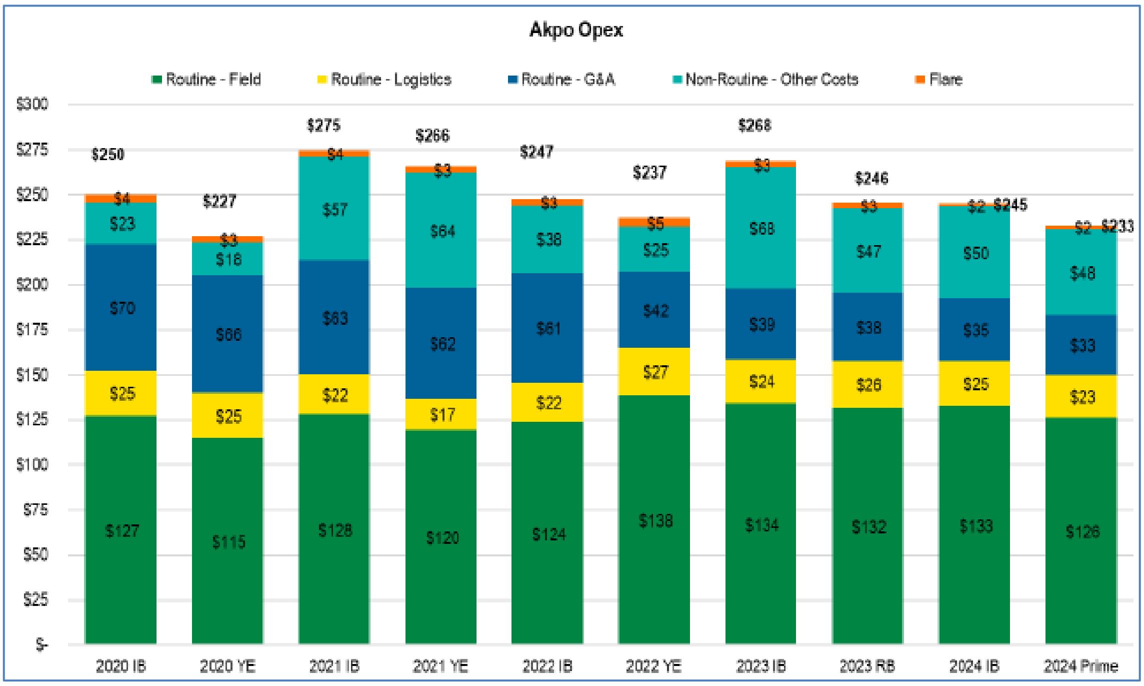


Figure 5-62 Akpo historical Opex (Prime Reserves Presentation Dec 2023)

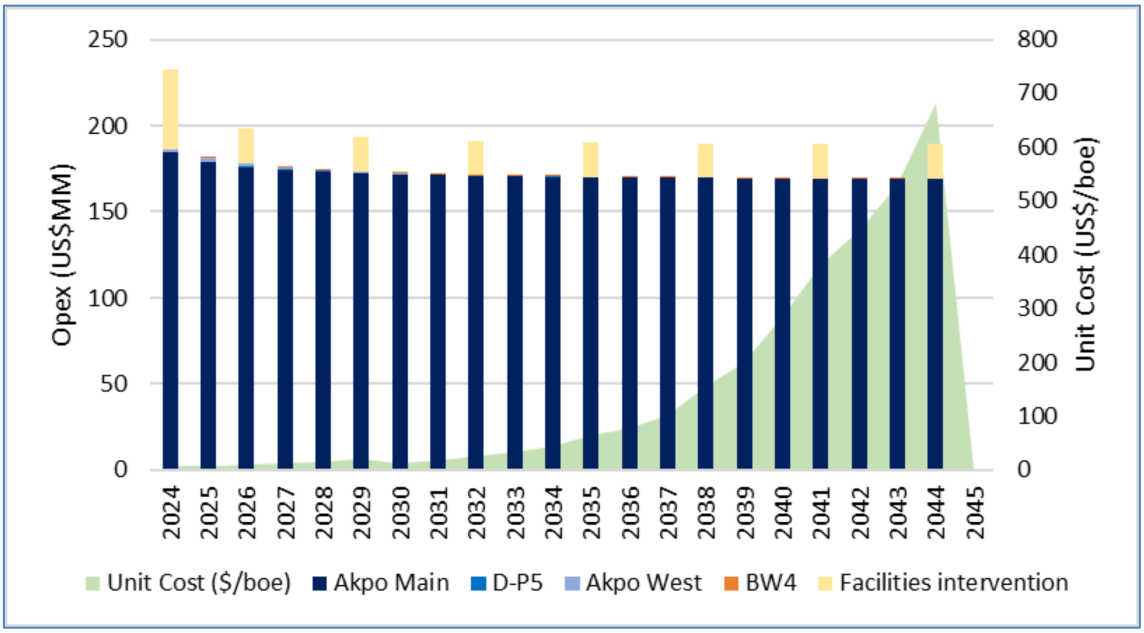


Figure 5-63: RISC's Akpo 2P operating cost forecast

Going forward Prime consider 85% of recurrent operating costs are fixed and 15% of costs vary with production. Prime have added non-recurrent costs of US$20 million every 3 years for major planned facilities maintenance campaigns which RISC has increased to US$25 million. Gas flaring fees are included in the recurrent operating costs based on historical performance.

In the 2P case, RISC's operating costs are forecast to reduce from approximately US$234 million in 2024 (including facilities intervention costs) to US$169 million in 2044 averaging approximately US$182 million pa as can be seen in Figure 5-63.

5.5.3. Abandonment Costs

Akpo decommissioning costs are forecast to be approximately US$800 million, comprised of US$448 million in well P&A and US$353 million in facilities decommissioning. RISC consider these estimates to be reasonable. Additionally, US$28.8 million has been forecast for Akpo 5 infill wells (1 well is a sidetrack so only 4 additional wells to be abandoned) and US$7 million for the DP-5 well.

Well P&A costs are estimated to be approximately US$7 million per well based on 17.5 days and a spread rate of US$410,000 per day (US$250,000 for rig and US$160,000 for support services). In addition to this, mobilization and demobilization costs are estimated to be US$10 million in total.

It should be noted that although Akpo is predicted to reach end of economic field life before Egina, abandonment will not be executed until Egina end of field life.

Although discussions are ongoing with respect to phasing the abandonment costs, Prime has assumed a linear annual distribution approach with expenditure from 2025 to end of Akpo field life. RISC sees this as appropriate.

5.6. Reserves and Contingent Resources Summary

The gross licence and Prime net entitlement oil and gas developed reserves associated with the Akpo field are shown in Table 5-16. The oil and gas undeveloped reserves associated with the D-P5 infill well, B-W4 infill well and Akpo West development are shown in

Table 5-17, Table 5-18 and Table 5-19. The contingent resources associated with the 5 further infill wells and Akpo MGI project are shown in Table 5-20 and Table 5-21.

It should also be noted that each project results in incremental volumes being produced from the Akpo main reserves case due to an extension of the economic life of the field. Furthermore, with some projects accelerating production there can be negative incremental tail volumes. However, if the economic life of the field falls earlier than the technical cut-off of the individual project, the negative impact of accelerated production is not seen. These factors can therefore result in the total incremental reserves or resources attributed to a project being greater than the incremental EUR of the project alone.

Table 5-16: Akpo gross and Prime net entitlement developed reserves as of 1 January 2024

Oil	Unit	Reserves		
		1P	2P	3P
Akpo oil (incl. recent infill wells), gross to PML 2	MMstb	60.6	97.8	135.4
Prime net entitlement	MMstb	10.2	16.1	21.9
Sales gas				
Akpo gas (inc. recent infill wells), gross to PML 2	Bcf	91.1	189.2	302.9
Prime net entitlement	Bcf	14.6	30.3	48.5

Notes:
1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

Table 5-17: Akpo undeveloped reserves for DP-5 infill well as of 1 January 2024.

Oil	Unit	Reserves		
		1P	2P	3P
DP-5 infill well, gross to PML 2	MMstb	5.3	8.8	14.1
Prime net entitlement	MMstb	0.9	1.4	2.3
Sales gas				
DP-5 infill well, gross to PML 2	Bcf	75.6	180.5	299.1
Prime net entitlement	Bcf	12.1	28.9	47.9

Notes:

1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

Table 5-18: Akpo undeveloped reserves for B-W4 infill well as of 1 January 2024

Oil	Unit	Reserves		
		1P	2P	3P
B-W4 infill well, gross to PML 2	MMstb	3.8	5.4	7.0
Prime net entitlement	MMstb	0.6	0.9	1.1
Sales gas				
BW-4 infill well, gross to PML 2	Bcf	2.3	8.3	12.0
Prime net entitlement	Bcf	0.4	1.3	1.9

Notes:

1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

Table 5-19: Akpo undeveloped reserves for Akpo West development as of 1 January 2024

Oil	Unit	Reserves		
		1P	2P	3P
Akpo West, gross to PML 2	MMstb	8.1	11.8	15.4
Prime net entitlement PML 2	MMstb	1.4	1.9	2.4
Akpo West + Main tail, gross to PML 2	MMstb	12.9	18.5	19.7
Prime net entitlement PML 2	MMstb	2.3	3.1	3.1
Sales gas				
Akpo West, gross to PML 2	Bcf	66.3	137.4	248.2
Prime net entitlement PML 2	Bcf	10.6	22.0	39.7
Akpo West + Main tail, gross to PML 2	Bcf	75.8	148.6	253.4
Prime net entitlement PML 2	Bcf	12.1	23.8	40.5

Notes:

1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

Table 5-20: Akpo contingent resources for 5 further infill wells as of 1 January 2024

Oil	Unit	Contingent resources		
		1C	2C	3C
Akpo 5 infill wells, gross to PML 2	MMstb	19.0	25.9	34.5
Prime net entitlement	MMstb	3.3	4.3	5.5
Sales gas				
Akpo 5 infill wells, gross to PML 2	Bcf	38.9	59.8	77.8
Prime net entitlement	Bcf	6.2	9.6	12.5

Notes:

1. The 1C, 2C and 3C incremental oil and gas resources are greater than the incremental EUR due to project extending the economic field life.
2. "Gross" licence reserves are 100% of total field reserves.
3. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
4. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
5. Sales Gas resources have had fuel gas deducted.
6. Volumes are based on conversion of both licences to PIA terms.

Table 5-21: Akpo contingent resources for Akpo MGI as of 1 January 2024

Oil	Unit	Contingent resources		
		1C	2C	3C
Akpo MGI, gross to PML 2	MMstb	34.5	49.1	58.5
Prime net entitlement	MMstb	5.9	8.0	9.3
Sales gas				
Akpo MGI, gross to PML 2	Bcf	-132.6	-118.5	26.5
Prime net entitlement	Bcf	-21.2	-19.0	4.2

Notes:

1. The 1C, 2C and 3C incremental oil resources are greater than the incremental EUR due to project extending the economic field life.
2. The 1C and 2C incremental gas resources are negative due to the injection of gas in this project decreasing the overall gas resources.
3. “Gross” licence reserves are 100% of total field reserves.
4. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
5. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
6. Sales Gas resources have had fuel gas deducted.
7. Volumes are based on conversion of both licences to PIA terms.

The Akpo blowdown produces gas from the Akpo reservoir D gas cap. This results in large incremental gas production but removes the pressure support to the oil rim, resulting in a tail of negative incremental oil production. However, the blowdown will be done in conjunction with the MGI project, which results in positive incremental oil recovery but reduces incremental gas recovery. The 1C and 2C gas resources are negative due to more gas being injected as part of the MGI than produced by the blowdown.

Table 5-22 shows a comparison of the Year-End 2022 Akpo developed and undeveloped reserves with the Year-End 2023 estimates.

Table 5-22: Akpo Reserves Reconciliation Compared to Year-End 2022 Report

Oil	Unit	Reserves		
		1P	2P	3P
Akpo Field Gross at 31 Dec 2022	MMstb	87.4	137.4	197.8
Akpo Field production, 1 Jan to 31 Dec 2023	MMstb	25.5		
Akpo Field Revisions	MMstb	15.8	11.8	-0.4
Akpo Field Gross on 1 Jan 2024	MMstb	77.8	123.7	171.9
Sales gas				
Akpo Field Gross at 31 Dec 2022	Bcf	298.3	435.2	860.5
Akpo Field production, 1 Jan to 31 Dec 2023	Bcf	97.7		
Akpo Field Revisions	Bcf	34.6	177.9	99.4
Akpo Field Gross on 1 Jan 2024	Bcf	235.3	515.4	862.2

Notes:

1. “Gross” licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

RISC has included a separate table for fuel gas reserves (Table 5-23 and Table 5-24) for Akpo and Akpo West, respectively. These are not sales volumes but are gas volumes consumed in the operations. Under some jurisdictions these can be included in reserves.

Table 5-23: Akpo Fuel Gas reserves as of 1 January 2024

Gas Consumed in Operations	Unit	Reserves		
		1P	2P	3P
Fuel gas used at Akpo (incl. AU-P4 & D-P5)	Bcf	12.1	20.3	28.9
Prime net entitlement	Bcf	1.9	3.2	4.6

Notes:

1. “Gross” licence reserves are 100% of total field reserves.
2. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
3. These are not to be added to the sales gas reserves and must be reported separately as per PRMS 2018 reporting standard.

Table 5-24: Akpo West Fuel Gas reserves as of 1 January 2024

Gas Consumed in Operations	Unit	Reserves		
		1P	2P	3P
Fuel gas used at Akpo West	Bcf	8.8	12.7	16.5
Prime net entitlement	Bcf	1.4	2.0	2.6

Notes:

1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
3. These are not to be added to the sales gas reserves and must be reported separately as per PRMS 2018 reporting standard.

6. PML 3 – Egina Field Reserves

6.1. Field Description

The Egina oil field is located offshore Nigeria, approximately 200 km South of Port Harcourt, in water depths ranging from 1,110 to 1,750 m. It is developed using horizontal subsea wells tied to an FPSO and started production in December 2018. Total is the operator.

Egina was discovered by the exploration well EGA-1 in October 2003. The well was drilled in the Southern part of the field and it encountered hydrocarbons in middle to late Miocene reservoirs. The principal discoveries were the massive sand reservoirs of R1180 East and R1246.

The field was appraised between June 2004 and July 2006 with the drilling of EGA-2, EGA-3 and EGA-4 in the North and EGA-5 in the South. The principal reservoirs encountered by these appraisal wells were R1180 West and R1120.

Development studies carried out between 2007 and 2008 culminated in submission of the initial Egina Field Development Plan in May 2008. The plan developed the then estimated 544 MMstb of reserves in three reservoirs R1120, R1180 and R1246 with 39 subsea wells (20 oil producers and 19 water injectors) tied back via five manifolds, six double injection tees and five single injection tees to an FPSO. Pressure maintenance is by water injection in the three reservoirs with full voidage replacement. In 2008, the Reservoir Model V1 (RMV1) was completed resulting in the addition of a water injector to the 39 wells in the Egina FDP Rev0.

In 2011, the building of the Reservoir Model V2 (RMV2) was completed. The basis for RMV2 was the 2007 3DHD seismic (475 km^2) acquired for Egina field development and processed in time by Western Geco. Based on RMV2, the field reserves were revised to 548 MMstb to be developed with 44 subsea wells (21 oil producers and 23 water injectors) tied back to an FPSO. Consequently, an Addendum to the initial Egina FDP Rev0 was submitted in September 2011 and was approved by NAPIMS in January 2015 and DPR in July 2015. The 2018 FDP Rev1 includes development of the R1110 reservoir.

Development drilling started in December 2014 with first oil achieved on 29 December 2018. Water injection commenced on 31 January 2019. Various technical issues contributed to a delayed field production ramp-up between February and April 2019, but field plateau of approximately 200,000 bopd was reached on 30 May 2019. Sixteen oil producers and fourteen water injectors have been drilled and completed on the Egina field, with oil rates from 4,000 to 30,000 bpd per well.

A further 9 wells are included in the current development plan. Prime's forecasts consider 9 wells as firm on the drilling sequence and include the additional 9 wells to the current 30 wells in its forecasts. RISC accept this and include the additional 9 firm wells in our forecasts. Well locations will be refined based on production data and the latest 4D monitor survey.

Cumulative oil production up to and including 31 December 2023 is 256 MMstb. Fourteen injectors have injected 359 MMbbl water. Cumulative water production is 59.3 MMbbl, with a field water cut of 43%.

6.1.1. Geoscience Overview

RISC audited the Prime static modelling work for YE2021. The YE2021 conclusions are presented below for completeness as part of the YE2023 review.

The following section represents a summary of the geological evaluation of the field described in the Egina Field Development Plan (Egina FDP Revision 1, September 2018), in addition to other presentation material and reports provided by Prime.

The Egina field is located in PML 3 in the Nigerian deep offshore. It is located in the internal part of the compressional tectonic zone, to the North of the external zone, which is dominated by toe-thrusts (Figure 6-1).

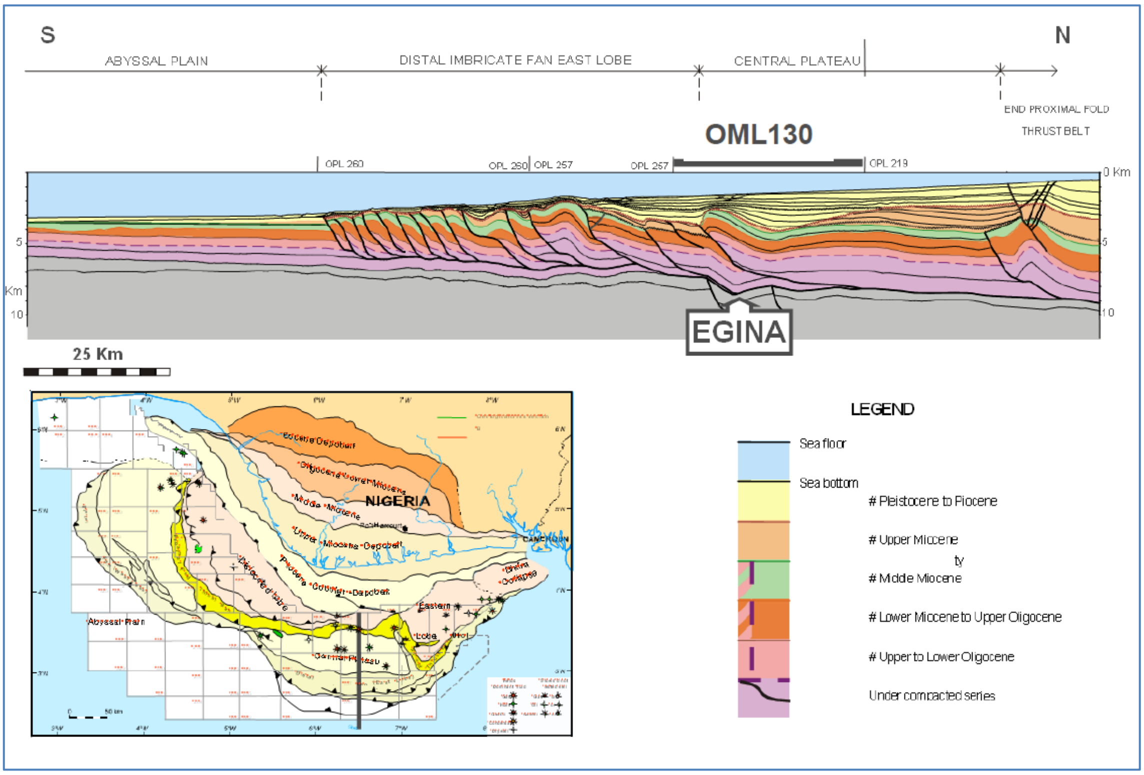


Figure 6-1: Egina Field Structural Setting

The Egina structure is a four-way dipping anticline with an axis aligned NE-SW approximately 20 km to the southwest of Akpo. This anticlinal fold is located above the lateral ramp of a major thrust, the frontal ramp of which is located some 6 km to the southwest of Egina field where it forms the Egina Ridge structure.

The anticlinal structure is divided into a northern and southern part by the presence of a reverse fault aligned perpendicular to, and roughly half-way along, the axis of the main anticlinal structure. No movement is detected on this fault in reservoirs younger than the main R-1180. Gentle folding associated with this N-S aligned compression divides the main Egina anticline into two smaller four-way dip structures. At the exploration and appraisal stage, the Northern structure was penetrated by EGA-2, EGA-3, and EGA-4 while the southern structure was penetrated by EGA-01/EGA-1-T1 and EGA-5 (Figure 6-2).

Multiple reservoir intervals are stacked in the Egina main area with four major hydrocarbon bearing intervals: R1110, R1120, R1180 East & West and R1246. There are a number of additional smaller reservoirs, but these are not material in terms of hydrocarbon volumes and are not currently developed. The developed perimeter of R1180 East is the only one encompassing the two culminations of the Egina structure while R1180 West and R1120 perimeters are located on the northern structure and R1246 perimeter is located on the southern structure (Figure 6-2). Figure 6-3 highlights the three main reservoir intervals in a correlation through the five exploration and appraisal wells. R1110 and R1120 is the youngest reservoirs while the R1246 is the oldest. The same correlation is illustrated on a seismic section in Figure 6-4.

As with the Akpo field there is significant in-field faulting, mainly orientated NE-SW, many of which are not thought to be sealing by the operator although are likely to provide a baffling effect for production. However, multiple Gas and Oil contacts are encountered within each reservoir and faulting is likely to contribute towards this reservoir compartmentalisation, in combination with different structural configurations and facies variations. Indeed, lateral communication whether related to facies variation or faulting remains a key uncertainty in Egina and further understanding will only develop with ongoing production and analysis of future 4D monitor seismic surveys.

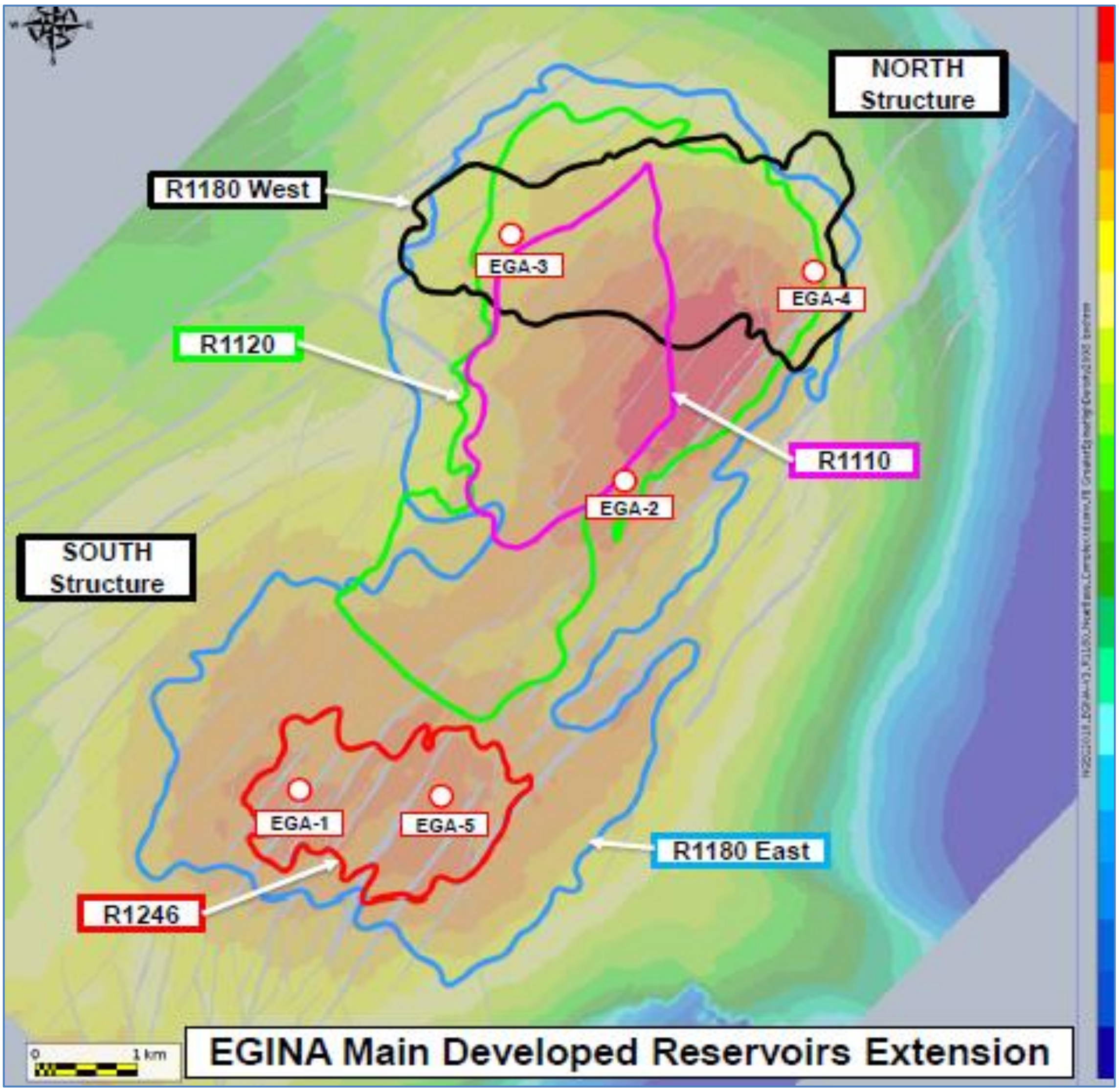


Figure 6-2: Top R-1180 depth structure map with Egina Main developed reservoir extension.

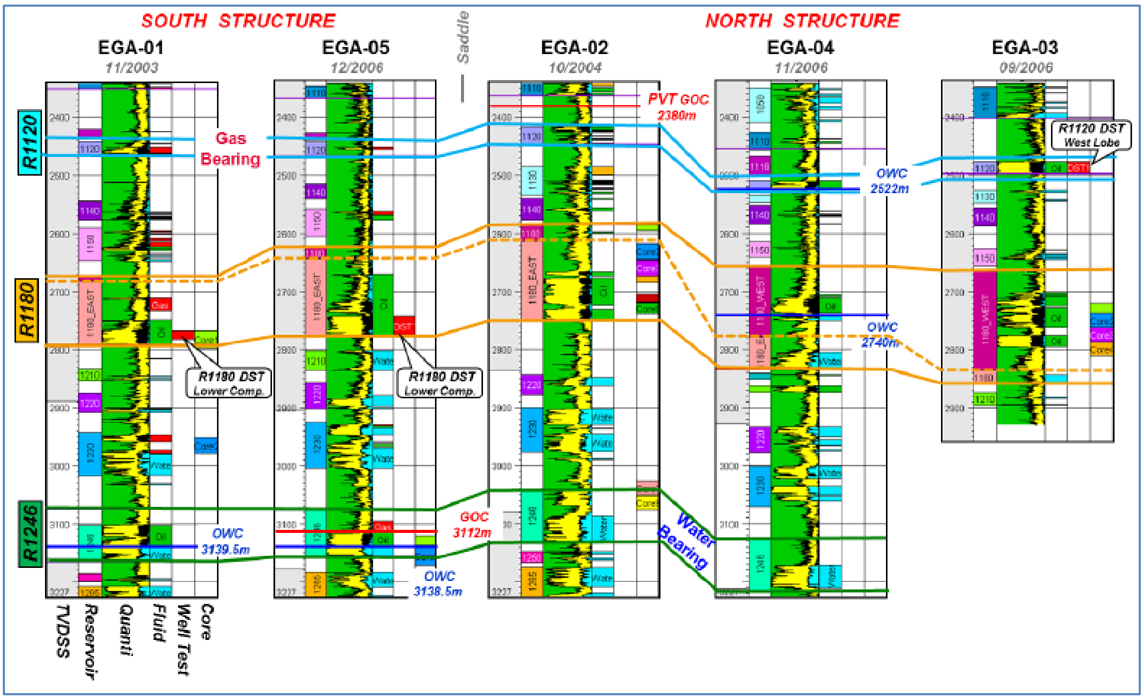


Figure 6-3: Egina Main Correlation through exploration and appraisal wells

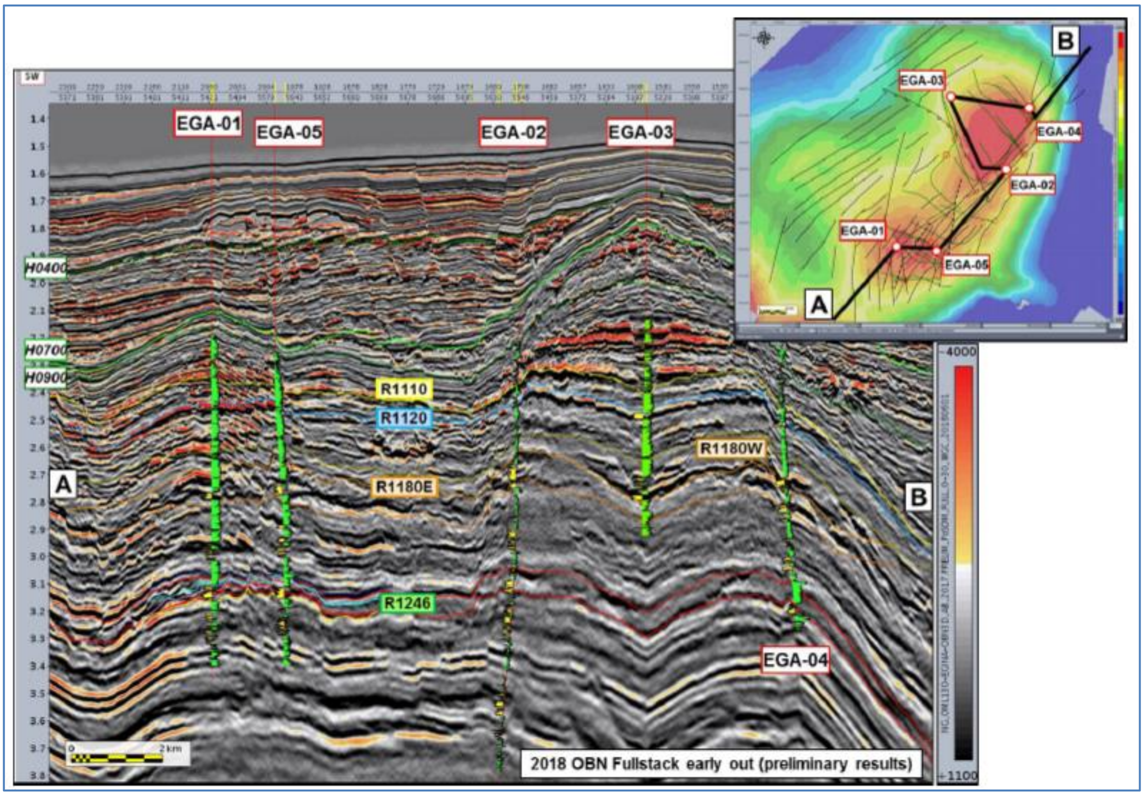


Figure 6-4: Seismic section showing structural geometry & stratigraphy of the Egina Field.

During the first phase of exploration, OPL 246 was covered by 3D seismic, with two main surveys done by the seismic contractor Geco-Prakla: between 1998 and 1999 (Eastern part of the licence, 1800 km^2) and between 1999 and 2000 (Western part of the licence, 1,225 km^2). These acquisitions have been the basis for defining the exploration and appraisal drilling programme and for the evaluation of the original Egina Field Development Plan ReV0 (Reservoir Models RMV0 and RMV1). In 2007, a high density (HD) 3D seismic survey was acquired for the Egina field (475 km^2). Various different re-processing studies and inversion volumes of this vintage were generated through 2009-2017 with different objectives, but all contributed to refinements to geological modelling and reservoir characterisation understanding in each of the different reservoirs and fed into development well planning.

A new seismic data acquisition using Ocean Bottom Nodes (OBN) was performed in 1Q 2017 to improve 3D seismic quality (resolution, Signal/Noise ratio) and serve as a 4D baseline with final processed products delivered towards the end of 2019 after significant project delays. In March 2020, the operator presented material indicating that a significant improvement in sand identification and mapping is now being achieved using the final PSDM products, and which is allowing the optimisation of development well placement. RISC understand that this is feeding into new reservoir models being produced by the operator. The first monitor survey was originally planned for 2Q 2020 but has been pushed back to 1Q 2021 as a result of the COVID-19 pandemic. It is expected that the monitoring surveys will identify swept/bypassed areas, water front movement and possible gas cap formation to enhance field management and plan further development drilling as has been successful in Akpo and Agbami fields.

The depositional model for Egina is similar to the other PML 2, PML 3 & PML 4 fields and comprises a turbiditic system which is described as including the following from up-slope to down-slope (Figure 6-5):

- A deep erosive canyon-like channel segment;
- An erosive and constructive channel system where levees develop on the shoulder of the channel system;
- A depositional channel system where energy is too weak to erode the substratum; and
- Lobe complexes formed at the end of the system.

The Egina field consists of several reservoirs corresponding to different complexes (Figure 6-6) with a general NE-SW orientation. Most of the reservoirs (R1110, R1180 and R1246) correspond to channel-levee systems with lateral and vertical organizations in terms of sand distribution and grain size, with the coarsest (poorly sorted) fraction concentrated in basal channel lags as described at the base of the Lower Complex of R1180 West for example, and finer better sorted sediments in the upper parts of channel fills, and their associated proximal levees. In some cases, the complex is terminated by channel abandonment facies comprising thin sand to shaly sediments. Fine sand and well sorted sediment reach the terminal parts of these systems, forming lobes as encountered in the R1120 reservoir.

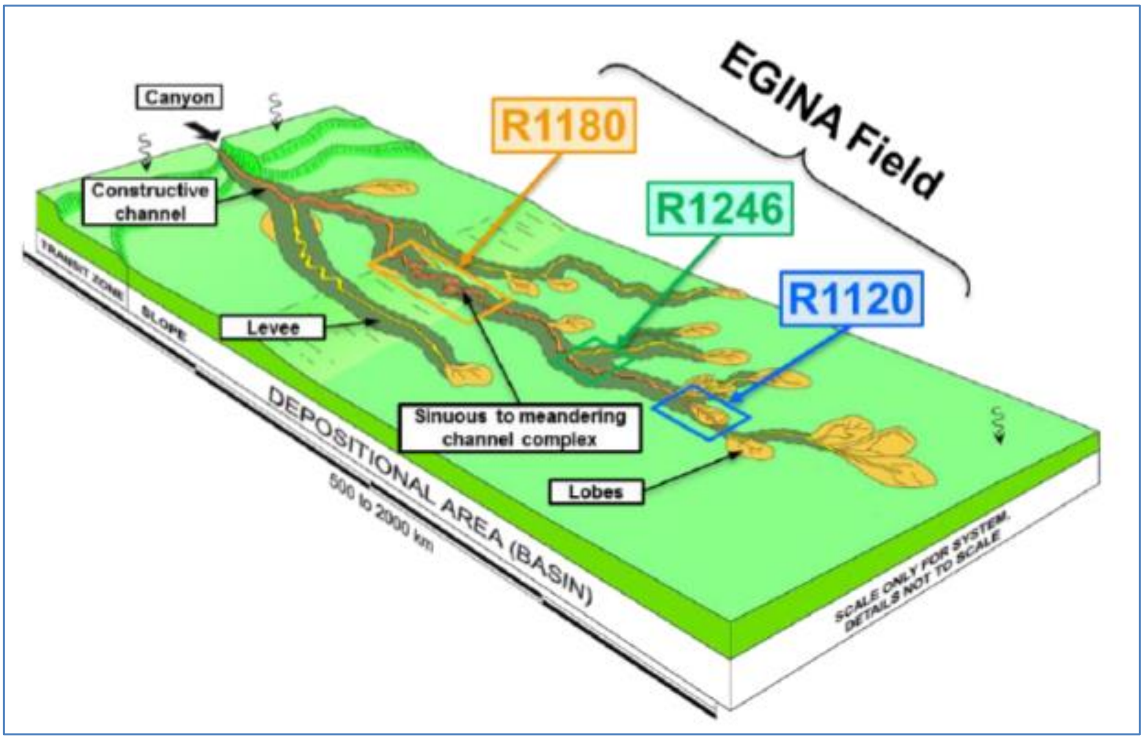


Figure 6-5: Egina Field Depositional Model

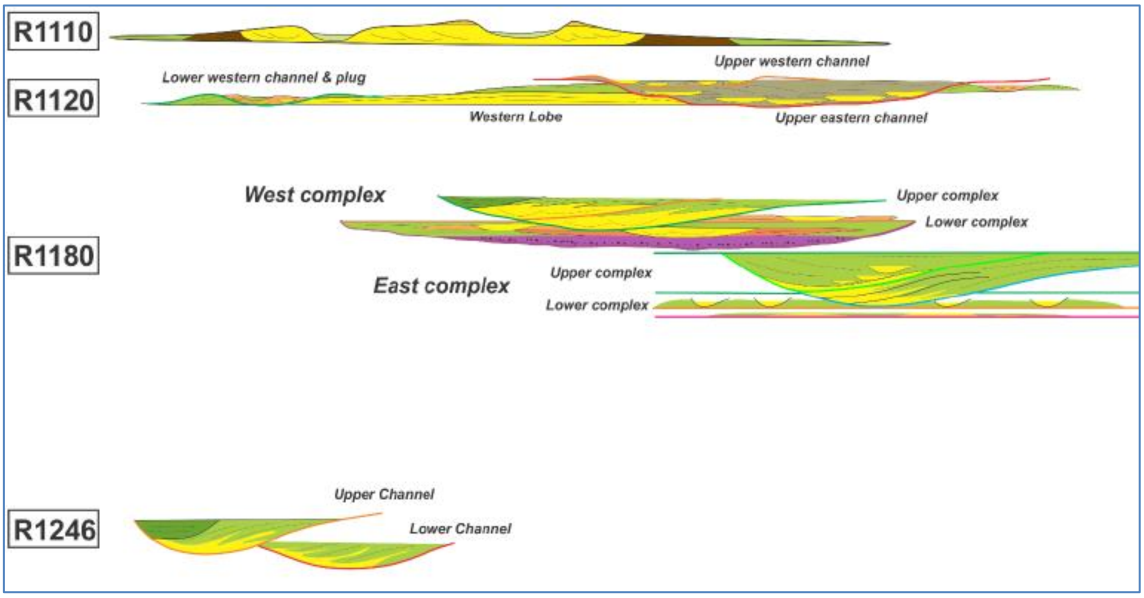


Figure 6-6: Schematic Representation of main reservoir architecture of developed Egina Reservoirs

The Egina reservoir sandstones exhibit excellent reservoir properties with average porosities typically in the range of 15-27% and permeabilities in the range 150-3,000 mD with better quality observed in channel facies vs lobes. Reservoir units are typically shale dominated on a gross basis and can be highly variable in terms of net to gross and reservoir thickness, although the main reservoir sand packages can be correlated across the field with a high degree of confidence. The lateral variability is a function of the depositional system and variation between depositional facies (e.g., channel vs overbank vs lobe) which can make reservoir distribution difficult to predict despite the large number of well penetrations.

Seismic data are not typically of sufficient quality / resolution to accurately map individual sand bodies within each reservoir, although is sufficient to map the main channel fairways with fair accuracy in many cases using seismic attributes from the various reprocessed and inversion products.

RISC understands that the operator is currently working to update a new static model (RMv4) based on OBN seismic and incorporating wells drilled since 2018. During 2022 Prime made geological adjustments to the models based on the 4D-M1 and latest production data: more baffling effects than initially considered and reduction in STOIIP mainly in R1180. Prime have included sand distribution in the Architectural Elements facies which controls the preferential path for water movement.

R1180 STOIIP has the largest uncertainty of the Egina reservoirs and the conclusion of our model reviews is that the Prime model is a fair representation of STOIIP, but perhaps slightly optimistic regarding the population of Architectural Elements ("AEs") when calibrated to the seismic data. Conversely, we viewed the Total model as pessimistic.

The other key reservoir in Egina in terms of STOIIP is the R1120. RISC were provided with the Prime R1120 V1 static model and some documentation describing the model build and comparing the Prime model with the Total RMv3 model which RISC has not reviewed.

The Prime models follow standard industry practice and quality control checks within the model regarding interpreted facies, porosity and water saturation suggest the model honours the wells drilled in the reservoir. For this review Prime provided its v2 models that integrate data from all wells drilled so far in the field and OBN seismic data interpretation. The volumes did not change significantly from v1 models. In RISC's opinion the model is a fair representation of field architecture and volumes, although RISC recognise the interpretation of the AEs that form the main control on model property distribution carry uncertainty. RISC's YE2021 (unchanged YE2023) proposed STOIIP for the Egina Field is shown in Table 6-1, in close agreement with Prime estimates. RISC reviewed the material provided by Prime on uncertainty analysis performed on their R1180 and R1120 models (which account for approximately 90% of field STOIIP) and regard this as a reasonable attempt to characterise STOIIP uncertainty resulting in low to high range of -13% and +19% on base case STOIIP respectively.

Table 6-1: Egina Field Best Case STOIIP by reservoir (MMstb)

Evaluation	R1110	R1120	R1180 W	R1180 E	R1246	Total
Total RMv3 Model STOIIP (MMstb)	48	210	195	442	44	939
Prime v1 Model (2019) STOIIP (MMstb)	43	198	735		45	1021
RISC STOIIP for YE2023 report (MMstb)	43	198	685		45	971
Prime v2 Model (Aug 2020) STOIIP (MMstb)	43	226	754		50	1074
Prime v2 Model (Aug 2021) STOIIP (MMstb)	**57**	**222**	**725**		**51.5**	**1056**
Prime v2 Model (Aug 2022) STOIIP (MMstb)	**57**	**212**	**653**		**46**	**968**

Notes:

1. RISC accepts Prime v2 Model (Aug 2022) STOIIP as a valid representation of STOIIP given the uncertainty ranges in estimating STOIIP. Both RISC and Prime STOIIP's are reasonable representations but RISC has used its own figure for this report.
2. Bold text has been added for YE2023 reporting

RISC note that uncertainty in the interpretation of Architectural Elements (AE's) was not included. RISC see this as a key uncertainty as AE's form the hard constraint for the population of all other reservoir properties in the model and the interpretation of AE's from seismic attributes carries some uncertainty. RISC propose to widen the STOIIP uncertainty range to account for this to -16% and +22% (Table 6-2).

Table 6-2: Egina Field Gross STOIIP (MMstb)

	Low	Best	High
Egina Field STOIIP (R1110, R1120, R1180 and R1246)	815	971	1185

Prime's updated STOIIP of 968 MMstb confirms RISC's estimates from YE2021 (Table 6-1) and accepted given the history matches discussed below.

Prime updated the history match in Sept 2022. The key updates were:

- Seismic OBN Inversion and 4DM1 interpretation were incorporated.
- A new set of reservoir properties based on seismic inversion, fault transmissibility changes, aquifer strength, some local vertical transmissibility modifications, and changes to well PI.
- 4D-M1 confirmed some compartmentalization of the reservoir and highlighted some baffling between injectors and producers. (Considered to be mitigated by wells intersecting multiple panels.
- R1180 reservoir: a decrease in the EUR in the model to 332 MMstb from 374 MMstb mainly due to facies redistribution and history matching to 4D-M1 interpretation.
- R1120 reservoir: 4D-M1 fast track interpretation validated the infill wells WI A-WN2 and OP A-PS-1 and remain on plan for 2023 (Figure 6-7). Forecast EUR was reduced by 3.8 MMstb to 100 MMstb.

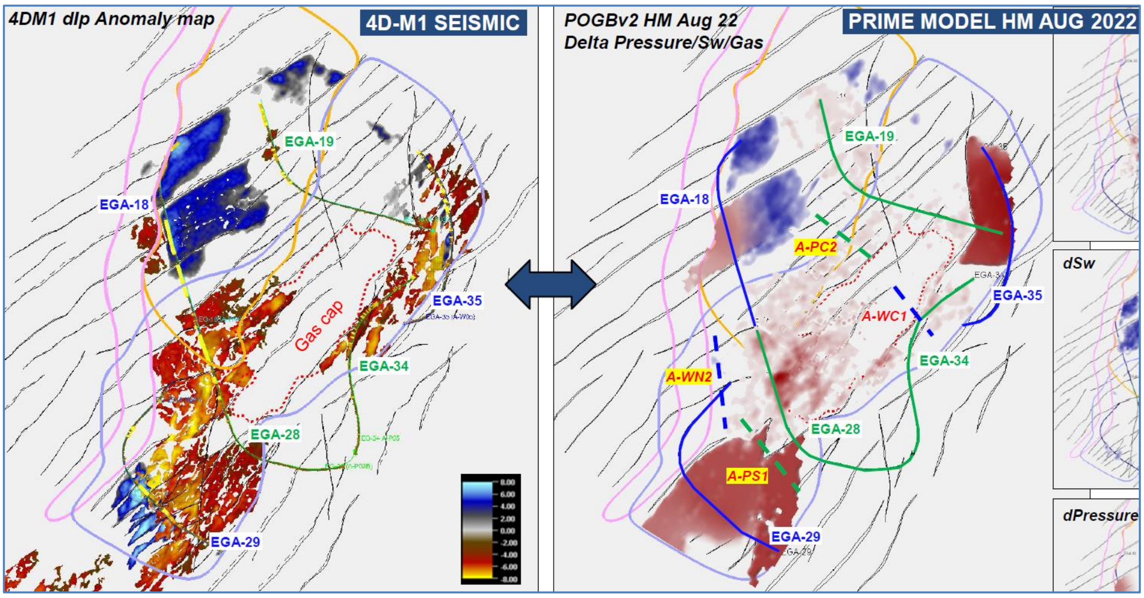


Figure 6-7: Egina R1120 4D vs August 2022 History Match

- R1246 reservoir: 4D-M1 results confirmed limited pressure support, most of the injected water from EGA-30 flows North. Forecast EUR was reduced by 5.7 MMstb to 12.5 MMstb, two water shut-off interventions would restore 0.8 MMstb.
- R1110 reservoir: 4D-M1 confirmed communication across the sandy erosive channel. Forecast EUR was reduced by 1.2 MMstb to 11.1 MMstb which includes one of the intended infill water injection wells.
- The complete set of infill wells are:
    1. R1110: 2 water injectors.
    2. R1120: 2 producers + 2 injectors.
    3. R1180E: 3 producers.
    4. R1180W: No infills.
    5. R1246: No infills.
- Once optimizations were made the 4 history matched models were coupled to allow constraint modelling and to produce 2P production forecasts.
- Prime 1P and 3P forecasts are generated using DCA.

The 4D-M1 data, interpretation and insights are amongst the highest quality information available for reservoir management and understanding. Prime's reduction of mid case STOIIP to 968 MMstb and EUR to 462 MMstb (a reduction of 45 MMstb) for YE2022 estimate was considered a well calibrated and suitable change which RISC fully supported.

6.1.2. Reservoir Fluid Properties

Egina oil is low viscosity, medium gravity oil with the bubble point 5% to 17% below the initial reservoir pressure.

Table 6-3: Egina reservoir fluid properties

Property	Unit	Oil column
Pressure	psia	3,535 – 4,285
Temperature	deg C	45 - 61
Formation volume factor (Boi)	rb/stb	1.3 – 1.7
Gas oil ratio (Rsi)	scf/stb	538 - 679
Oil viscosity (in-situ)	cP	1.0 – 1.8
Stock tank oil gravity	deg API	25 - 41

Associated and gas-cap gas contains 90% methane, 3-4% Carbon Dioxide and negligible Nitrogen.

6.1.3. Production Facilities

The development will eventually consist of 39 subsea wells (currently 30) connected to an FPSO. Most of the wells are horizontal, 7 are deviated. The remaining 9 wells are scheduled to be drilled in 2023 (4 wells), 2024 and (5 wells) as shown in Figure 6-8. The wells are tied into an umbilical and flowline system consisting of 2 production loops, 3 water injection lines and 8 risers. Oil is exported through twin export lines to offloading tankers via an offloading buoy. The facility has the capacity limits shown in Table 6-4. There are seawater injection facilities and gas lift.

Table 6-4: Egina facility production constraints

Specification	Capacity
Oil production	208,000 bbl/d
Liquid production	429,000 bbl/d
Water production	289,000 bbl/d
Water injection	470,000 bbl/d
Gas production	360 MMscf/d
Gas lift	198 MMscf/d
Gas export	162 MMscf/d

The facility is estimated to use 25 MMscf/d of gas as fuel. Excess gas is exported via a 16” line 150 km to the Akpo export line where gas is transported to the Bonny LNG plant. A schematic representation of the Egina FPSO is shown in Figure 6-8.

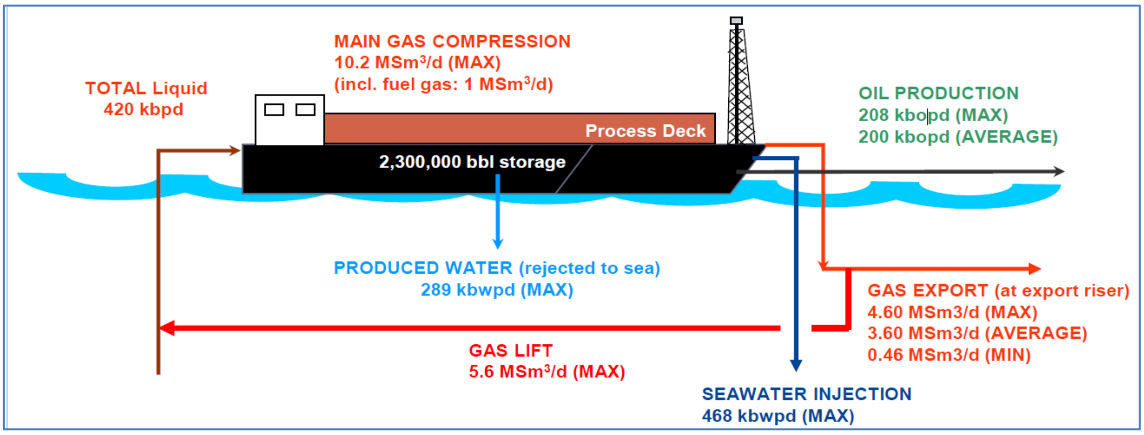


Figure 6-8 Schematic Representation of Egina FPSO

6.1.4. Production History

Figure 6-9 shows the Egina production history to 10th December 2023. Egina started production in December 2018 and reached plateau production (facility oil capacity) of 208,000 bopd in June 2019 with 15 production wells. Cumulative production to 31st December 2023 was 256.1 MMstb.

Production was reduced to 120,000 bopd in May 2020 and remained restricted due to OPEC quotas until June 2021. Since June 2021 the field has been producing at well capacity. A significant change in performance can be seen during 2023 where the gas production exponentially increased from 65 MMscf/d in May 2023 to 170 MMscf/d in November 2023 before dropping back to 70MMscf/d in December 2023. Oil production was 93,000 bopd.

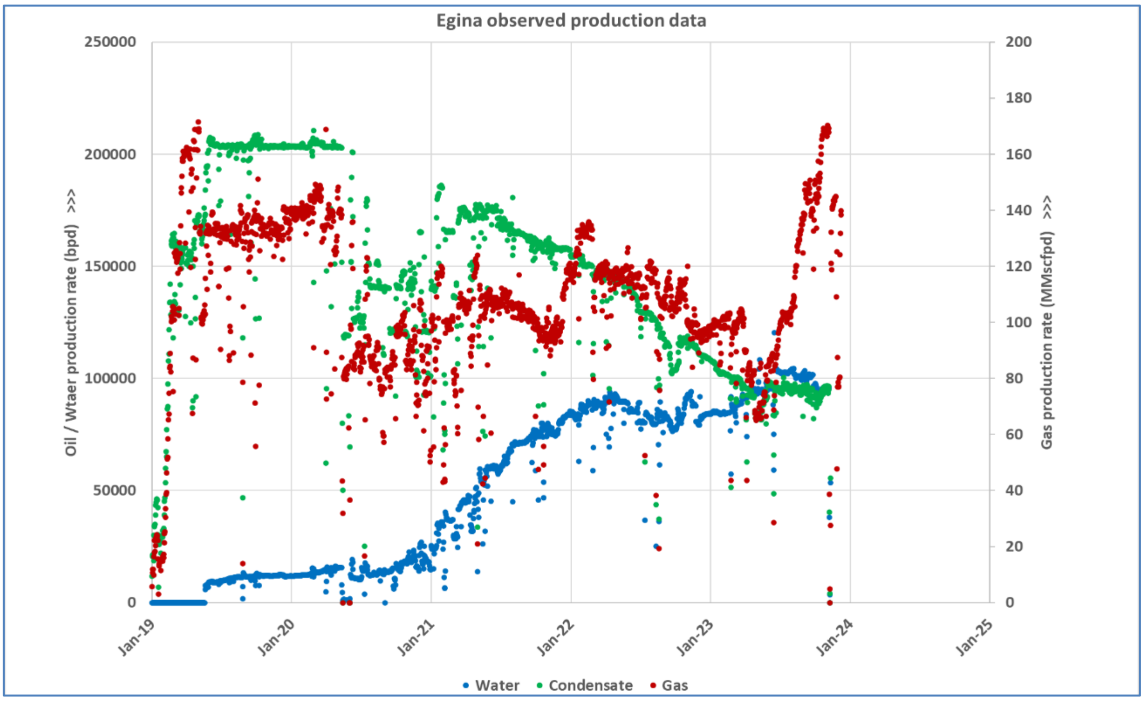


Figure 6-9: Egina production history.

Water injection started in February 2019 and reached 300,000 bpd mid 2019 with 14 injectors. Water production started in May 2019 and is currently 95,000 bwpd.

The GOR was steady at 650 to 700 scf/stb until 2022 where GOR has increased to 1,000 scf/stb and continue to climb to 1760 scf/stb in October 2023 before decreasing to 1400 scf/stb as of 10th December 2023

Artificial lift is currently not used as the relatively high GOR provides adequate lift. Gas lift facilities are installed in anticipation of its potential requirement later in the field life.

The current cumulative oil production per well varies from 1.5 to 30 MMstb for different wells.

The highest producer (B-P07-11) has produced dry oil at 24,000 bopd since start-up with constant GOR, constant flowing bottom hole and constant wellhead (2,400 psia) pressures. The well began declining in June 2022 and was producing 13,000 bopd at10th December 2023. The poorest producer (10-P1-36) has produced between 2,000 and 2,000 bopd dry oil with increasing GOR (5,200 to 7,800 scf/stb). Fourteen of the current sixteen production wells have produced more than 20% water cut. The highest water producer (B-P02-15, R1180 reservoir) started 5% water cut after 5 months (1.2 MMstb oil) and steadily increased to 93.5% after 5 years and 7.3 MMstb cumulative oil production. Although variable, well performance has generally been in line with the FDP forecast.

Three wells drilled in 2023, one producer (EGINA-39) in R1120 reservoir and well was TD on 25th July 2023. The well came onstream in October 2023 and currently producing at 4,500 bopd. Two injector wells (EGINA-37 and EGINA-38) drilled in R1110 and R1120 respectively. Well EGINA-37 has been drilled to support EGINA-36 producer, and well EGINA-38 has been drilled to support EGINA-28 and EGINA-39 producers and de-risking potential future wells in the reservoir.

Seventeen oil producers and 16 water injectors have been drilled to date. There are six firm infill wells, re-scheduled to be drilled in 2024 and beyond. A-P06 and 10-P2 wells will be drilled in R1120 and R1110 reservoirs in 2024 respectively. A-P06 will be a gas producer targeting the southern structure of R1120. The well will also test and sample a potential oil rim. The 10-P2 well will be an oil producer, targeting the northern area, out of reach for EGA-36 in R1110 reservoir. It will also be the long-term back-up of EGA-36. There will be four wells plus one sidetrack to be drilled in 2025. The additional four infill opportunities are currently being investigated in reservoirs A-Upper (ALS 1+3), A Lower (AUP8) and B-W4 (Water injector in B reservoir) for 2025. The sidetrack planned for 2025 is mainly for water shut off in EGA-18 and to restore potential in EGA-19 in R1120. The wells are to be validated/confirmed by 4D seismic interpretation.

The **R-1110 reservoir** has been developed with one oil producer and 2023 infill water injector (EGA-37). EGA-36 (10-P1) was shut-in during 2021 due to lack of pressure support, and was restarted in 2022. The well has responded well to water injection from EGA-37 and is currently producing at 5,000 bopd. The GOR is falling to 8,600 scf/stb from 11,000 scf/stb pre injection.

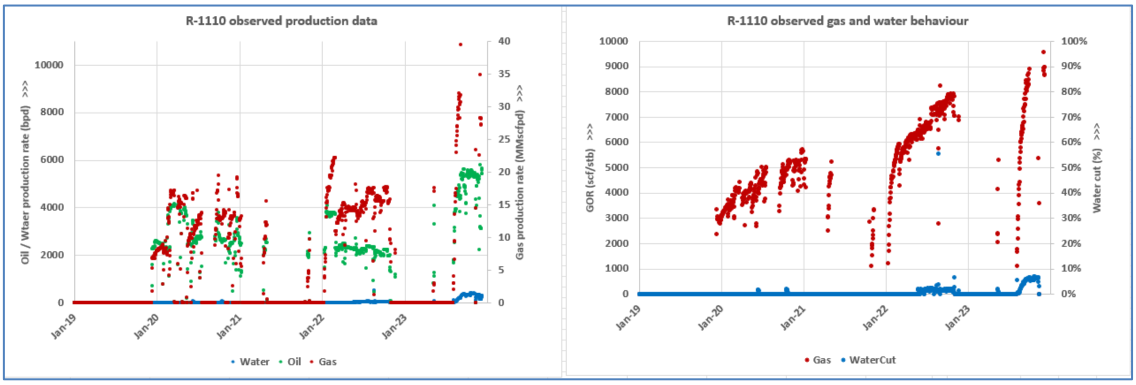


Figure 6-10: Egina R-1110 production history.

The **R-1120 reservoir** has been developed with four oil producers and four water injectors. Minor water production (4%) is seen in one well with 40% in a second. The third well remains dry (Figure 6-11). Drilling additional producers and injectors in the reservoir has resulted in increase in production by approximately 5,000 bopd which means that reservoir-based Decline Curve Analysis is not viable. It is worth noting that the second most prolific well in the reservoir (PN1C/A-P02B/28) is responsible for approximately 40% of the total production and is benefiting from the newly drilled injector well and is in ramp-up mode (Figure 6-12).

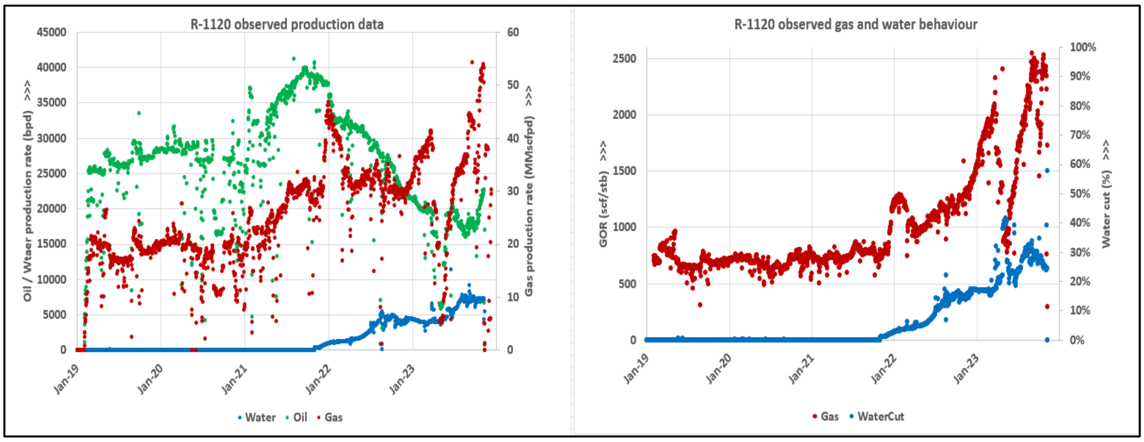


Figure 6-11: Egina R-1120 production history.

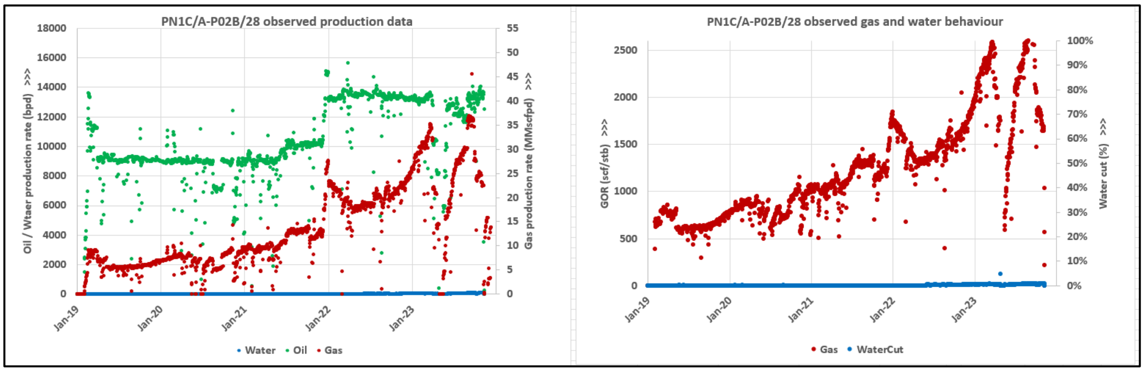


Figure 6-12: Well EGA-28 observed oil production.

The **R-1180 reservoir** has been developed with ten oil producers and ten water injectors. The water cut has risen to 57% with nine of the ten producing wells above 37% water-cut (Figure 6-13).

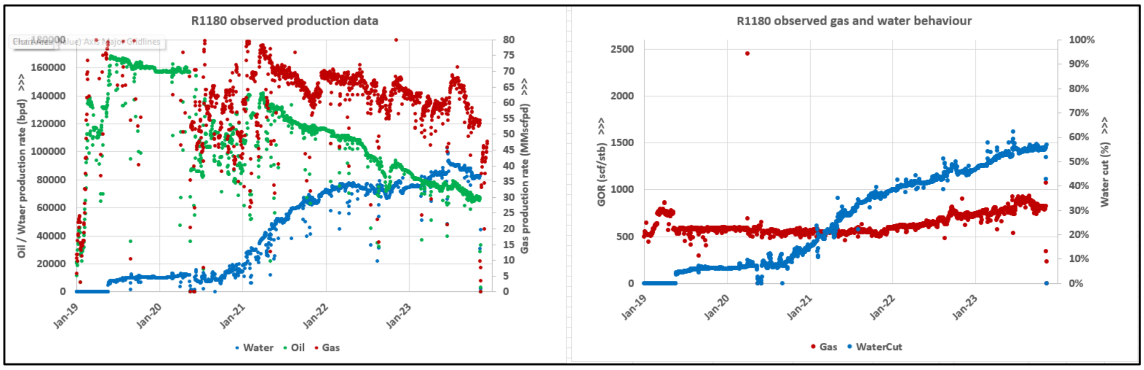


Figure 6-13: Egina R-1180 production history.

Production was cut back from May 2020 to June 2021 due to Opec quotas. However, the reservoir has produced at maximum deliverability since that time. Oil rate decline has increased during 2022 with rising GOR's being observed. Well EGA-10 is the third biggest producer with cumulative production of 23.2 MMstb to 10th December 2023 and has been on decline since mid-2023. GOR increased to 700 scf/sb but dropped to 600 scf/stb and then back to the historical trend.

Figure 6-14 shows the production history of well EGA-10.

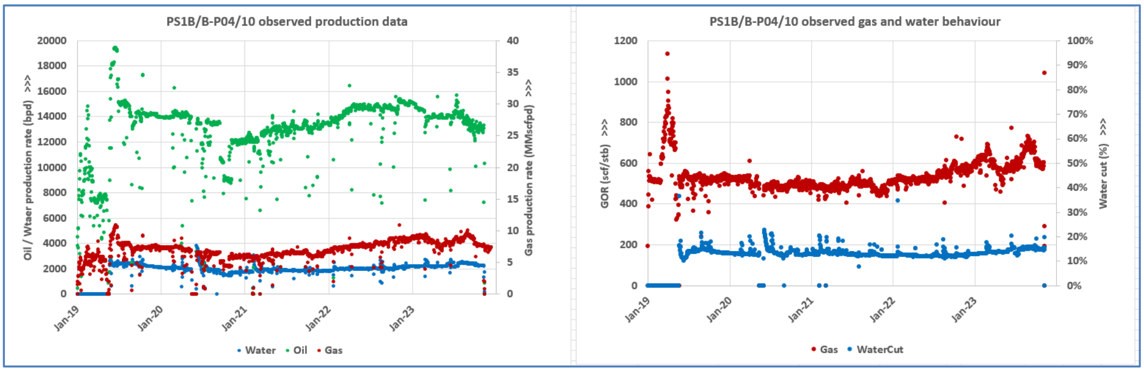


Figure 6-14: Well EGA-10 observed oil production.

Figure 6-15 shows an exponential decline fitted to the most recent production data from R1180 which is similar to 2022 performance. This is due to steep increase in GOR which started from late 2021 and has reached 800 scf/stb. This represents a 45% increase in the GOR and will affect reserves. The estimated EUR using exponential decline is 238 MMstb.

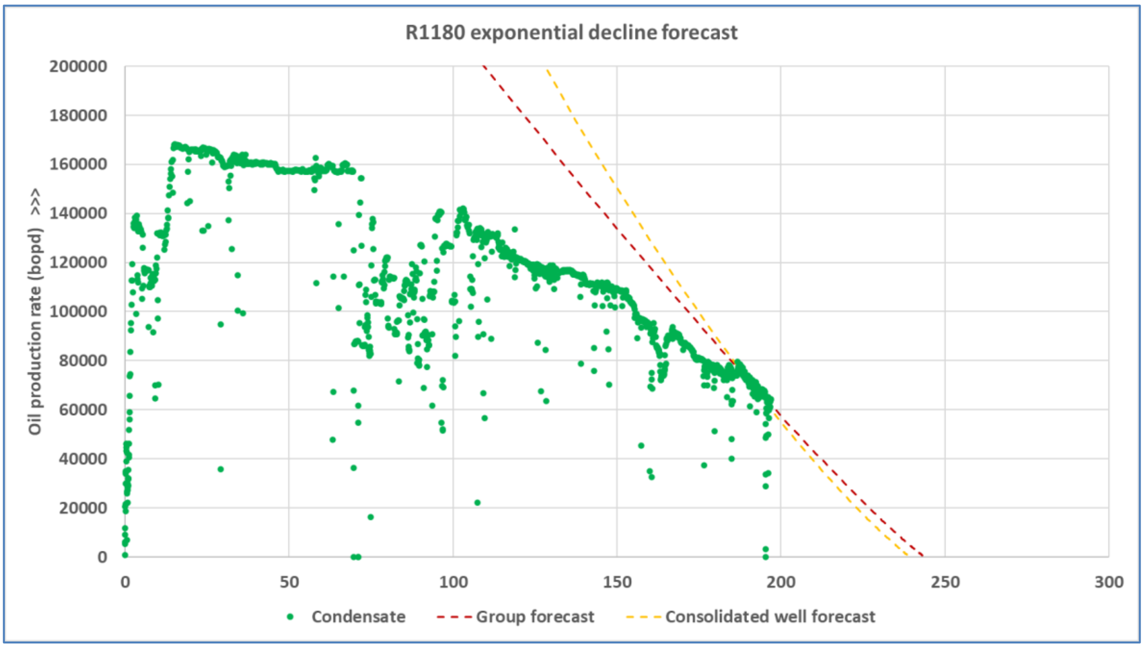


Figure 6-15: Egina R-1180 exponential decline forecast.

Two infill producers are proposed in the R-1180 reservoir (one in R1180 East and one in R1180 West). Figure 6-16 shows the forecast residual oil maps for R1180 East and West.

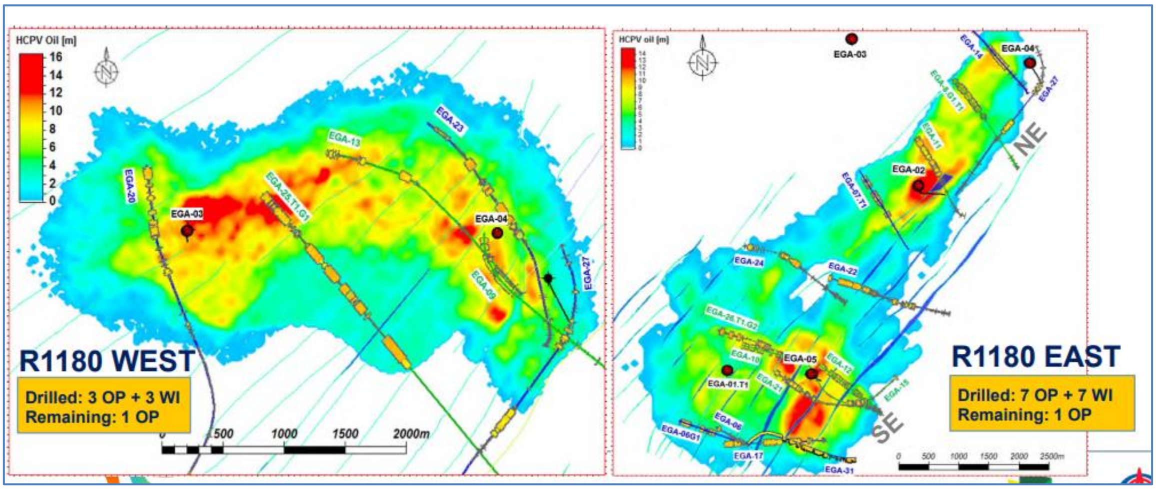


Figure 6-16: R1180 East and West forecast residual oil..

The R-1246 reservoir has been developed with two oil producers and one water injector. EGA-32 has watered and been shut-in since July 2022 out which leaves EGA-33 as the only producing well in the reservoir. No further development is planned.

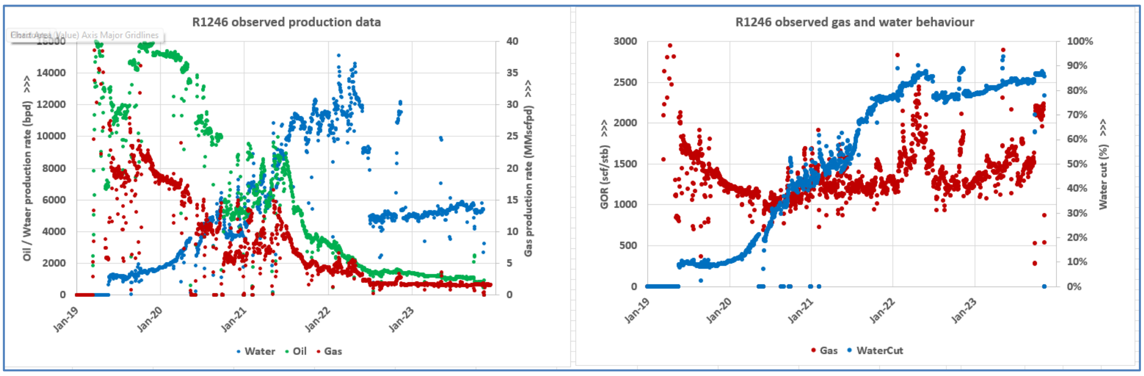


Figure 6-17: Egina R-1245 production history.

The reservoir has largely been produced at maximum deliverability. Figure 6-18 shows the EGA-33 performance which exhibited a steep increase in water cut and GOR trend from 2021.

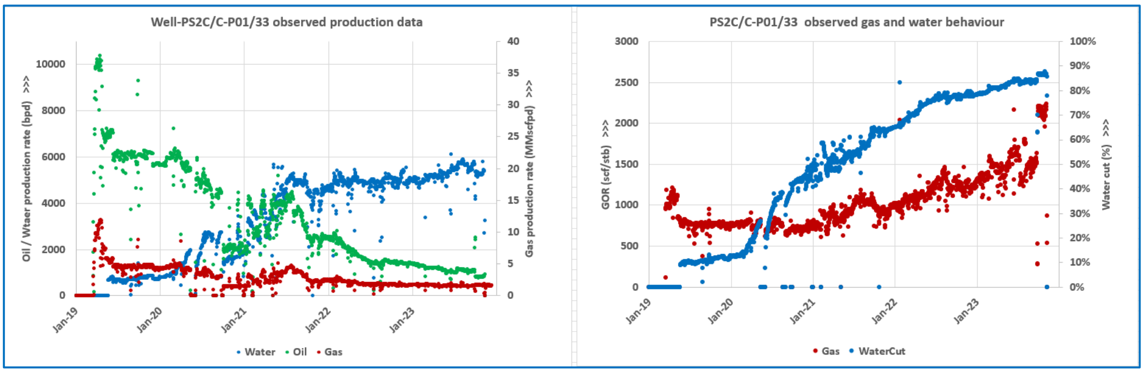


Figure 6-18: EGA-33 observed production.

6.1.5. Resource History

In 2017-2018 the operator (Total) provided a preliminary RMv3 update to their FDP STOIIP and resources estimates. Prime considered these conservative and conducted their own v2 evaluation, Table 6-5. The Egina wells show higher porosity than used in the RMv3 modelling. RISC estimate this will increase STOIIP by about 10% and accounts for the majority of the difference between Prime v2 and RMv3 STOIIP. Prime updated their v2 evaluation with history matching for YE2021 and YE2022. There have also been two revisions of the static model in March and July 2023 with revised STOIIP of 963 MMstb and 995 MMstb respectively.

Table 6-5: Egina STOIIP updates (RMPv2/V3, RMv3, Prime v1 Dynamic Model)

EGINA STOIIP (mmbbl)		FDP (RMP v2) 2011	TOTAL RMv3 Models	Prime v2 Static (Aug 2022)	Prime v2 Static (Mar 2023)	Prime v2/v3 Static July 2023
R-1110		0	48	57	57	57
R-1120		229	210	212	212	218
R-1180	West	329	195	653	648	674
	East	680	442			
R-1246		40	44	46	46	46
SUM (STOIIP)		1278	939	968	963	995

RISC has reviewed the history match of the coupled model and consider it reasonable for oil and gas. RISC note that the water production from the model shows higher values than actual production and is therefore likely to require monitoring or modification. Figure 6-19 & Figure 6-20 show the history matched oil & gas and water production for YE2023.

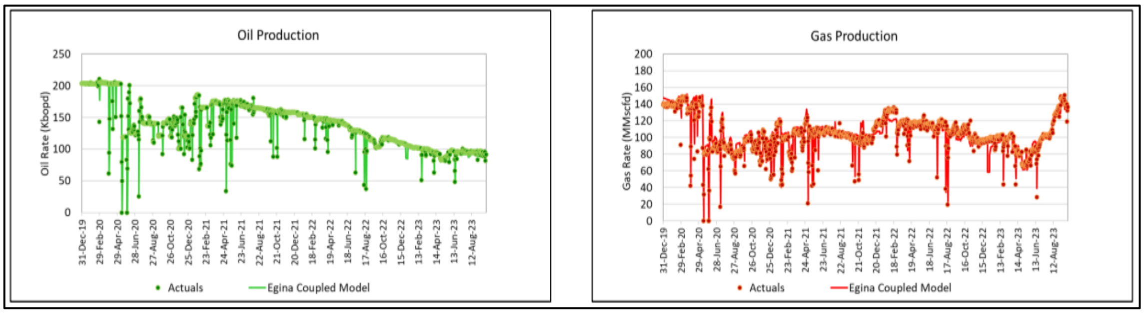


Figure 6-19: Egina Field history match of gas production.

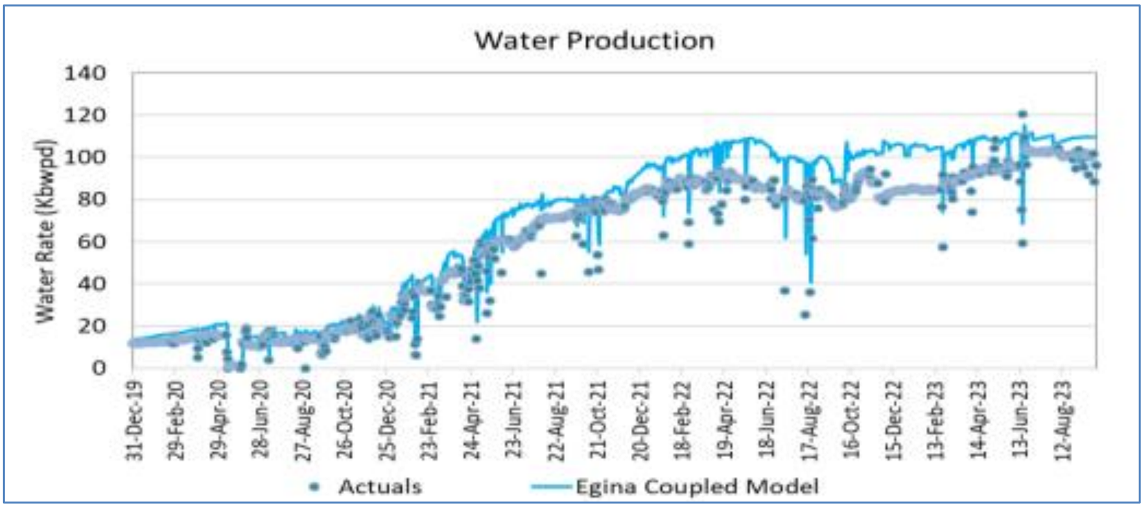


Figure 6-20: Egina Field history match (water production).

The history match was achieved by adjusting aquifer strength, fault transmissibility, well productivity and some local vertical transmissibility adjustments and PV multipliers. Table 6-6 shows the technical recoverable oil estimates including infill wells.

Table 6-6: Egina EUR updates (RMPv2, RMv3, Prime v2/v3 2022 &2023)

Technical Recovery (mmbbl)		FDP (RMP v2) 2011	TOTAL RMv3 Models	Prime v2 Coupled HM Aug 2022	Prime v2 Coupled HM Mar 2023	Prime v2/v3 Coupled HM July 2023
R-1110		0	19	17	17	20
R-1120		82	82	98	98	106
R-1180	West	160	*112*	332	325	317
	East	288	*191*			
R-1246		18	18	14	14	13
SUM (Recoverable)		**548**	**422**	**462**	**454**	**456**
Number of Dev Wells		**44**	**37**	**39**	**38+1ST**	**39+1ST**

The Prime 2P estimate (456 MMstb) is derived from simulation using a model history matched to July 2023 and the current 33 wells (17 producers, 16 injectors), plus 6 additional wells and one planned sidetrack during 2024 to 2025. The reduction in 2P from YE2022 to YE2023 is 6 MMstb. Prime 1P to 3P range of EUR is estimated as 352 to 541 MMstb; approximately +/-6%; a reduction from 373 to 577 MMstb.

6.2. Further Development Plans

Six additional wells plus a sidetrack, 5 oil producers and 1 water injector, are planned in 2024-2025 and incorporated into the forecasts. The 4D-M1 seismic monitor survey acquired in 4Q 2021 has been used to confirm final infill well locations.

Figure 6-21 shows Prime's forecast for the existing 33 wells. Figure 6-22 shows their incremental forecast for the 9 infill wells (undeveloped).

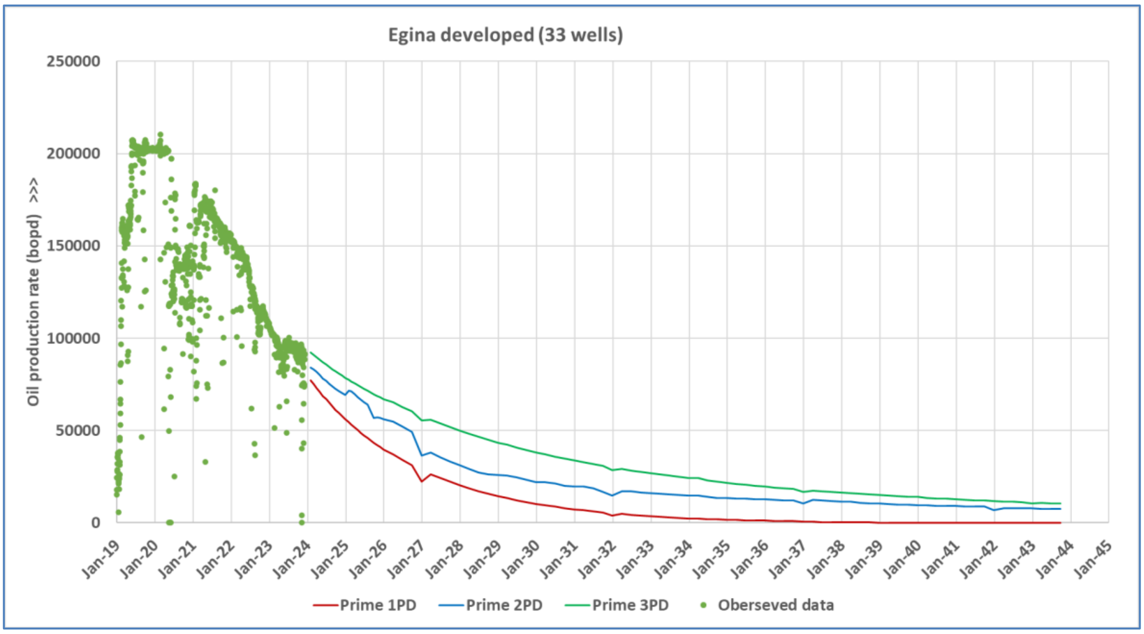


Figure 6-21: Egina NFA (33 wells) forecast (Prime).

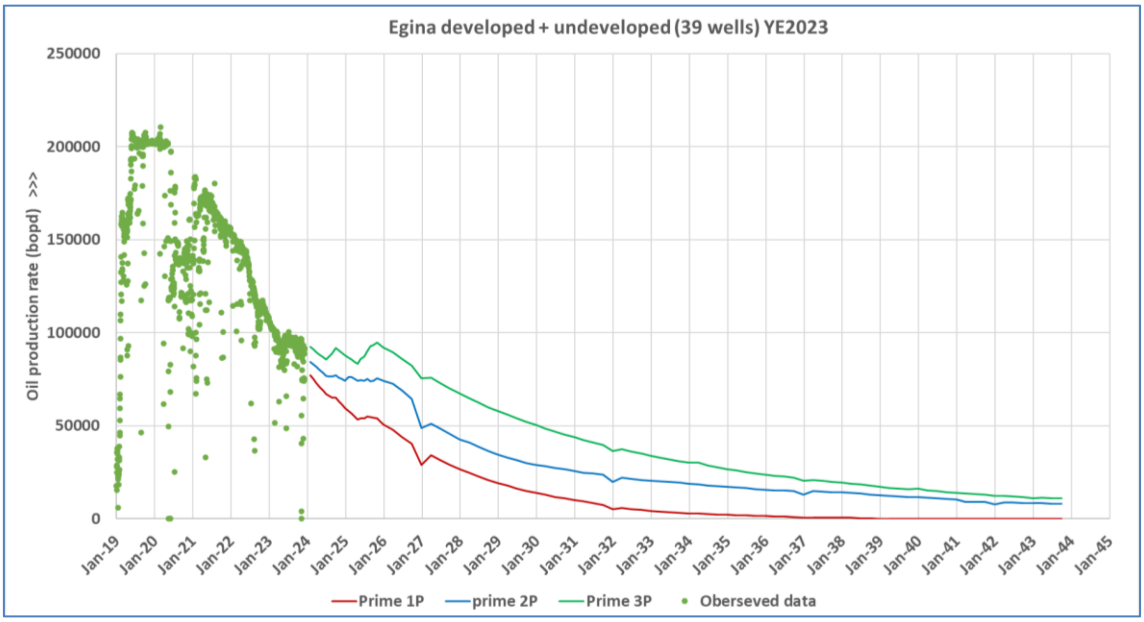


Figure 6-22: Egina Developed + Undeveloped (9 infill wells) forecast (Prime).

The incremental recovery from the 9 infill wells ranges from 2.5 to 9.0 MMstb per well, compared to 3 to >30 MMstb per well from the initial wells. Including the simulation model review, RISC accept the incremental infill forecast as reasonable.

Egina West is an exploration prospect. Conceptual development uses four subsea wells (two oil producers, two water injectors) tied back to Egina. Egina West production, or cost forecasts are not included in the forecasts.

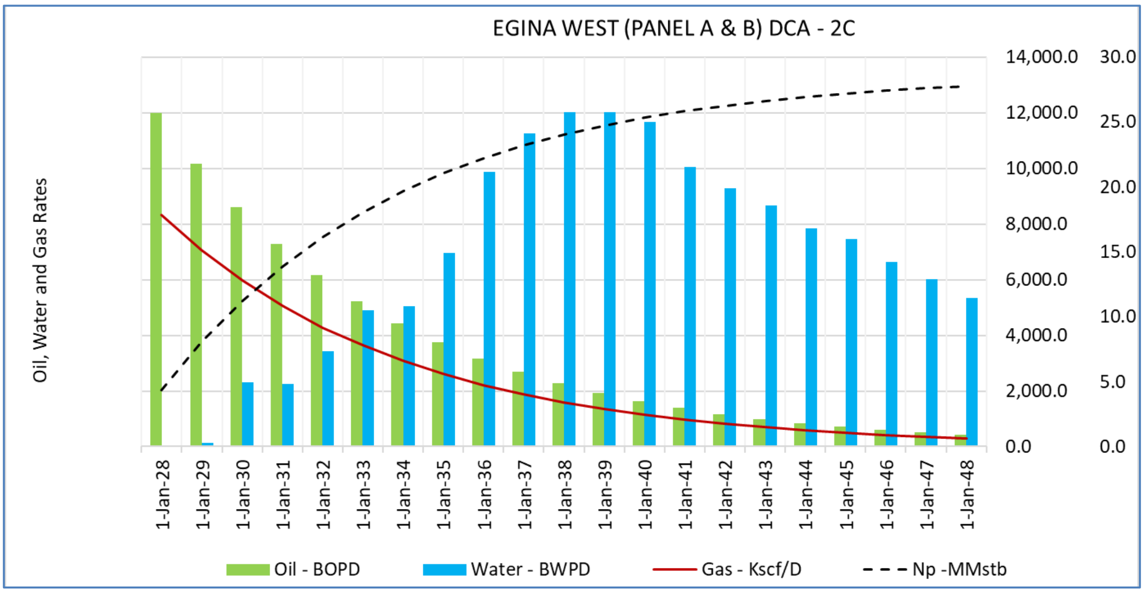


Figure 6-23: Egina West prospective 2U forecast.

An Egina West exploration well has been scheduled for 2023. Prime's production forecast is unchanged since last year (Figure 6-23).

6.3. Production Forecasts

Figure 6-24 shows Prime's and RISC's 1P, 2P and 3P developed oil forecasts with the current 33 wells. The field is forecast to produce at full potential, and not constrained by OPEC quotas.

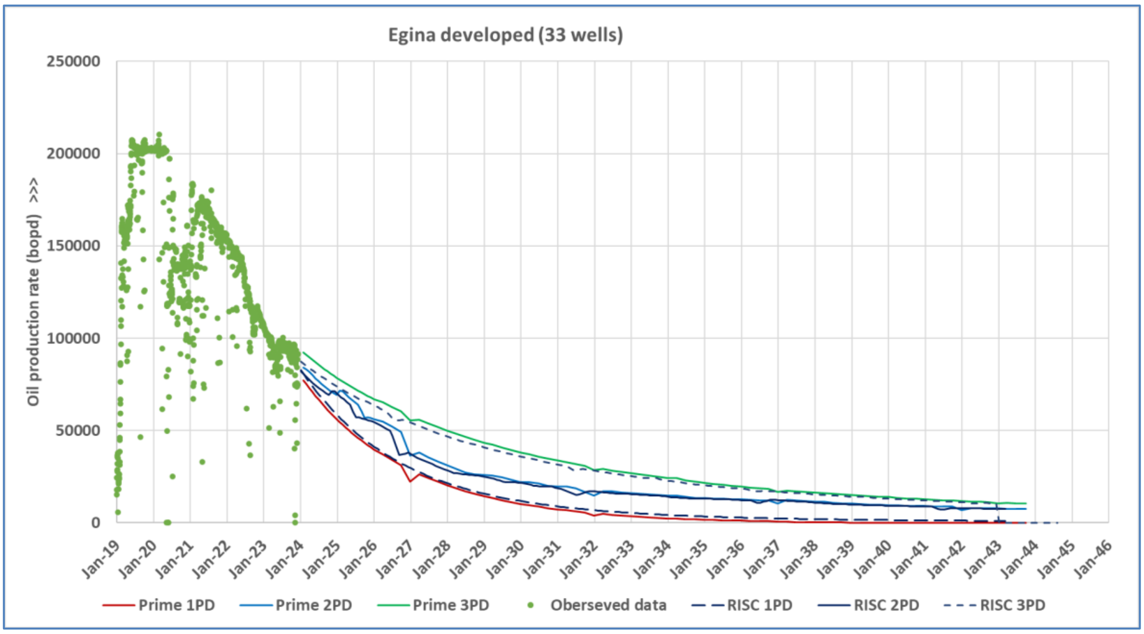


Figure 6-24: Egina 1P, 2P and 3P developed oil forecasts.

Figure 6-25 shows Prime's and RISC's 1P, 2P and 3P developed plus undeveloped oil forecasts with 39 wells.

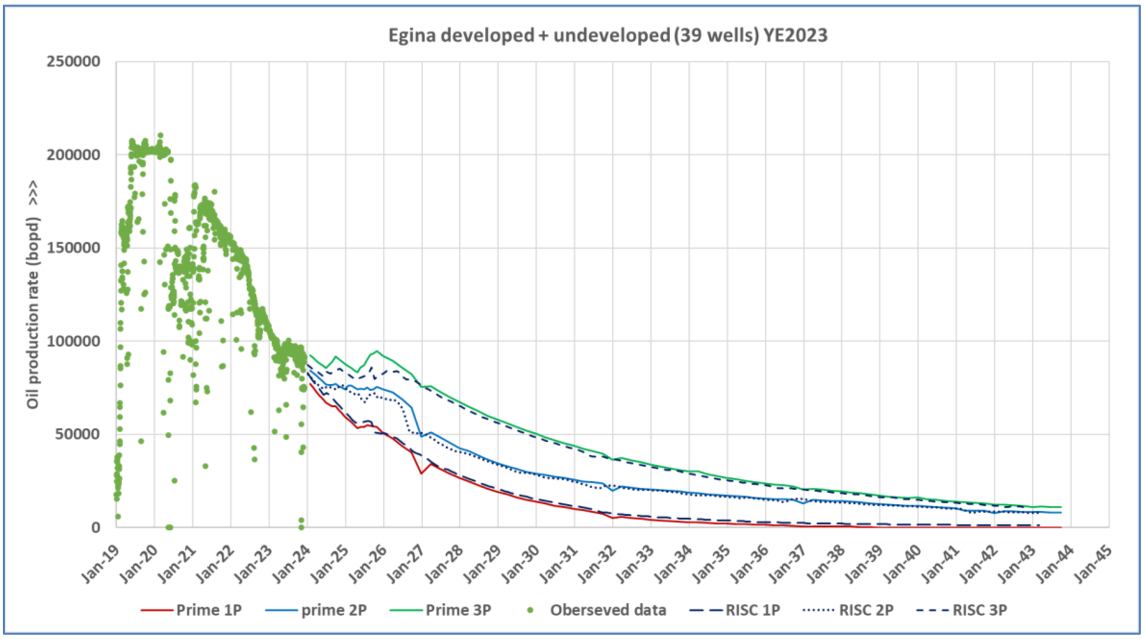


Figure 6-25: Egina 1P, 2P and 3P developed plus undeveloped oil forecasts.

Figure 6-27 & Figure 6-27 shows RISC's 1P, 2P and 3P forecasts, and Prime's 2P forecast in detail.

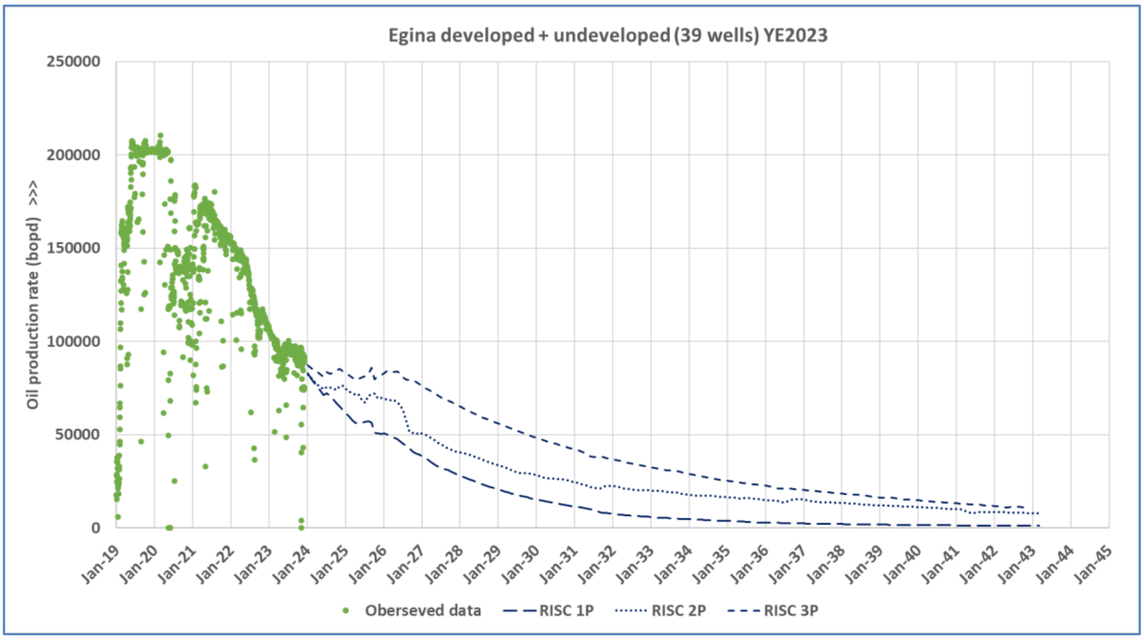


Figure 6-26: RISC's 1P, 2P and 3P profiles.

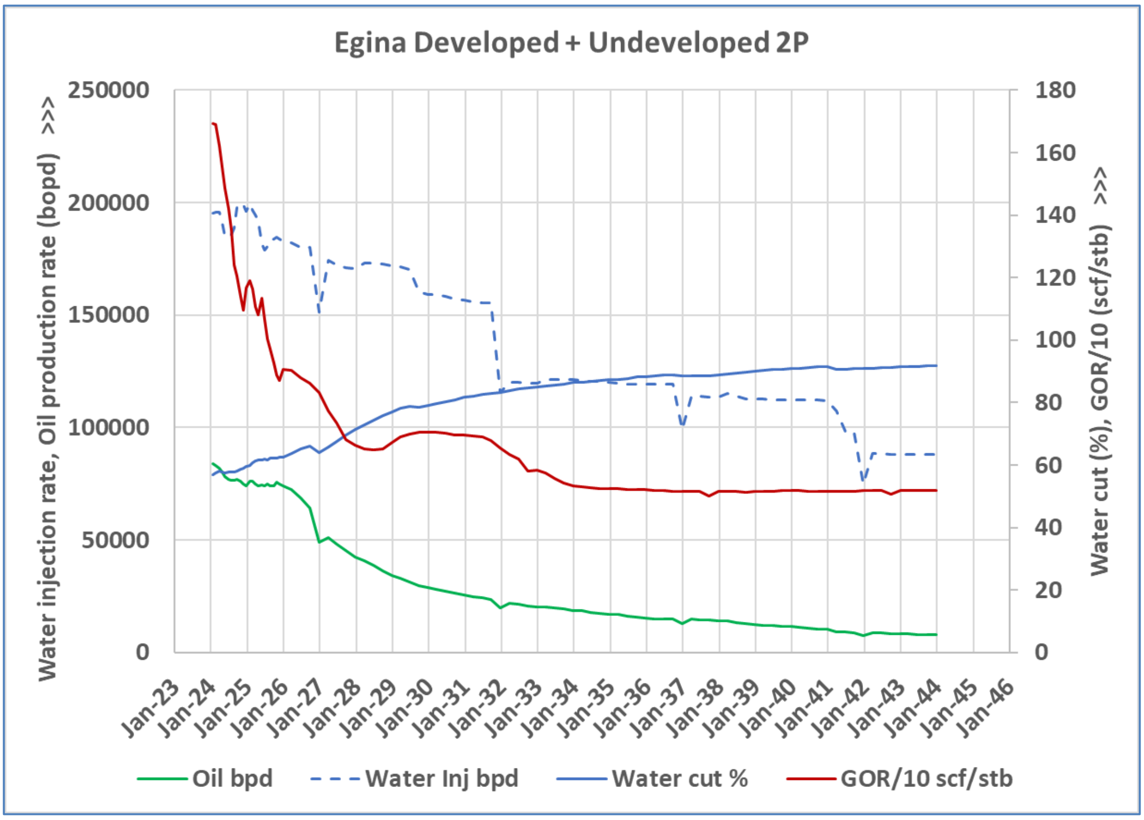


Figure 6-27: Egina 2P oil, water and gas forecasts (Prime).

- The water cut is forecast to steadily increase to 91%.
- The GOR reduces and stabilizes at approximately 500 scf/stb.
- Water injection is reduced to maintain voidage replacement as oil and liquid rates reduces.
- The facility water, liquid or gas constraints are not forecast to be exceeded.

Significant changes to performance were observed in the R1180 reservoirs in 2023 together with an increase in total field GOR. These are changes that DCA could not have forecast. DCA has only been used by RISC for 1P estimates since approximately 25% of the Egina production is on plateau and new wells have been introduced. RISC's 2P and 3P estimates have been derived from adjusting Prime forecasts. Given the recent changes in reserve estimates, RISC's estimate of reserve uncertainty is -36% +50% of 2P.

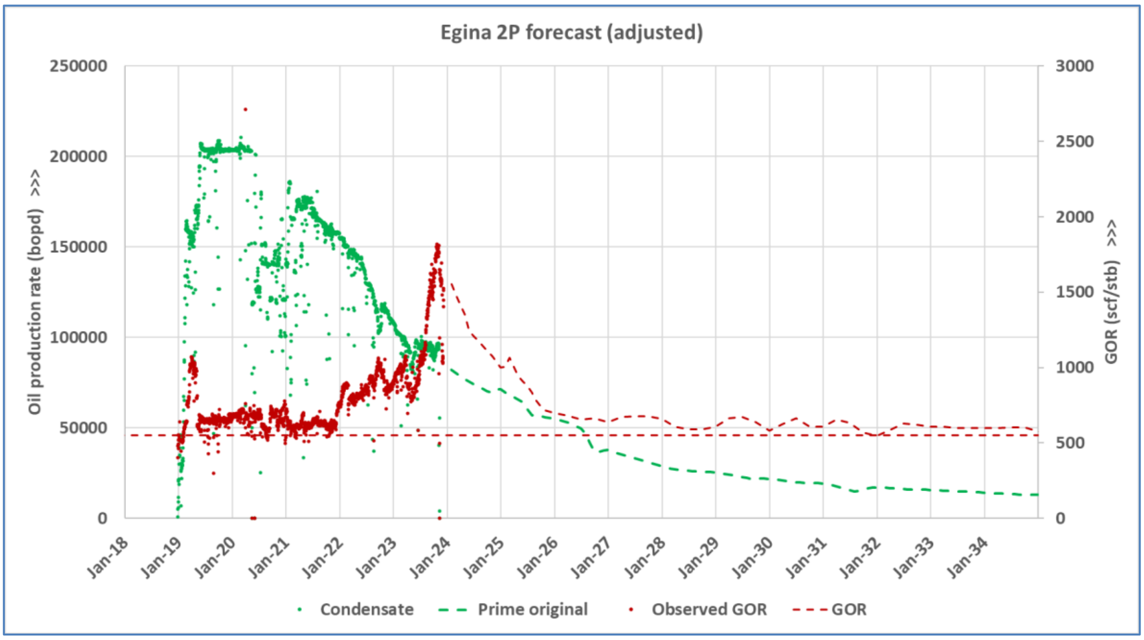


Figure 6-28: Egina Prim's adjusted (2P) forecast.

RISC's 1P estimate is based on Decline Curve Analysis. RISC's 2P is based on a 13 MMstb reduction/ adjustment to the Prime 2P simulation forecast and the 3P is based on a 25 MMstb reduction to the Prime 3P forecast.

RISC supports Prime's reserve estimation methods as reasonable. The simulation that has been calibrated with 4D monitor surveys is best in class. Changes to Prime models in 2022 include:

- A new updated history match model with results of EGA-37 for R1110 reservoir was carried out in July 2023.
- History matched model to July 2023 for R1180 reservoir: A decrease in the EUR in the model to 320 MMstb from 324 MMstb including the two proposed infill wells mainly due to changes in transmissibility configuration among producers and injectors.
- History matched model to July 2023 for R1120 reservoir: Reservoir configuration was adjusted to include main results from infill wells EGA-38 and EGA39. No Impact to EUR of 100.7 MMstb.
- History matched model to July 2023 for R1246 reservoir: No significant change in EUR for the reservoir. STOIIP of 46 MMBoe and EUR of 12.7 MMstb including one Water Shut-off (WSO).
- History matched model to September 2023 for R1110 reservoir: Model updated with EGA-37 and EGA-38 results. Production and injection data from the new wells confirmed communication but with string baffling. The results are in line with 4D-M1 interpretation.

The expected recovery to end 2044 for the Egina reserves forecasts are given in Table 6-7. These are equivalent to the extended profiles for the 1P, 2P and 3P forecasts, but ceasing at end 2044 licence expiry instead of at the economic limits.

Table 6-7: Egina technical remaining recovery Cases

Egina Field estimated recovery to end 2043		Low	Mid	High
Oil, MMstb	Developed	81.0	163.8	230.6
	Dev+ Undev	95.8	199.4	284.6
Gas, Bcf	Developed	69.9	124.3	168.9
	Dev+ Undev	82.48	152.1	213.1
Gas Sales, Bscf from 31/12/2023	Developed	34.2	51.1	78.0
	Dev+ Undev	41.9	72.8	113.4
1. Gas sales have had fuel and flare gas deducted. Egina fuel gas requirements are estimated to be 12 MMscf/d plus 10% of gas production. Flare is estimated at 1% of gas production.				

6.4. Cost Forecasts

RISC has reviewed the costs in the economic model. We have compared these with costs in the budget, Field Development Plan, cost models provided by Prime and our own tools and benchmarks and made modifications where we consider appropriate. All costs are reported on 100% basis in US$ 2024, real terms.

6.4.1. Capital Costs

Going forward total capital costs of US$1,082 million (excluding abandonment) are forecast to 2028[30].

Table 6-8: Egina capital cost summary to 2028 (US$ million)

$ million	Egina 33 Wells	Egina West	2 future wells I	5 future wells II	Total
D&C	0	159	127	253	539
Facilities	270	242	9	22	543
Total	**270**	**0**	**136**	**275**	**1,082**

[30] ‘Facilities’ includes ongoing capex after 2027 is USD$27 million.

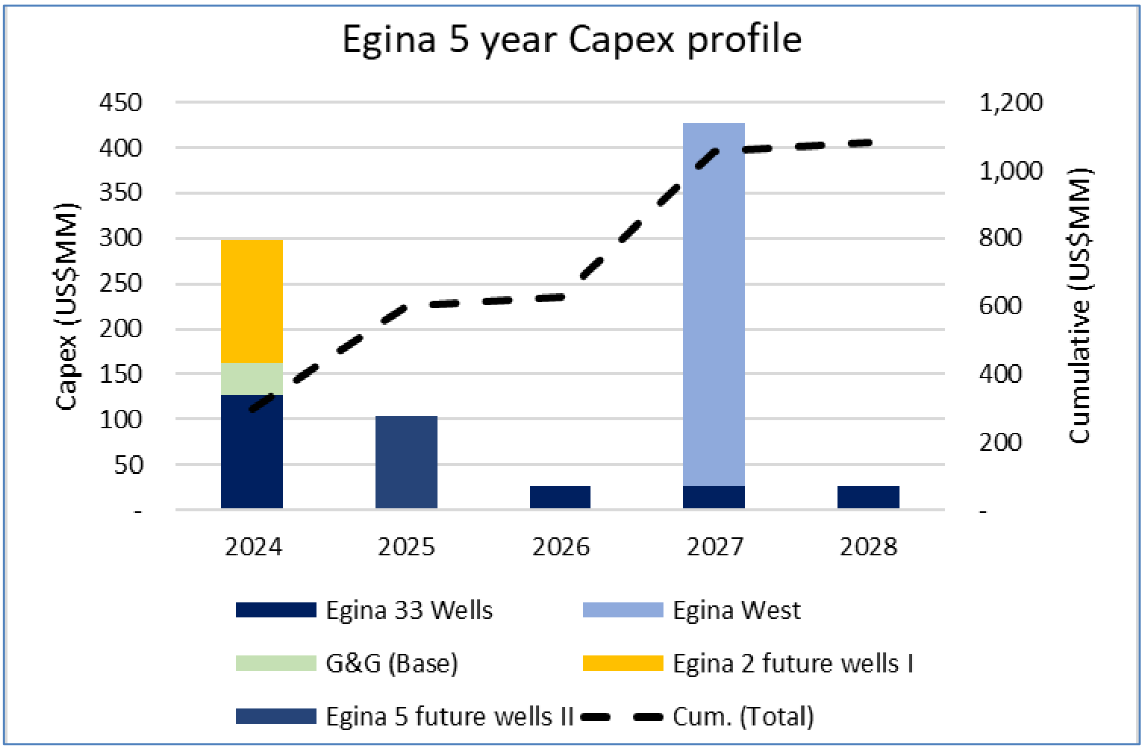


Figure 6-29: Egina capex forecast to 2028.

The drilling and completion costs for the 4 Egina West wells have been forecast to cost US$159 million with drilling scheduled to start in Q3 2027. Each well is forecast to take 36 days to drill and cost approximately US$40 million. The spread rate used in calculating the drilling costs is US$1,100,000/day. This has been estimated using current drilling costs US$1,200,000/day and applying the forward brent curve to estimate a cost in 2027 which RISC views as reasonable.

The Operator plans to drill the 'Egina 5 future wells' in Q1 to Q4 2025 at an estimated cost of US$253 million. Prime forecast that the 3 wells Egina -42/43/44 will take 45 days which has increased from 36 days previously estimated as a result of more information gleaned from the current drilling program. Egina-45 has been forecast to take 55 days and the Egina-18 side track to take 30 days which has been increased from 25 days. A rig spread rate of US$1,100,000/day has been used and a mobilization fee of US$10 million has been allocated to the project (Demobilization costs have been allocated to Akpo).

The 'Egina 2 Future wells' are planned to be drilled in Q3 and Q4 of 2024 at a cost of US$127 million. Prime has increased the estimate of the time required to drill these wells based on information from the current drilling program. The Egina-40 well has increased from 40 to 45 days and Egina-41 well increased from 36 to 48 days. A spread rate of US$1,200,000/day has been as per the drilling rig contract under the current program.

The Operator has forecast around USD$270 million to be spent on the existing facilities (33 wells) which includes USD$34 million on geophysics and geoscience studies for the field, facilities upgrades, capital spares, integrity works and well interventions. A general allowance has been included in 2026 through to 2028 of USD$27 million per annum. An additional $242 million for the tying in and FPSO topsides upgrades for the Egina West wells.

The Operator has forecast USD$31 million for tying in the 'future Egina 2 & 5 wells'.

Overall RISC views the Capex as reasonable.

6.4.2. Operating Costs

In 2023 the actual revised budget achieved was US$213 million, US$8 million less than the initial budget due to reductions in routine and non-routine costs. In 2024 Prime has assumed a budget of US$212 million which is slightly less than the Operators budget of US$223 million. The Operator has historically contained a contingency in the budget which RISC views as prudent as it avoids the operator having to come back to the joint venture partners to request additional budget in the event of minor cost overruns and sees Prime's assumption as reasonable. RISC have reviewed the WP&B for 2024 and see the costs as reasonable and in line with previous years.

Going forward, Prime consider 85% of recurrent operating costs are fixed and 15% of costs vary with production. Costs are referenced to a base case cost which is an average of the 2021, 2022 and 2023 operating costs. In addition, Prime add non-recurrent costs of US$20 million every 5 years for major planned facilities maintenance campaigns, and gas flaring fees of US$3.5/Mcf. We have adjusted the major maintenance cost to US$25 million every 5 years. We also note the facility intervention is every 5 years at Egina, compared to 3 years at Akpo, this is because Egina is a newer FPSO with better monitoring system.. In general, we consider Prime's operating cost forecast to be reasonable.

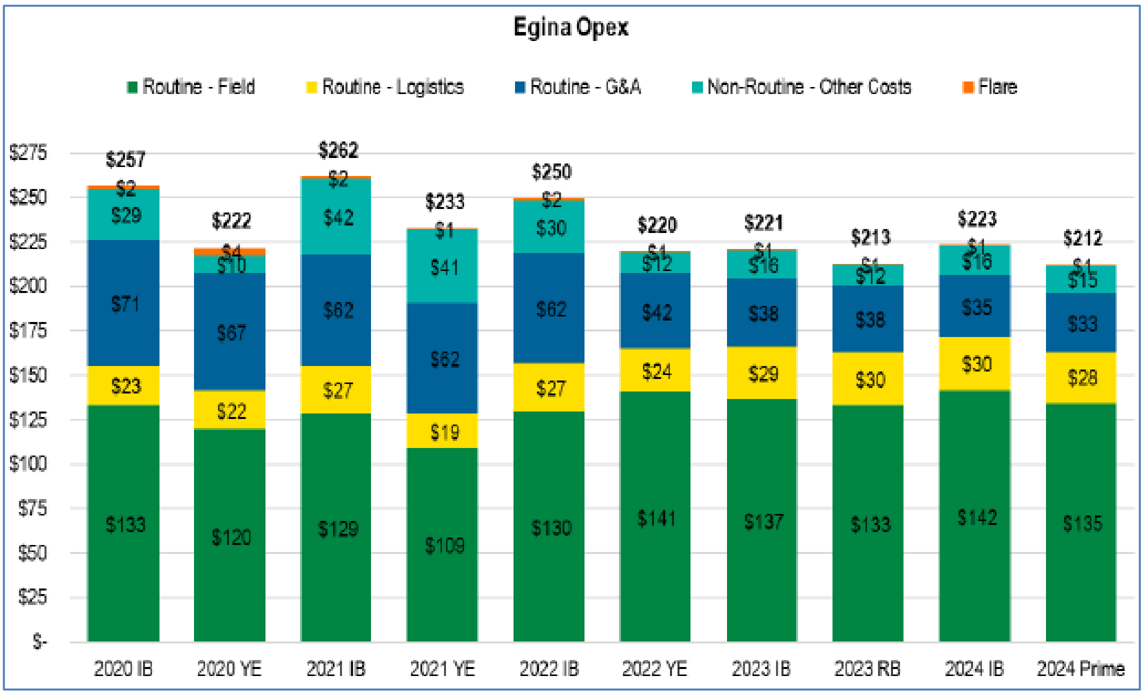


Figure 6-30 Egina's historical Opex (Prime Reserves Presentation Dec 2023).

In the 2P case RISC forecast operating costs to reduce from approximately US$212 million pa in 2024 to US$170 million pa in 2043 (Figure 6-31).

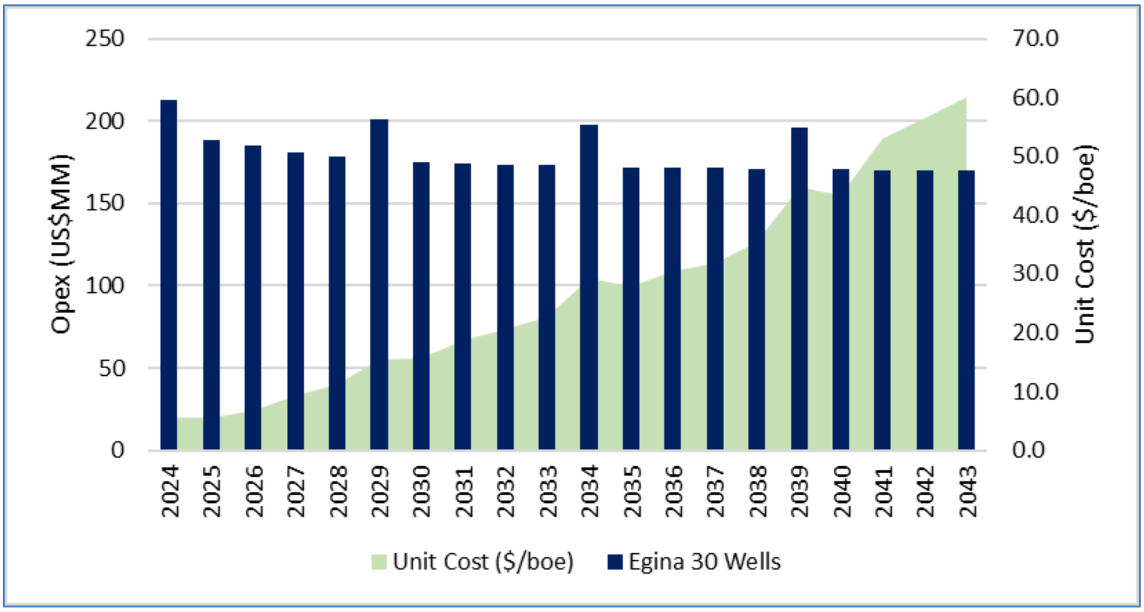


Figure 6-31: Egina: RISC 2P Opex forecast.

6.4.3. Abandonment Costs

Well P&A and facility decommissioning costs are forecast to be approximately US$682 million for the original 30 wells development (US$300 million wells, US$380 million facilities) plus US$86 million for the additional 9 infill wells. Well P&A costs are estimated to be approximately US$7 million per well based on 17.5 days per well and a spread rate of US$410,000/d (US$250,000/d rig + US$160,000/d services) plus US$10 million mobilization/demobilization costs. This cost was estimated by TOTAL in 2019. Although rig rates have recently increased, the brent forward curve would indicate that they are likely to drop. RISC view the abandonment costs as reasonable.

Although discussions are ongoing with respect to provisioning the abandonment costs, Prime has assumed a linear annual distribution approach with expenditure from 2025 to end of Egina field life as outlined in Section 9.2.2. RISC sees this as appropriate.

6.5. Egina Field Reserves and Contingent Resources Summary

The gross licence and Prime net entitlement oil and gas developed reserves associated with the Egina field are shown in Table 6-9. The further 6 infill wells plus one sidetrack are split into two separate projects consisting of 2 and 4+1ST wells, respectively. The undeveloped reserves associated with each project are shown in Table 6-10 and Table 6-11. The Egina undeveloped reserves associated with field life extension from the infill wells are shown in Table 6-12.

The Egina contingent resources associated with the field life extension due to the Preowei infill development are shown in Table 6-13. The eight additional wells planned in the Preowei field are a contingent project and extend the Egina/Preowei economic cut-off in all cases. This results in some incremental contingent recovery in Egina when compared to the reserves case.

Table 6-9: Egina gross and Prime net entitlement developed reserves as of 1 January 2024

Oil	Unit	Reserves		
		1P	2P	3P
Egina oil (30 wells), gross to PML 3	MMstb	94.8	158.6	220.5
Prime net entitlement	MMstb	15.8	26.5	36.0
Sales gas				
Egina gas (30 wells), gross to PML 3	Bcf	33.9	50.8	77.7
Prime net entitlement	Bcf	5.4	8.1	12.4

Notes:

1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

Table 6-10: Egina 2 infill wells gross & Prime net entitlement undeveloped reserves as of 1 January 2024

Oil	Unit	Reserves		
		1P	2P	3P
Egina oil (2 wells), gross to PML 3	MMstb	8.2	14.9	30.8
Prime net entitlement	MMstb	1.4	2.4	4.8
Sales gas				
Egina gas (2 wells), gross to PML 3	Bcf	5.1	9.8	24.5
Prime net entitlement	Bcf	0.8	1.6	3.9

Notes:

1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

Table 6-11: Egina 4 infill wells & ST: Prime net entitlement undeveloped reserves as of 1 January 2024

Oil	Unit	Reserves		
		1P	2P	3P
Egina oil (4 wells & ST), gross to PML 3	MMstb	3.9	21.1	24.0
Prime net entitlement	MMstb	0.8	3.4	3.7
Sales gas				
Egina gas (4 wells & ST), gross to PML 3	Bcf	2.6	12.2	10.9
Prime net entitlement	Bcf	0.4	1.9	1.7

Notes:

1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

Table 6-12: Egina undeveloped reserves on 1 January 2024: life extension by infill well development

Oil	Unit	Reserves		
		1P	2P	3P
Egina life extension, gross to PML 3	MMstb	8.9	0.0	0.0
Prime net entitlement	MMstb	1.7	0.0	0.0

Notes:

1. The undeveloped projects extend the Egina base field life in the 1P case, but do not change the field life in the 2P and 3P cases.
2. "Gross" licence reserves are 100% of total field reserves.
3. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
4. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
5. There are no Egina sales gas reserves associated with the life extension.
6. Volumes are based on conversion of both licences to PIA terms.

Table 6-13: Egina contingent resource on 1 January 2024: life extension by Preowei infill development

Oil	Unit	Contingent Resources		
		1C	2C	3C
Egina life extension, gross to PML 3	MMstb	1.5	0.0	0.0
Prime net entitlement	MMstb	0.3	0.0	0.0

Notes:

1. The contingent projects extend the Egina base field life in the 1C case, but do not change the field life in the 2C and 3C cases.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. There are no Egina sales gas resources associated with the life extension.
5. Volumes are based on conversion of both licences to PIA terms.

Table 6-14 shows a comparison of the Year-End 2022 Egina developed and undeveloped reserves with the Year-End 2023 estimates.

Table 6-14: Egina Reserves Reconciliation Compared to Year-End 2022 Report

Oil	Unit	Reserves		
		1P	2P	3P
Egina Field Gross at 1 Jan 2023	MMstb	133.0	225.7	324.2
Egina Field production, 1 Jan 2023 to 31 Dec 2023	MMstb	33.9		
Egina Field Revisions	MMstb	7.8	2.8	-14.9
Egina Field Gross on 1 Jan 2024	MMstb	106.9	194.6	275.4
Sales gas				
Egina Field Gross at 1 Jan 2023	Bcf	78.6	129.1	210.7
Egina Field production, 1 Jan 2023 to 31 Dec 2023	Bcf	31.2		
Egina Field Revisions	Bcf	-5.8	-25.0	-66.5
Egina Field Gross on 1 Jan 2024	Bcf	41.6	72.8	113.1

Notes:

1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

RISC included a separate table for fuel gas reserves (Table 6-15). These are not sales volumes but are gas volumes consumed in the operations. Under some jurisdictions these can be included in reserves.

Table 6-15: Egina Fuel Gas reserves as of 1 January 2024

Gas Consumed in Operations	Unit	Reserves		
		1P	2P	3P
Fuel gas used at Egina	Bcf	40.7	79.6	99.9
Prime net entitlement	Bcf	6.5	12.7	16.0

Notes:

1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
3. These are not to be added to the sales gas reserves and must be reported separately as per PRMS 2018 reporting standard.

7. PPL 261 - Egina South Field Contingent Resources

There are no updates from Prime for YE2023 except production has been shifted from 2028 in YE2022 to 2030 in YE2023. We support the work as reasonable and have estimated the 1C to 3C uncertainty range.

Egina South Discovery lies 20 km southwest of the Egina Field in PPL 261 in approximately 1,650 m WD.

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, R1230, R1246 and R1265 reservoirs, Figure 7-1.

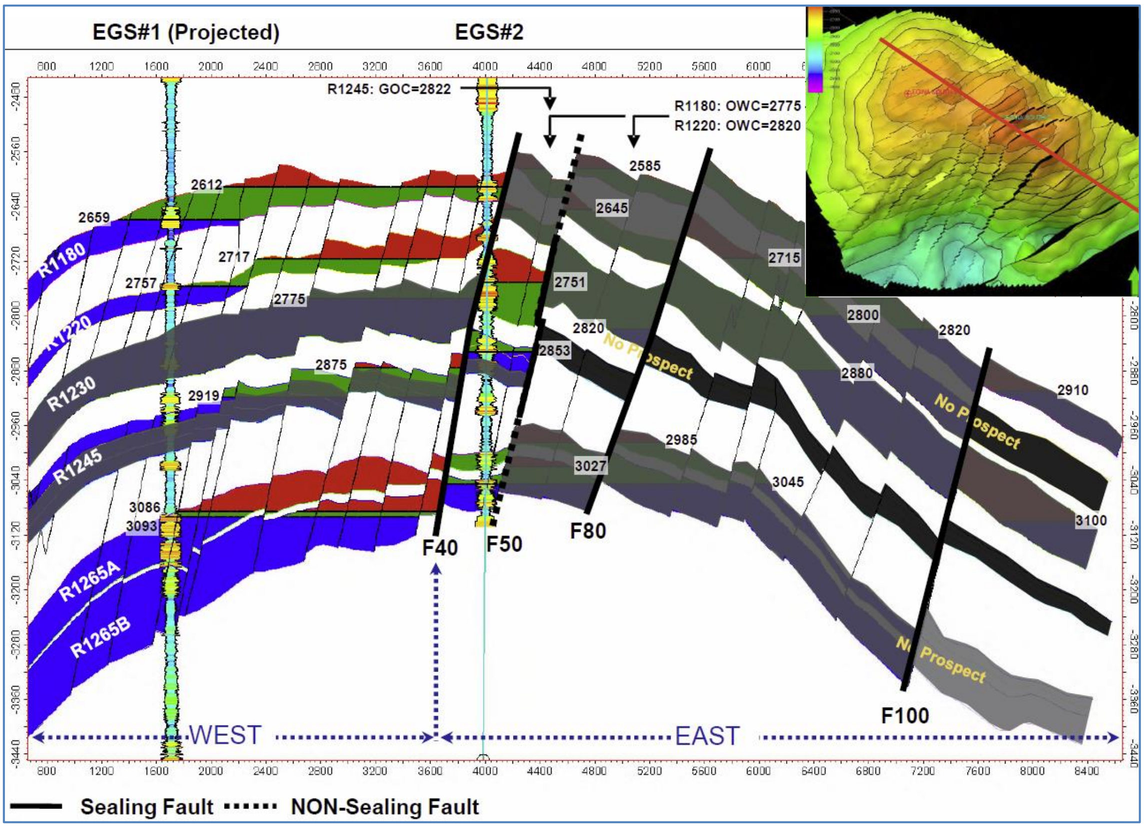
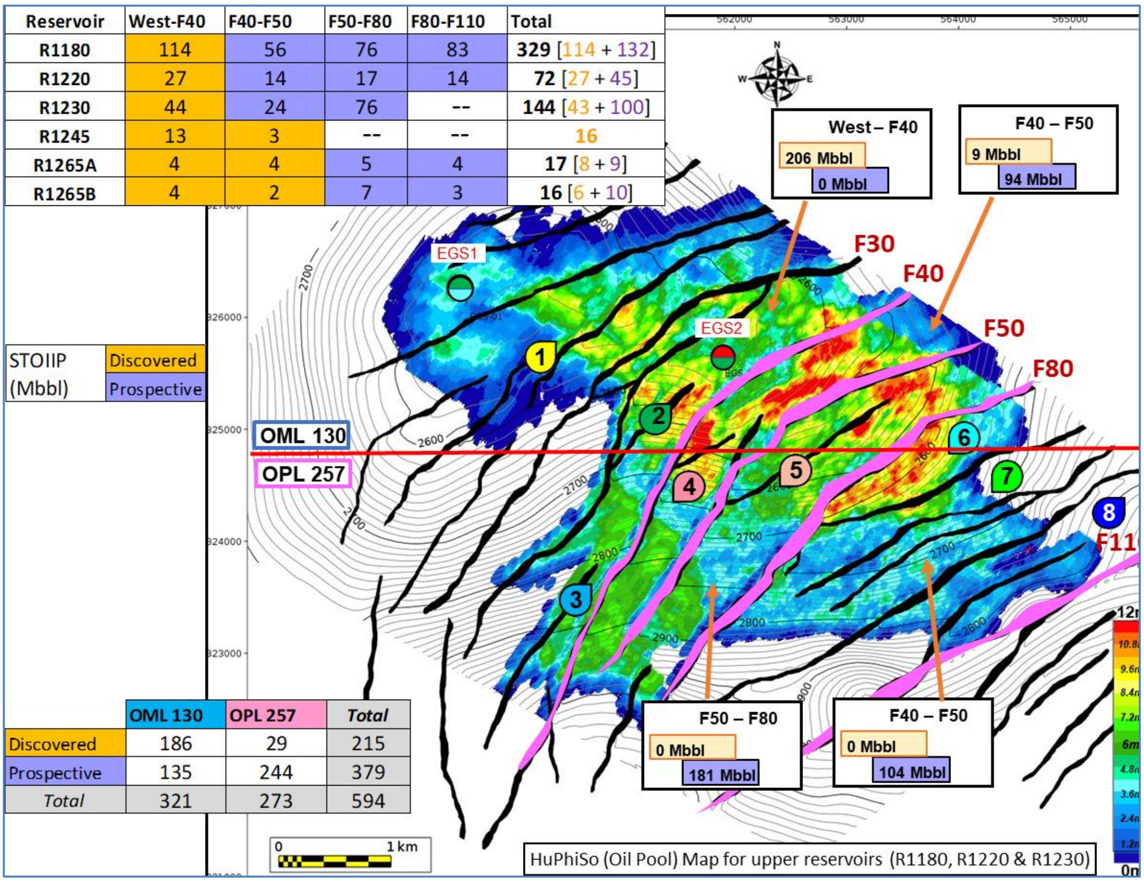


Figure 7-1: Egina South Cross Section.

The reservoir is divided into the discovered Egina South West block and the largely undiscovered East Blocks, Figure 7-2:

- Prime estimates a total of 180 MMstb 2C recoverable volume from 470 MMstb STOIIP in Egina South field; 115MMstb from R1180 reservoir and 65MMstb from R1230 reservoir. This 2C number excludes recoverable volumes from minor reservoirs (R1220, R1245 and R1265).
- The reservoir intervals are similar to the main Egina field.



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 7-2: Egina South A Top Reservoir Depth Map, discovered and undiscovered STOIIP.

RISC performed a high-level review of the 2019/2020 TOTAL V2 static model provided by Prime for YE2021 and determined that the model was a good representation of the input data, fit for purpose and follows standard industry practice. Results of the model review showed that the total base case STOIIP estimate for the field at that time was 594 MMstb, an approximately 250% increase in the STOIIP compared to earlier TOTAL V1 static model (164 MMstb). The volume increase was attributed mainly to a deeper fluid contact as delineated from well-calibrated, reprocessed seismic, and seismic anomalies calibrated as direct hydrocarbon indicators (DHI) from modeling.

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).

TotalEnergies have performed a comprehensive analysis on the Egina South STOIIP, and RISC supports the 594 MMstb STOIIP with 2C recoverable volume of 180 MMstb. A model revision (RMV4) is planned following ongoing reprocessing of the seismic data in the Egina South field but the impact on STOIIP and recoverable volumes is as yet unknown. Prime are conducting further ongoing studies.

7.1. Production Forecast

Prime has developed production forecasts for the discovered and prospective resources, developed with 12 wells using water injection (Figure 7-3). Nine of these wells are targeting the resources in the R1180 reservoir (4 oil producers and 5 water injectors) and 3 of the wells are targeting the R1230 reservoir.

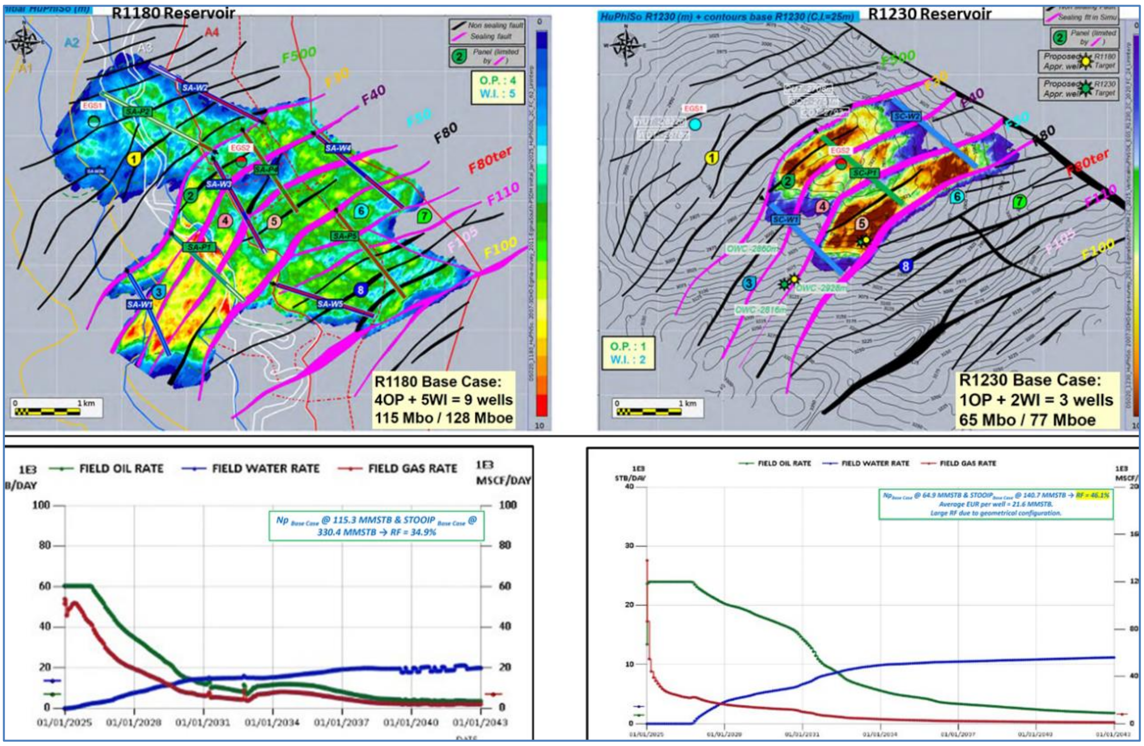


Figure 7-3: Egina South Contingent Resources.

Prime estimate 180 MMstb contingent oil resource from discovered and prospective oil STOIIP of 470 MMstb (30% oil recovery factor). A plateau oil rate of 84,000 bopd is forecast for 14 months from 1/1/2026. Water injection is initially 70,000 and 40,000 bpd in the R1180 and R1230 reservoirs respectively, but injection is reduced as oil and liquid rates reduce. RISC consider the production forecast as reasonable.

22.5% of the forecast EUR is in discovered resources with the remaining 77.5% prospective (Table 7-1).

Table 7-1: Egina South STOIIP and EUR

MMstb	R1180 STOIIP	R1230 STOIIP	Total STOIIP	R1180 EUR	R1230 EUR	Total EUR
Discovered	93.9	23.4	117.3	28.4	11.9	40.3
Prospective	235.3	117.3	352.6	85.5	53	138.5
Total	**329.2**	**140.7**	**469.9**	**113.9**	**64.9**	**178.8**

RISC consider the in-place and recoverable volumes to be reasonable. We estimate +/- 40% uncertainty on the contingent resources and +/-50% on the prospective resources.

7.2. Costs Forecasts

Egina South is 20 km from Egina in a water depth of 1,650 m. Prime have considered that 12 wells using a subsea tie-back will be required to develop Egina South (See Figure 7-4). Since last year the project has been delayed by 2 years and first oil is scheduled for 2030.

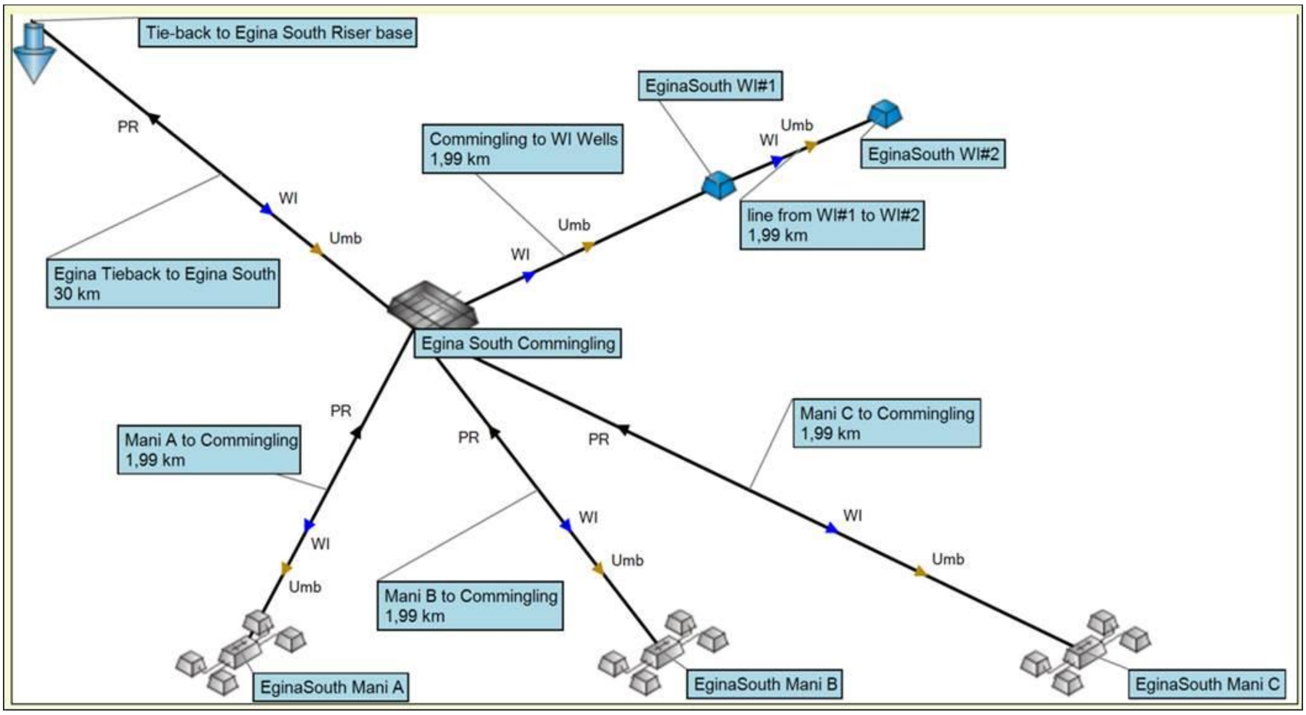


Figure 7-4 Schematic of Prime's field development.

Prime have advised RISC that the facility costs in the economic model are Prime's share and that that 55% of the costs are in the OML-130 license and 50% of those costs are attributable to Prime through the PSA. Thus, Prime's share, USD$187 million for facilities Capex is USD$680 million in total.

RISC have assumed that the 12 wells will take on average 45 days to drill (Similar to other wells in the current Egina drilling program) and complete with an average rig rate of USD$1,100,000/day with USD$15 million mobilization and USD$10 million demobilization.

Table 7-2: RISC's Egina South capital costs

Phase	Appraisal well USD million	Dev. Wells USD million	Facilities USD million	Total USD million	ARO USD million
Egina South	53	619	680	1,352	156

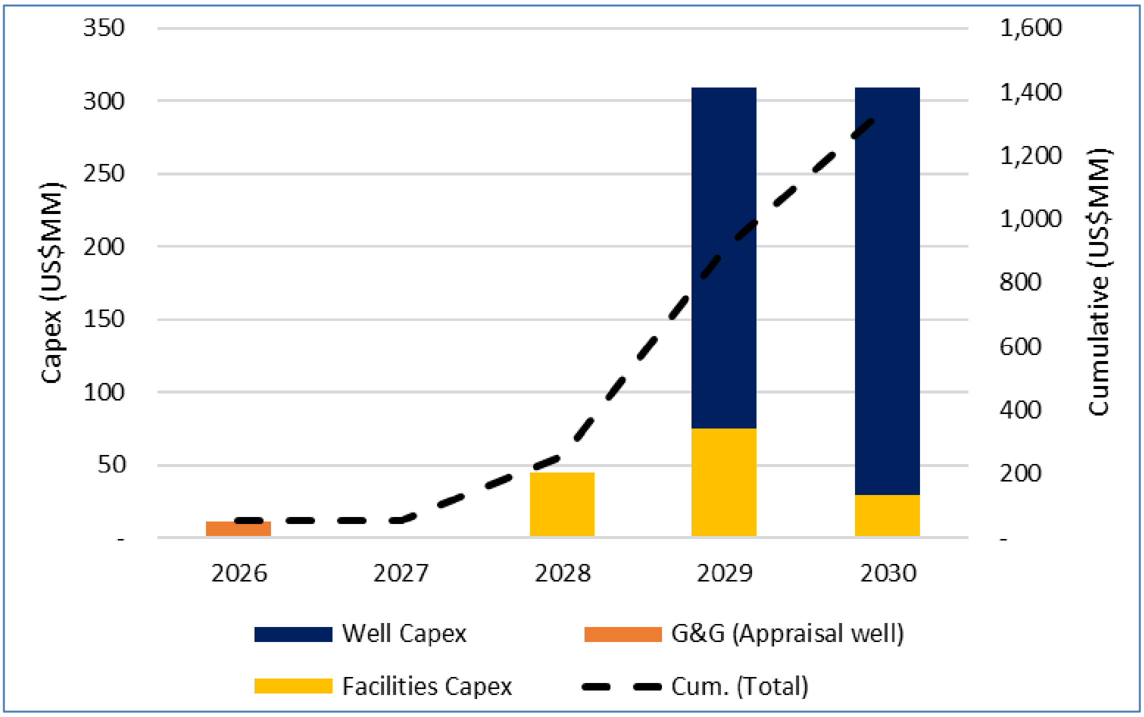


Figure 7-5: RISC's Egina South Capex forecast.

The operating costs in the first full year of production have been predicted by Prime to be USD$7.3 million pa and reduce to 0.6 million per annum towards the end of field life (See Figure 7-6). RISC views these costs as reasonable.

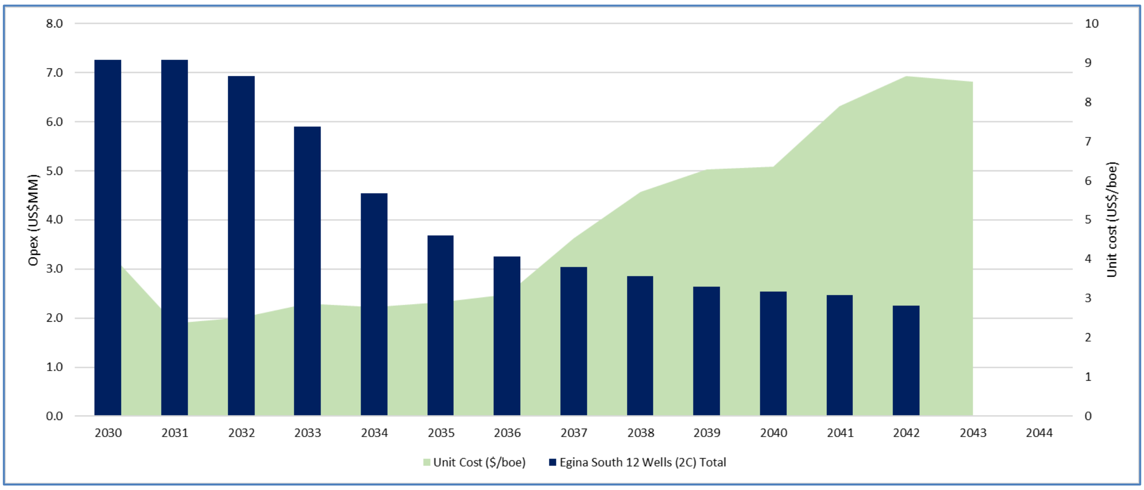


Figure 7-6: RISC's Egina South operating cost forecast 2C case

7.3. Egina South Field Contingent Resources

The contingent resources associated with the Egina South development are shown in Table 7-3.

Table 7-3: Egina South contingent resources as of 1 January 2023

Oil	Unit	Reserves		
		1P	2P	3P
Egina South (12 wells), gross to PPL 261	MMstb	17.8	34.3	48.1
Prime net entitlement	MMstb	3.0	5.6	7.7
Sales gas				
Egina South (12 wells), gross to PPL 261	Bcf	12.2	22.9	32.1
Prime net entitlement	Bcf	2.0	3.7	5.1

Notes:

1. Licence reserves exclude approximately 15% of the discovered resources for R1180 which are outside of the block.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PPL 261 is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

8. PML 4 – Preowei Field Reserves

8.1. Field Description

The Preowei field is located approximately 175 km from Port Harcourt, within the PML 4 (formerly known as Oil Mining Lease 130), in water depths ranging from 1,100 to 1,300 m. Distances to the main existing fields or future infrastructure are:

- 29 km to the North of Egina field and Egina FPSO (OML130, operated by TUPNI);
- 20 km to the North-West of AKPO field & AKPO FPSO (OML130, operated by TUPNI).

The field is operated by Total and Prime has a 16% working interest. All volumes considered as reserves and contingent resources fall within the PML 2, PML 3 & PML 4 licence boundary.

The Preowei field, as part of the original OPL246, was discovered during the exploration phase of the block along with the Akpo condensate field, Egina Main and Egina South.

The discovery well Preowei-1, drilled in late 2003 through the crest of the structure encountered three main hydrocarbon bearing reservoirs aged Mid to Upper Miocene: R759 (gas/oil), R790 and R811, both oil and water bearing.

An appraisal well, Preowei-2, was drilled in 2005 on the south-eastern flank of the structure. The well encountered degraded reservoirs in R759 which were gas and water bearing. The R790 and R811 reservoirs were oil and water bearing, respectively. Preliminary development studies were performed in 2010 and 2015 with a recommendation to drill a third appraisal well. After prioritizing Akpo and Egina wells the joint venture agreed to drill Preowei-3 in 2017. At that time, a screening phase of the conceptual studies was launched to anticipate the well's results.

Preowei-3, the second appraisal well, was drilled in 2017 and provided calibration for the southern flank of the structure, where R759, R790 and R811 were found oil bearing.

Following the successful results of Preowei-3, an update of the geoscience evaluation was performed to support the concept selection phase of the development studies. The results of these studies form the basis for the current FDP which was submitted to the Nigerian Authorities in December 2018 and obtained approval in the second quarter 2019. The FDP proposes nine oil producers and 9 water injectors to be connected to Egina FPSO through a Single Heated Production line of 29 km. The Egina FPSO is designed to take production from a subsea development of Preowei at the end of the Egina plateau. Following tie-back, surplus gas will be exported via the Egina-Akpo gas line to the Nigeria LNG (NLNG) plant, with commercial terms agreed under the GSPA and as for Egina. Further contingent producer-injector pairs are also being considered by the JV to exploit other areas of the field.

The COVID-19 global pandemic impacted the timeline for Preowei development with the project FEED significantly deferred. The FEED is now planned to resume Q1 2023 with the Operator targeting FID in Q4 2024 and first oil Q3 2026. A baseline 4D seismic survey is planned for 2023.

The licence was renewed in 2023 for 20 years with the conversion to the PIA and new licence name.

8.1.1. Geoscience Overview

The following section represents a summary of the geological evaluation of the field described in the latest Preowei Field Development Plan (Preowei FDP, December 2018), in addition to other presentation material and reports provided by Prime (2020-2023).

Block PML 2, PML 3 & PML 4 is situated at the Nigerian Atlantic margin which has formed during the development of the Atlantic Ocean in Cretaceous and Tertiary ages. Sediment deposition over the Cretaceous rift caused the development of a major petroleum basin with three structural zones (Figure 8-1):

- An extensional zone with listric faults and roll-overs;
- A central translational zone with anticlines and thrust structures; and
- A compressional zone with toe-thrust belts.

PML 2, PML 3 & PML 4 is located in the internal part of the compressional zone which is dominated by toe-thrusts and anticlines. Within OML130, the Preowei field constitutes the southern section of an elongated thrusted anticline that extends northwest. An extrados graben can be identified at its crest which is limited by two normal boundary faults to the North and South. The main reservoirs in the PML 2, PML 3 & PML 4 fields are deep-water turbidite complexes deposited during the Miocene with a general NE-SW direction, as presented in Figure 8-2 for R759. The creation of the thrust system occurred after deposition of the R759, R790, and R811 reservoir systems.

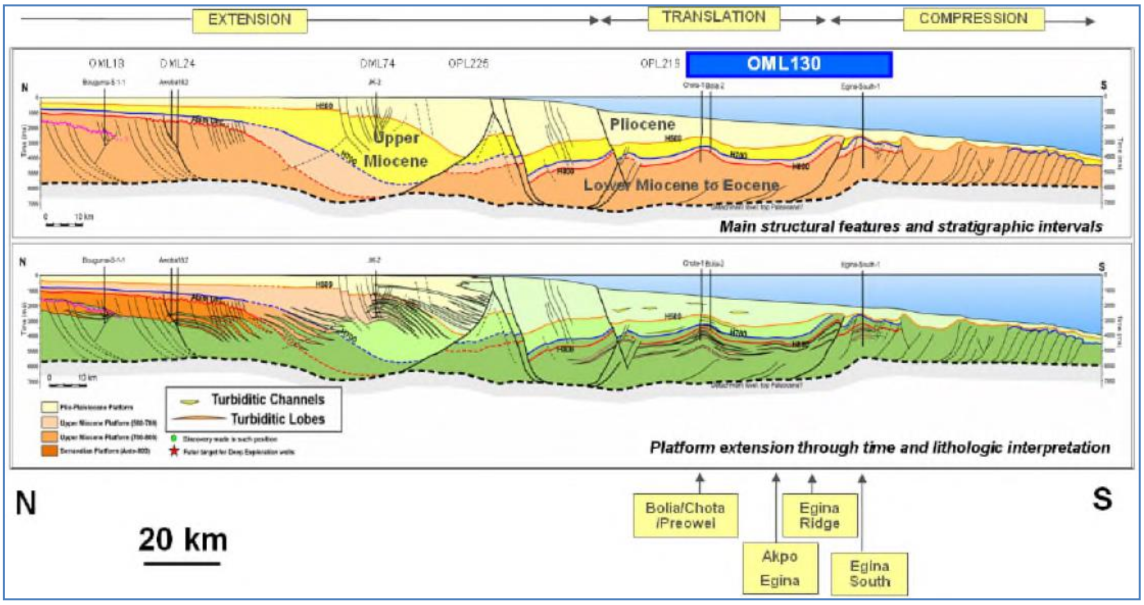


Figure 8-1: Structural and Sedimentary context of Preowei Field

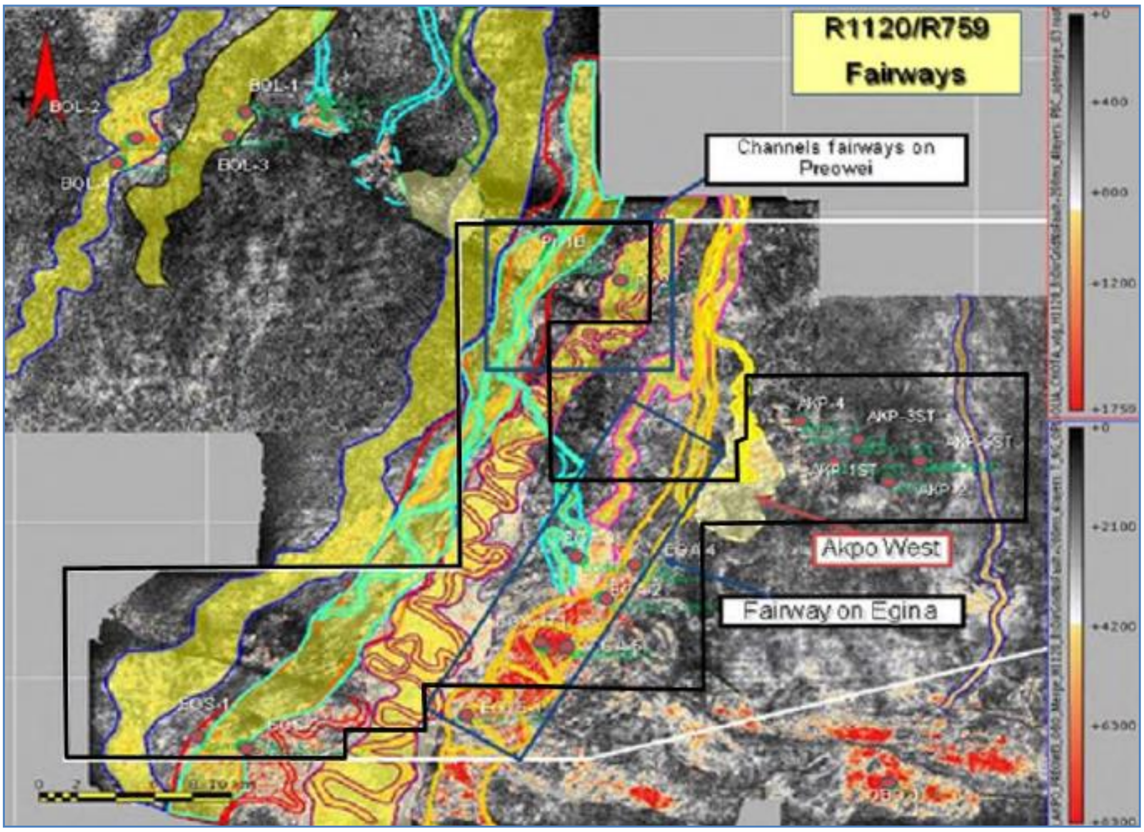


Figure 8-2: Regional Channel Fairways passing through Preowei R759.

The Preowei structure is a steeply four-way dipping, highly faulted, NW-SE elongated thrusted anticline with extrados, radial and collapse faults, formed against a thrust on its southern limit (Figure 8-3). The central area of the anticline is characterized by NW-SE trending extrados faults related to its collapse and the formation of a graben. Coming from the South-East the dip of the faults changes in the central area from SSW to NNE. The extrados faults have a significant impact on the compartmentalization of the central graben as their throw is generally significantly larger than the sand thickness. At the steeply dipping flanks radial faults can be observed. In terms of compartmentalization, they appear to particularly impact the R759 and R790 series. Finally, small collapse faults are present up-dip on the Southern flank of the structure. Their throw appears to be generally smaller than the sand thickness and they mostly impact the R759 and R790 intervals.

Compartmentalization due to the numerous faults plays a major role in the Preowei field. In order to aid the definition of compartments for the development scheme, the faults in the development perimeter have been analysed and grouped into two classes: sealing faults across which no communication is possible and possibly sealing faults across which the communication is unknown. Faults with throws larger than the apparent sand thickness are classified as sealing whereas faults with throws smaller than the apparent thickness are considered possibly sealing. Well results and pressure data suggest varying hydrocarbon contacts between different compartments and different pressure regimes within the main reservoir sands supporting the idea of significant compartmentalisation. After the field is developed and over time, as more production data are collected, the understanding of field compartmentalisation will improve. The acquisition of 4D monitor surveys, as has been shown with the other PML 2, PML 3 & PML 4 fields, will also provide particularly useful information in this regard.

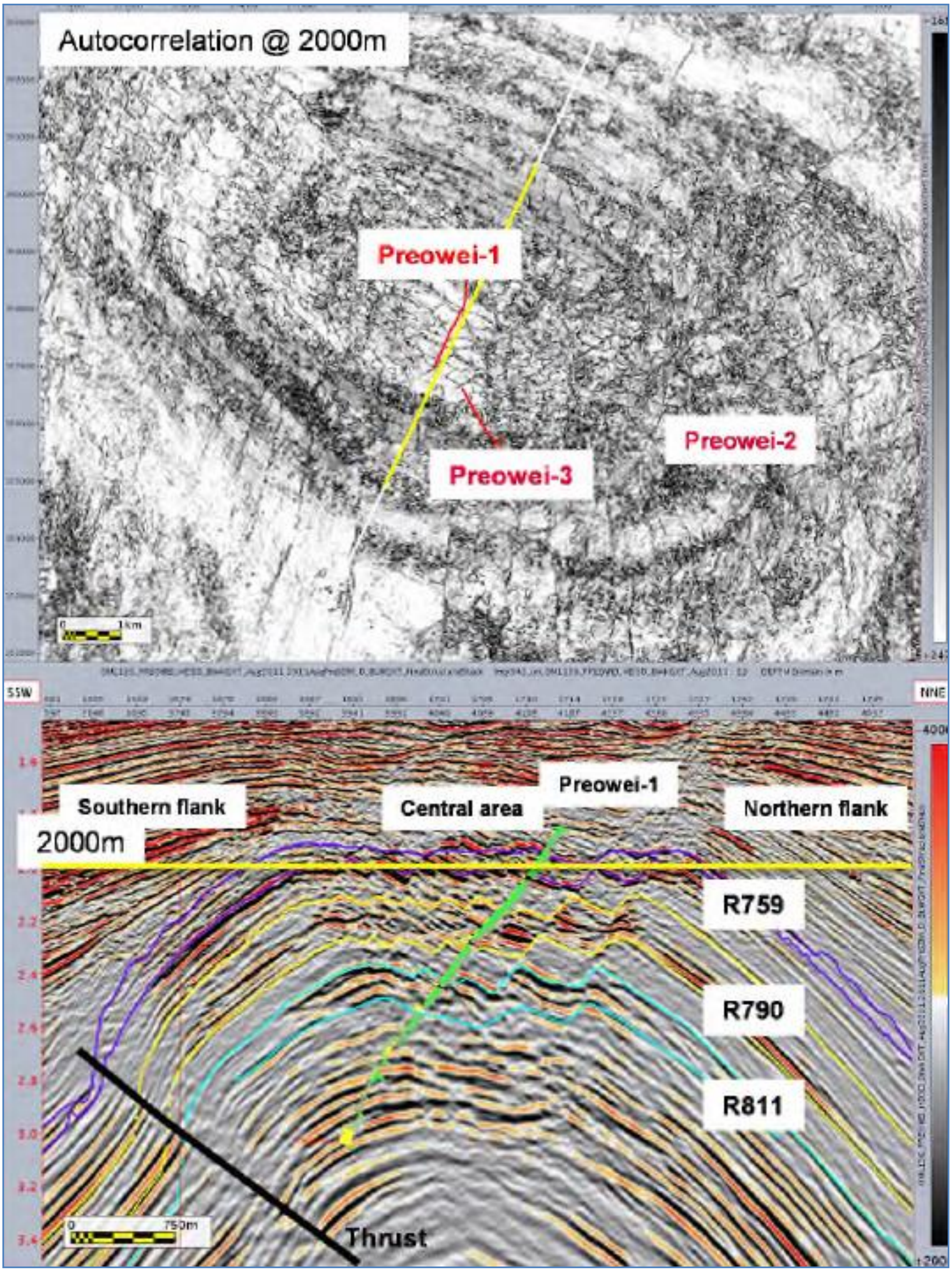


Figure 8-3: Seismic Cross Section & Autocorrelations showing infield faulting and main reservoirs.

The latest full interpretation and modelling study for Preowei was completed in 2018 as documented in the FDP, building on an earlier study in 2010. This evaluation of Preowei is based on the 3D HD PSDM processing of the 2008 acquisition. A full stack as well as angle-stacks (6°-18°, 18°-30°, 30°-42°, and 42°-52°), tomographic velocity and anisotropy cubes were available. Initial interpretations were made on the fast-track PSTM processing in 2010, but the 2011 PSDM processing showed some improvements in the definition of faults and horizons and an increased S/N ratio, particularly in the deeper reservoir levels (around the R811 interval). Six horizons representing the envelopes for the three main reservoir zones were inherited from the 2010 study, namely: Top R759a and Top R759c for R759, Top R790 and Top R800 corresponding to R790, and for the R811 Top R811a and Base R811c. Additional horizons to refine the reservoirs (limited to the development perimeter) were interpreted in the 2018 study.

Dual azimuth reprocessing was completed in 2018 and the results of this were incorporated into the reservoir model build in 2020. Seismic amplitudes have been used extensively to highlight hydrocarbon bearing reservoirs and predict hydrocarbon contacts. The wells drilled on the field to date have shown the amplitudes to be reliable hydrocarbon indicators. RISC note that the initial development wells target the areas of brightest amplitudes.

Preowei reservoirs can be described as a series of single to multiple storey complexes of Miocene turbiditic erosive constructive channels. According to regional studies, sediment sourcing is identified to the northeast of OML-130 with the main turbidite fairways passing through Preowei and continuing to the southwest towards Egina South and Egina.

Within these turbiditic series, four hydrocarbon bearing stratigraphic intervals have been identified during the exploration and appraisal phase of Preowei structure: R641 (gas bearing), while R759, R790 and R811 are oil bearing. Development is focused on the last three reservoirs, with burial depths ranging between 800 m and 1,500 m.

The R759 reservoir is subdivided into three units: R759a, R759b (main) and R759c. Pressure data indicates vertical disconnection between all sub-units, and lateral disconnection between the three drilled wells. R759c, identified as erosive/constructive channel fill, constitutes the main reservoir unit, with 18 m of net TST encountered by Preowei-1, and 10 m TST in Preowei-3. Preowei-2 on the eastern flank, encountered an interbedded interval of thin sands and silts of 1-2m net TST. Based on well and seismic data, R759c is interpreted as a system of several NE-SW channel complexes, which may not be connected, eroded by a massive channel corresponding to the base of R759b (B-main), recognized on seismic but not penetrated by wells, as presented in Figure 8-4. Within the R759c reservoir two distinct oil-water contacts have been identified on seismic in the north area, at 2,140 and 2,080 mSS. No oil-water contact has been encountered within the central area, supported by ODT of 2036 mSS in Preowei-1 and strong seismic amplitudes down to 2,075 mSS. On the southern flank several contacts have been identified on seismic which appear to be limited by sealing faults.

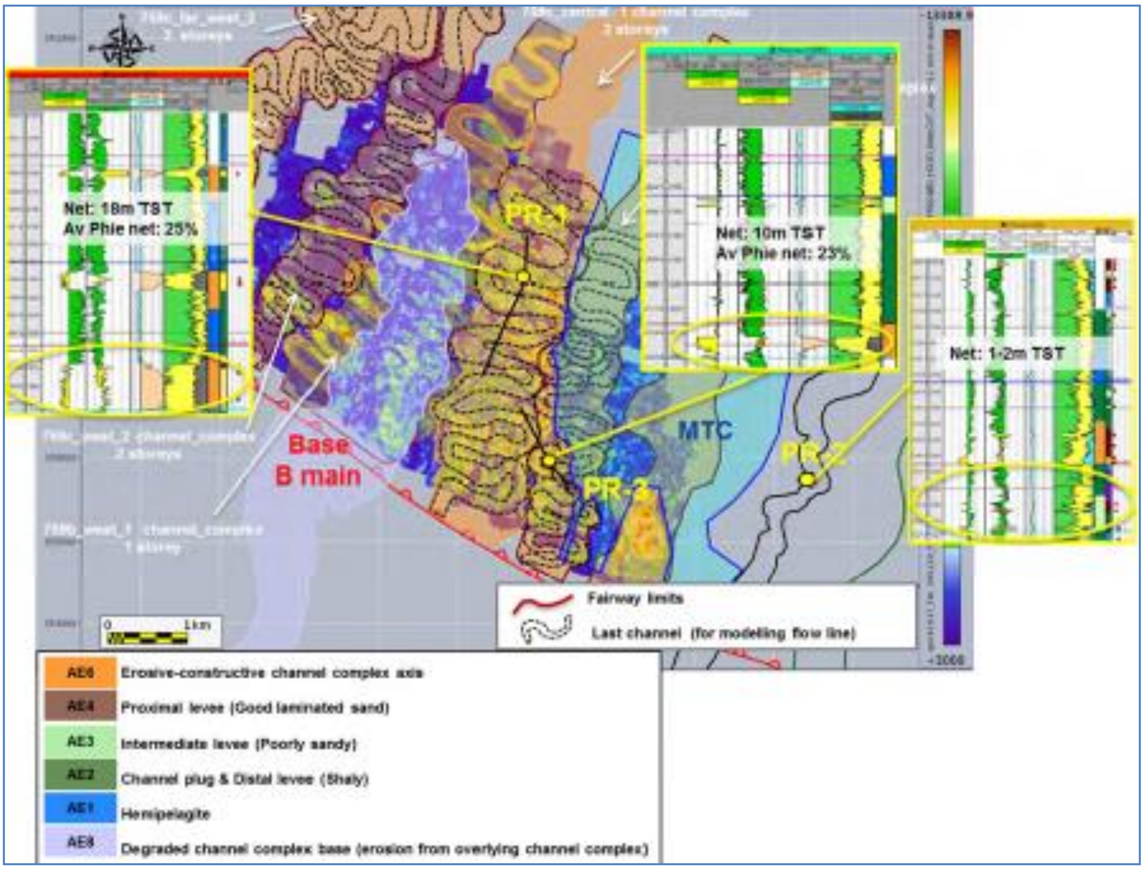


Figure 8-4: R759c Architectural Elements interpretation

The R790 reservoir is subdivided into R790a and R790b with each unit further subdivided into separate channel complexes, A-L1 and A-L2 within R790a and BL1 and B-L2 within R790b. The B-L1 channel complex is the focus for development, while A-L2 complex in the Preowei-2 area is considered a potential upside. Neither A-L1 nor B-L2 were penetrated by the exploration and appraisal wells but are considered as upside.

Unit B-L1 (Figure 8-5) is interpreted as a NE-SW fairway complex of laterally stacked meandering channels passing through the centre of the Preowei structure. It is calibrated by Preowei-1 with 28m of net TST (oil and water) and Preowei-3 with net TST of 23 m (oil). Amplitude degradation suggests its presence is limited to the west and it is restricted in the east by the A Lower fairway. In B-L1 two oil-water contacts have been interpreted; 2,262 mSS in the central area encountered by Preowei-1, and assumed valid for the north flank, and a single contact for the south flank at 2,540 mSS interpreted from amplitudes shut-off.

The A-L2 fairway, trending NE-SW to the east of B-L2 is interpreted as a complex of meandering, erosive channels, encountered fully oil bearing at Preowei-2 with net TST of 12bm. In A-L2 the central area of this fairway has been proved fully oil bearing by Preowei-2 with ODT at 2,443 mSS. A southern contact is interpreted from seismic at 2,540 mSS with 2,350 mSS interpreted in the northern area.

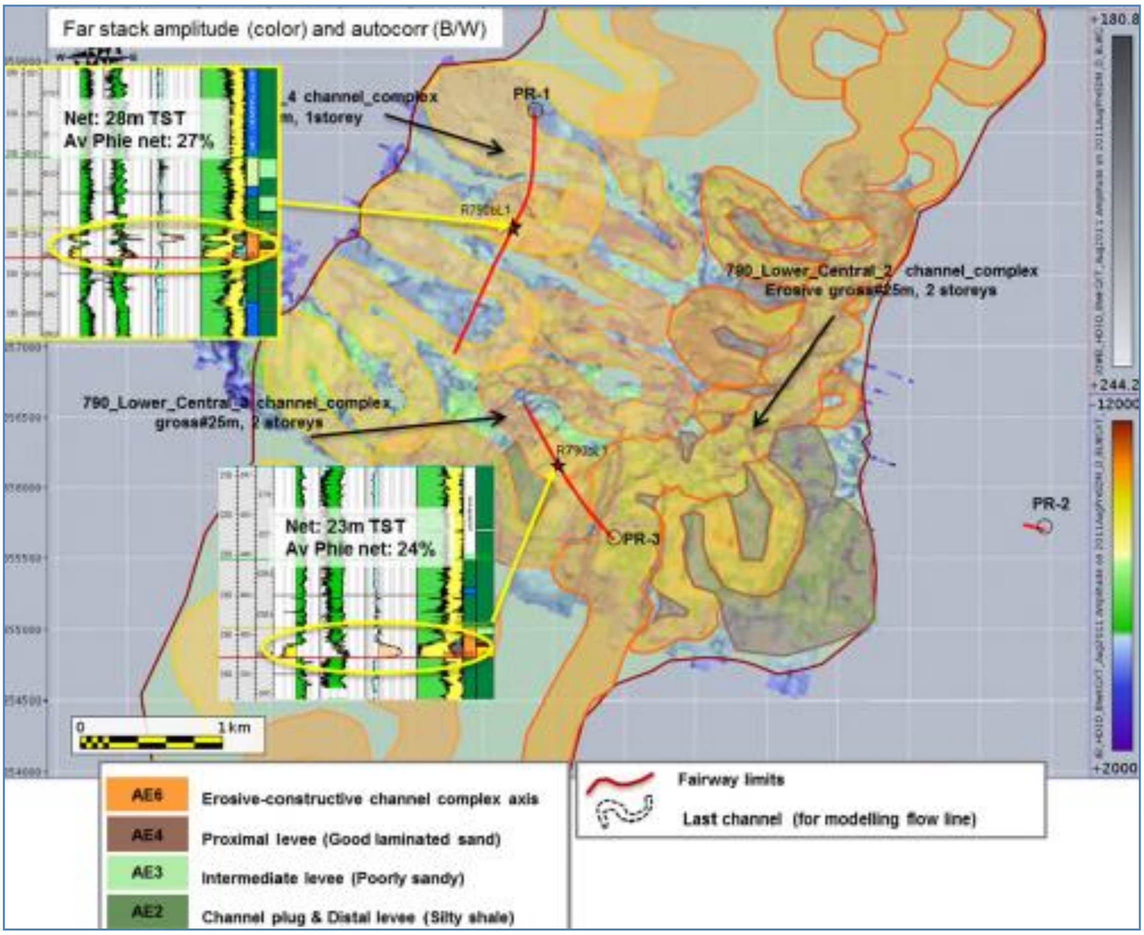


Figure 8-5: R790b-L1 Architectural Elements interpretation

The R811 interval comprises sub-units R811a, b and c with the main focus for development being the R811a. For R811a a net TST of 13 m was found by well Preowei-1, while 26 m TST were encountered by Preowei-3. Preowei-2 penetrated 45 m net TST of water bearing sands. Facies interpretation of the R811a reservoir consists of three fairways enclosing 2-3 storey laterally stacked meandering channel complexes, namely the Central, East1 and East2, which are seemingly not laterally connected (Figure 8-6). An oil-water contact for the north area is interpreted around 2,450 mSS as per amplitude shut-off for the main fairway, and at 2,545 mSS for the East fairway. For the central area R811a is considered fully oil bearing with Preowei-1 encountering an oil-water contact at 2,507 mSS, consistent with amplitude shut-off and flat-spots. On the south flank amplitude shut-off is visible at approximately 2,545 mSS which is consistent with Preowei-3 R811a and R811b pressure data.

RISC have reviewed the static model, reports and information provided by Prime regarding Preowei STOIIP. Fieldwide best estimate STOIIP as estimated by Prime and the operator is shown in Table 8-1. This fieldwide Prime STOIIP is derived from the static models provided to RISC in 2018. There is good agreement in best case STOIIP between Prime and the operator and RISC views both to be a fair representation of best/mid case fieldwide STOIIP.

The 2018 static model volumetric output was verified and agrees with that claimed for the development zone fault compartments targeted by the planned wells (238 MMstb). The model is detailed in terms of its geological input and is of high lateral and vertical resolution. The facies elements and oil column model distribution are heavily controlled by seismic derived input trend maps and polygons, and these have been faithfully replicated laterally and vertically in the final output parameters (facies, porosity, SW, NTG etc.). As previously discussed, the seismic derived input appears reasonable and is supported by the well penetrations to date.

Separate grid models have been constructed for each of the major reservoir zones – the R759, R790 and R811. Given the structural complexity due the extensive collapse faulting in additional to the detailed facies model this is a sensible approach. This enables a detailed representation of fault displacement at all levels which is crucial for well placement design and volumetric assessment of individual compartments. Some compartments are only 200-300m wide in places. Each grid has a fine degree of horizontal and vertical resolution – cell sizes are ~60m*60m laterally and significantly less than 0.5m thick in all reservoir zones. This enables the model to capture the narrow fault compartments and complexities of smaller channels and heterolithic facies. By using separate grids for each zone, the cell count can be kept at a reasonable number and hopefully negates the need to upscale for simulation.

Checks were made in the previous year end reviews to ensure the model property distributions reasonably capture the well petrophysical input. The geological model captured the property ranges observed at the well locations for the main net reservoir facies elements.

In the absence of uncertainty analysis by Operator or Prime, RISC has estimated a range of Preowei STOIIP to reflect uncertainty in the depositional facies, reservoir architecture and compartmentalisation with variable OWCs likely in different compartments within the field, in addition to the limited number of wells drilled on the structure. RISC propose a STOIIP range in Table 8-2 based on the Prime best estimate STOIIP. RISC expects that the STOIIP range will change significantly through time, reducing as more wells are drilled and more is learnt about the field.

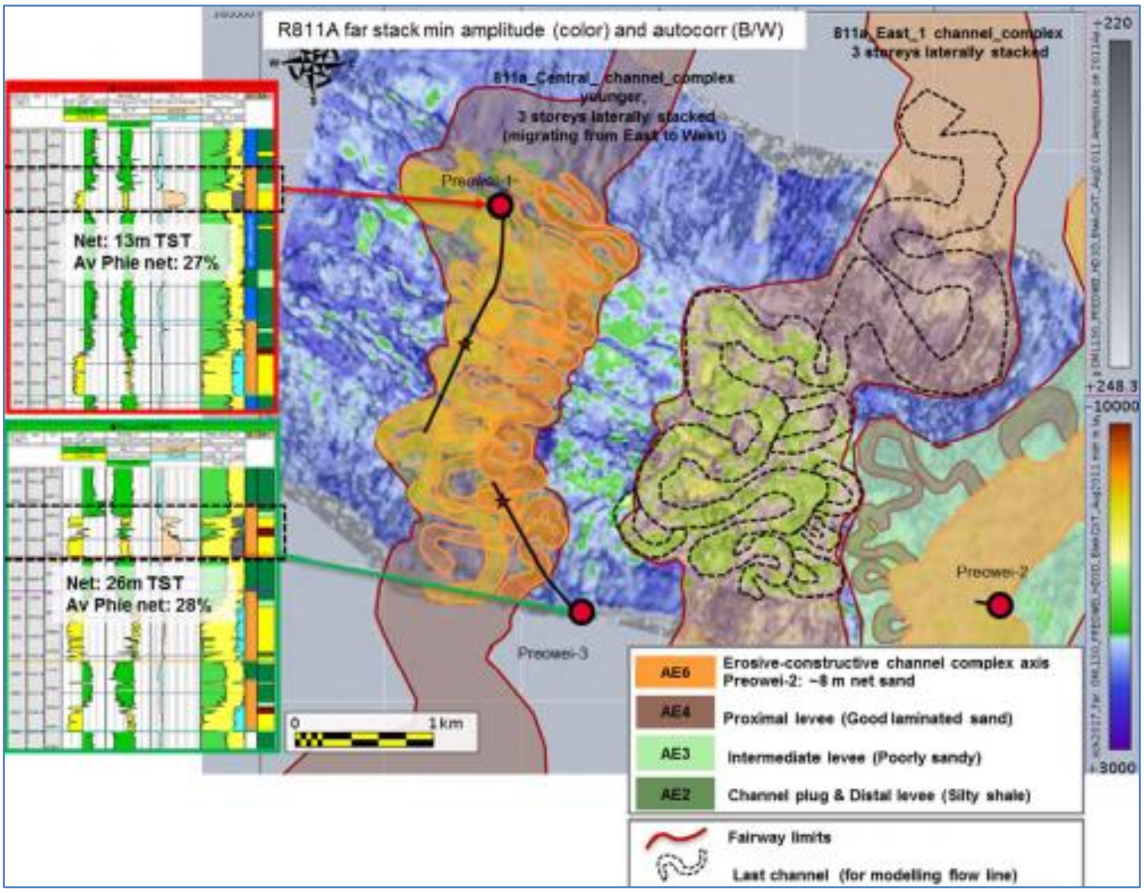


Figure 8-6: R811a Architectural Elements interpretation

Table 8-1: Preowei Field Best Estimate STOIIP by reservoir (MMstb)

Evaluation	R759	R790	R811	Total
Prime STOIIP (MMstb)	333	273	171	777
Total STOIIP (MMstb)	312	282	168	762

Table 8-2: Preowei Field STOIIP (MMstb)

	Low	Best	High
Preowei R759, R790, R811 STOIIP (MMstb)	450	777	1350

The Field Development Plan describes the field areas that are part of the initial phase of field development, defined by restricted segments created in the static model and reservoir simulation based on in-field faulting and reservoir compartmentalisation. These segments are predominantly located in the southern part of the field in each of the three main reservoirs.

A structural and stratigraphic interpretation, as well as static model rebuilt, was carried out in the field and peer reviewed in 2020. Based on this review, a new base case STOIIP estimate of 223 MMstb was calculated for the development area of the field (Table 8-3). This volume is made up of 85 MMstb, 74 MMstb and 64 MMstb across the three main R759c, R790 and R811s reservoir zones respectively. This evaluation, as reported in the Value Enhancement study (2020), was performed within a smaller development perimeter as there are fewer wells: 16 wells in 2020 vs 18 wells in the 2018 FEED case.

Table 8-3: Preowei Field Development Area Best Estimate STOIIP (MMstb)

	R759	R790	R811	Total
Preowei R759, R790, R811 STOIIP (MMstb) (2020)	85	74	64	223

8.1.2. Reservoir Fluid properties

All oil samples taken at Preowei have shown similar fluids, 150-300 psi undersaturated at initial reservoir pressures. Small differences in PVT properties are interpreted as identifying lateral and vertical discontinuities between the reservoirs and fault compartments.

Table 8-4: Preowei decontaminated reservoir fluid properties.

Reservoir	R759c		R790b		R811a	
Well	Preowei-1	Preowei-3	Preowei-2	Preowei-3	Preowei-1	Preowei-3
Perforated Interval (m/TVDSS)	-2020 to -2037				-2431 to -2441	
Reservoir depth (m/TVDSS)	-2028.5	-2130.1	-2439.9	-2367.5	-2436	-2521.4
Reservoir pressure (bar.a)	234.4	245.1	284.2	278.3	309.2	307.8
Reservoir temperature (°C)	52.8	60.8	67.2	70.0	72.5	75.9
Bubble Point (bar.a)	225.2	224.5	262.5	265.5	293.2	281.6
Reservoir fluid density (kg/m3)	820.1	816.6	812.5	821.9	804.5	805.7
Saturation fluid density (kg/m3)	819.3	813.7	806.7	819.9	803.9	801.2
Reservoir fluid viscosity (cp)	1.5	1.3	1.7	1.2	1.0	1.0
Boi Multi Stage (m3/Sm3)	1.2	1.2	1.2	1.2	1.2	1.2
Rs Multi Stage (Sm3/Sm3)	86.1	83.1	83.0	89.5	98.2	98.9
Liquid density at T (kg/m3)	896.3	912.1	903.0	919.8	914.3	920.7

The associated gas will be processed by the Egina FPSO and exported to shore (post fuel and flare).

8.1.3. Well Testing

DSTs were only conducted in Preowei-1, in two of the three major zones to be developed. Rock properties are excellent, with Darcy permeabilities. The DST interpretations support the high potential flow rates and the compartmentalized nature of the reservoir.

Table 8-5: Preowei-1 well test results

DST	Zone	Gross interval (m)	Oil rate (Mstb/d)	Kh (mD.m)	S	Remarks
DST 1	R811a	10	4.2	36,300	20	Permeability circa 3 Darcies. Linear composite 3 zone model, in a closed reservoir. Connected volume 27.4 MMstb (STOIIP).
DST 2	R759c	24	5.9	170,000	31	Permeability circa 10 Darcies. Channel system (boundaries 400m and 500m) with a third boundary at 80m from the well. Minimum connected volume 45 MMstb (STOIIP).

8.1.4. Production Facilities

The 2018 FDP envisages that Preowei will be developed with subsea wells, tied back to the Egina FPSO. No artificial lift is expected but the backpressure at the Preowei wells will be reduced with the use of gas lift at the riser base.

The operator has modelled the Preowei-Akpo-Egina fields with the Egina FPSO capacities and set a maximum liquid rate of 65,000 blpd from the Preowei field. A peak gas rate of 30 MMscf/d is forecast for delivery to the Egina FPSO. Availability of 93% is assumed for all production forecasts.

8.2. Development Plans

8.2.1. Drilling and Completions

With all the reservoirs of interest close to saturation pressure, water injection will be used to provide pressure support and sweep oil towards the production wells. The field is highly compartmentalized in all reservoirs, so each compartment requires a producer-injector pair to ensure adequate pressure support and sweep.

All 16 wells (8 oil producers and 8 water injectors) are planned to be horizontal through the reservoir with the completion designed to access multiple reservoir compartments. All the wells are equipped with single standalone screen completion, with some wells having mechanical zone selectivity.

Four of the planned 16 wells are scheduled to commence production at the first oil date. This is 2 producers and 2 water injectors, all in the R811 reservoir. The remaining 12 wells (in the 2P case) are to be drilled and commence production by the end of the first production year.

8.2.2. Facilities

Egina FPSO was designed as a regional hub, able to accommodate production from other fields within OML130 or beyond. The proposed development consists of a subsea tie-back to the FPSO. The subsea tieback will consist of a single 12'', 29 km heated production line to the FPSO. A Value Enhancement Study in June 2021 recommended the use of Wet Direct Electrical Heating (DEH). Tie-ins are planned to be made at subsea level, hence resulting in minor topside modifications. Riser base gas lift is planned with no requirement for multiphase pumps or subsea separation envisaged.

8.2.3. Schedule

The current Operator schedule assumes FID will be taken in Q4 2024. The FEED study is currently underway, and the Operator has suggested that progress to FID is 44.8%. Drilling is planned to commence in Q1 2027 leading to first oil in Q3 2027. In addition, the baseline 4D seismic survey acquisition is planned in Q1 2024. RISC considers this schedule to be tight but achievable.

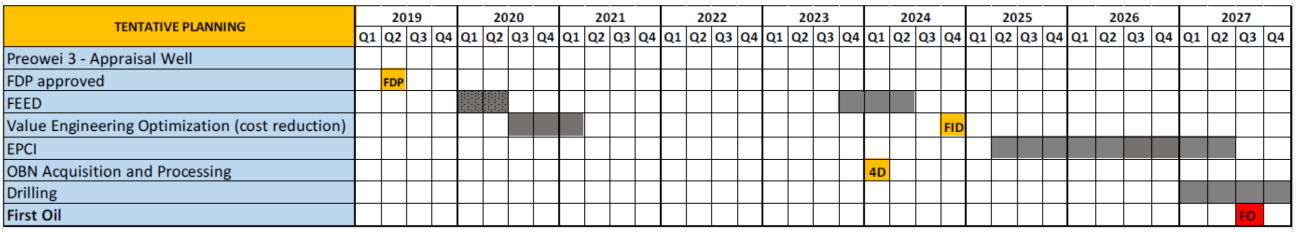


Figure 8-7 Current Operator schedule for Preowei (Reserves Audit presentation Dec 2023)

RISC's production forecasts assume a first oil date of 1/8/2027 for the reserves cases (Initial 16 wells) and 1/10/2029 for the contingent resources cases (further 8 wells).

8.3. Production Forecasts

The field is highly compartmentalised and the reported resources only include the discovered/appraised compartments in the field. Other compartments, with significant potential recovery, may be appraised and developed in future. There will be a significant appraisal and monitoring program, including interference tests, that starts before first oil and as the field commences production.

To plan the field development the operator built a reservoir simulation model. This was coupled with a model of the surface facilities, to better forecast the rates and pressures, as presented in the FDP. RISC had access to Prime's work, with adjustments made to the reservoir model with the knowledge gained from the full coupled simulation. In 2022, Prime simulated a 2P cases (16 wells) which RISC has used as a basis for its 2P cases. In 2022 Prime also simulated 2P+2C cases, with an additional 8 contingent wells, which RISC has used as the basis for its 2C cases. These production profiles were not changed between YE2022 and YE2023, other than shifting the starting date of the first oil.

Liquid production was limited to 65,000 blpd and the fieldwide availability was 94.5% (including planned shutdowns every 6 years from 2028).

Average oil recovery per production well in the 2P case is about 14 MMstb. The contingent production wells recover about 9 MMstb each.

The recovery factors are low (2P 15%, 2P+2C 19%) as most of the field will not be accessed by the development wells. However, the recovery factors within the developed area for the 2P case is circa 51%.

8.3.1. Forecast Methodology

RISC reviewed the FDP, simulation models and associated documentation, and we accept Prime's modelling as reasonable. The simulation respects the facilities limits and forecasts appropriate recovery factors with development wells only in appraised compartments. These simulations have been adopted as RISC's 2P and 2P+2C cases, from which RISC's 2C case was derived.

In the absence of an uncertainty assessment for the developed areas STOIIP, RISC scaled Prime's 2P forecasts by ±35% and Prime's 2C forecasts by ±50% to generate Low and High case technical forecasts for oil and associated gas.

Gas forecasts are based on simulation outputs, scaled in each forecast case to account for the cumulative oil production. As water injection will be used in each compartment to maintain reservoir pressure, the Gas-Oil Ratio is reasonably flat in all forecasts at circa 500 scf/stb. The Expected Ultimate Recoveries (EUR) for the Preowei reserves forecasts are given in Table 8-6. These volumes are based on forecasts ceasing at end 2044 instead of at the economic limit.

Table 8-6: EUR of Preowei Reserves Cases

Preowei Reserves EUR	1P	2P	3P
Recovery to End 2044, Oil, MMstb	74	113	149
Recovery to End 2044, Sales Gas, Bcf	35	53	70

The Expected Ultimate Recoveries for the Preowei contingent (8 wells) forecasts are given in Table 8-7. These volumes are based on forecasts ceasing at end 2044 instead of at the economic limit.

Table 8-7: EUR of Preowei Contingent Resources Cases

Preowei Contingent EUR	1C	2C	3C
Recovery to End 2044, Oil, MMstb	18	35	41
Recovery to End 2044, Sales Gas, Bcf	9	17	20

RISC's oil forecast cases are given in the plots below.

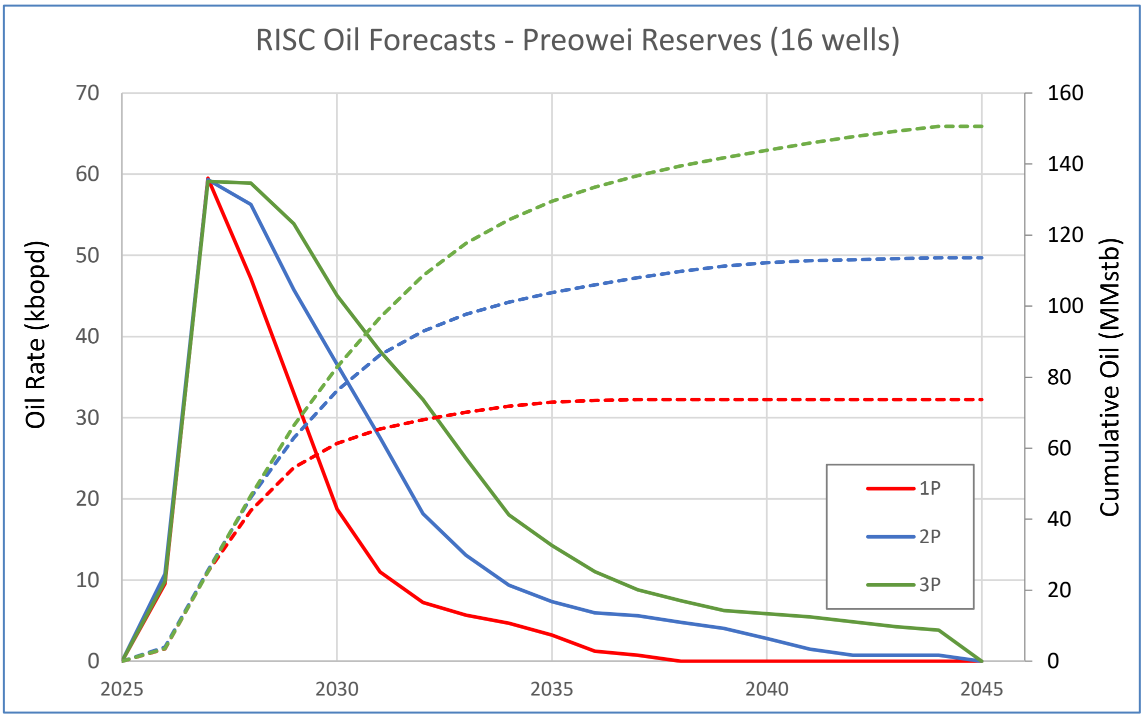


Figure 8-8: Preowei 1P, 2P and 3P Oil Forecasts

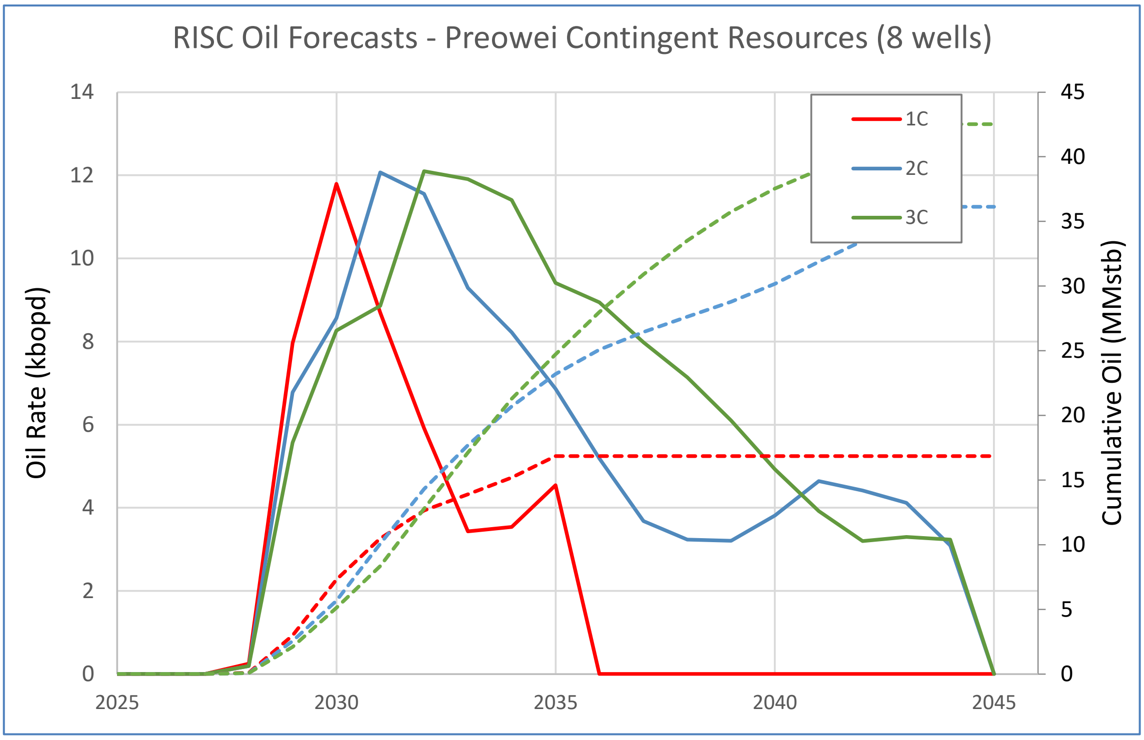


Figure 8-9: Preowei 1C, 2C and 3C Oil Forecasts

Gas usage is assumed at the Akpo FPSO only, with fuel gas of 3.37% of produced gas, and flared/vented gas of 1.05%.

RISC's sales gas forecast cases are given in Figure 8-10 & Figure 8-11.

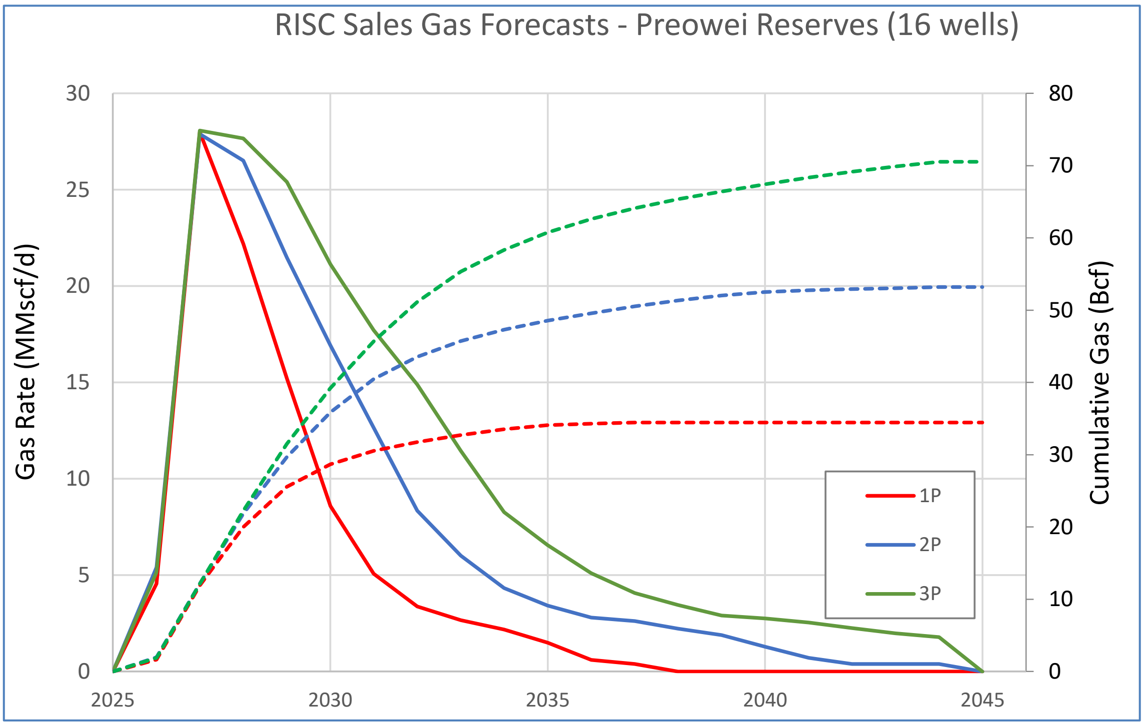


Figure 8-10: Preowei 1P, 2P and 3P Sales Gas Forecasts.

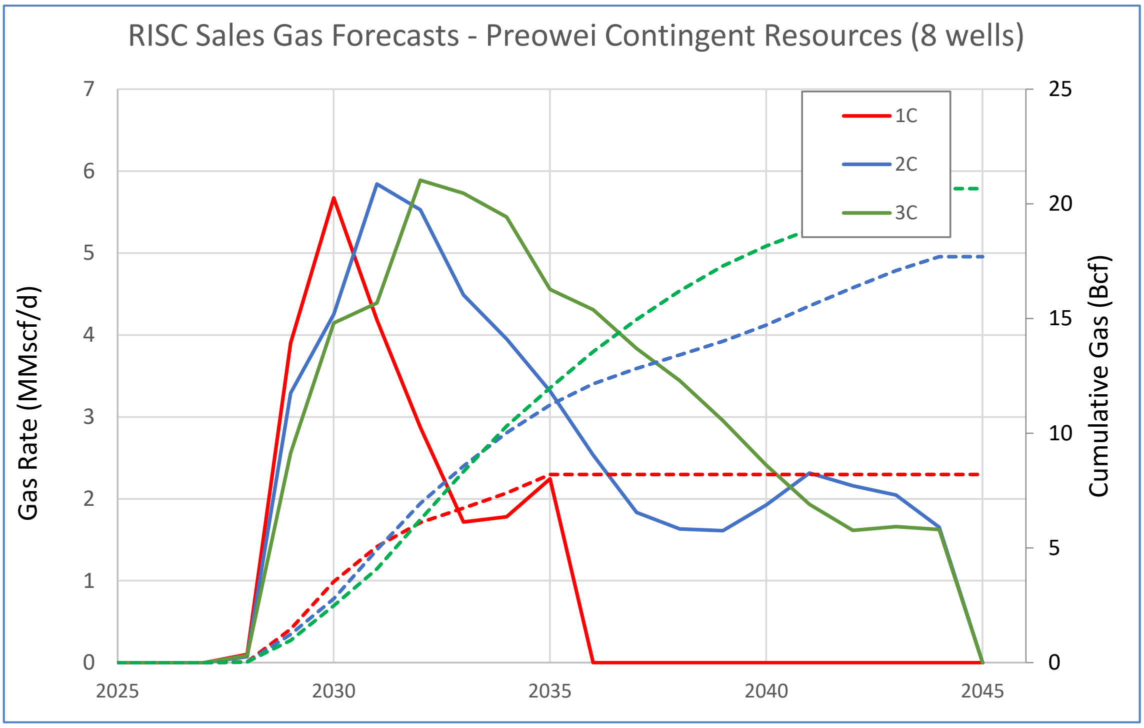


Figure 8-11: Preowei 1C, 2C and 3C Sales Gas Forecasts.

8.4. Cost Forecasts

8.4.1. Capital Costs

Preowei total capital costs are forecast to be just under US$1.7 billion (excluding abandonment) for the 16 well first phase of field development. The 16 development wells (8 water injectors and 8 producers) are forecast to cost US$617 million down from US$660 million last year after reallocation of some mobilization and demobilization costs. The rig spread rates used reflect the current market rates as discussed below. Facilities costs are forecast by Prime to be approximately US$1,014 million, slightly higher than last year. This compares to the Operators' P50 estimate of US$1.187 billion and P10 of 950 million. Therefore, in our view Prime's estimate is slightly optimistic. Geology and geophysics costs of US$35 million for seismic in 2024 are included in the facilities cost.

The second phase of 8 contingent wells to be tied back will involve an estimated 292 US$372 million to be spent on drilling and completions in 2028 and 2029.

The estimated cost phasing can be seen in Figure 8-12. The Operator currently forecasts FID in Q4 2024 and first oil in Q3 2027.

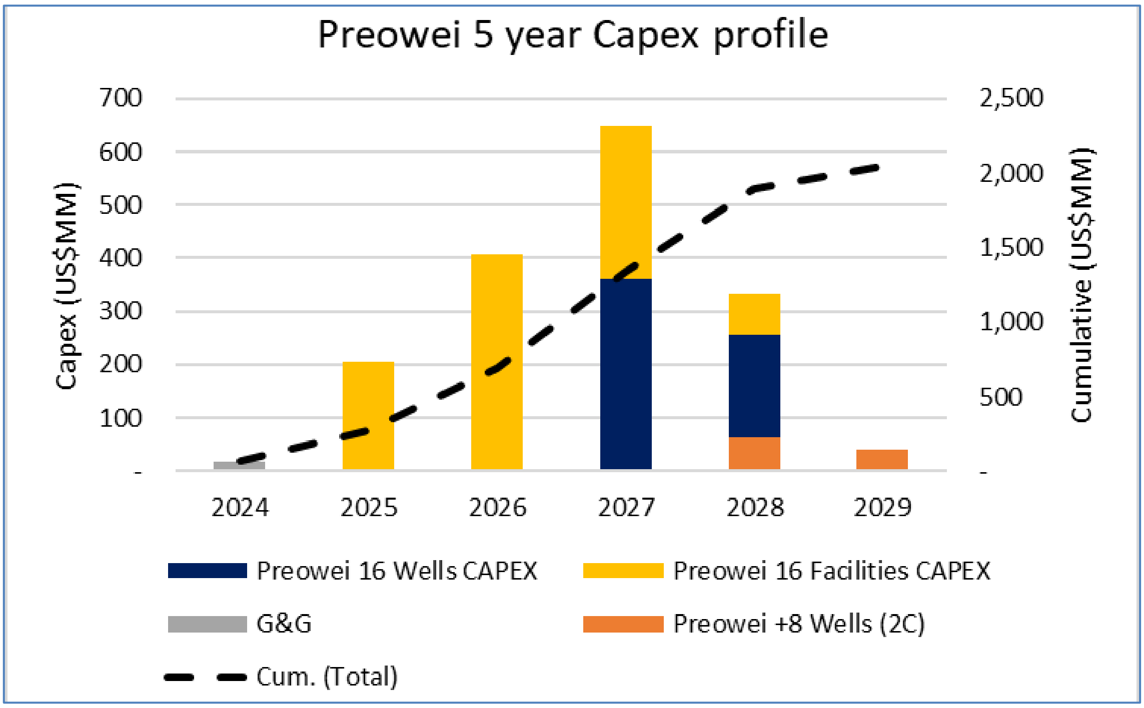


Figure 8-12: Preowei capex forecast by project to 2029.

The well costs of approximately US$38 million per well are equivalent to a spread rate of US$1,100,000/day and average time to drill and complete the wells of 35 days, based on experience from Egina. The spread rate assumption of US$1,100,000/day reflects the outcome Prime expects from rig contract negotiations.

Prime's capital cost forecasts are summarized in Table 8-8.

Table 8-8: Prime Preowei capital cost summary

Item Cost US$ million	Preowei 16 wells	Preowei + 8 wells	Total Cost US$ million
D & C	617	292	909
Facilities	1054	80	1134
Total	**1671**	**372**	**2043**

8.4.2. Operating Costs

Prime forecast 2P operating costs of US$13 million pa in the first full year of operation for the initial 16 wells in 2027 and US$4 million for the second 8 wells which falls to US$0.2 and 2.6 million respectively in 2044. RISC's opex forecast can be seen in Figure 8-13. Overall RISC views the incremental Opex as reasonable with the unit opex around USD 1.0 million/boe. However, RISC considers the reduction in Opex for the initial 16 wells to USD$0.2 million per annum as too low and has considered the costs to reduce to USD$0.9 million per annum and no further.

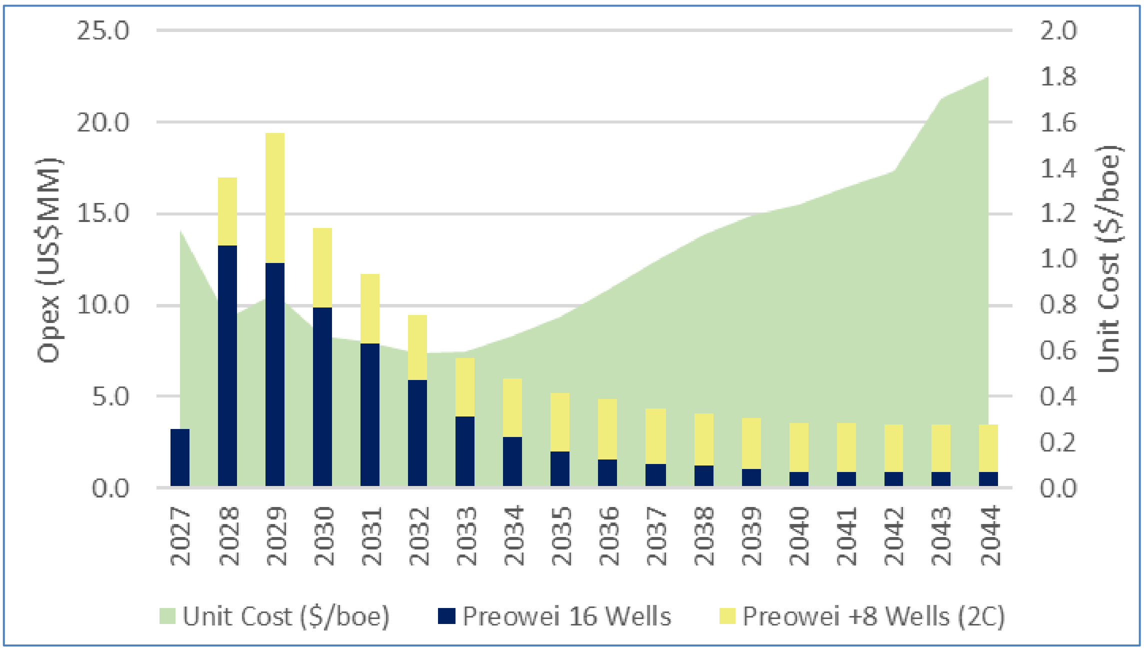


Figure 8-13: Preowei RISC Opex Forecast 2P Case.

8.4.3. Abandonment Costs

RISC estimates well P&A and facility decommissioning costs (using data from TOTAL's Egina abandonment cost estimation) of approximately US$140 million for the initial 16 well development. Well P&A costs are estimated to be approximately US$7 million per well based on 17.5 days per well and a spread rate of US$410,000/day (US$250,000/day rig + US$160,000/day services) plus US$20 million for decommissioning the subsea facilities and US$5 million mobilization/demobilization costs. This compares to costs of US$114 million in the economic model which appears to be for well P&A only.

Incremental costs for the 8 contingent resource wells are estimated to be US$67 million, comprising US$57 million for wells and US$10 million for facilities.

Under the licence terms, abandonment provisions for new fields starts upon first oil.

8.5. Preowei Reserves and Contingent Resources Summary

RISC classifies the initial 16 well project as reserves.

Prime stated that the Preowei FDP has been approved by the government and FEED had been initiated (paused initially due to the Covid challenges and then waiting for the Petroleum Industry Act). The Value

Engineering Optimization further improved the attractiveness of the project. FEED is planned to resume early 2023. Prime states that all partners are aligned to pursue Preowei and are targeting FID in Q1 2024.

The gross licence and Prime net entitlement oil and gas reserves associated with the Preowei field are shown in Table 8-9. The contingent resources associated with the eight additional infill wells are shown in Table 8-10.

Table 8-9: Preowei gross and Prime net entitlement undeveloped reserves as of 1 January 2024

Oil	Unit	Reserves		
		1P	2P	3P
Preowei oil (16 wells), gross to PML 4	MMstb	72.3	113.1	148.8
Prime net entitlement	MMstb	12.4	18.7	24.1
Sales gas				
Preowei gas (16 wells), gross to PML 4	Bcf	33.8	52.9	69.7
Prime net entitlement	Bcf	5.4	8.5	11.2

Notes:

1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in Section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. Sales Gas resources are adjusted for fuel gas.
5. Volumes are based on conversion of both licences to PIA terms.

Table 8-10: Preowei contingent resources for 8 additional wells as of 1 January 2024

Oil	Unit	Contingent Resources		
		1C	2C	3C
Preowei 8 infill wells, gross to PML 4	MMstb	19.4	35.2	41.8
Prime net entitlement	MMstb	3.3	5.7	6.6
Sales gas				
Preowei 8 infill wells, gross to PML 4	Bcf	9.4	17.2	20.3
Prime net entitlement	Bcf	1.5	2.7	3.2

Notes:

1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

Table 8-11 shows a comparison of the Year-End 2022 Preowei developed and undeveloped reserves with the Year-End 2023 estimates.

Table 8-11: Preowei Reserves Reconciliation Compared to Year-End 2022 Report

Oil	Unit	Reserves		
		1P	2P	3P
Preowei Field Gross at 1 Jan 2023	MMstb	72.3	113.0	148.8
Preowei Field Revisions	MMstb	0.0	0.1	0.0
Preowei Field Gross on 1 Jan 2024	MMstb	72.3	113.1	148.8
Sales gas				
Preowei Field Gross at 1 Jan 2023	Bcf	33.7	52.9	69.7
Preowei Field Revisions	Bcf	0.0	0.1	0.0
Preowei Field Gross on 1 Jan 2024	Bcf	33.8	52.9	69.7

Notes:
1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net entitlement for oil is calculated using the method described in Section 9.3 of this report.
3. Prime net entitlement for gas in PML 2, PML 3 & PML 4 is 16%.
4. Sales Gas resources have had fuel gas deducted.
5. Volumes are based on conversion of both licences to PIA terms.

The reserves at Preowei have not changed between YE2022 and YE2023.

Prime's fuel gas reserves can be seen in Table 8-12. These are not sales volumes but are gas volumes consumed in the operations (CiO).

Table 8-12: Preowei Fuel Gas reserves as of 1 January 2024

Gas Consumed in Operations	Unit	Reserves		
		1P	2P	3P
Fuel gas used at Preowei	Bcf	1.2	1.9	2.5
Prime net entitlement	Bcf	0.2	0.3	0.4

Notes:
1. "Gross" licence reserves are 100% of total field reserves.
2. Prime net working interest for fuel gas in PML 2, PML 3 & PML 4 is 16%.
3. These are not to be added to the sales gas reserves and must be reported separately as per PRMS 2018 reporting standards.

9. Economic Analysis

The economic model for the assets was provided by Prime for RISC's use in this YE2023 review. RISC has traced and checked the flow of calculations in the economic model as part of its quality control of outputs. Quality control of the input parameters by RISC included a review of production, costs, oil and gas pricing, inflation factors, effective date, exchange rates and fiscal terms. Adjustments were made to input parameters as considered necessary.

The model required inputs for OML 127 to be gross field volumes. However, the inputs for PML 2, PML 3 & PML 4 were required to be multiplied by 0.5 since PML 2, PML 3 & PML 4 is divided into two contracts, a PSA, and a PSC each holding 50% of the block.

RISC has used the existing historical cost and depreciation calculations provided by Prime and has not made any adjustments to Prime's tax position listed in the economic model.

RISC notes that several changes were made to the economic model in 2023 because of the introduction of the Petroleum Industry Act (PIA). These updates were used in the calculation of reserves and were checked as part of RISC's quality control process.

9.1. Licence Ownership

Table 9-1 and Table 9-2 summarise the current participating interests of Prime in OML 127 and PML 2, PML 3 & PML 4, respectively.

Table 9-1: OML 127 ownership

OML 127	Licence interest
FAMFA Oil Limited	60%
Star Deep Water Petroleum Limited (operator)[31]	32%
Prime 127 Limited	8%

The Agbami field straddles OML 127 and OML 128. A 2005 Agbami Unit Agreement (AUA) makes provisions for splitting production from Agbami between the two blocks in accordance with the agreed tract participation. The current tract participation for OML 127, agreed by Equity Determination in 2010, is 62.4619%. The final procedure to adjust the tract participation was completed in 2015 and increased the OML 127 participation to 72.0640%. At the effective date of this review the adjusted participation had not been implemented and so 62.4619% has been applied for reserves determination.

[31] Affiliate of Chevron Corporation

Table 9-2: PML 2/3/4 & PPL 261PSA (50% of licence) interests

PML 2, PML 3 & PML 4 & PPL 261	PSA interest
SAPETRO Limited	20%
Total Upstream Nigeria Limited (operator)	48%
Prime 130 Limited	32%

9.2. Fiscal Terms and Economic Inputs

9.2.1. Fiscal Terms

The fiscal terms applicable to OML 127 and PML 2, PML 3 & PML 4 as of 1 January 2024 are summarized in Table 9-3 and Table 9-4, respectively. The PIA was passed into law on the 16th of August 2021 and introduces several changes to the petroleum industry in Nigeria. This includes changes to the fiscal terms in existing leases. Both PML 2, PML 3 & PML 4 and OML 127 converted to the PIA terms in June 2023 and March 2023, respectively. The updated fiscal terms associated with the PIA are incorporated into Table 9-3 and Table 9-4.

Table 9-3: Fiscal assumptions for OML 127 as of 1 January 2024

	Oil		Gas
Royalty per production	< 50,000 bopd	5.0%	0%
	> 50,000 bopd	7.5%	
Additional royalty build up based on oil price (USD/bbl)	0 – 50	0.0%	
	50 – 100	5.0%	
	100 – 150	10.0%	
CIT	30%		
Education tax	2.44%		
NDDC levy	3%		
NASEI levy	0.3%		
Host communities fund	3%		
Capital allowances	20% for 5 years, limit of 67%		
NESS fee	0.12%		

Table 9-4: Fiscal assumptions for PML 2/3/4 & PPL 261 as of 1 January 2024

	Oil		Gas
Royalty per production	< 50,000 bopd	5.0%	0%
	> 50,000 bopd	7.5%	
Additional royalty build up based on oil price (USD/bbl)	0 – 50	0.0%	
	50 – 100	5.0%	
	100 – 150	10.0%	
CIT	30%		
Education tax	2.44%		
NDDC levy	3%		
NASEI levy	0.3%		
Host communities fund	3%		
Capital allowances	20% for 5 years, limit of 67%		
NESS fee	0.12%		

PIA royalties are applicable to Agbami, Akpo and Egina as of 1 January 2024. Preowei will not pay any royalties until the end of the 5 years holiday after first oil.

Figure 9-1 and Figure 9-2 show the revenue breakdown of the PSAs in OML 127 and PML 2, PML 3 & PML 4 respectively as of 1 January 2024. The economic model utilizes this methodology to calculate the reserves and resources net to Prime in each licence. This is described in more detail in section 9.3.

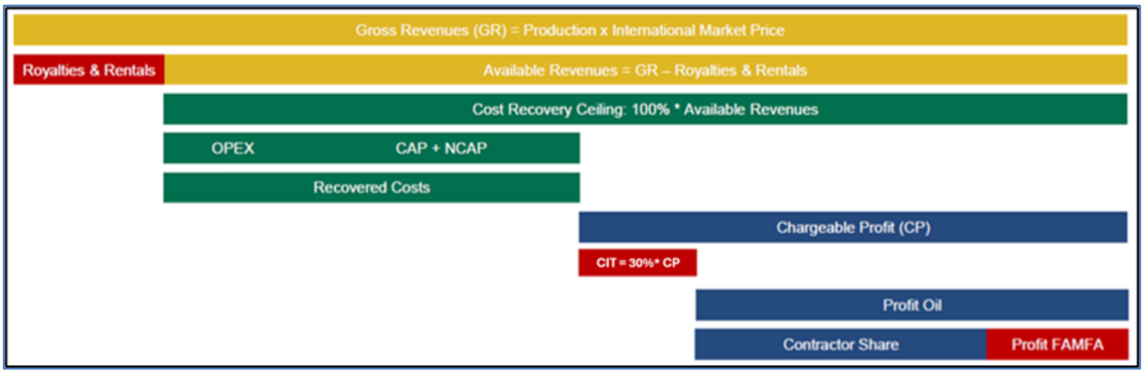


Figure 9-1: OML 127 PSA revenue breakdown as of 1 January 2024

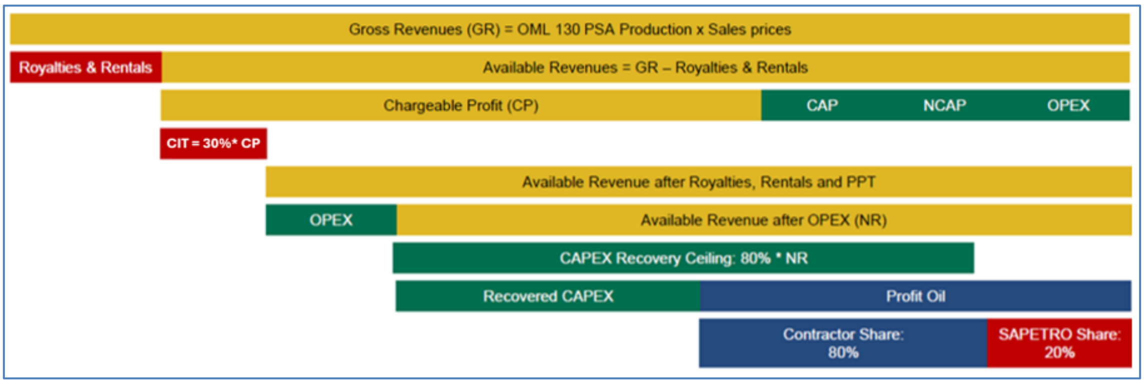


Figure 9-2: PML 2/3/4 & PPL 261 PSA revenue breakdown as of 1 January 2024

The contractor and FAMFA profit oil split as of 1 January 2024 is based on OML 127 cumulative oil production as described in Table 9-5.

Table 9-5: Contractor profit oil split in OML 127

Cumulative oil production (MMbbl)	Contractor profit share (%)
-	80%
351	65%
751	55%
1,001	50%
1,501	40%

9.2.2. Production and Cost Profiles

The production, opex and capex (including drilling costs) from the individual field sections of this report have been used in the economic analysis.

The specific abandonment costs for each field are stated in the corresponding sections of this report. Discussions are ongoing with respect to the provisioning of abandonment costs, however Prime has assumed a straight-line approach. This involves allocating a constant portion of the costs to each year until the end of field life. Prime has assumed the start date for this allocation to be in 2025 as both Agbami and Egina (which is the reference for Akpo) are modelled to have their mid case economic cut offs at least 10 years after this time. Prime also assumed an interest rate for the decommissioning fund account as the proportioning of costs configures a long-term investment.

9.2.3. Oil Price Forecast

Prime has used the Brent forward curve to forecast the oil price in 2024 and 2025 followed by a flat real price of US$75/bbl (RT2024) from 2026 onwards. RISC accepts Prime's forecast and has used it in each reserve and contingent resource case. The Brent oil price forecast inflated at 2.5% pa from 2024 is shown in Table 9-6.

Table 9-6: Prime oil price forecast (nominal US$/bbl)

2024	2025	2026	2027	2028	2029	2030	2031
82.0	78.0	78.8	80.8	82.8	84.9	87.0	89.2

9.2.4. PML 2, PML 3 & PML 4 Gas Monetization and Price

In this report the gas associated with Akpo, Egina and Preowei oil production is considered as reserves.

A Gas Utilisation Agreement was signed in 2005 for Akpo to export gas. The gas buyer consortium was responsible for construction and operating of the gas export system to the onshore Nigeria LNG plant in return for receiving 1 Tcf of sales gas at zero cost. The gas is partly re-injected and partly exported onshore via the Akpo-Amenam pipeline to Bonny Terminal. The total cumulative volume of 1 Tcf from Akpo was achieved in July 2018. Thereafter, gas has been sold under a new gas sales and purchase agreement to the NNPC/TEPNG JV which continues to sell gas to Nigeria LNG.

The contract gas price in the economic model has been calculated by applying a monthly Brent adjustment and subtracting a handling fee.

9.2.5. Discount Rate

A discount rate of 10% has been used.

9.2.6. Inflation Rate

All costs are estimated as of 1 January 2024 and escalated at 2.5% from 2024 onwards.

9.3. Economic Results

Cash flow analysis was conducted to determine economic cut-offs for the 1P, 2P, and 3P cases to determine reserves. Analysis was also run on the 1P+1C, 2P+2C and 3P+3C cases to determine contingent resources.

Cashflows have been calculated net to the Prime interest. Prime's net entitlement to the oil reserves and resources in each field have been estimated using the economic model provided by Prime. Contractor entitlement volumes in each period, measured in millions of barrels of oil, are calculated as that period's contractor revenue (i.e., cost oil, contractor profit oil and tax oil) divided by the received product price. Entitlement volumes are classified as reserves. The volumes associated with contingent projects are classified as contingent resources.

RISC has analysed the incremental economics of all undeveloped and contingent projects. We are satisfied that all reserves projects are economically viable in a 1P, 2P and 3P case when using the oil price forecast shown in section 9.2.3. Most of the contingent projects are economically viable.

The end of field life dates for the developed plus undeveloped reserves and contingent resources cases are shown in Table 9-7.

Table 9-7: End of field life dates for reserves and contingent resources cases

	Economic Cut-off					
	1P	2P	3P	1P+1C	2P+2C	3P+3C
OML 127						
Agbami	Sep-40	Dec-44	Dec-44	Feb-44	Dec-44	Dec-44
Ikija	-	-	-	Feb-44	Dec-44	Dec-44
PML 2, PML 3 & PML 4 & PPL 261 (formerly OML 130)						
Akpo	May-34	Mar-38	Aug-41	Sep-38	Oct-41	Oct-43
Egina	Jul-36	Mar-44	Oct-44	Jun-38	Nov-44	Feb-45
Preowei	Jul-36	Mar-44	Oct-44	Jun-38	Nov-44	Feb-45
Egina South	-	-	-	Jun-38	Nov-44	Feb-45

The gross licence developed plus undeveloped reserves and contingent resources are shown in Table 9-8.

Table 9-8: Gross licence reserves and resources as of 1 January 2024

	Gross licence reserves			Gross licence resources		
	1P	2P	3P	1P+1C	2P+2C	3P+3C
OML 127 (Oil, MMstb)						
Agbami	127.4	227.6	298.3	145.8	251.5	330.6
Ikija	-	-	-	46.9	82.2	102.6
PML 2, PML 3 & PML 4 & PPL 261 (formerly OML 130) (Oil, MMstb)						
Akpo	77.8	123.7	171.9	131.3	198.7	265.0
Egina	106.9	194.6	275.4	108.4	194.6	275.4
Preowei	72.3	113.1	148.8	91.7	148.3	190.6
Egina South	-	-	-	17.8	34.3	48.1
Total oil (MMstb)	**384.3**	**659.0**	**894.4**	**541.9**	**909.7**	**1,212.2**
PML 2, PML 3 & PML 4 & PPL 261 (formerly OML 130) (Gas, Bcf)						
Akpo	235.3	515.4	862.2	141.5	456.7	966.5
Egina	41.6	72.8	113.1	41.6	72.8	113.1
Preowei	33.8	52.9	69.7	43.2	70.1	90.0
Egina South	-	-	-	12.2	22.9	32.1
Total sales gas (Bcf)	**310.6**	**641.2**	**1,045.0**	**238.5**	**622.6**	**1,201.8**

Notes:

1. For OML 127 “Gross” licence reserves are 62.4619% of total field reserves.
2. For PML 2, PML 3 & PML 4 & PPL 261 (formerly OML 130) “Gross” licence reserves are 100% of total field reserves.
3. Sales Gas resources are adjusted for fuel gas.
4. Volumes are based on conversion of both licences to PIA terms.
5. Agbami has zero sales gas, therefore zero sales gas reserves.
6. Additions beyond the field level have all been made arithmetically, as a result RISC cautions that the 1P aggregate quantities may be very conservative estimates and the 3P aggregate quantities may be optimistic due to portfolio effects.

The net entitlement developed plus undeveloped reserves and contingent resources to Prime’s interest in the two licences are summarized in Table 9-9.

Table 9-9: Prime net entitlement reserves and resources as of 1 January 2024

	Prime net entitlement reserves			Prime net resources		
	1P	2P	3P	1P+1C	2P+2C	3P+3C
OML 127 (Oil, MMstb)						
Agbami	19.3	30.7	38.2	22.2	33.6	41.6
Ikija	-	-	-	6.5	10.1	11.8
PML 2, PML 3 & PML 4 & PPL 261 (formerly OML 130) (Oil, MMstb)						
Akpo	13.1	20.2	27.6	22.3	32.5	42.5
Egina	18.0	32.2	44.4	18.3	32.0	44.2
Preowei	12.4	18.7	24.1	15.7	24.5	30.7
Egina South	-	-	-	3.0	5.6	7.7
Total oil (MMstb)	**62.8**	**101.9**	**134.4**	**88.0**	**138.3**	**178.5**
PML 2, PML 3 & PML 4 & PPL 261 (formerly OML 130) (Gas, Bcf)						
Akpo	37.6	82.5	137.9	22.6	73.1	154.6
Egina	6.7	11.7	18.1	6.7	11.7	18.1
Preowei	5.4	8.5	11.2	6.9	11.2	14.4
Egina South	-	-	-	2.0	3.7	5.1
Total sales gas (Bcf)	**49.7**	**102.6**	**167.2**	**38.2**	**99.6**	**192.3**

Notes:

1. Prime net entitlement for oil is calculated using the method described in this section of the report.
2. Prime net entitlement for gas in PML 2, PML 3 & PML 4 & PPL 261 (formerly OML 130) is 16%.
3. Sales Gas resources are adjusted for fuel gas.
4. Volumes are based on conversion of both licences to PIA terms.
5. Agbami has zero sales gas, therefore zero sales gas reserves.
6. Additions beyond the field level have all been made arithmetically, as a result RISC cautions that the 1P aggregate quantities may be very conservative estimates and the 3P aggregate quantities may be optimistic due to portfolio effects.

Appendix A – RISC Production and Cost profiles

Agbami

The Agbami gross field oil production and cost profiles are shown in the following tables. It should be noted that the profiles include production and costs from the 6 undeveloped PAIDP wells. The resources and costs from the 6 contingent PAIDP wells are not included.

Table 9-10: Agbami gross field technical oil production profiles

Agbami gross field technical oil production profiles (Thousand bbl/d)			
Year	1P	2P	3P
2024	75.9	94.8	96.4
2025	58.7	85.9	86.1
2026	57.4	84.9	96.3
2027	60.3	88.7	110.0
2028	44.6	75.4	88.9
2029	42.2	58.9	87.1
2030	35.8	63.6	78.5
2031	30.7	55.8	71.4
2032	26.5	48.4	65.6
2033	23.2	43.9	60.5
2034	20.4	37.9	56.2
2035	18.2	32.5	52.5
2036	16.3	30.4	49.2
2037	14.6	31.6	46.2
2038	13.3	29.0	43.6
2039	12.1	28.1	41.2
2040	11.0	26.9	39.1
2041	10.2	25.0	37.1
2042	9.4	24.1	35.3
2043	8.7	21.1	33.7
2044	8.1	20.7	32.2

Table 9-11: Agbami 2P gross field technical cost profiles

Agbami 2P gross field technical cost profiles ($US MM 2024)				
Year	Facilities & G&G	Wells	Opex	Abex
2024	306	0	324	0
2025	164	0	301	34
2026	140	401	287	34
2027	217	100	292	34
2028	76	0	277	34
2029	65	0	262	34
2030	20	0	278	34
2031	20	0	270	34
2032	20	0	258	34
2033	20	0	256	34
2034	20	0	272	34
2035	20	0	251	34
2036	20	0	250	34
2037	20	0	256	34
2038	20	0	262	34
2039	20	0	249	34
2040	20	0	254	34
2041	20	0	248	34
2042	20	0	265	34
2043	20	0	251	34
2044	20	0	243	34

Akpo

The Akpo gross field oil and gas production and cost profiles are shown in the following tables. It should be noted that the profiles include production and costs from the undeveloped D-P5 and B-W4 wells, and the Akpo West development. The resources and costs from the contingent 5 infill wells and Akpo MGI projects are not included.

Table 9-12: Akpo gross field technical oil production profiles

Akpo gross field technical oil production profiles (Thousand bbl/d)			
Year	1P	2P	3P
2024	49.1	57.7	66.3
2025	39.7	54.8	70.0
2026	28.7	44.2	59.7
2027	21.8	33.7	45.7
2028	17.8	27.7	37.6
2029	14.8	23.0	31.2
2030	11.9	18.6	25.3
2031	10.4	16.3	22.1
2032	8.8	13.8	18.9
2033	7.4	11.6	15.8
2034	6.7	10.6	14.4
2035	6.0	9.4	12.8
2036	5.1	8.1	11.0
2037	4.8	7.5	10.3
2038	4.3	6.8	9.3
2039	3.8	6.0	8.2
2040	3.6	5.7	7.7
2041	3.3	5.2	7.1
2042	2.5	3.9	5.4
2043	2.3	3.7	5.0
2044	2.1	3.3	4.6

Table 9-13: Akpo gross field technical gas production profiles

Akpo gross field technical gas production profiles (MMscf/d)			
Year	1P	2P	3P
2024	96.9	164.6	232.4
2025	34.9	139.7	244.4
2026	0.0	74.0	176.0
2027	0.0	21.1	103.7
2028	0.0	0.0	67.8
2029	133.3	200.2	267.0
2030	123.3	184.4	245.4
2031	95.4	143.6	191.8
2032	77.5	117.2	156.9
2033	63.2	96.1	129.0
2034	53.2	81.5	109.7
2035	44.7	68.9	93.1
2036	36.8	57.3	77.7
2037	33.4	52.2	71.1
2038	29.3	46.1	63.0
2039	24.8	39.5	54.2
2040	22.9	36.7	50.5
2041	20.3	32.8	45.4
2042	0.0	3.4	0.0
2043	0.0	0.8	0.0
2044	0.0	0.1	0.0

Table 9-14: Akpo 2P gross field technical cost profiles

Akpo 2P gross field technical cost profiles ($US MM 2024)				
Year	Facilities & G&G	Wells	Opex	Abex
2024	123	187	235	0
2025	28	0	192	44
2026	22	0	213	44
2027	22	0	183	44
2028	22	0	181	44
2029	22	0	204	44
2030	22	0	177	44
2031	22	0	176	44
2032	21	0	200	44
2033	21	0	174	44
2034	21	0	173	44
2035	21	0	198	44
2036	21	0	172	44
2037	21	0	172	44
2038	21	0	197	44
2039	21	0	171	44
2040	0	0	171	44
2041	0	0	196	44
2042	0	0	171	44
2043	0	0	170	44
2044	0	0	170	0

Egina

The Egina gross field oil and gas production and cost profiles are shown in the following tables. It should be noted that the profiles include production and costs from the planned 6 undeveloped wells and 1 sidetrack.

Table 9-15: Egina gross field technical oil production profiles

Egina gross field technical oil production profiles (Thousand bbl/d)			
Year	**1P**	**2P**	**3P**
2024	72.3	76.6	84.0
2025	55.8	71.0	81.5
2026	45.4	61.0	81.3
2027	33.1	45.4	70.7
2028	24.3	37.4	60.6
2029	17.9	30.6	52.3
2030	13.4	26.4	45.3
2031	9.6	22.6	39.1
2032	6.6	20.9	34.6
2033	5.2	19.2	30.8
2034	4.2	17.1	27.1
2035	3.3	15.8	24.0
2036	2.6	14.7	21.3
2037	2.2	14.0	19.4
2038	1.8	12.7	17.5
2039	1.6	11.6	15.6
2040	1.4	10.6	13.9
2041	1.2	8.8	12.5
2042	1.1	8.2	11.2
2043	1.0	7.7	10.8
2044	0.0	0.0	0.0

Table 9-16: Egina gross field technical gas production profiles

Egina gross field technical gas production profiles (MMscf/d)			
Year	1P	2P	3P
2024	63.8	76.3	90.0
2025	30.7	51.7	61.4
2026	12.6	31.2	40.6
2027	6.1	15.3	31.7
2028	0.6	11.1	21.9
2029	0.0	7.8	20.0
2030	0.0	4.7	15.0
2031	0.0	1.3	10.7
2032	0.0	0.0	8.0
2033	0.0	0.0	5.8
2034	0.0	0.0	3.7
2035	0.0	0.0	0.7
2036	0.0	0.0	0.0
2037	0.0	0.0	0.0
2038	0.0	0.0	0.0
2039	0.0	0.0	0.0
2040	0.0	0.0	0.0
2041	0.0	0.0	0.0
2042	0.0	0.0	0.0
2043	0.0	0.0	0.0
2044	0.0	0.0	0.0

Table 9-17: Egina 2P gross field technical cost profiles

Egina 2P gross field technical cost profiles ($US MM 2024)				
Year	Facilities & G&G	Wells	Opex	Abex
2024	171	127	212	0
2025	49	253	188	40
2026	27	0	185	40
2027	27	0	181	40
2028	27	0	178	40
2029	27	0	201	40
2030	27	0	175	40
2031	27	0	174	40
2032	27	0	174	40
2033	27	0	173	40
2034	27	0	197	40
2035	27	0	172	40
2036	27	0	172	40
2037	27	0	172	40
2038	27	0	171	40
2039	27	0	196	40
2040	27	0	171	40
2041	27	0	170	40
2042	27	0	170	40
2043	27	0	170	40
2044	27	0	167	0

Preowei

The undeveloped Preowei gross field oil and gas production and cost profiles are shown in the following tables. It should be noted that the profiles do not include production and costs from the planned 8 contingent infill wells.

Table 9-18: Preowei gross field technical oil production profiles

Preowei gross field technical oil production profiles (Thousand bbl/d)			
Year	1P	2P	3P
2024	0.0	0.0	0.0
2025	0.0	0.0	0.0
2026	0.0	0.0	0.0
2027	5.8	7.2	8.5
2028	57.7	58.0	58.8
2029	48.8	56.8	59.0
2030	34.3	46.8	54.0
2031	19.9	37.2	45.4
2032	11.6	28.4	38.3
2033	7.5	18.8	32.4
2034	5.8	13.4	25.2
2035	4.8	9.6	18.2
2036	3.4	7.5	14.4
2037	1.4	6.0	11.1
2038	0.7	5.6	8.9
2039	0.5	4.9	7.5
2040	0.0	4.1	6.3
2041	0.0	2.9	5.9
2042	0.0	1.6	5.5
2043	0.0	0.8	4.9
2044	0.0	0.7	4.3

Table 9-19: Preowei gross field technical gas production profiles

Preowei gross field technical gas production profiles (MMscf/d)			
Year	1P	2P	3P
2024	0.0	0.0	0.0
2025	0.0	0.0	0.0
2026	0.0	0.0	0.0
2027	2.7	3.7	4.5
2028	27.3	27.3	28.0
2029	22.9	26.7	27.6
2030	15.8	22.0	25.5
2031	9.1	17.2	21.3
2032	5.3	13.0	17.8
2033	3.5	8.6	14.9
2034	2.7	6.2	11.5
2035	2.2	4.4	8.3
2036	1.6	3.5	6.6
2037	0.7	2.8	5.1
2038	0.4	2.6	4.1
2039	0.4	2.3	3.5
2040	0.4	1.9	2.9
2041	0.4	1.3	2.7
2042	0.4	0.8	2.5
2043	0.0	0.4	2.3
2044	0.0	0.4	2.0

Table 9-20: Preowei 2P gross field technical cost profiles

Preowei 2P gross field technical cost profiles ($US MM 2024)				
Year	Facilities & G&G	Wells	Opex	Abex
2024	70	0	0	0
2025	206	0	0	0
2026	408	0	0	0
2027	288	362	3	7
2028	78	255	13	7
2029	5	0	12	7
2030	5	0	10	7
2031	5	0	8	7
2032	5	0	6	7
2033	5	0	4	7
2034	5	0	3	7
2035	5	0	2	7
2036	5	0	2	7
2037	5	0	1	7
2038	5	0	1	7
2039	5	0	1	7
2040	5	0	1	7
2041	5	0	1	7
2042	5	0	1	7
2043	5	0	1	7
2044	5	0	1	0

10. Declarations

10.1. Terms of Engagement

This report, any advice, opinions, or other deliverables are provided pursuant to the Engagement Contract.

10.2. Authorisation for release

This report is final and is authorised for release.

Gavin Ward.

Gavin Ward

Director

RISC (UK) Limited

11. 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

Term	Definition
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 (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

Term	Definition
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)
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

Term	Definition
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 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

Term	Definition
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

Term	Definition
TVD	True vertical depth
UR	Ultimate recovery
US$	United States dollar
US$ million	Million United States dollars
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