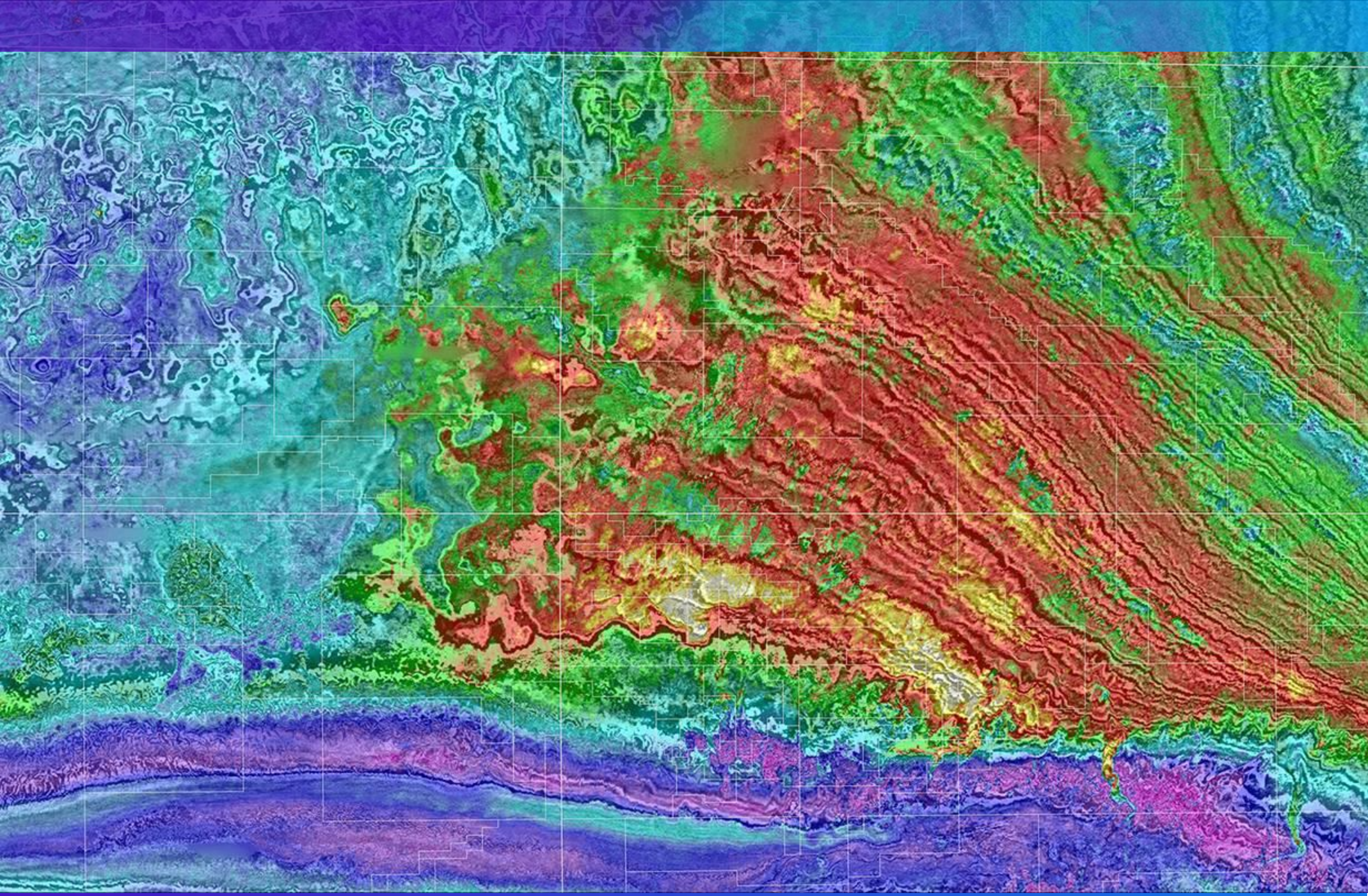

COMPETENT PERSONS REPORT

R1234 Licence Area, Agadem Basin, Niger

For
Savannah Energy PLC
Strand Hanson Limited
finnCap Ltd
Panmure Gordon (UK) Limited

DISCLAIMER AND CONDITIONS OF USAGE

Professional Qualifications

CGG Services (UK) Limited (CGG) is a geological and petroleum reservoir consultancy that provides a specialist service in field development and the assessment and valuation of upstream petroleum assets.

CGG has provided consultancy services to the oil and gas industry for over 50 years. The work for this report was carried out by CGG specialists having between five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG has no commercial arrangement or interest with Savannah Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

Data and Valuation Basis

In estimating petroleum in place and recoverable, CGG has used the standard techniques of petroleum engineering. There is uncertainty inherent in the measurement and interpretation of basic geological and petroleum data. There is no guarantee that the ultimate volumes of petroleum in place or recovered from the field will fall within the ranges quoted in this report.

CGG has independently assessed the proposed development schemes and validated estimates of capital and operating costs, modifying these where it was judged appropriate. The capital and operating costs have been combined with production forecasts based on the Reserves or Resources at the P90 (Proved), P50 (Proved + Probable) and P10 (Proved + Probable + Possible) levels of confidence and the other economic assumptions outlined in this report in order to develop an economic assessment for these petroleum interests. CGG's valuations do not take into account any outstanding debt or accounting liabilities, nor future indirect corporate costs such as general and administrative costs.

CGG has valued the petroleum assets using the industry standard discounted cashflow technique. In estimating the future cashflows of the assets CGG has used extrapolated economic parameters based upon recent and current market trends. Estimates of these economic parameters, notably the future price of crude oil and natural gas, are uncertain and a range of values has been considered. There is no guarantee that the outturn economic parameters will be within the ranges considered.

In undertaking this valuation CGG have used data supplied by Savannah Energy PLC in the form of geoscience reports, seismic data, engineering reports and economics data. The supplied data has been supplemented by public domain regional information where necessary.

CGG has used the working interest percentages that Savannah Energy PLC has in the Properties, as communicated by Savannah Energy PLC. CGG has not verified nor do they make any warranty to Savannah Energy PLC's interest in the Properties.

Within this report, CGG makes no representation or warranty as to: (i) the amounts, quality or deliverability of reserves of oil, natural gas or other petroleum; (ii) any geological, geophysical, engineering, economic or other interpretations, forecasts or valuations; (iii) any forecast of expenditures, budgets or financial projections; (iv) any geological formation, drilling prospect or hydrocarbon reserves; (v) the state, condition or fitness for purpose of any of the physical assets, including but not limited to well, operations and facilities related to any oil and gas interests or (vi) any financial debt, liabilities or contingencies pertaining to the organisation, Savannah Energy PLC.

CGG affirms that from 1st October 2021 (the effective date of the evaluation) to the date of issue of this report, 1) there are no material changes known to CGG that would require modifications to this report, and 2) CGG is not aware of any matter in relation to this report that it believes should and may not yet have been brought to the attention of Savannah Energy PLC.

In order to conform to the AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange, CGG has compiled this CPR to conform with Petroleum Resources Management System (PRMS) (2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE). Further details of PRMS are included in **Appendix A** of the CPR.

Conditions of Usage

This report was compiled using existing data during the period 1st February 2021 to 1st October 2021. However, if substantive new data or facts become available or known, then this report should be updated to incorporate all the relevant data.

CGG has made every reasonable effort to ensure that this report has been prepared in accordance with generally accepted industry practices and based upon the data and information supplied by Savannah Energy PLC for whom, and for whose exclusive and confidential use (save for where such use is for the Purpose), this report is made. Any use made of the report shall be solely based on Savannah Energy PLC's own judgement and CGG shall not be liable or responsible for any consequential loss or damages arising out of the use of the report.

The copyright of this CPR document remains the property of CGG. It has been provided to Savannah Energy PLC, Strand Hanson Limited, finnCap Ltd and Panmure Gordon (UK) Limited for the purpose of Savannah's re-admission to trading on AIM, its inclusion in the related AIM Admission Document and disclosure on the Savannah's website in accordance with the AIM Rules and specifically to the AIM Note for Mining, Oil & Gas Companies (these together being the "Purpose"). CGG agrees to disclose the enclosed CPR to Savannah Energy PLC, Strand Hanson Limited, finnCap Ltd and Panmure Gordon (UK) Limited for the Purpose. The recipient should also note that this document is being provided on the express terms that, other than for the Purpose, it is not to be copied in part or as a whole, used or disclosed in any manner or by any means unless as authorised in writing by CGG. Notwithstanding these general conditions, CGG additionally agrees to the publication of the CPR document, in full, on Savannah Energy PLC's website in accordance with the AIM rules.

The accuracy of this report, data, interpretations, opinions and conclusions contained within, represents the best judgement of CGG, subject to the limitations of the supplied data and time constraints of the project. In order to fully understand the nature of the information and conclusions contained within the report it is strongly recommended that it should be read in its entirety.

CGG Services (UK) Limited Reference No: BP510				
Rev	**Date**	**Originator**	**Checked & Approved**	**Issue Purpose**
01	17th December 2021	AKS/PC/PMD/TU	AW	Final Report

Date	**Originator**	**Checked & Approved**
Signed:	***AKS/PC/PMD/TU***	

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1 EXECUTIVE SUMMARY

At the request of Savannah Energy PLC (Savannah), Strand Hanson Limited, finnCap Ltd and Panmure Gordon (UK) Limited, CGG Services (UK) Limited (CGG) have prepared a Competent Persons Report (CPR) relating to the R1234 licence area (the Licence Area) operated by Savannah in the Agadem Rift Basin (ARB), Niger.

Savannah Energy Niger is the Operator of the R1234 Licence Area with a 100% ownership. Savannah has a 95% interest in Savannah Energy Niger.

Licence	Operator	Savannah Interest (%)	Status	Licence expiry date	Licence Area
R1234*	Savannah Energy Niger	95%	Exploration	2031	13,655 km^2

Table 1-1 Current Licence Details

*The Company has agreed with the Ministry of Petroleum to amalgamate the four licence areas (covered by the previous R1/R2 PSC and the R3/R4 PSC) into a single PSC. The new PSC (being the R1234 PSC) will be valid for up to 10 years from the date of signing the agreement. The new PSC has been approved by the Council of Ministers on 16 December 2021.

The Licence Area covers an area of 13,655km^2, representing approximately 50% of the original Agadem permit which was mandatorily relinquished in July 2013 by the China National Petroleum Corporation (CNPC). The Agadem Rift Basin is a part of the wider Central African Rift System (**Figure 1-1**) in which significant oil has been discovered. In the Agadem Rift Basin, three fields are currently on production. Oil from the three fields is currently evacuated by pipeline to the Zinder refinery, located in Niger.

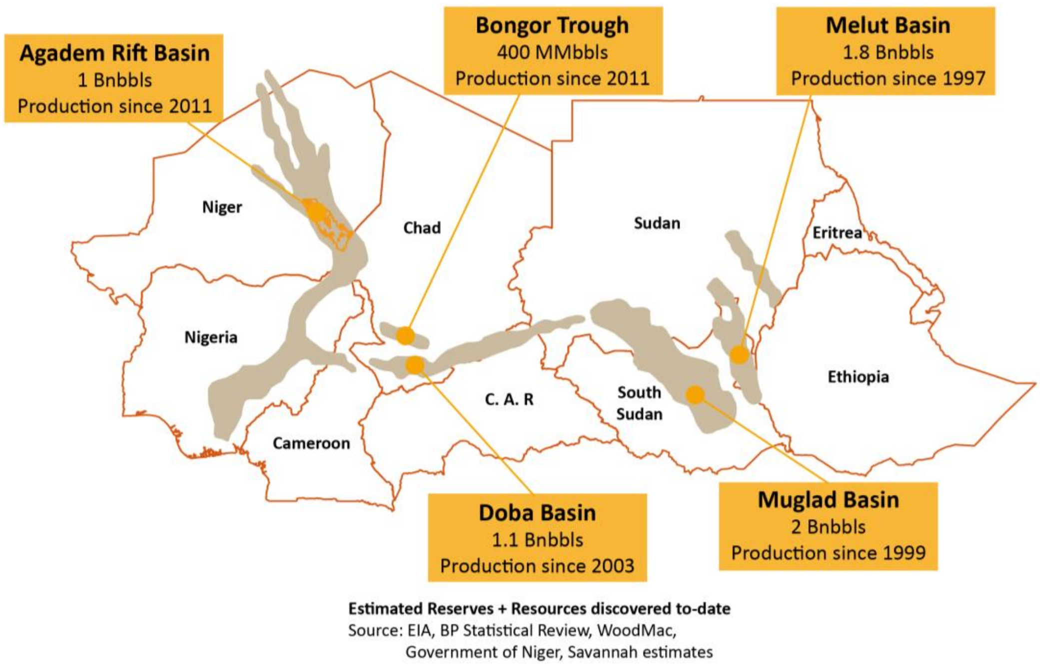


Figure 1-1 The Central African Rift System Discovered Resources (*Source: Savannah, 2021*)

Between 2008 and 2019, CNPC markedly increased the success rate of exploration in the basin, with c. 110 discoveries from 137 wells (80% success rate) establishing 2P Reserves of just under 1 billion barrels. Most of the discoveries were made in the Sokor Alternances and demonstrate the low risk profile of this Tertiary play. In addition, several light oil discoveries have been made in the Cretaceous Yogou play directly to the south east of Savannah's R3 area, which highlight the potential of this under-explored play.

Following its entry into Niger in 2014, Savannah has built a comprehensive database composed of existing 2D/3D seismic and well data, which have been interpreted to both build and de-risk the current exploration portfolio. To complement the existing dataset, Savannah acquired a Full Tensor Gravity Gradiometry (FTG) and High-Resolution Airborne Magnetic (HRAM) surveys in 2014/2015 over the full Agadem Rift Basin. Back in 2016, Savannah identified the R3 East area as a low risk exploration region (93% success rate in surrounding wells), believed to be an extension of the light oil play successfully drilled by CNPC. To derisk this area, Savannah completed the acquisition and processing of an 806km^2 3D seismic survey in 2016/2017. Interpretation of the survey confirmed a number of previously identified Tertiary structures in the Sokor Alternances, and five of these were subsequently drilled in a back-to-back campaign in 2018. These discoveries (namely Bushiya, Amdigh, Kunama, Eridal and Zomo) confirm the presence of light sweet crude and a good quality reservoir analogue to the currently producing fields. Amdigh's STOIIP estimates show the discovery to be one of the 10 largest in the basin. It should be noted that the average size of the Savannah discoveries, c. STOIIP of 30MMstb, is in-line with the basin exploration statistics.

Savannah has built an exploration portfolio containing a total of 146 prospects and leads to-date (**Figure 1-2**) with a total Unrisked Best Estimate of c. 6.7 bn bbls Oil Initially In-Place. In addition to the prospect and lead inventory within proven plays, Savannah has also identified several new, potentially significant exploration plays which offer genuine high risk, high reward upside.

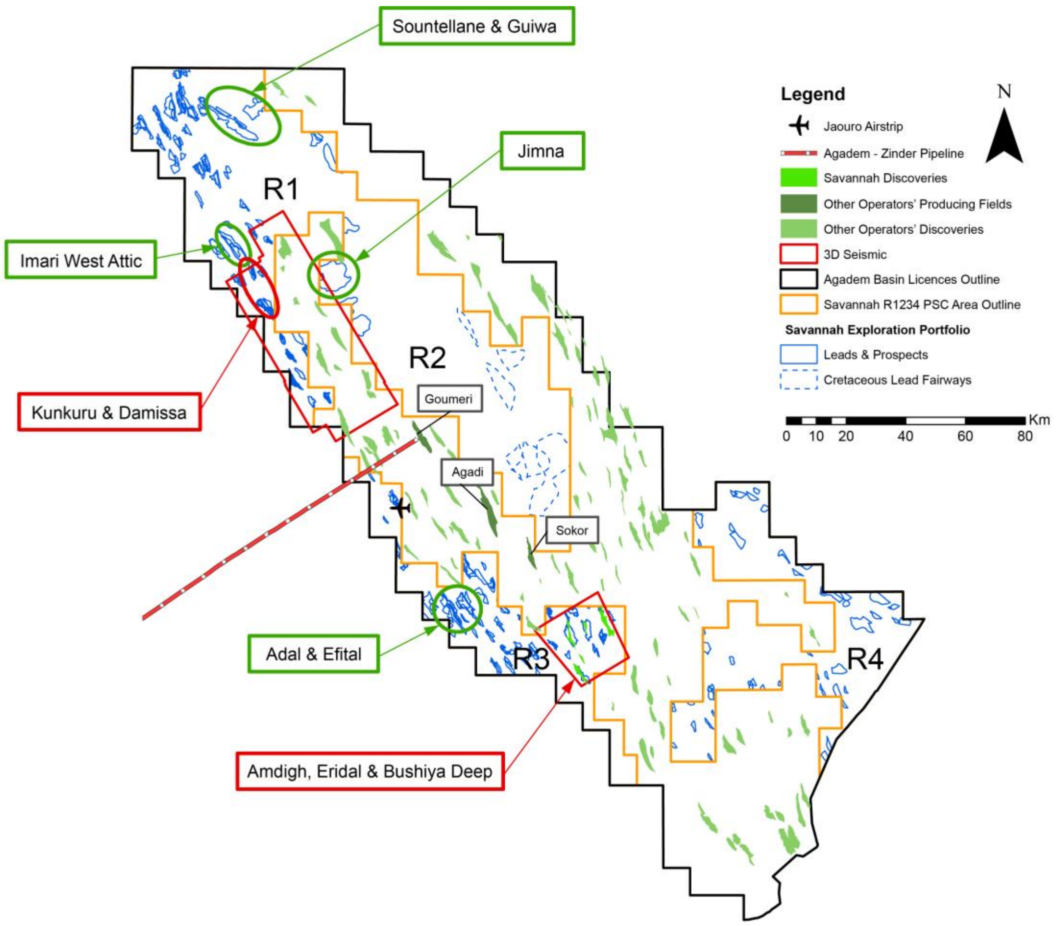


Figure 1-2 Savannah's Prospects and Leads Portfolio (*Source: Savannah, 2021*)

CGG has estimated STOIIP and Resource volumes for the five discoveries made on the R3 area in 2018 and a subset of eleven prospects and leads from Savannah's extensive exploration portfolio comprising of up to 146 prospects and leads, and has also provided estimates of the yet-to-find resources in the Licence Area. The eleven prospects and leads have been identified as potential candidates for the next exploration drilling campaigns across the Licence Area.

In addition, CGG has calculated expected recovery factors, and verified indicative economics for the early development scheme proposed by Savannah. CGG has conducted a technical review of the five discoveries that have been drilled in 2018, namely: Bushiya, Amdigh, Eridal, Kunama and Zomo. **Figure 1-3** is a map of the R3 East area showing the five oil discoveries which oil sampling confirm oils to be medium to light (24º to 33º API) and "sweet" (<0.5 wt. % Sulphur). The reservoir quality varies from medium (E1 and E2) to high (E3 to E5) and is in-line with the neighbouring CNPC producing fields and discoveries.

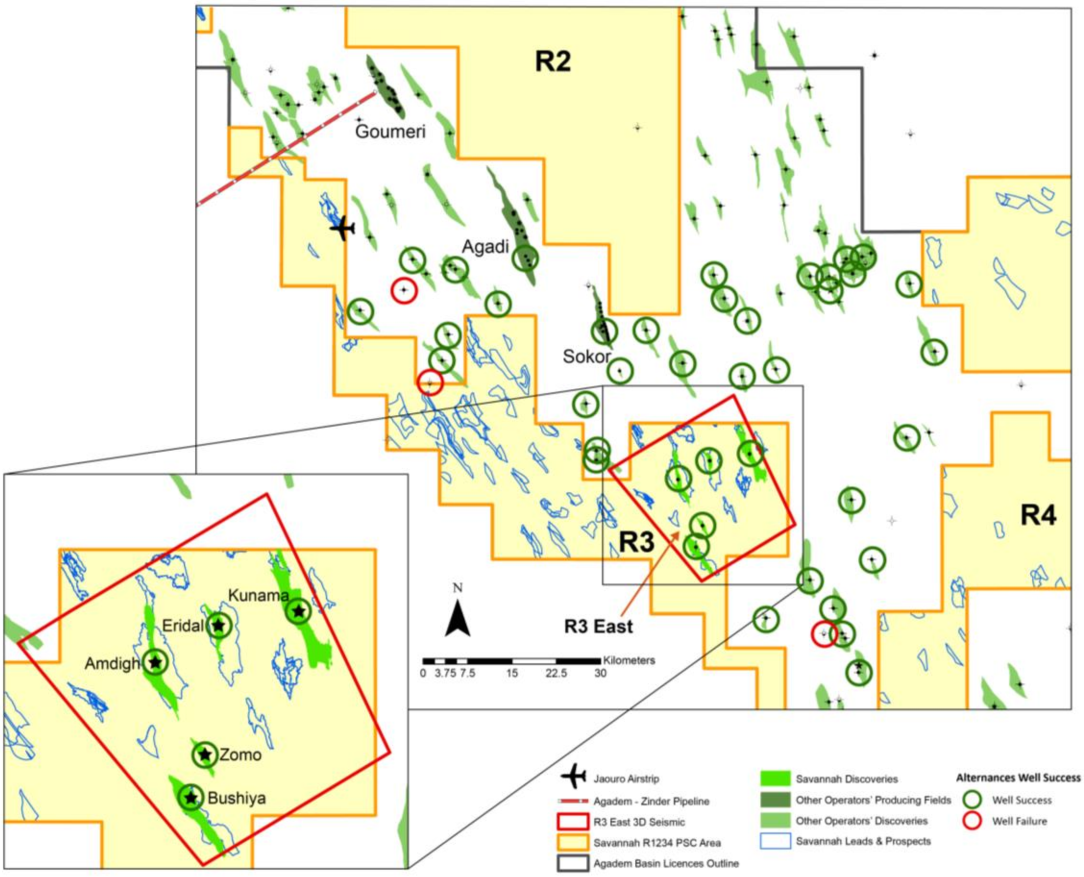


Figure 1-3 Map showing the location of the five 2018's discoveries (*Source: Savannah, 2021*)

CGG has used expected recovery factors for the discoveries from analysis of the existing producing fields in the basin. Based on this analysis and benchmarking against other analogue fields, CGG has applied recovery factors of 23%, 28% and 33% to the STOIIP figures to calculate recoverable volumes for the low, best and high Contingent Resources cases, respectively.

Contingent and Prospective Resources have been calculated by CGG in accordance with the Petroleum Resources Management System (PRMS, 2018) and the PRMS Guidelines (2011) and the AIM Note for Oil and Gas Companies (2009) for the discoveries and identified prospects and leads; these are summarised in the following tables.

	Contingent Resources (MMstb)							
	Gross			Net attributable				
Discovery	1C	**2C**	3C	1C	**2C**	3C	**Risk factor**	**Operator**
Amdigh	*7.2*	18.4	*83.9*	*6.8*	17.5	*79.7*	low	Savannah
Eridal	*4.3*	6.2	*8.5*	*4.0*	5.9	*8.1*	low	Savannah
Bushiya	*3.3*	6.2	*12.9*	*3.2*	5.9	*12.3*	low	Savannah
Kunama	*1.8*	4.2	*9.3*	*1.8*	4.0	*8.8*	low	Savannah
Zomo*		0.2			0.2		medium	Savannah
Total**	***16.7***	**35.0**	***114.6***	***15.8***	**33.3**	***109.1***		

* Indicative Resources pending PSDM evaluation,
** Arithmetic sum excluding Zomo, Total may not add exactly due to rounding

Notes

1. *Contingent Resources are those quantities of petroleum estimated to be potentially recoverable from known (discovered) accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies*
2. *Contingent Resources are stated before the application of a risk factor and an economic cut-off*
3. *1C, 2C and 3C categories account for the uncertainty in the estimates and denote low, best and high outcomes*
4. *The risk factor means the estimated chance that the volumes will be commercially extracted*
   Risk factor: low = > 75%, medium = 25% - 75%, high = <25%
5. *Full definitions of the Contingent Resource categories can be found in Appendix A*
6. *Net: the portion of the gross resources attributable to Savannah before royalties, taxes and government share of profit*

Table 1-2 Contingent Resources

Similar to the Contingent Resources, CGG has applied recovery factors of 23%, 28% and 33% to the STOIIP figures to calculate recoverable volumes for the low, best and high Prospective Resource cases, respectively. Individual stratigraphic reservoir volumes have been summed probabilistically, in order to calculate an overall prospect or lead resource total. Most prospects and leads are composed of stacked targets in the Upper Sokor, Sokor Alternances and Yogou formations which will be accessible from a single well trajectory.

CGG has reviewed Savannah's in-house methodology for assessing gross mean Unrisked STOIIP for the selected eleven prospects and leads, and found it to be reasonable. CGG has also validated Savannah's volumetric input parameters, and found them to be reasonable. CGG has further evaluated Savannah's assessment of exploration risk, and found that to be reasonable too. Although some differences do exist between CGG and Savannah, this level of disparity often results from small differences in data interpretation and calculation methodology. Savannah has completed the Pre-Stack Depth Migration (PSDM) processing for the R3 East seismic survey in 2019. Based on the newly interpreted PSDM, 3D geocellular models have been built for the Amdigh and Eridal discoveries. Savannah has stated that the resulting oil in-place volumes are in-line with the PSTM based estimates presented in this report. CGG has not reviewed these latest estimates at this stage, since Savannah is still progressing with further work on the other discoveries and its exploration portfolio.

Prospect/Lead	Unrisked Prospective Resources (MMstb)						Risk factor
	Gross			Net			
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	
Bushiya Deep	1.8	7.6	22.5	1.7	7.3	21.3	medium
Amdigh Deep	2.6	10.9	32.7	2.4	10.4	31.0	medium
Eridal Deep	1.7	6.9	20.0	1.6	6.6	19.0	medium
Adal	3.2	20.6	72.6	3.0	19.6	69.0	medium
Efital	8.7	44.0	130.0	8.3	41.8	123.5	medium
Sountellane	9.4	35.8	108.2	8.9	34.0	102.8	medium
Damissa	13.2	66.9	188.1	12.5	63.6	178.7	low
Imari W Attic	8.8	45.4	149.5	8.3	43.1	142.0	high
Guiwa	6.5	30.0	89.8	6.2	28.5	85.3	high
Kunkuru	1.9	10.4	31.3	1.8	9.9	29.8	low
Jimna	17.2	81.5	254.8	16.3	77.4	242.0	high
Total*	**74.9**	**360.1**	**1099.4**	**71.2**	**342.1**	**1044.4**	

* Arithmetic sum, Total may not add exactly due to rounding

Notes

1. *Prospective Resources are the volumes estimated to be potentially recoverable from undiscovered accumulations through future development projects*
2. *Volumes are sub-divided into low, best and high estimates to account for the range of uncertainty in the estimates, which correspond to the P90, P50 and P10 percentiles from the probabilistic analysis*
3. *The Prospective Resources are stated on an "unrisked" basis and before the application of an economic cut-off*
4. *Full definitions of the Prospective Resource categories can be found in Appendix A*
5. *The risk factor is defined as the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface, from any prospective stratigraphic level in the defined prospect*
   Risk factor: low = > 75%, medium = 25% - 75%, high = <25%
6. *Net: the portion of the gross resources attributable to Savannah before royalties, taxes and government share of profit*
7. *Savannah is the Operator of the assets*

Table 1-3 Selected Prospective Resources (for a subset of 11 out of 146 prospects/leads portfolio)

CGG has conducted a separate 'yet-to-find' analysis, which estimates the quantity of oil that may ultimately be expected to be found on Savannah's Licence Area, based on previous discoveries made in the basin. This is a proprietary methodology created by CGG and does not reflect a replication of Savannah's work. The method calculates discovered STOIIP per km^2 for areas with similar characteristics, which are then adjusted and applied to the Licence Area. It should be noted that these yet-to-find volumes are not linked to Savannah's planned exploration campaign. They are estimates of what could ultimately be discovered across the plays analysed, assuming a seismic and exploration drilling campaign of similar density to that employed to-date. The results of this analysis are presented in **Table 1-4**.

Licence	Gross Prospective Resources – "yet to find" (MMstb)					
	Unrisked			Risked		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
R1234	**2561**	**6801**	**9987**	**1000**	**2695**	**3868**

Table 1-4 Estimate of gross Unrisked and Risked "yet to find" Resources

Since the drilling of the five discoveries, Savannah has developed an Early Production Scheme (EPS) which includes evacuation of crude via a new 90km pipeline between Amdigh and the Goumeri Export Station (GES) (**Figure 1-4**). The proposed development plan utilises an Early Production Facility (EPF) to be installed at Amdigh, which will permit early revenues. The recent development in the construction of the Niger to Benin export route is a milestone, that provides Savannah with an alternative route for its crude but more importantly it will enable the full potential of the Licence Area to be unlocked.

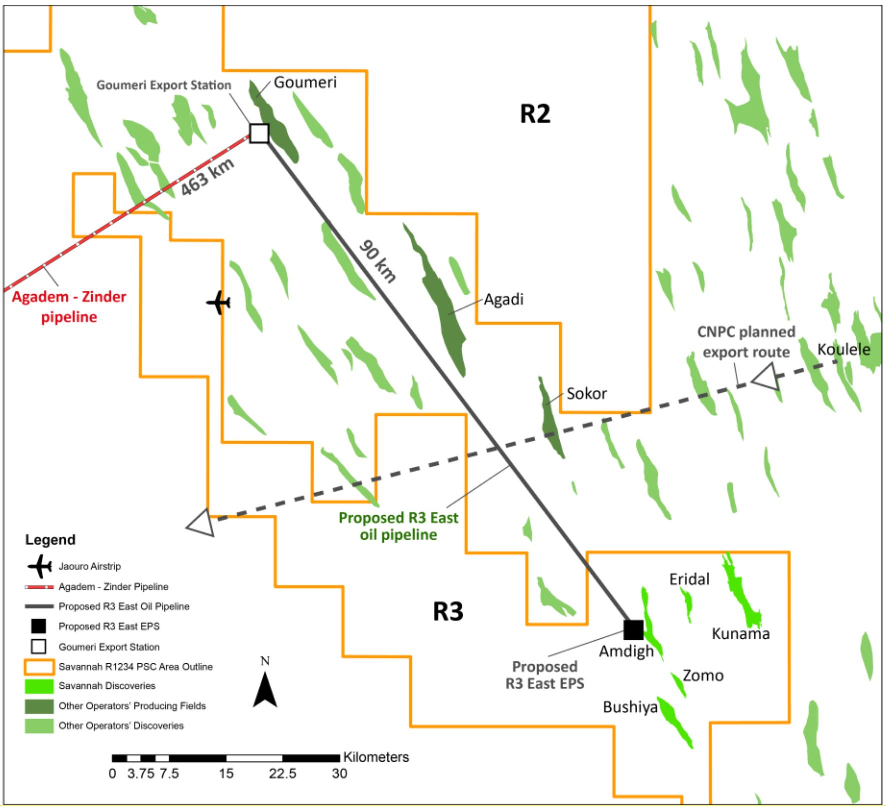


Figure 1-4 Proposed Early Production Scheme Development (Source: Savannah, 2021)

The proposed Development Scheme is summarised below.

Phase 1 - Early Production

- Expected to deliver a plateau of c. 1,500 bopd from initial well testing
- Procurement and installation of a 5,000 bopd Early Processing Facility (EPF)
- Planned construction of a c. 90km pipeline between the EPF and the Goumeri Export Station (GES). Crude is then piped to the SORAZ refinery at Zinder (using the existing 463km Agadem to Zinder pipeline)

Phase 2 - Ramp-up and Further Development

- Use of existing EPF and 90km pipeline
- Construction of a gathering system which will enable the fields tested in Phase 1 to be fully developed and tied into the EPF
- Drilling Appraisal and Development wells
- Production expected to ramp up to around 5,000 bopd which will continue to be handled by the refinery at Zinder

The results of the economic analysis are presented in the table below and are based on a US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively. Beyond 2024, the price is escalated at 2% per year

Case	2C
NPV0 (US$MM)	443.3
NPV10 (US$MM)	150.2
NPV10/bbl (US$)	6.4

Notes

1. *NPVs are based on net economic production to Savannah of 23 MMstb and post 15% government back-in right*

Table 1-5 Indicative Economics (net to Savannah) for Discoveries

NPV10 sensitivities have also been performed on costs and oil price. The results of this analysis are tabulated below.

The break-even refinery gate oil price, which would enable Savannah to generate a 10% IRR on the development would be approximately US$30/bbl, assuming costs at this oil price level would be reduced by at least 20% from those prevailing at US$60/bbl. CGG has assessed this assumption and considers it to be reasonable.

As a further sensitivity, the economics of tying-in a 20 MMstb prospect to the Amdigh facilities have also been evaluated. On the basis of minimal modifications to the facilities, this analysis yielded an incremental unrisked NPV10 of approximately US$100MM net to Savannah.

Case	2C
Base case	150.2
+15% factor on costs	122.3
-15% factor on costs	176.7
Oil price - US$50/bbl	70.4
Oil price - US$60/bbl	142.0
Oil price - US$70/bbl	197.4
Oil price - US$80/bbl	248.9
Oil price - US$90/bbl	297.3
Oil price - US$100/bbl	344.0
Production volume +25%	214.1
Year 1 production 2,500 bopd	156.9

Table 1-6 Sensitivities for Indicative Economics (NPV10 net to Savannah, US$MM)

2 INTRODUCTION

2.1 Overview

The R1234 Licence Area is located in the oil prolific Agadem Rift Basin (ARB) in South East Niger. The Licence Area covers a c.13,655km^2 area, representing approximately 50% of the original Agadem permit which was mandatorily relinquished by CNPC in July 2013. The location of the assets is provided in **Figure 2-1**.

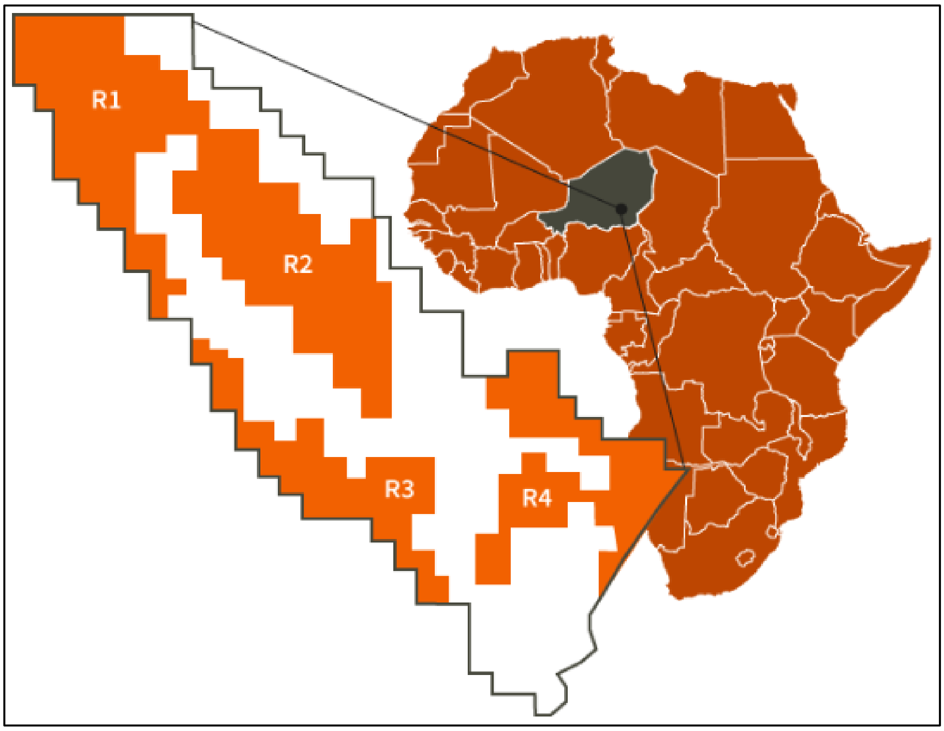


Figure 2-1 Map showing location of the assets (*Source: Savannah, 2017*)

Savannah's licence is situated in the Mesozoic to Cenozoic Agadem Rift Basin of Eastern Niger. The Agadem Rift Basin (ARB) is comparable in scale to the North Sea rift system (**Figure 2-2**). The rift basins of Niger are part of the Central African Rift System. The Central African Rift System is a proven hydrocarbon province in Niger, Chad, Sudan and South Sudan. The topography in the Licence Area is relatively flat and although it is a desert there are no significant mobile sand dunes. The area is c.200km away from the nearest major population centres. Wells drilled to-date have been vertical or slightly deviated and to the best of our knowledge have been completed using industry standard drilling procedures and equipment.

This assessment is based on information provided by Savannah, by the Niger Ministry of Energy and Petroleum to Savannah, and on information in previous CGG in-house studies of African rift systems.

Savannah Energy Niger is the Operator of the R1234 Licence Area with a 100% ownership. Savannah has a 95% interest in Savannah Energy Niger.

The basin shows classic rift geometries (**Figure 2-3**) and in the Savannah Licence contains multiple stacked hydrocarbon plays **(Figure 2-4)**.

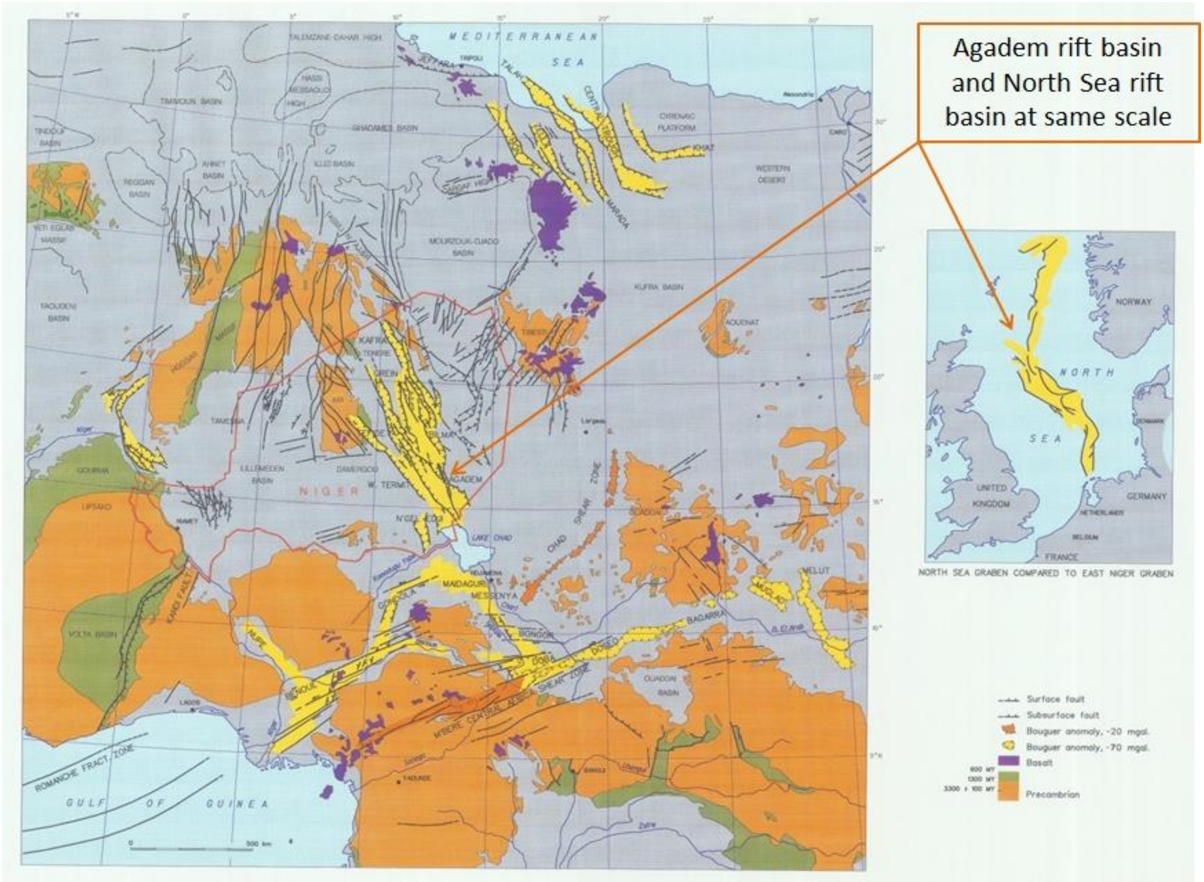


Figure 2-2 Map comparing magnitudes of the basins of Niger and the North Sea

(Source: Niger Ministry of Energy & Petroleum, and in-house Robertson studies, 2017)

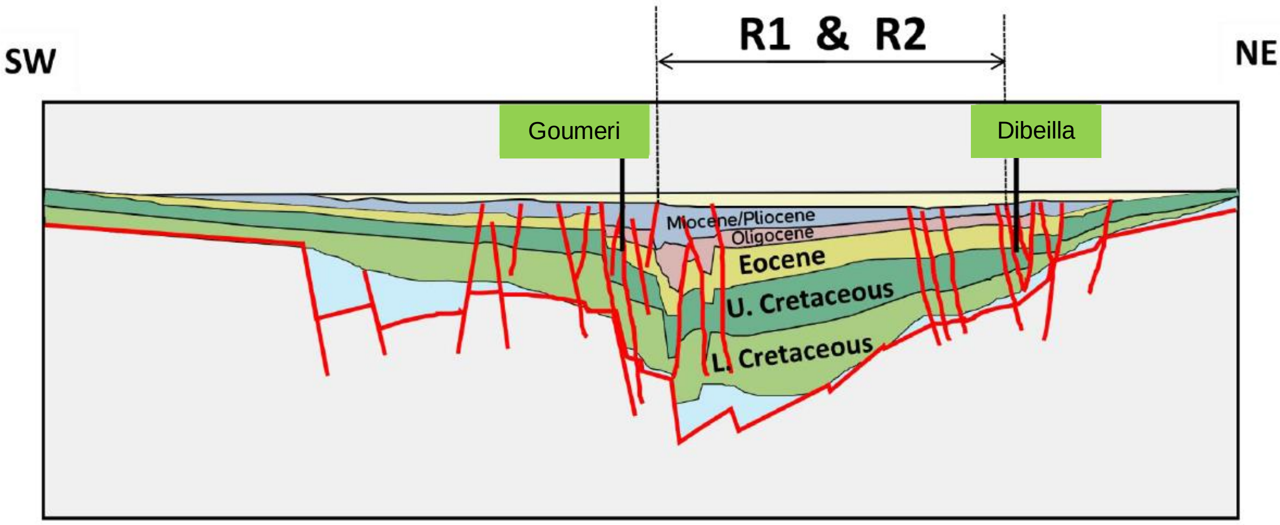


Figure 2-3 Schematic South-West to North-East Cross-Section through the Agadem Rift Basin, Niger

(Source: Niger Ministry of Energy & Petroleum and Savannah, 2017)

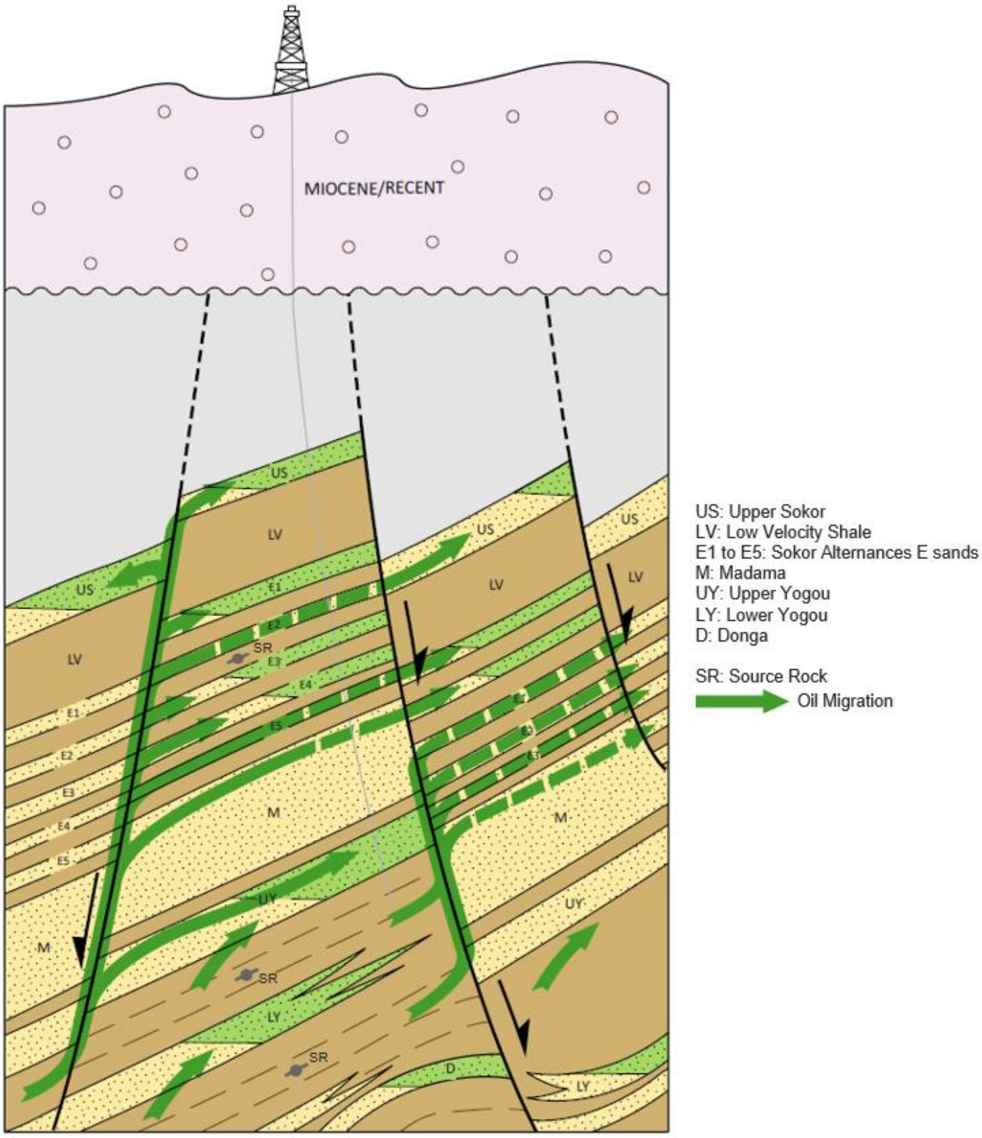


Figure 2-4 Schematic South-West to North-East cartoon cross-section to illustrate the main trapping and charging mechanisms in the Agadem Rift Basin *(Source: Savannah, 2019)*

2.2 Sources of Information

In completing this evaluation, CGG has reviewed information and interpretations provided by Savannah's technical team as well as utilising complementary information from the public domain.

Data utilised by CGG in the preparation of this CPR has included:

- Location maps
- Geological and reservoir reports
- Well logs of drilled wells
- Seismic workstation projects and associated interpretations
- Work plans and budgets

In conducting their evaluation, CGG has relied upon the accuracy and completeness of information supplied by Savannah. As the assets in question are in the exploration phase, no site visit has been conducted by CGG.

2.3 Principal Contributors

CGG employees and consultants involved technically in the drafting of this CPR have between 5 and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Andrew Webb

Andrew Webb has supervised the preparation of this CPR. Andrew is the Asset Evaluation Manager CGG. Andrew joined the company as Economics Manager in 2006. He graduated with a degree in Chemical Engineering and now has over 30 years' experience in the upstream oil and gas industry. He has worked predominantly for US independent companies, being involved with projects in Europe and North Africa. He has extensive experience in evaluating acquisitions and disposals of asset packages across the world. He has also been responsible for the booking and audit of reserves both in oil and gas companies, but also as an external auditor. He is a member of the Society of Petroleum Engineers and an associate of the Institute of Chemical Engineers.

Rob Crossley

Dr Rob Crossley has provided petroleum geological inputs to this CPR. He is Chief Geologist in the Geoconsulting Group at CGG, having joined the company as sedimentologist in 1986. He graduated in 1976 with a PhD jointly from the Universities of London and Lancaster. He has particular expertise in the geology of petroleum systems in rift basins and now has 31 years' experience in the upstream oil and gas industry. Rob's involvement with asset evaluation projects has been global but focused predominately in Europe, Africa, Middle East, Far East and South America.

Dr. Arthur Satterley

Arthur Satterley has a BSc 1st Class in Geology, University College of Wales and a PhD from the University of Birmingham on Upper Triassic reef limestones and a post-doctoral research experience on platform carbonate margins. He has 25 years' experience of petroleum geological evaluations and resource assessments for both oil and gas fields throughout the exploration and development life cycle. He has experience of carbonate and clastic reservoirs in most major petroleum provinces.

Toni Uwaga

Toni Uwaga has an MSc from Heriot Watt University, Edinburgh, in Petroleum Engineering. He has 22 years' industry experience. Over the years he has worked on oil and gas projects spanning the North Sea, East Irish Sea, Gulf of Guinea, Middle East, India, Malaysia, North America and the Caribbean Sea. He functioned as Reserves Coordinator for Shell

Petroleum Development Company, Nigeria. He has participated as Lead Reservoir Engineer in several CPRs across the various regions he has worked. He is a member of the Geological Society of Trinidad and Tobago (GSTT) and the Society of Petroleum Engineers (SPE). He has written several technical papers, published by GSTT and SPE.

Peter Wright

Peter Wright gained an MA in Engineering from Cambridge University and an MBA from Cranfield University. He has over 20 years' experience in the economic evaluation of upstream oil and gas assets including exploration prospects, development projects and producing assets. His career has included working as a director of specialist economics focussed consulting companies, and has covered a variety of asset types both onshore and offshore in Europe and the rest of the world. He also regularly delivers training courses on petroleum economics and risk analysis at various centres around the world. He is a member of the Society of Petroleum Engineers.

2.4 Evaluation methodology

In evaluating the Resources associated with the discovered fields, CGG has used the accepted standard industry techniques of geological, engineering and economic estimation.

As an initial stage in the evaluation process, Savannah demonstrated the seismic interpretations during a visit by CGG to their office in October 2019. During the other visits, geological, engineering and commercial issues were also discussed face to face with Savannah's technical staff.

CGG has independently validated reservoir properties, Hydrocarbon Initially in Place, Resources, projections of production profiles and estimates of capital and operating costs provided by Savannah. The Resources have been valued using Savannah's economic model based on predicted market trends. Estimates of these economic parameters are uncertain, and sensitivities derived from the base case have been considered.

CGG has relied on the validity, accuracy and completeness of the raw data provided by Savannah, and has not verified that data in any way, nor conducted any independent investigations or surveys. It should be noted that there is significant uncertainty inherent in the interpretation of geological and engineering data relating to hydrocarbon accumulations. These interpretations are subject to change over time as more data becomes available, and there is no guarantee that the ultimate hydrocarbon volumes recovered will fall within the ranges quoted.

In addition, CGG has estimated resource volumes for eleven indicative prospects and leads selected by Savannah from its exploration portfolio. These prospects and leads are currently under consideration as potential further drilling candidates in Savannah's next exploration drilling campaign. CGG has also provided estimates of the yet-to-find resources in the licence.

In estimating the resource volumes for the prospects and leads, CGG has used the standard techniques of geological estimation to develop the technical sections of this CPR. Resource ranges (low, mid and high cases) have been determined using probabilistic methods.

The evaluation has been performed in accordance with the:

- Petroleum Resources Management System (PRMS, 2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE)
- AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG has no commercial arrangement or interest with Savannah Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

3 RESOURCE DESCRIPTION

3.1 Tectonostratigraphy

The onset of rifting commenced in the Lower Cretaceous and subsidence continued into the Late Cretaceous. The basin was subjected to a tectonic event in the Santonian-Campanian that caused rift flank uplift and folding of the sediments in the basin floor. Subsidence subsequently continued steadily into the Cenozoic. A second major phase of rift faulting occurred in the Oligo-Miocene, before the basin returned to slow subsidence through the Plio-Pleistocene.

The sedimentary fill of this rift basin contains interbedded packages of sandstone and shale with a total thickness of more than 5km across much of the area. The depositional setting is predominantly fluvial and lacustrine, with marine incursions occurring during the Late Cretaceous. Shales units are often organic-rich, containing both algal and terrestrial kerogen. Shales at Cretaceous level have entered the oil window across much of the basin. The latest phase of rifting was in the northern part of the basin accompanied by minor igneous centres, but these centres were too small to have a major influence on thermal maturity of the basin.

The basin received substantial clastic fluvial input, and sedimentation kept pace with subsidence for prolonged periods. This ensured that sand-rich sequences were repeatedly deposited across much of the area. Seismic interpretation suggests that there was a period in the Late Cretaceous when subsidence outpaced sedimentation and this was accompanied by uplift of the basin margins. Erosion of the basin flanks provided a potential additional source of sand that could be emplaced by gravitational flow into the deeper water settings.

Consequently, the basin offers source and reservoir potential in multiple stratigraphic intervals, including at levels that to-date have received few well penetrations. The fault blocks created by late Cenozoic faulting formed the traps targeted by almost all exploration drilling to-date, whereas the structures formed by Santonian-Campanian tectonics are essentially unexplored.

3.2 Depositional models

It is important that the correct depositional model is applied, since this affects the way in which potential resources in undrilled acreage and the appropriate recovery factors, are estimated.

The Agadem Rift Basin contains a sedimentary fill of more than 5km and forms part of the Central African Rift System. However, it is apparent from the seismic and well data that, in the Licence Area, classical rift basin depositional models, involving deep lake basins, prograding deltas and alluvial fans along fault scarps, do not apply. The reflector packages at seismic scale are remarkably layer-cake, with minimal evidence of prograding or shingled features. Inter-well correlation of wireline packages tens to hundreds of metres thick is relatively straight-forward over distances of tens of kilometres. Sands at the E3 level in the NW part of the basin, which are normally too thin to be considered in volumetric estimates, often contain oil. Since these sands are far above the oil window, the oil indicates that the thin sands have substantial lateral continuity in order to connect to the faults which provide the vertical migration conduits. The depositional models need also to address the paucity of peats, coals, evaporites and conglomerates through most of the section.

Savannah's biostratigraphy data suggests that throughout the Cenozoic and Cretaceous, deposition occurred in a relatively arid climatic regime, but with substantial influxes of fresh water. In the context of local aridity, this implies input from major rivers. This input persisted irrespective of whether the depositional setting in the basin was entirely terrestrial or was subjected to marine flooding. These conditions are compatible with CGG's in-house palaeogeographic and palaeoclimatic modelling for the area.

The layer cake depositional geometries are interpreted by CGG as resulting from sedimentation keeping pace with subsidence because of high influxes of fluvial clastic sediment. The high fluxes of clastic sediment appear not to be due to rapid erosion of local highs, since extraclast conglomerates are largely absent. The amount of core data available is limited but suggests that the sandstone sequences are fine to medium grained, with quartzose pebbles (less than 10mm in diameter) occurring only occasionally in the Madama Formation. Our overall interpretation is therefore of rivers with relatively large discharges draining wet climatic areas, traversing a low relief landscape and depositing their sediment in a shallow basin in an arid setting.

3.3 Petroleum geology of stratigraphic units

3.3.1 Upper Sokor Formation

Savannah currently carries oil volumes at this level in six of the prospects and leads reviewed. This represents a potentially important new play in the basin, and so has warranted particular scrutiny. This new play is supported by seismic, hydrocarbon shows and well testing.

The phase of rift faulting that created most of the structural traps in the proven Sokor Alternances and Yogou plays post-dated deposition of the Upper Sokor and so also created structural traps at the Upper Sokor level.

Many of the Eocene exploration wells were drilled vertically to target footwall closures at the Sokor Alternances, and so either penetrated the Upper Sokor in hanging-wall sections, or failed to fully penetrate the Upper Sokor sequence, owing to the magnitude of heave on the bounding fault. Consequently, the Upper Sokor is under-represented in the existing well data sets, so estimation of resource potential at this level cannot be determined directly from the existing exploration statistics. The geological context of this potential play was therefore examined in order to provide a basis for resource estimation and geological risking.

Hydrocarbon charge: Basin modelling undertaken by Savannah indicates that source rocks at Cretaceous levels would have been oil mature at the time of Oligo-Miocene rifting, so the rift faulting could have provided charge pathways into the Upper Sokor. Subsequent burial by late syn-rift fill and during post-rift basinal subsidence, might have resulted in additional maturation at Cretaceous levels, potentially resulting in further charge to the stacked plays.

In order to reach the Upper Sokor play, hydrocarbons have to penetrate the Low Velocity Shale (LVS). This shale is present throughout the basin, and is typically about 100m thick, so is potentially a barrier to vertical migration. However, oil has been recovered from the Upper Sokor level in at least six wells, and shows have been reported at this level in at least another 12 wells. Most shows at this level are in areas remote from igneous features, so contact metamorphic maturation of shales above the LVS is not considered by CGG to be the explanation for the majority of shows in the Upper Sokor. Consequently, it is concluded that rift faults have provided migration pathways through the LVS in some areas.

It is not clear whether these shows occur exclusively up-dip from faults with throws greater than 100m, which would juxtapose Sokor Alternances sands against Upper Sokor sands, or whether temporary dilation on fault planes by tectonic movement and/or hydrocarbon fluid pressure provided migration paths directly through the Low Velocity Shale.

Biodegradation: Ordinarily bitumen formation through biodegradation might be considered an important risk in hydrocarbon basins at depths of less than 1600m. The Upper Sokor is the shallowest play identified to-date in the Basin, with most prospects and leads identified to-date occurring at depths of less than 1600m, compared with depths of about 1600m to 3500m for the other plays. CGG has not encountered accounts of significant bitumen deposits in this basin, so biodegradation is not considered to be a major issue. Nonetheless, some evidence of biodegradation, as interpreted from gas chromatograms, does occur in 15 of the oils examined by IGI (2015). The 15 biodegraded oils range in API gravity from about 17° to 30°.

The available evidence, which is limited, suggests that the oils found in the Sokor Alternances and Yogou formations come from a mixture of marine and lacustrine sources. Wax is present in some oils but does not appear to be a dominant feature of the hydrocarbons reported to-date.

The relationship between biodegradation, API and viscosity is not straight-forward, particularly in the case of the wax component of crudes. Biodegradation may contribute to decreased API gravity, but the negative impact of a slight API decrease can be offset by lowered pour points and less wax deposition in pipework and processing facilities (Wenger *et al*., 2002).

To conclude, there is no available evidence that oils at Upper Sokor level have been damaged by biodegradation, but also the number of penetrations that could potentially have penetrated oil accumulations at Upper Sokor level is very limited, so this remains an area of uncertainty at the shallowest levels.

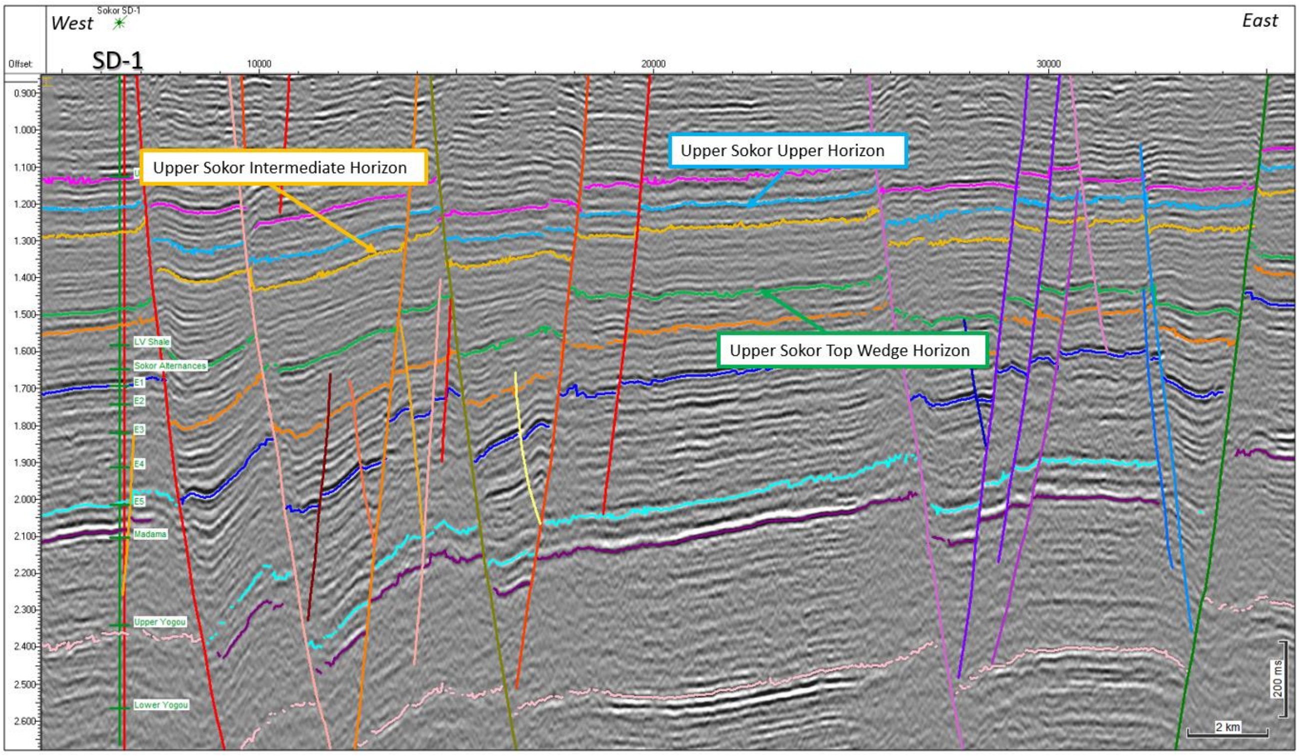


Figure 3-1 W-E 3D seismic profile through Sokor SD-1 well, in the R3 East 3D (*Source: Niger CPR 2017*). The Upper Sokor contains variable amplitudes within a subtle sedimentary wedge above the LV Shale (green to orange markers)

Depositional model: The wells show that the Upper Sokor comprises reservoir-seal couplets similar to those in the Sokor Alternances. Seismic review suggests these sand-shale sequences in the lower part of the Upper Sokor show a mixture of layer cake and gentle wedge geometries. The wedges thicken towards some faults. Most of the displacement on these faults was much later, but it appears that a brief phase of minor movement occurred on some faults during deposition of the lower part of the Upper Sokor. These features are illustrated in **Figure 3-1**. Modern Lake Chad provides a potentially useful analogue for the depositional model envisaged for the Upper Sokor. The gross tectonostratigraphy of modern Lake Chad is similar in that the clastic inputs to the area have evidently been sufficient to infill all the accommodation space created in the Niger to Chad sectors of the basin during late Cenozoic rifting.

The hydrological budget of the Lake Chad is nearly balanced, with most of its water inflowing from the south. Inflow is via groundwater throughout the year, and is supplemented by major flow in rivers during the southern wet season. The subdued geometry of the lake basin ensures that the lake shows large fluctuations in area in response to modest changes in lake level, and this occurs on time-scales of tens to thousands of years. The result is that lake-margin swamps are largely ephemeral and the organic matter is rapidly oxidised when the lake recedes, so no peat accumulates over most of the basin. The groundwater-fed swamps on the southern margin are potential exceptions that may allow some peat accumulation.

The advance and retreat of the shorelines results in laterally persistent sheets of sand. In addition, the lake flats exposed during low stands become areas of sand deposition, with reworking by ephemeral run-off and by wind. The result can be sand systems that show excellent sorting and lateral continuity, though individual beds of sand may be no more than a few metres thick.

These patterns resemble features revealed by horizon slice amplitude extraction in the lower part of the Upper Sokor. The extractions on sandy intervals could be interpreted as representing a coalescence of sandy facies including broad curving beach ridges, irregular fluvial sand sheets, and sand reworked by wind or waves. The extractions on more mud-rich horizons suggest a more homogeneous distribution of facies which in this context might include mud-dominated lacustrine-alluvial deposits, with the higher amplitudes including peat deposits preserved preferentially on the subsiding side of faults.

There is no obvious difference in reflector character between the Upper Sokor and the underlying Sokor Alternances in seismic sections. These interpretations therefore also support the relatively layer-cake depositional model adopted here for the Sokor Alternances, with correspondingly beneficial implications for hydrocarbon production.

3.3.2 Sokor Alternances Formation

Savannah currently carries oil volumes at this level in six of the prospects and leads reviewed.

This play has been extensively drilled within the retained acreage of the Agadem Rift Basin, and the discovery data mostly reflect the success of this play. The oil at Eocene level represents leakage from Cretaceous levels, predominantly up faults and across faults where sands are juxtaposed. The faults were mostly active in the late Oligocene, and modest subsidence, not accompanied by major faulting, has continued since.

The Sokor Alternances contain many more reservoir/top seal couplets than the Upper Yogou. Only a small proportion of the Sokor Alternances Eocene sands contain oil – probably because of trap leakage across faults in these relatively sandy sequences. It is unusual to find more than three or four charged reservoirs in the Eocene fields.

3.3.3 Madama Formation

Savannah does not currently carry any oil volumes at this level in the prospects and leads reviewed.

The Madama Formation is present in all wells drilled to that depth across the basin. This formation has a distinctive seismic character that could be traced across the basin on all seismic reviewed.

In many fault blocks, the Madama Formation may carry attic oil trapped against shales in the Lower Sokor Alternances. CGG thus views the Madama Formation as a potential subject of prospective resource volume upside.

3.3.4 Yogou Formation

Savannah currently carries oil volumes at this level in ten of the prospects and leads reviewed.

Basin modelling, and the distribution of discoveries across the Agadem Rift Basin, demonstrates that the majority of the oil in the Eocene accumulations was generated from Cretaceous source rocks, at Yogou or deeper levels. The Yogou reservoirs effectively sit within the oil window, with very short migration paths from kitchen to trap. The Yogou reached maximum maturity during the subsidence which post-dated Oligo-Miocene faulting, and today the Yogou sequence remains in the oil window across much of the basin. It is therefore inferred that whilst some traps at Yogou level may temporarily have been breached during faulting, charge of Yogou traps will have continued through to the present day.

In the Dinga Slope and Dinga Ridge areas, a number of large structures, that are visible on 2D seismic at Yogou level, do not exist at shallower Eocene levels. These large structures show relatively few Cenozoic faults.

Review of 2D and 3D seismic across the basin suggests that the Yogou Formation was deposited during the sag phase that post-dated Cretaceous rifting. CGG interprets the relationships exhibited on seismic and the new biostratigraphic data obtained by Savannah from cores at Upper Yogou level, as indicating that deposition of Upper Yogou sands (and ultimately Madama sands), was triggered by tectonic movements during the Santonian to early Maastrichtian. This correlates with a regional tectonic event that affected several Cretaceous rift basins along the Central African Rift System.

Review of the available porosity-depth data suggests that the Yogou sands lie on a trend that is 2-3% higher than that of the Eocene section. This might be a function of overpressure, or initially better quality reservoir facies.

Review of the available log profiles suggests that multiple reservoir-seal couplets are present in the Yogou, and as long as there are on average four or more of these, then the numbers of separate accumulations at Yogou and Eocene Sokor Alternances levels can be expected to be similar.

At Yogou level, shale seals will be more compacted, and consequently more effective than at Eocene level, where shale seals are proven by numerous accumulations. In addition, review of the 3D seismic data shows that faults at Eocene levels tend to merge into a smaller number of faults at greater depth. This means that the risk of trap breaching by faults is reduced at Yogou level. This in turn means that traps are more likely to be filled to-spill at Yogou levels than within the Eocene and Miocene sections.

There will be several Yogou structures where fault seal risk is high because the sand-rich Madama Formation is on the downthrown side of the fault trap. However, in contrast to the situation in the Eocene, where the distribution of cross-fault leakage into sands is hard to predict, such structures at base Madama level should be readily imaged on 3D seismic, and thus should be avoidable for drilling.

The reduction in numbers of faults with depth suggests that the size of individual fault block traps will be greater at Yogou than at Eocene levels.

Recently, testing of the Upper Cretaceous Yogou reservoirs has proven productive, giving similar, or better, flow rates than in the Eocene section. The good reservoir performance appears to result from a combination of reasonable retained porosities and lower viscosity oils than in the Eocene section.

3.3.5 Lower Yogou and Donga Formation

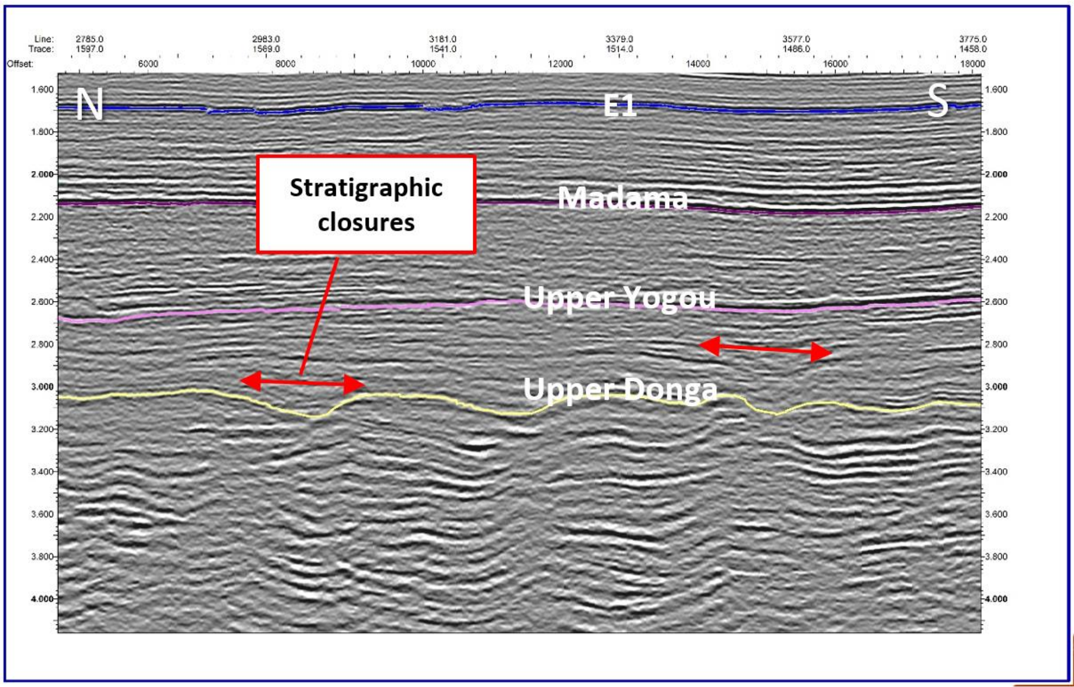
Cretaceous folding and Cenozoic faulting together form an additional set of trapping geometries beneath Savannah's acreage at Lower Yogou and Donga levels. **Figure 3-2** illustrates these features. In some parts of Savannah's acreage these intervals are found at depths that are relatively easily drillable.

The depositional setting implied by biostratigraphic data, limited geochemical analyses, and the widespread occurrence of gas shows far outside the footprint of the main gas window at Yogou level suggests that a mature source rock is present at Donga or deeper levels.

Thin sandstones occur at Donga and older stratigraphic units in wells around the basin edges, and nothing is known about sand distributions beneath the basin axis, but the amplitude variations at these depths suggest that multiple lithologies, potentially including reservoir facies, may be present.

The Donga interval is modelled as being within the gas window in the deepest parts of the basin, so any oil source rocks present will have charged reservoirs in this and overlying intervals before oil expulsion started from the Yogou source rocks. It is not presently clear what proportion of reservoirs in this interval will now be gas charged rather than containing oil.

Savannah has only evaluated the play potential in this stratigraphic interval, following on from its detailed investigations of the Upper Yogou prospectivity. For this reason, Savannah has not yet interpreted the interval to the level where prospects and leads can be added to its proprietary exploration portfolio. The play is, however, included in this yet-to-find analysis included in this CPR (**Section 4.3**).



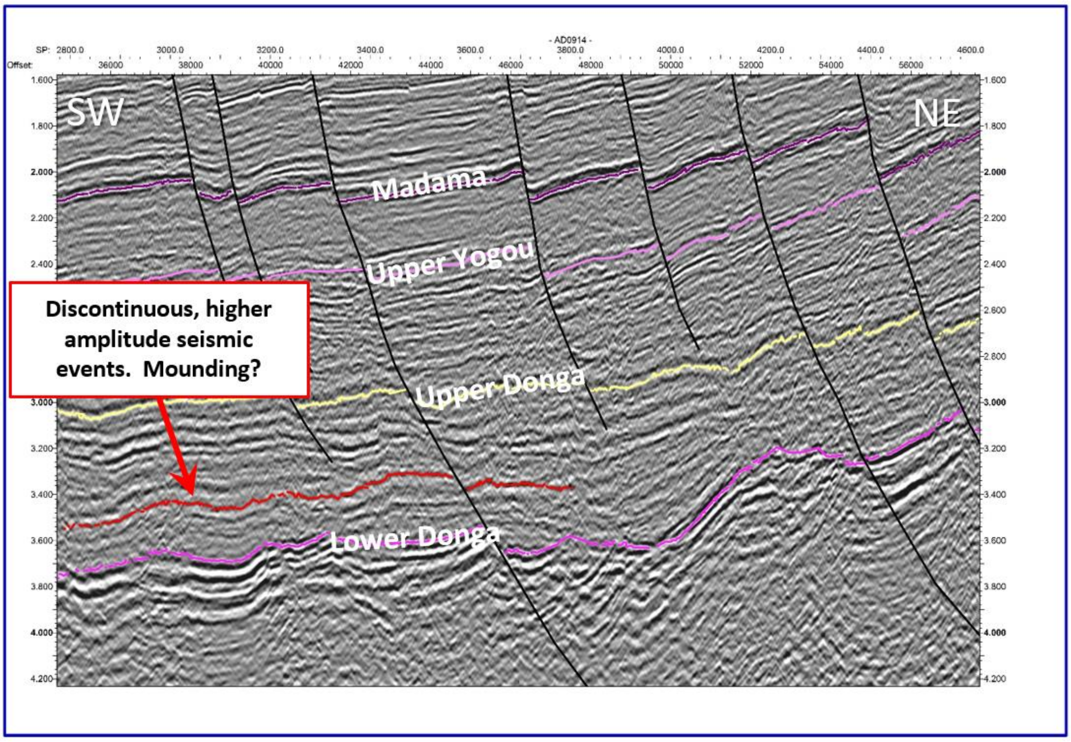


Figure 3-2 Structures at the Lower Yogou and Donga levels – Top: Arbitrary line within the R3 East 3D seismic survey Bottom: 2D seismic line within the R4 area *(Source: Savannah, 2019)*

References

Wenger, L. M., Davis, C.L. and Isaksen, G.H., 2002. Multiple Controls on Petroleum Biodegradation and Impact on Oil Quality. SPE Reservoir Evaluation & Engineering, October, p. 375-383.

3.4 Discoveries

In 2018, Savannah selected five prospects to be drilled from their portfolio in the R3 East portion of the Licence area. Of the five wells drilled (i.e. Amdigh-1, Eridal-1, Bushiya-1, Kunama-1 and Zomo-1), all found hydrocarbons within the Sokor Alternances (Eocene age) and can be considered discoveries giving a success rate of 100%. The high success rate is aligned with to-date basin statistics with c. 115 discoveries from 142 wells (>80% success rate).

All the structures are within the R3 East 3D seismic survey acquired by Savannah in 2016/2017 and also lie within the NW-SE regional oil discovery trend observed in the neighbouring CNPC licence (**Figure 3-3**).

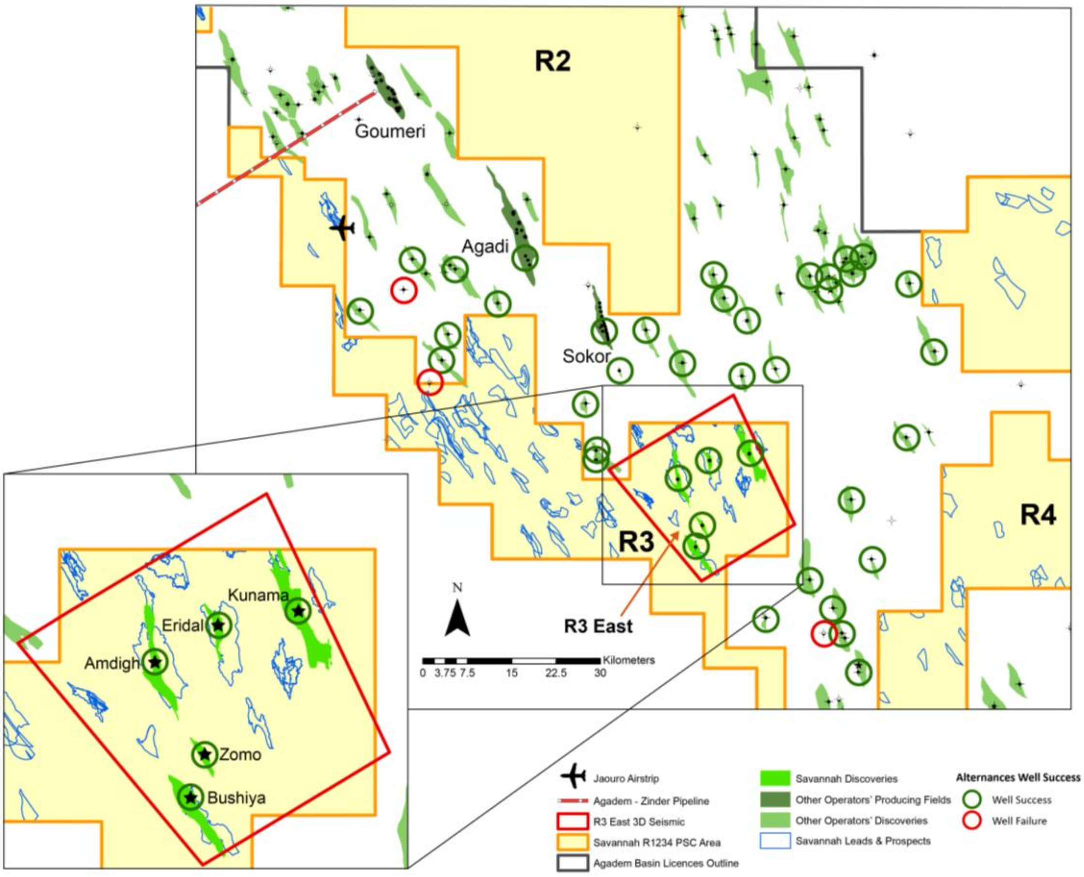


Figure 3-3 Location map of discoveries within the R3 East 3D survey (red polygon, source: Savannah, *2021)*

CGG had access to Savannah's seismic project interpretation and performed a detailed QC of the interpreted closure areas (polygons) for the discoveries, confirming that the numbers of the estimated areas were reliable. All the well information mentioned below was provided by Savannah, and no further interpretation or petrophysical analyses were performed by CGG. Graphs and all the petrophysical parameters used in the Savannah volumetric calculations are extracted from documents given to CGG (R3 East Feasibility Study Report, Corporate and Technical presentations). It should be noted that the seismic interpretation used to generate depth maps and volumetric estimates is based on the Pre-Stack Time Migration (PSTM) R3 East 3D dataset processed in 2017. Savannah has now completed a Pre-Stack Depth Migration (PSDM) re-processing of the R3 East 3D seismic survey and its interpretation. Based on the newly interpreted PSDM, 3D geomodels have been built for the Amdigh and Eridal discoveries. Savannah has stated that the resulting oil in-place volumes are in-line with the PSTM based estimates. CGG has not reviewed these latest estimates at this stage, since Savannah is still progressing with further work on the other discoveries and its exploration portfolio.

3.4.1 Amdigh discovery

Located in the central-north of the R3 East 3D survey, the trap consists of a tilted fault block, and encountered oil columns (c. 20m total net pay) in sequences E1, E2 and E3 of the Sokor Alternances. The well was drilled down to a TD of 2469 m MDBRT (2049 m TVDSS) after penetrating 55 m into the Madama Fm (**Figure 3-4**). The presence of oil in the E1 and E2 was confirmed by recovery of oil samples and by the interpretation of Reservoir Formation Tester (RFT) pressure data. The analysis of the E1 sample show an oil API gravity of 27.5° which is consistent with offset wells along trend and the depth/API trend observed across the basin. Based on the RFT interpretation, the E3 interval was considered as pay.

Within the same discovery, Savannah identified different segments for the E1, E2 and E3 (**Figure 3-5**), which were taken into consideration. The discovery well is drilled in segments 1&2, and it is considered that segment 3 is very likely to be in pressure communication due to the low displacement on the bounding fault especially towards the top of the structure. It is less clear if segments 4, 5 and 6 also form part of the discovery and hence those segments have been removed from the low and most likely cases and only considered in the high case (**Section 4**).

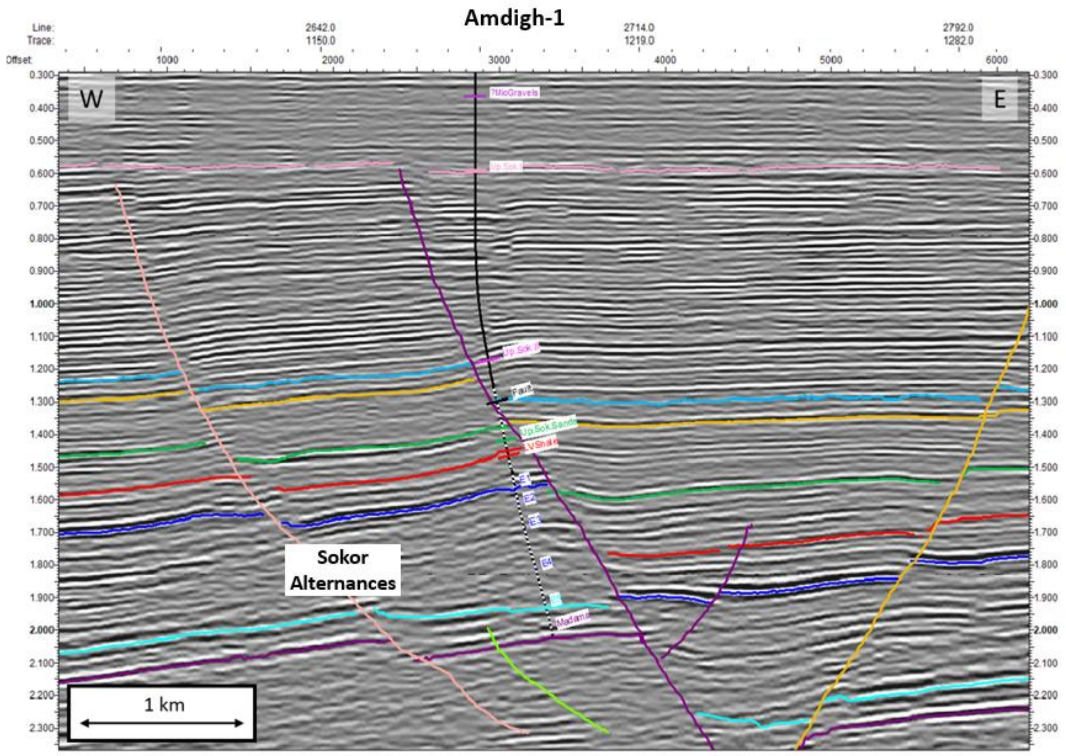


Figure 3-4 PSTM Seismic Section through the Amdigh-1 discovery well (Source: Savannah, 2019)

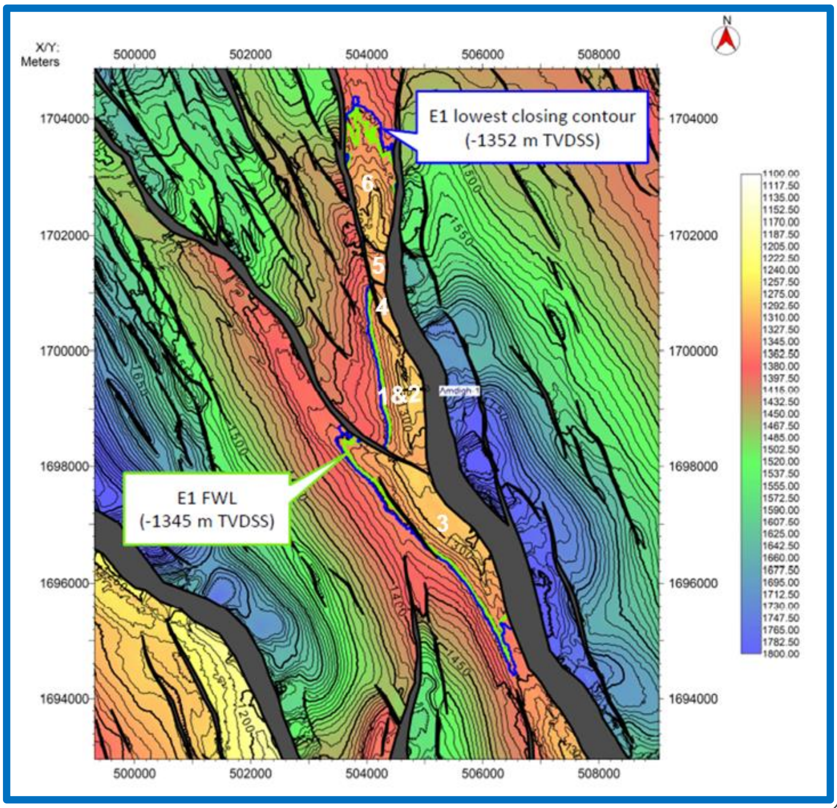


Figure 3-5 Amdigh E1 structural depth map (based on PSTM dataset) and the six segments *(Source: Savannah, 2019)*

3.4.2 Bushiya discovery

This discovery is situated in the southern part of the R3 East 3D survey, and the trap is a tilted fault block type. Bushiya-1 was drilled down to a TD of 2200 m MDBRT (1811 m TVDSS) after penetrating 109 m into the Madama Fm (**Figure 3-6** and **Figure 3-7**). Two oil columns were encountered in the E1 and E3 intervals with an estimated c. 10 m total net pay. The E1 column was proven by recovery via RFT of a 24.2°API oil sample, inline with the Amdigh-1 oil analysis from the same interval. The E3 oil column was interpreted from the RFT pressure data.

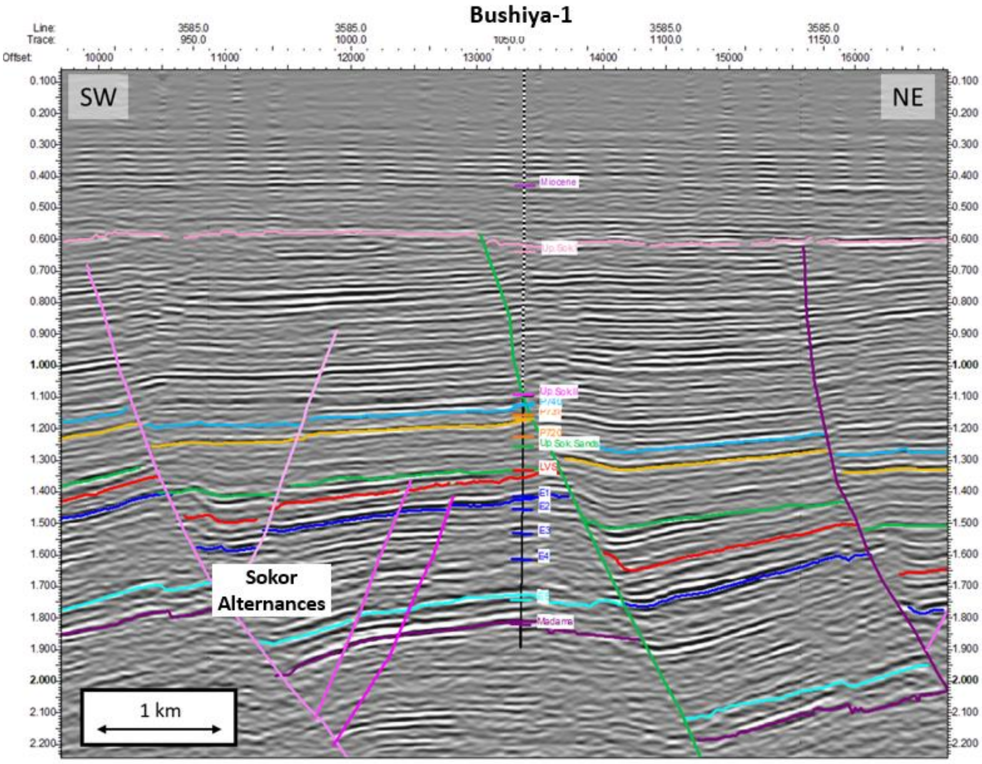


Figure 3-6 PSTM Seismic Section through Bushiya-1 discovery well *(Source: Savannah, 2019)*

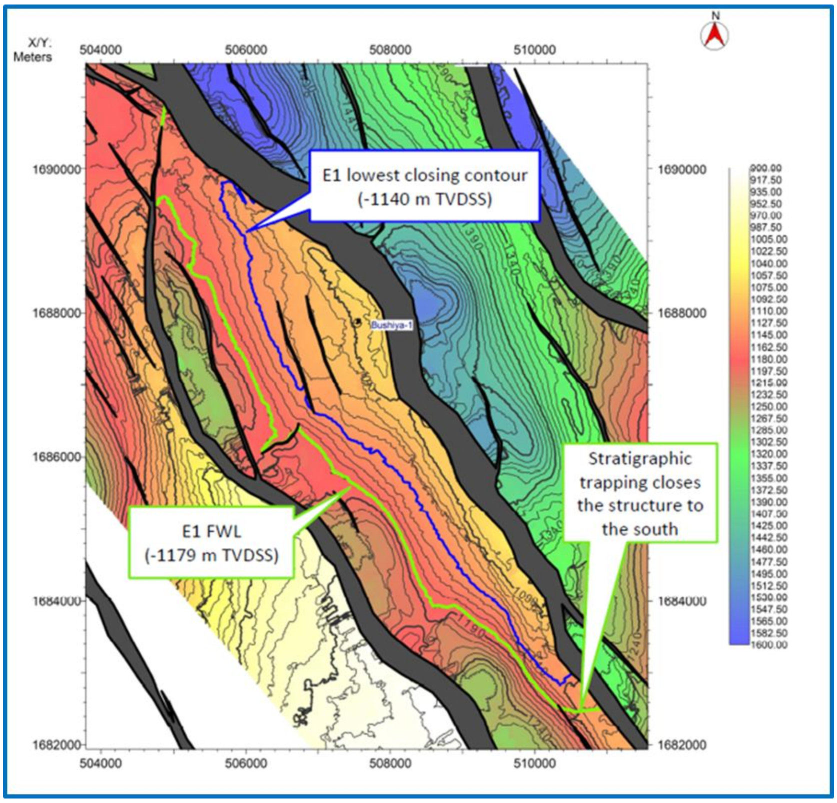


Figure 3-7 Bushiya E1 structural depth map *(based on PSTM dataset, source: Savannah, 2019)*

3.4.3 Kunama discovery

The Kunama-1 discovery is located in a slightly tilted block and was drilled down to a TD of 2460 m MDBRT (2118 m TVDSS) after penetrating 100 m into the Madama Fm (**Figure 3-8** and **Figure 3-9**). An oil column was proven in the E1 interval in the Sokor Alternances by recovery of 28°API oil in an RFT sample. A second oil sample of 24.6°API gravity was recovered by RFT in the E5 interval. A total net pay of c. 9 m was interpreted from logs. As for the oil recovered in Amdigh-1 and Bushiya-1, the oils in both E1 and E5 intervals are light. RFT pressure interpretation at Kunama was used to define a range of contact for subsequent STOIIP estimation.

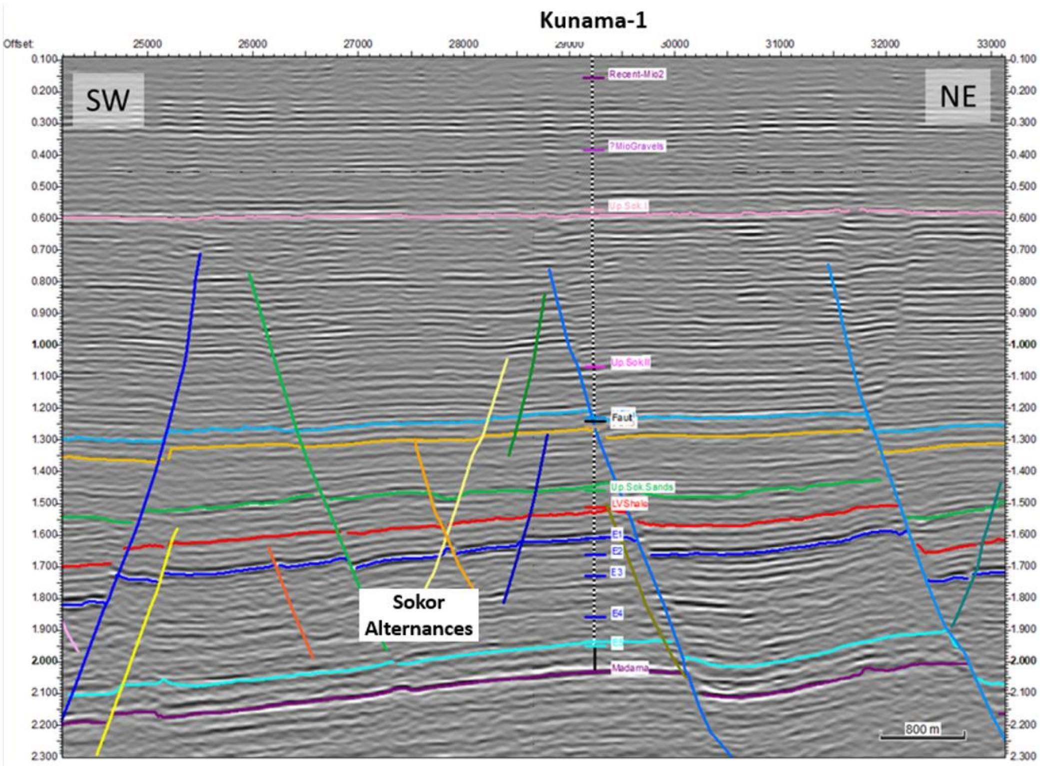


Figure 3-8 PSTM Seismic Section through discovery well Kunama-1 *(Source: Savannah, 2019)*

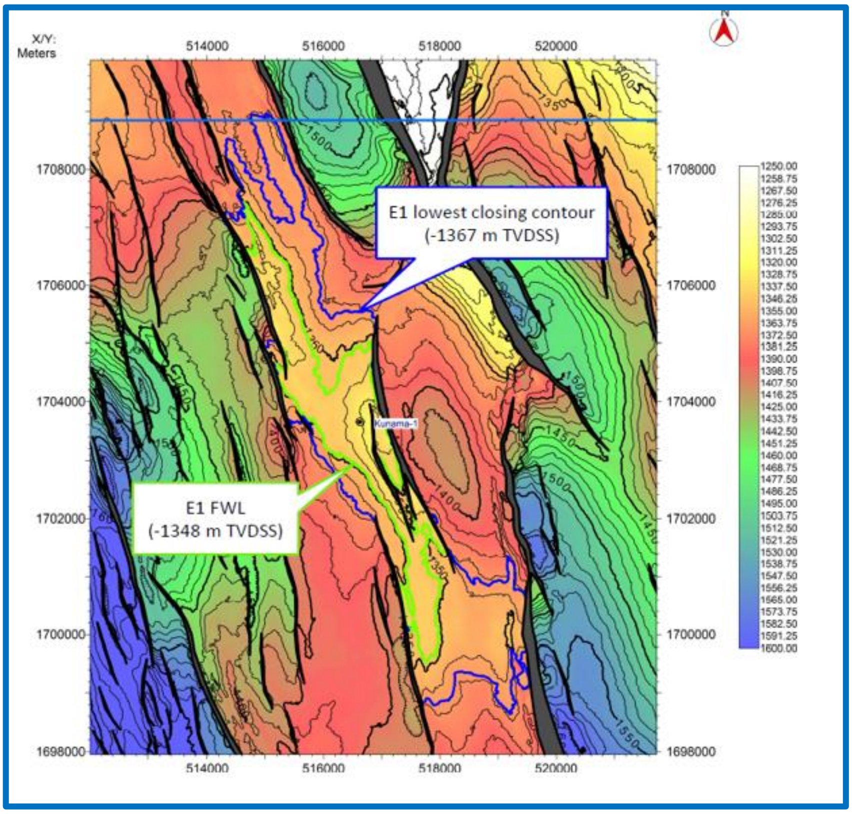


Figure 3-9 Kunama E1 structural depth map *(based on PSTM dataset, source: Savannah, 2019)*

3.4.4 Eridal discovery

This is a tilted fault block, located to the east of Amdigh. Eridal-1 was drilled down to a TD of 2542 m MDBRT (2203 m TVDSS) after penetrating 97 m into the Madama Fm (**Figure 3-10** and **Figure 3-11**). The well encountered oil in the Sokor Alternances E1 section (c.10 m net pay), as proven by RFT gradient analysis, a RFT oil sample (33 °API) and petrophysical analysis. Interpretation of the RFT pressure data show that the E1 sand contains an oil column which is continuous within the pay section.

Along the same structural trend but to the south the Ourami-1 well (oil shows present in the Alternances) penetrated these levels but was likely drilled out of closure.

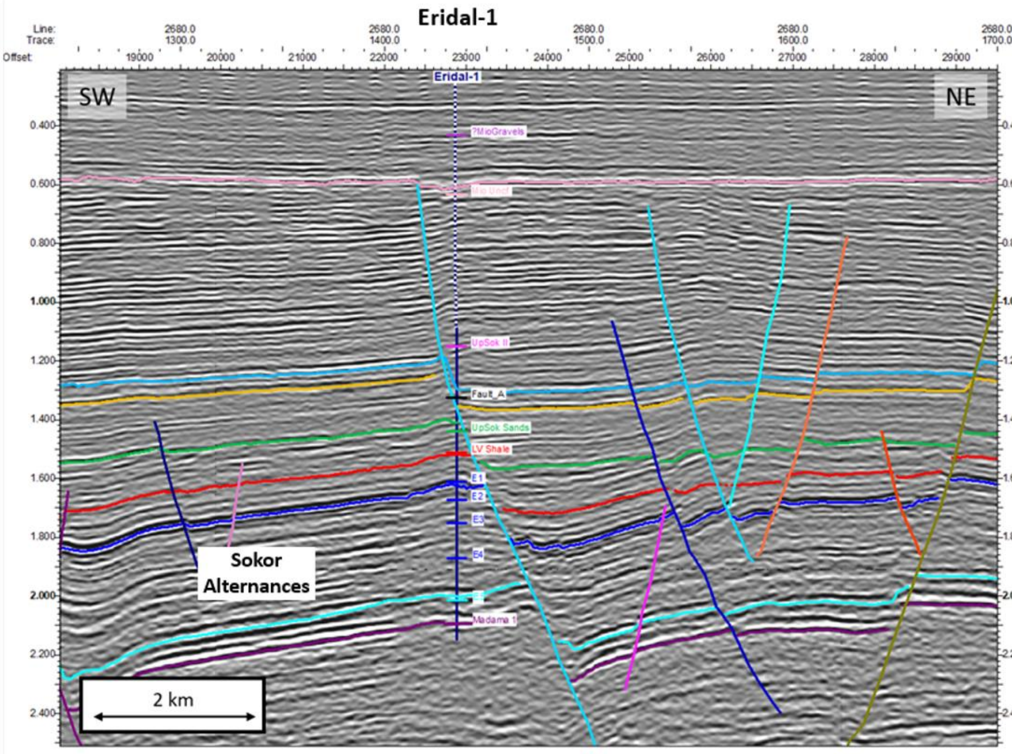


Figure 3-10 PSTM Seismic Section through Eridal-1 discovery well *(Source: Savannah, 2019)*

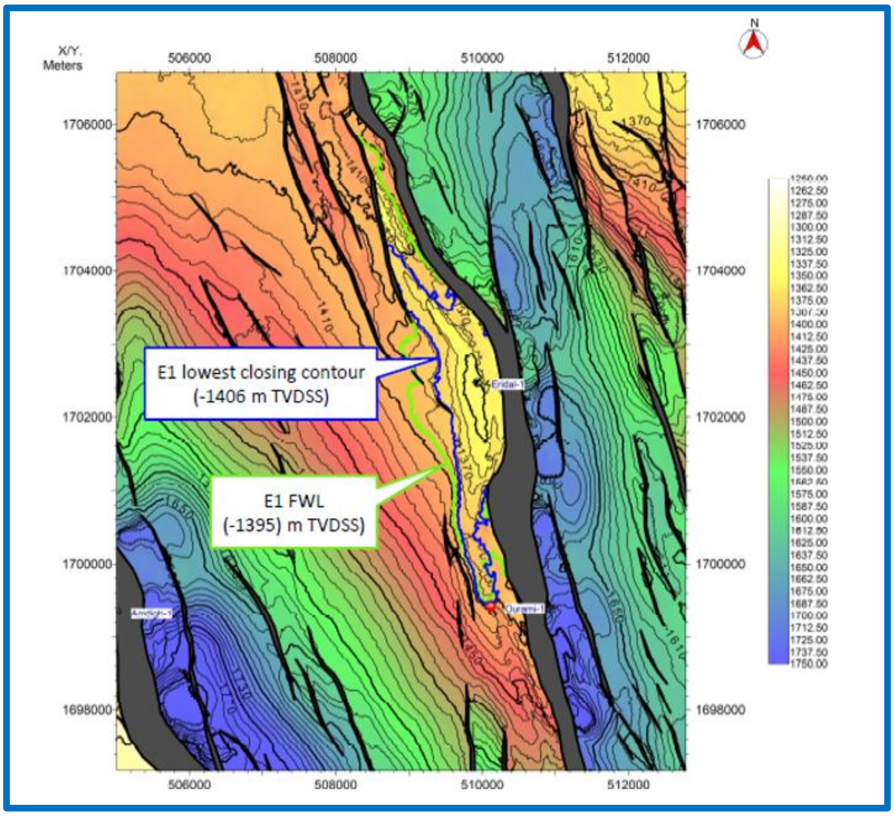


Figure 3-11 Eridal E1 structural depth map *(based on PSTM dataset, source: Savannah, 2019)*

3.4.5 Zomo discovery

The Zomo-1 well was drilled on a structure immediately along strike from the Amdigh discovery and was drilled down to a TD of 2499 m MDBRT (2119 m TVDSS) after penetrating 97 m into the Madama Fm (**Figure 3-12** and **Figure 3-13**). The well encountered an oil column (5.4 m net pay) in the E1 interval of the Sokor Alternances. An oil sample was recovered with an API gravity of 23.7°.

An extensive RFT program was carried out in Zomo-1 to investigate its hydrocarbon column and possible relationship of the column to the proven columns in Amdigh-1. According to Savannah's interpretation, the RFT analysis proves that the oil columns in Zomo-1 and Amdigh-1 are separate.

Overall, the oils discovered in the five discoveries are medium to light (24º to 33º API) and "sweet" (<0.5 wt. % Sulphur) which is consistent with offset wells along trend and the depth/API trend observed across the basin.

Petrophysical analysis results in high calculated water saturations throughout the proven pay zone where oil was recovered. The implied low oil saturations are considered incompatible with the rest of the dataset for the well. Furthermore, oil producers in neighbouring fields also exhibits low oil saturations based on petrophysical interpretation but are actually good oil producers. Therefore, the estimated pay has been adjusted by Savannah to take account of this uncertainty in water-saturation which CGG has judged a conservative approach to the net pay estimation.

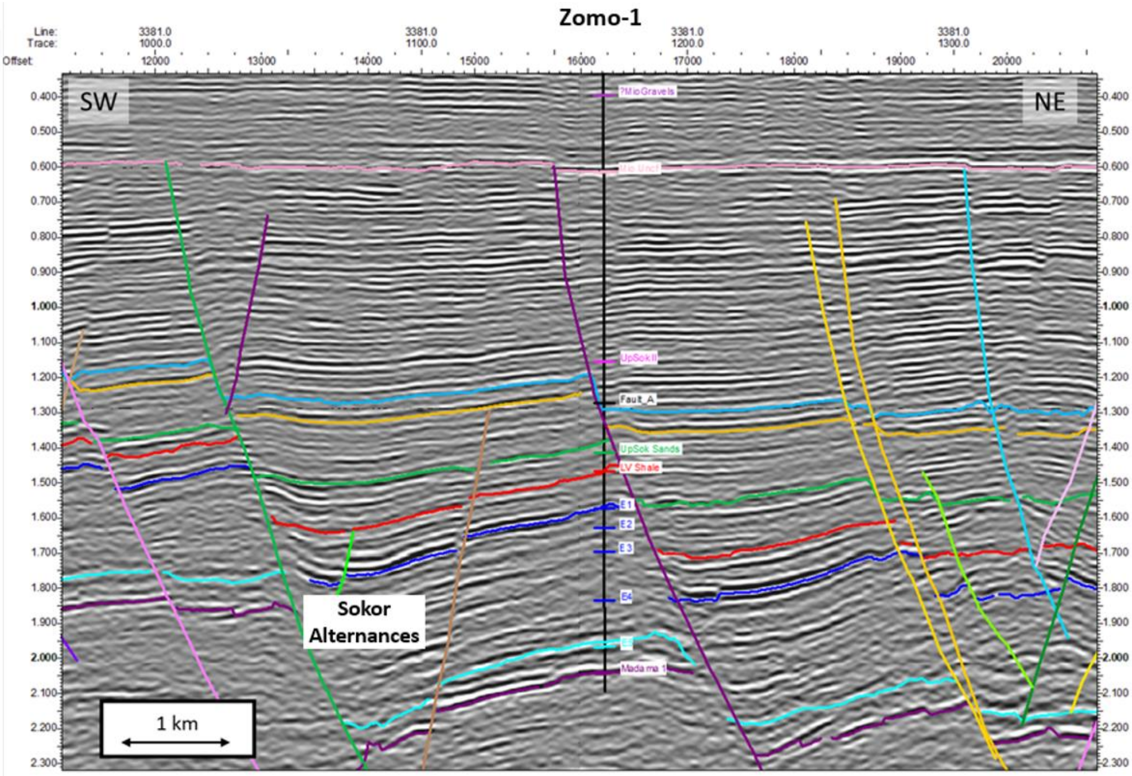


Figure 3-12 PSTM Seismic Section through Zomo-1 discovery well *(Source: Savannah, 2019)*

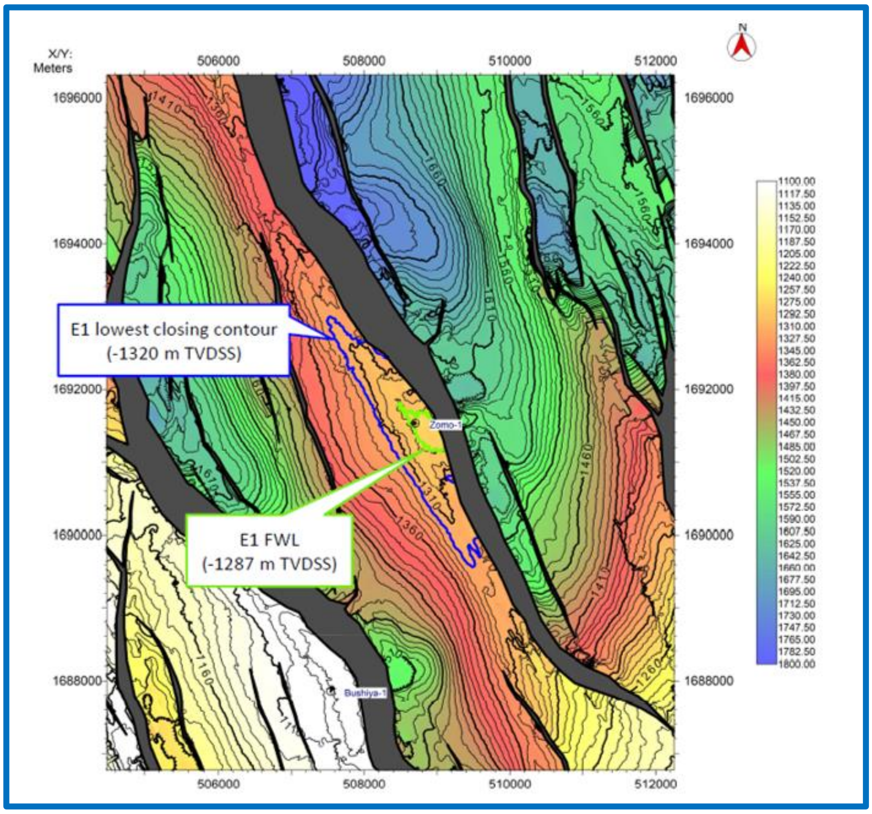


Figure 3-13 Zomo E1 structural depth map *(based on PSTM dataset, source: Savannah, 2019)*

3.5 Prospects and Leads

The high discovery rate (>80% including the Savannah discoveries) within the Eocene Sokor Alternances demonstrates the richness of the basin. The discoveries follow two trends of rift-related tilted fault blocks on either side of the main rift and merge into one zone at the southern end. The central part of the main rift, across the R2 area, has less faulting of Oligocene-Miocene age, and has not been as extensively explored. This area could contain more subtle larger traps, especially in the Cretaceous intervals.

Within the Sokor Alternances, the main risk is the fault seal which requires sand/shale juxtaposition. The historical drilling show that within this interval, there is sufficient shale in the section to result in there being a high chance that there will be sand against shale in at least one of the sands, which the high success rate validates. Variations in fault throw could result in restricting trap size on any given sand interval, but this could result in increasing the area of seal in one of the other sands. In the R3 area, there are five Sokor Alternances sand intervals (E1 through E5) thus maximising the chance of success. R3 East lies within the western fault and discovery trend, as can be seen in **Figure 2.4**. The R3 Central area has only 2D coverage and thus the Sokor Alternances Formation has to be treated as a single unit, for the purposes of volumetric calculation, as the individual sand intervals cannot be seismically defined.

As noted in **Section 3.3.1**, the overlying Upper Sokor sands are usually offset from the crest of the Sokor Alternances, by virtue of the configuration of the fault block. As most exploration wells in the basin have been vertical, and have targeted crests at the Sokor Alternances, closures at the Upper Sokor level have been frequently been missed by the drill bit. Closures at the Upper Sokor are thus valid exploration targets, and these traps have a better chance of sealing faults. In the future, Savannah aims to design its exploration wells in such a way to evaluate multiple targets at both stratigraphic levels in a single well bore.

The older parts of the Cretaceous Yogou Formation have not been widely targeted by earlier operators and thus this represents a target in areas where it is shallow enough. Several discoveries have been made in the Upper Yogou around the basin.

There have been numerous seismic programs in the area, comprising 2D lines of various vintages and modern 3D, as shown in **Figure 3-14**. The 3D surveys relevant to this review of the prospects are the R3 East 3D and the Dinga 3D, as outlined in red in **Figure 3-15**. The eleven prospects and leads reviewed by CGG are presented in **Figure 3-16.**

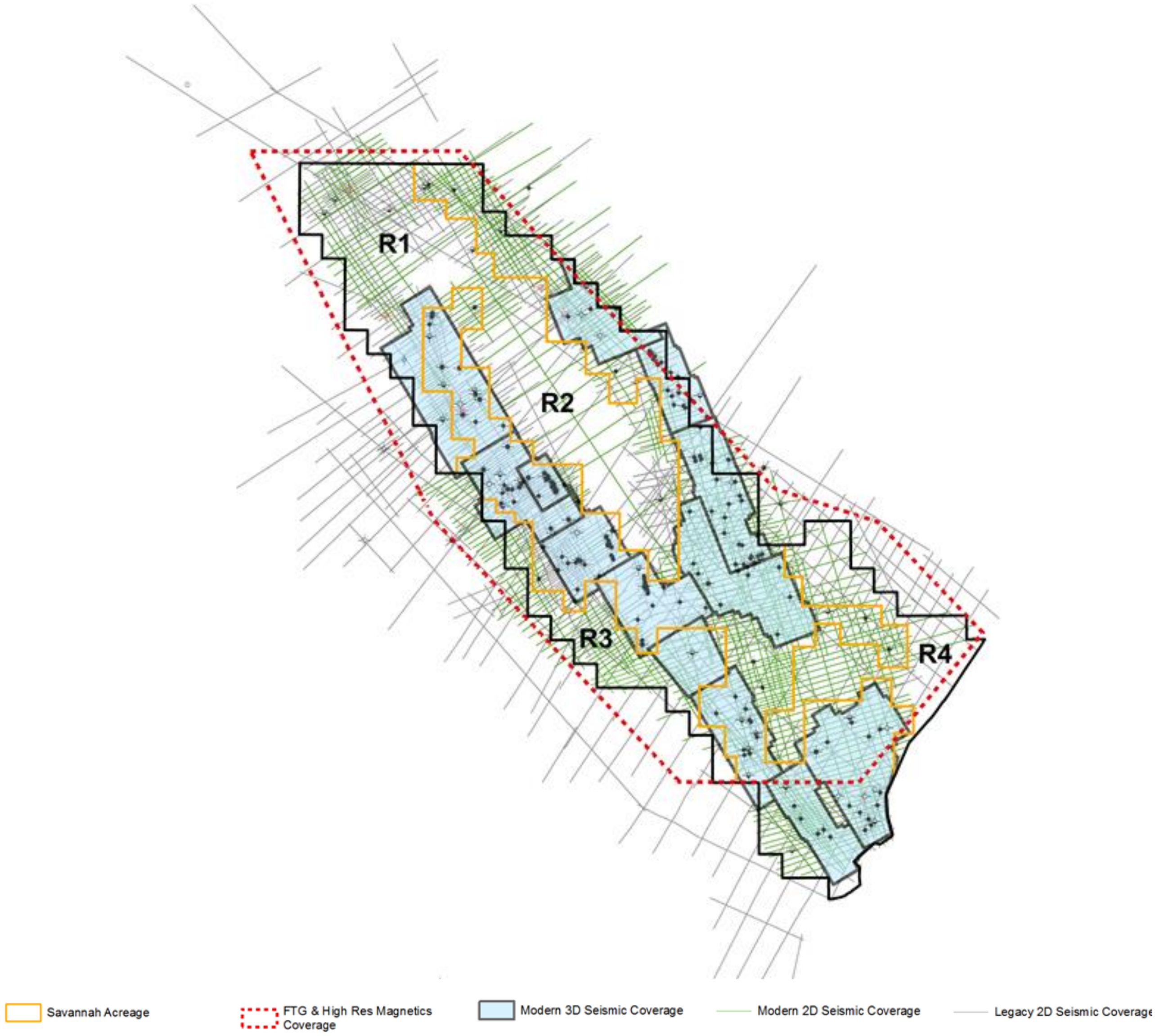


Figure 3-14 Seismic coverage in the Agadem Rift Basin *(Source: Savannah, 2019)*

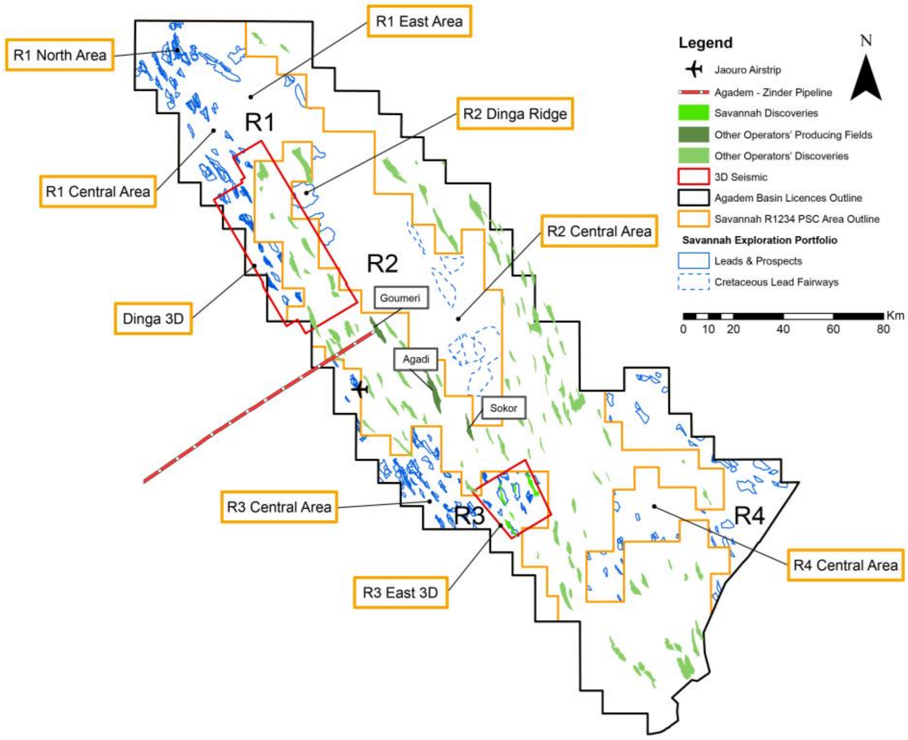


Figure 3-15 Savannah Prospects and Leads Portfolio with discovered fields and relevant 3D surveys (*Source: Savannah, 2021*)

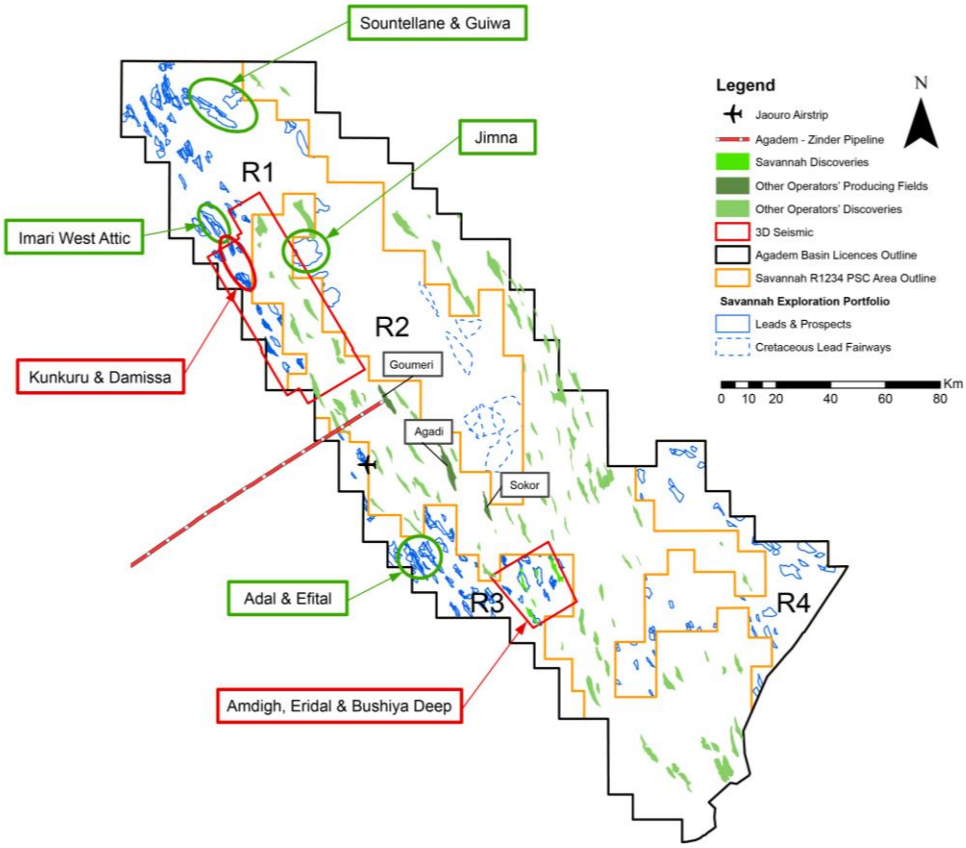


Figure 3-16 Map showing Prospects and Leads assessed by CGG (*Source: Savannah, 2021*)

4 RESOURCE ESTIMATION

4.1 Discoveries

CGG has estimated STOIIP and Resource volumes for the five discoveries resulting from Savannah's 2018 exploration drilling campaign. Based on the data provided, CGG made an independent estimation of the STOIIP with its own methodology to verify the estimated volumes of oil proposed by Savannah.

While visiting Savannah's offices (Data Room accessed 11th November 2019), CGG were provided access to the seismic data of the R3 East 3D survey in Kingdom™ in order to verify the seismic interpretation and confirm the closure polygon areas selected for each discovery as inputs for the volumetric calculations.

Currently the depth conversion for the discoveries is based on the pre-drill depth map which has had a uniform shift applied for each individual discovery interval to tie the grid to the wells. A PSDM volume has now being interpreted, which has used the velocity information at the wells and better constrains the geometries of the discoveries. Update of the Contingent Resources for all discoveries based on PSDM seismic data is pending further work by Savannah.

Based on those structural maps, a series of Area-Depth tables were created by Savannah to use in their calculations for each discovery, reservoir and in the case of Amdigh even for each segment. These were used to estimate the Gross Rock Volume (GRV).

Additionally, the volumetric estimations performed by Savannah for each discovery and reservoir levels were made available which included all input parameters.

CGG have carried out an independent review of the available data to perform their own estimations of the in-place volume ranges. The results show an overall match between the two estimations. The alteration of the distributions generally leads to a slightly wider range of values but overall, only minor differences are observed.

The results of CGG estimations are summarised in the following tables:

Discovery	STOIIP (MMstb)		
	P90	P50	P10
Amdigh	31.3	65.9	254.3
Eridal	18.5	22.3	25.8
Bushiya	14.5	22.0	39.2
Kunama	8.0	14.9	28.1
Zomo*		0.7	
Total**	**72.4**	**125.1**	**347.4**

* Single deterministic case only

** Arithmetic sum excluding Zomo, Total may not add exactly due to rounding

Table 4-1 STOIIP to be developed by Discovery

It should be noted that in the case of Amdigh, only segments 1, 2 and 3 are assumed to be developed in the low and best cases. Therefore, **Table 4-1** does not include all the STOIIPs for the P90 and P50 cases. The total STOIIP for Amdigh including all segments is 43.6 MMstb, 89.4 MMstb and 254.3 MMstb in the P90, P50 and P10 cases, respectively. Amdigh's STOIIP estimate show the discovery to be one of the ten largest in the basin.

Discovery	Contingent Resources (MMstb)		
	1C	2C	3C
Amdigh	7.2	18.4	83.9
Eridal	4.3	6.2	8.5
Bushiya	3.3	6.2	12.9
Kunama	1.8	4.2	9.3
Zomo*		0.2	
Total**	**16.7**	**35.0**	**114.6**

* Indicative Resources pending PSDM evaluation

** Arithmetic sum excluding Zomo, Total may not add exactly due to rounding

Table 4-2 Gross Contingent Resources

4.2 Prospects and leads

CGG has reviewed eleven exploration prospects and leads from Savannah's portfolio. The principal conclusions of our review of these prospects and leads are that: (1) the methodology used by Savannah to estimate gross mean Unrisked Prospective STOIIP volumes on these prospects and leads has been assessed as reasonable; (2) in aggregate, the structural prospects in the Alternances CGG assessed are seen as carrying a low exploration risk profile (i.e. carrying a similar risk profile to those drilled elsewhere in the basin to-date).

The basis for sand thickness, porosity, oil saturation and FVF values were all found to be reasonable. Minimum and maximum areas of accumulation were, in almost all cases, also found to be reasonable, or were slightly modified by CGG for this review. The known traps are not filled to-spill. The geological implications of this are discussed further in the discussion of "yet-to-find".

This review was undertaken to provide an independent validation of Savannah's numbers, as such a simplified version of the Savannah pay thickness approach was adopted, so that any differences in geological interpretation can be more readily compared.

The CGG depositional model summarised in **Section 3.2**, implies that "layer cake" geometries may apply to many of the reservoirs. **Section 5.3** describes CGG's engineering-based evaluation of Recovery Factor ranges that are considered reasonable for the basin. Both approaches suggest that Recovery Factors could be relatively high. CGG has concluded that a Recovery Factor of 28% should be used as a "Mid Case" for the purposes of this evaluation.

The existence of a stratigraphic play or plays across the basin could add a significant amount of potential resource, particularly in those areas where structural trapping and fault density are less apparent. Potential stratigraphic traps can be demonstrated to exist over large areas where sand distribution is likely to be controlled by subtle changes in thickness, facies type and topography. This is particularly the case where up-dip pinchouts have been mapped by Savannah, such as the Yogou interval across large parts of the R2 portion of the Licence area.

4.2.1 Geological uncertainty

CGG is generally in agreement with Savannah's mapping of prospects and leads in terms of minimum and maximum closure areas. When CGG's maximum closure areas are run on a fill-to-spill basis, the resulting unrisked STOIIP's are much larger than expected from Savannah's field size distribution for the basin. This supports the concept that many of the traps in the upper levels of the petroleum system in the Agadem Rift Basin may not be filled to-spill, and justifies Savannah's approach to mapping accumulation areas.

Savannah's proprietary geochemical modelling made available to CGG shows that the source systems in the Agadem Rift Basin started generating oil relatively recently: Donga and Yogou - mid Cenozoic to present day, base Sokor - Miocene to present day and main body of the Sokor section - Miocene to present day (but confined to the Dinga Trough). The modelled volumes of oil expelled are very large, at up to: 60 mmbbl/km^2 (Donga), 80 mmbbl/km^2 (Lower Yogou), 97 mmbbl/km^2 (Top Yogou), 50 mmbbl/km^2 (Base Sokor), 30 mmbbl/km^2 (Sokor in the Dinga Trough).

These volume estimates suggest that the basin has generated far more oil than is required to fill the traps to-spill. There are two possible explanations for why the traps are not filled to-spill. First, despite the relatively recent timing of oil generation, much of the oil may have leaked to surface. If this was the case, a high proportion of the wells drilled to-date would have encountered oil or bitumen whilst drilling through the shallow section. In the data reviewed, only six of the many wells drilled in this basin are reported to contain oil accumulations in the Upper Sokor and shallower section. However, the vast majority of the Upper Sokor penetrations were not drilled in closure and therefore this play remains largely under-explored.

CGG therefore considers the interpreted lack of fill-to-spill at individual traps to be due either due to leakage through the fault seals to traps at higher levels, or because of charge limitations. The charge limitations seem likely to be due either to the position of the trap on local migration pathways or due to retention of oil at deeper levels.

The importance of recognising that the traps are probably larger than the mapped accumulations becomes significant when considering yet-to-find in the deeper parts of the basin, where seals are likely to be better and the traps are closer to the mature source systems. Consequently, the deeper traps are more likely to be filled to-spill where charge volumes are adequate.

4.2.2 Risk factors

The standard industry methodology of assigning probabilities to the different components of the petroleum system has been employed. The product of these components then provides an estimate of the overall chance of successfully encountering hydrocarbons at the target (i.e. the geological chance of success).

Note that for the purposes of this evaluation, CGG defines a ‘target’ as a potentially hydrocarbon-filled trap at a specific stratigraphic level (e.g. Sokor Alternances or Upper Yogou). One prospect or lead may incorporate many stacked targets, and these may be evaluated by a single exploration well. Savannah has previously used the term ‘target’ in a different way to define the wrapped-up volume that incorporates all prospective reservoir intervals.

Most of the petroleum system elements are interpreted to be operating successfully for each prospect or lead. CGG considers that the greatest sources of risk at each target to be potential leakage through fault seals, and specific migration pathways/local charge volumes. In terms of the wrapped-up volume, the question of which target or targets will retain hydrocarbons represents uncertainty, not risk.

These elements are to some extent independent: geometries of juxtaposition of sand against shale, or the extent of shale smear on the fault, may mean that hydrocarbon is trapped in one target, whereas the seal for an underlying or overlying target may be breached.

In order to account for the multiple horizons in each prospect, the range of STOIIP and geological chance of success has been calculated for each target. These have then been combined probabilistically to derive an unrisked and risked distribution of STOIIP for each prospect.

The results from the five exploration wells confirm the prediction, both by CGG and Savannah, that the Alternances targets are low risk; oil was found in all five wells in this interval. The shallower level Upper Sokor targets were predicted to be high risk, and oil accumulations were not found at this level in any of the five wells.

4.2.3 STOIIP and Prospective Resource estimation

The table below summarises CGG’s assessment of the STOIIP and Prospective Resources for the prospects and leads shown in **Figure 3-16**. This table only presents 11 out of 146 prospects and leads identified by Savannah. Recovery factors of 23%, 28% and 33% have been associated with the P90, P50 and P10 probabilistically derived STOIIP cases respectively, in order to calculate Recoverable Resources. The derivation of these recovery factors is explained in **Section 5.0**.

Area	Prospect/lead		STOIIP (MMstb)			
			P90	P50	P10	Mean
R3 East	Bushiya Deep	Yogou Prospect	8.0	27.3	68.1	33.6
R3 East	Amdigh Deep	Yogou Prospect	11.2	39.1	99.0	48.6
R3 East	Eridal Deep	Yogou Prospect	7.4	24.8	60.5	30.3
R3 Central	Adal	Lead Total	13.9	73.6	220.0	87.8
R3 Central	Efital	Lead Total	37.8	157.0	394.0	170.0
R1	Sountellane	Lead Total	40.7	128.0	328.0	161.0
R1	Damissa	Prospect Total	57.4	239.0	570.0	283.0
R1	Imari West Attic	Lead Total	38.1	162.0	453.0	211.0
R1	Guiwa	Upper Sokor Lead	28.2	107.0	272.0	132.0
R1	Kunkuru	Prospect Total	8.2	37.3	94.9	45.6
R2	Jimna	Yogou Lead	74.8	291.0	772.0	130.0
Total*			**325.7**	**1286.1**	**3331.5**	**1332.9**

* Arithmetic sum

Notes:

1. *The volumes for individual prospect and lead totals are calculated probabilistically*

Table 4-3 Unrisked STOIIP by Prospect and Lead (for a subset of 11 out of 146 prospects/leads portfolio)

Area	Prospect/lead		Unrisked Prospective Resources (MMstb)				
			Gross				
			Low Estimate	Best Estimate	High Estimate	Risk factor	Operator
R3 East	Bushiya Deep	Yogou Prospect	1.8	7.6	22.5	medium	Savannah
R3 East	Amdigh Deep	Yogou Prospect	2.6	10.9	32.7	medium	Savannah
R3 East	Eridal Deep	Yogou Prospect	1.7	6.9	20.0	medium	Savannah
R3 Central	Adal	Lead Total	3.2	20.6	72.6	medium	Savannah
R3 Central	Efital	Lead Total	8.7	44.0	130.0	medium	Savannah
R1	Sountellane	Lead Total	9.4	35.8	108.2	medium	Savannah
R1	Damissa	Prospect Total	13.2	66.9	188.1	low	Savannah
R1	Imari W Attic	Lead Total	8.8	45.4	149.5	high	Savannah
R1	Guiwa	Upper Sokor Lead	6.5	30.0	89.8	high	Savannah
R1	Kunkuru	Prospect Total	1.9	10.4	31.3	low	Savannah
R2	Jimna	Yogou Lead	17.2	81.5	254.8	high	Savannah
	Total*		**74.9**	**360.1**	**1099.4**		

* Arithmetic sum

Notes:

1. *The volumes for individual prospect and lead totals are calculated probabilistically*

2. *The risk factor is defined as the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface, from any prospective stratigraphic level in the defined prospect*
   Risk factor: low = > 75%, medium = 25% - 75%, high = <25%

Table 4-4 Unrisked Prospective Resources by Prospect and Lead (for a subset of 11 out of 146 prospects/leads portfolio)

4.3 Yet-to-find analysis

The starting point for this analysis was the existing basin discovery density data which were then extrapolated into Savannah's acreage on the basis of structural domains. Using the available exploration data, CGG then estimated a geological adjustment factor to allow for variations within the structural domains that could affect prospect density and size. This includes lateral changes in fault density (which could affect prospect density in these predominantly structural traps) and vertical changes in structure and trap quality, that could result in different trap sizes from those in the Sokor Alternances (the discovery density data is derived almost entirely from drilling in the Sokor Alternances).

CGG then applied standard geological risking for Source, Reservoir, Charge, Trap and Preservation in order to estimate the chance of each play being successful in each structural domain in the Licence Area. **Table 4-5** summarises CGG's overall assessment of the Low, Best and High Case estimates, both unrisked and risked, for the R1234 Licence Area.

	Gross Prospective Resources – "yet to find" (MMstb)					
	Unrisked			Risked		
Licence	**Low estimate**	**Best estimate**	**High estimate**	**Low estimate**	**Best estimate**	**High estimate**
R1234	**2561**	**6801**	**9987**	**1000**	**2695**	**3868**

Table 4-5 Unrisked and risked gross "Yet to Find" prospective resource estimates

Across the Licence Area as a whole, the estimated average play geological chance of success (GCOS) for the Alternances in exploration terms is high (>75%). The lower geological chance of success estimated for the other plays mostly reflects uncertainty due to the limited amount of properly targeted drilling of those levels, rather than specific negative geological information.

5 RESERVOIR ENGINEERING

The main objective of CGG's reservoir engineering work was to provide an independent assessment of Savannah's estimated recovery per well (EUR/well) and recovery factor estimation. The following sections summarise the analysis.

5.1 Discovery PVT Evaluation

PVT samples were taken in four of the 2018 R3 East discovery wells. Downhole samples were retrieved in all cases via the wireline RFT tool; the samples are summarised below in **Table 5-1**. Overall, the discovered oils are medium to light (24 º to 33 º API) with a low sulphur content (<0.5 wt. %).

Indicator	Unit	Bushiya-1	Amdigh-1	Kunama-1	Eridal-1
Depth	mMD	1476.8	1712.4	1673.8	1719.4
E-Sequence		E1	E1	E1	E1
Type		Dead Oil	Dead Oil	Dead Oil	Dead Oil
Oil Density	g/cm³	0.9078	0.8893	0.8861	0.8591
Oil API @ 60ºF	°API	24.2	27.5	28	33.0

Table 5-1 Summary of Downhole samples

Savannah has used the Corelab PVT laboratory analysis results, alongside knowledge of offset well oil characteristics from previous analogue studies, to construct PVT models for use in production modelling. These PVT models were constructed within the industry-standard Petroleum Experts MBAL software package. The PVT models were applied for modelling both within MBAL as well as Petroleum Experts PROSPER (well modelling). Oil properties within the PVT models were varied with pressure/temperature by utilising PVT correlations from the literature.

5.2 Discovery Reservoir modeling

Savannah have built a Material Balance model using Petroleum Experts MBAL software for the 2018 discoveries. This R3 East MBAL model has been utilised primarily to:

- Capture and collate the data collected as part of the 2018 drilling program and learnings from prior and ongoing studies of Agadem Rift Basin (ARB) analogues into a model of the discovered reservoirs
- Simulate development scenarios to capture a range of potential production outcomes
- Conduct sensitivities to key uncertainties – importantly STOIIP & aquifer strength

Production profiles created from this model have been based on all available data and are specific to the underlying reservoir, well and project constraint assumptions of the scenario, many of which are uncertain. In order to be able to improve the prediction of water influx rates and timing, type curves have been derived from analogue fields.

5.3 Recovery factor estimation

The recovery factor is the recoverable amount of hydrocarbon-initially-in-place, normally expressed as a percentage. CGG has reviewed the MBAL work that has been carried out by Savannah with investigated Recovery Factor Sensitivity based on varying Aquifer Strength and water injection strategy. In light of the previous work that has been done on recovery factor estimation in the pre well estimates and the review of analogy and Empirical correlations, the approach that has been used is viewed as reasonable. CGG has applied recovery factors presented in **Table 5-2** to the STOIIP figures to calculate recoverable volumes.

Case	R.F. %
Low	23.0
Mid	28.0
High	33.0

Table 5-2 Summary of recovery factor used for resource assessment

Figure 5-1 shows the base case from the MBAL model used in the indicative economics which demonstrates that Savannah is being conservative in its approach to the development and expected Ultimate Recovery. CGG have reviewed the assumptions and inputs into the MBAL model and believes that it has been built in a through manner and does not overstate the potential from the discoveries given the uncertainties and lack of well test data at this time.

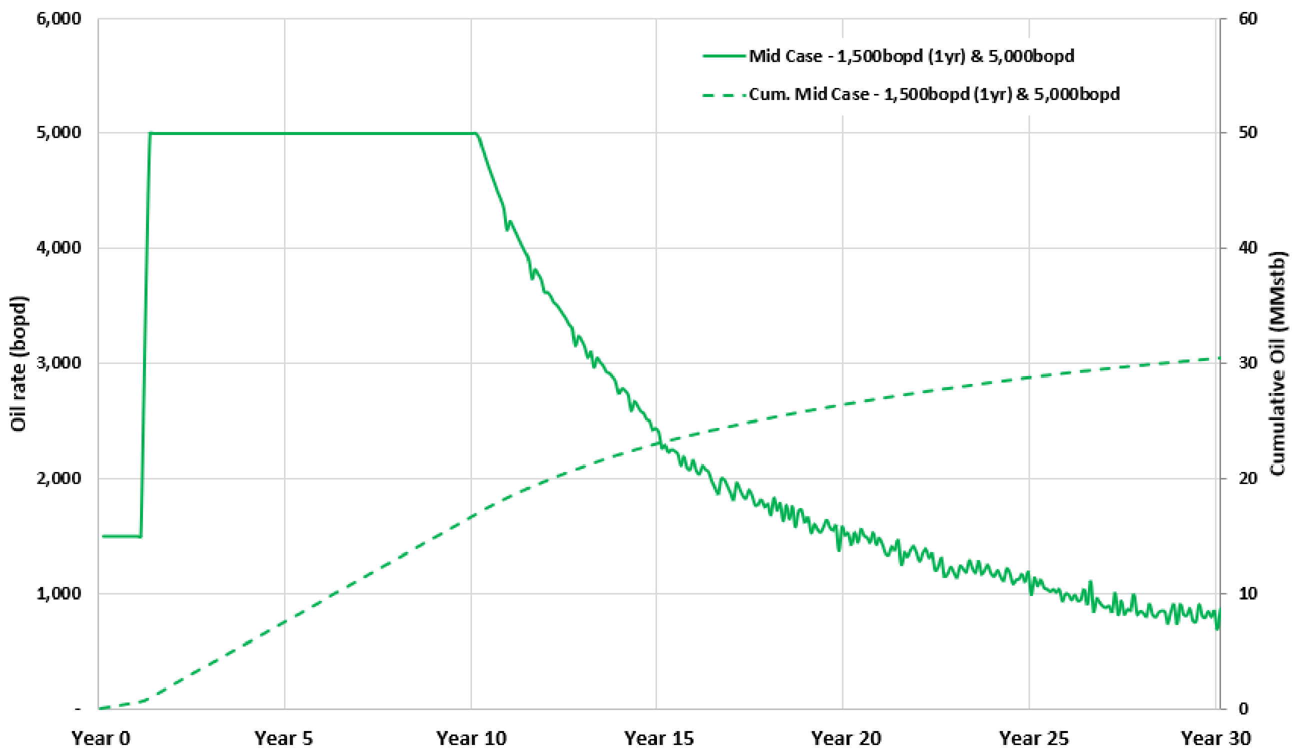


Figure 5-1 Base case Oil forecast for R3 East discoveries

6 DEVELOPMENT SCENARIOS

Savannah have prepared an early development scheme for exploiting the recent oil discoveries made by the company in the R3 East area. This development scheme is described and reviewed by CGG in the following sections.

Three fields (namely Goumeri, Sokor and Agadi) are on production in close proximity to the recent Savannah discoveries. CNPC currently sells domestically to the c. 20 kbpd capacity Zinder refinery, via the 463 km Agadem to Zinder domestic pipeline. The Société de Raffinage de Zinder (SORAZ) which operates the refinery, is a joint venture between CNPC (60%) and the Niger government (40%).

6.1 R3 East – Early Production Scheme

An Early Production Scheme has been proposed by Savannah, based on existing developments in the basin. The facility would be located at the Amdigh discovery, given its size and location relative to potential export routes. It is planned to develop the discoveries in two phases:

- Phase 1 – Early Production
- Phase 2 – Ramp-Up and Further Development

Figure 6-1 outlines the key components of the scheme.

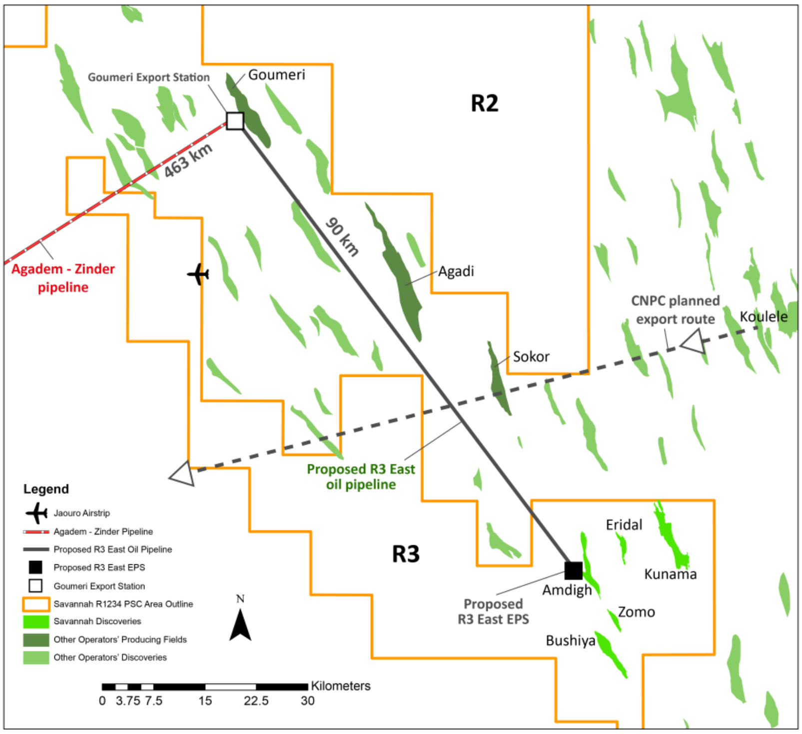


Figure 6-1 Proposed Early Production Scheme Development *(Source: Savannah, 2021)*

6.1.1 Phase 1 - Early Production

Phase 1 involves completion and production testing of Amdigh-1, Eridal-1, Bushiya-1 and Kunama-1 wells, with production processed using an EPF. Crude would then be exported via a planned c. 90km pipeline between the EPF and the Goumeri Export Station (GES). The crude would then be piped to the Zinder refinery (using the existing 463km Agadem to Zinder pipeline). Expected plateau rates are c. 1,500 bopd, which is scheduled after the completion of the well testing.

The key components of the Phase 1 development are detailed in **Figure 6-2** and **Figure 6-3**.

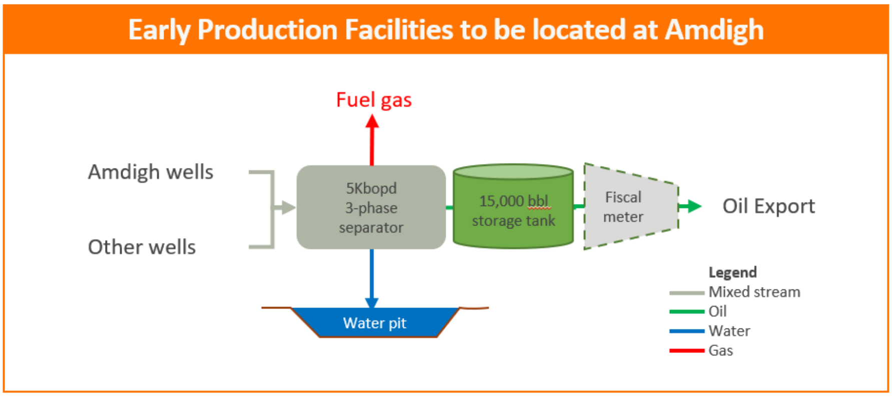


Figure 6-2 R3 East Early Production Facilities *(Source: Savannah, 2021)*

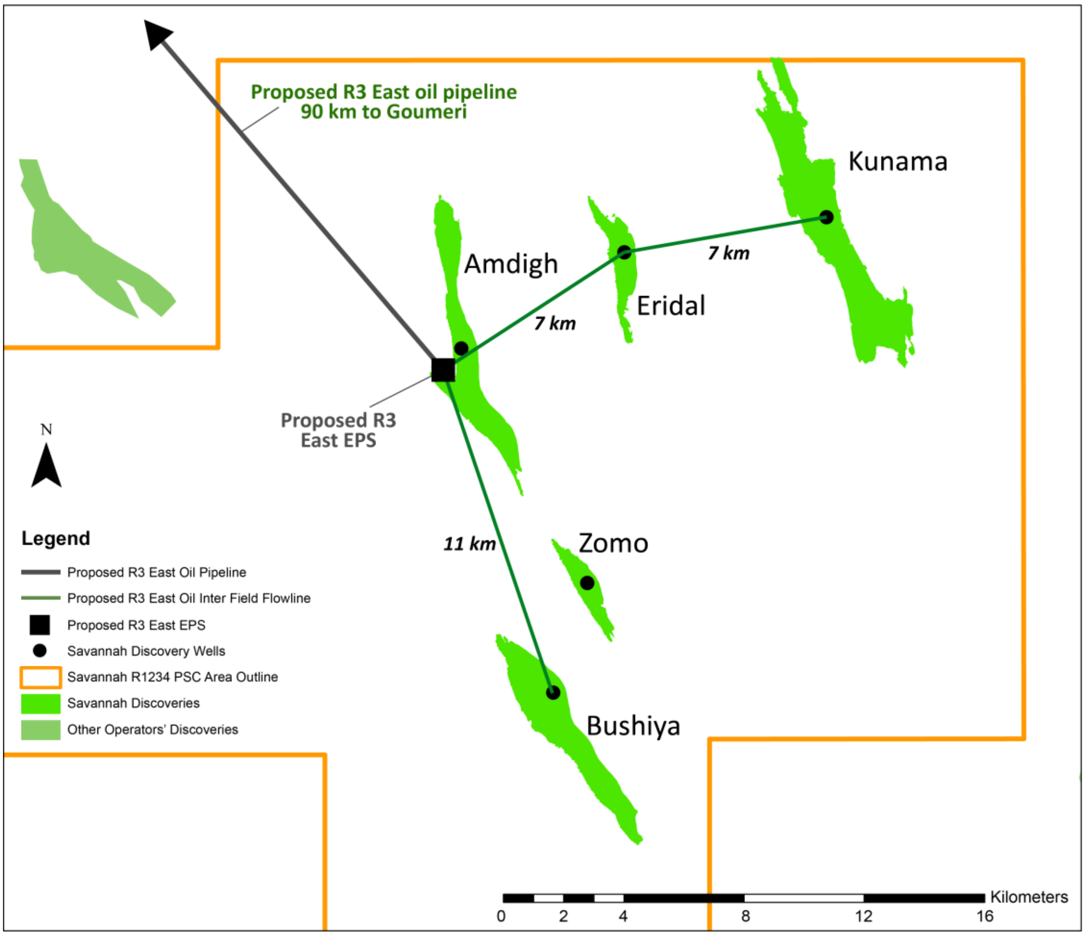


Figure 6-3 R3 East Early Production Development (Source: Savannah, 2021)

Total capital costs for Phase 1 have been estimated and are detailed in **Table 6-1**.

Item	Cost, US$MM
Completion and production testing of Amdigh-1, Eridal-1, Bushiya-1 and Kunama-1 wells	7.7
EPF construction costs	4.3
Amdigh to Goumeri pipeline	16.9
Other Capex (e.g. flowline, export station, civil works)	5.4
Total	**34.3**

Table 6-1 Phase 1 Capex Estimate

Operating costs for Phase 1 over the first year are estimated at US$0.5MM per month, consisting of EPF, pipeline, unloading station, water treatment and allocated in-country overhead costs. An additional US$0.02MM per month per well is estimated for pump fuel, water treatment of US$0.04MM per month and pipeline costs of US$0.9 per barrel.

Operating costs for the Goumeri to Zinder pipeline are shared with CNPC on a throughput basis assuming a total capacity of 20,000 bopd and a total annual cost of US$32.9MM per year. Based on the 5,000 bopd plateau rate, this equates to approximately US$0.68MM per month (equivalent to c. US$4.5 per barrel).

CGG has reviewed the proposed development solution and costs for Phase 1, and consider them to be reasonable.

6.1.2 Phase 2 – Ramp-Up and Further Development

After the initial production phase, further wells will be drilled to ramp up the production to 5,000 bopd, which will continue to be handled by the SORAZ refinery at Zinder. A simple water treatment facility will also be installed at Amdigh.

After the ramp up there will be additional cost associated with further drilling and intra field flowlines. This will create a gathering system to enable fields tested in Phase 1 to be fully developed and tied back to the Amdigh EPF.

Total capital costs for Phase 2 have been estimated and are detailed in **Table 6-2**. This cost will be spread over the full life of fields. The total external funding requirement for Phase 1 and 2, prior to the project becoming self-funding, is estimated at US$69.2MM (2021 prices).

Item	Cost, US$MM
Production/Injection Development wells	146.4
Intra-field flowlines	4.3
Water treatment	4.0
Phase 2 Total	**154.7**
Phase 1& 2 external funding requirement	**69.2**

Table 6-2 Phase 2 Capex Estimate

Operating costs for Phase 2 are estimated at US$0.5MM per month, consisting of EPF, pipeline, unloading station, water treatment and allocated in-country overhead costs. An additional US$0.02MM per month per well is estimated for pump fuel, water treatment of US$0.04MM per month and pipeline costs of US$0.9 per barrel.

Operating costs for the Goumeri to Zinder pipeline are shared with CNPC on a throughput basis assuming a total capacity of 20,000 bopd and a total annual cost of US$32.9MM per year. Based on the 5,000 bopd plateau rate, this equates to approximately US$0.68MM per month (equivalent to c. US$4.5 per barrel).

Abandonment costs are assumed to be 15% of Phase 1 and Phase 2 Capex.

CGG has reviewed the proposed development solution and costs for Phase 2, and consider them to be reasonable.

6.2 Export Pipeline Construction

Existing production in the Agadem Rift Basin (ARB) is currently transported through a 463 km pipeline to the domestic refinery at Zinder, located in the south of Niger. However, as the refinery has an approximate nominal capacity of only 20,000 bopd, an alternative evacuation route is required in order to maximise production from within the ARB where up to 1 Bbbl of 2P Reserves have been proven by CNPC in the adjacent licences to Savannah.

To meet this requirement, in September 2019 CNPC signed a Transportation Convention with the government of Niger to construct a 2,000 km oil export pipeline running from Koulele in Agadem (near the R3 area) to Port Seme on the Atlantic coast in Benin (**Figure 6-4**) (1,298 km in Niger, 684 km in Benin). This is understood to be CNPC's largest cross-border pipeline and is estimated to cost in the region of US$7 billion. The new international Niger-Benin export pipeline is expected to be completed in 2022.

Under the terms of the R1234 PSC, Savannah has access to Third Party infrastructure under terms that guarantee the owner a 12.5% return. On this basis Savannah estimate that the pipeline tariff would be in the order of US$14 per barrel in 2021 terms.

The development schemes for Savannah's discoveries to-date outlined in this report, do not assume usage of this export pipeline. However, due to its proximity to the R3 East discoveries and Savannah adjacent prospects, it does offer an alternative route to realise the full potential of Savannah's assets.

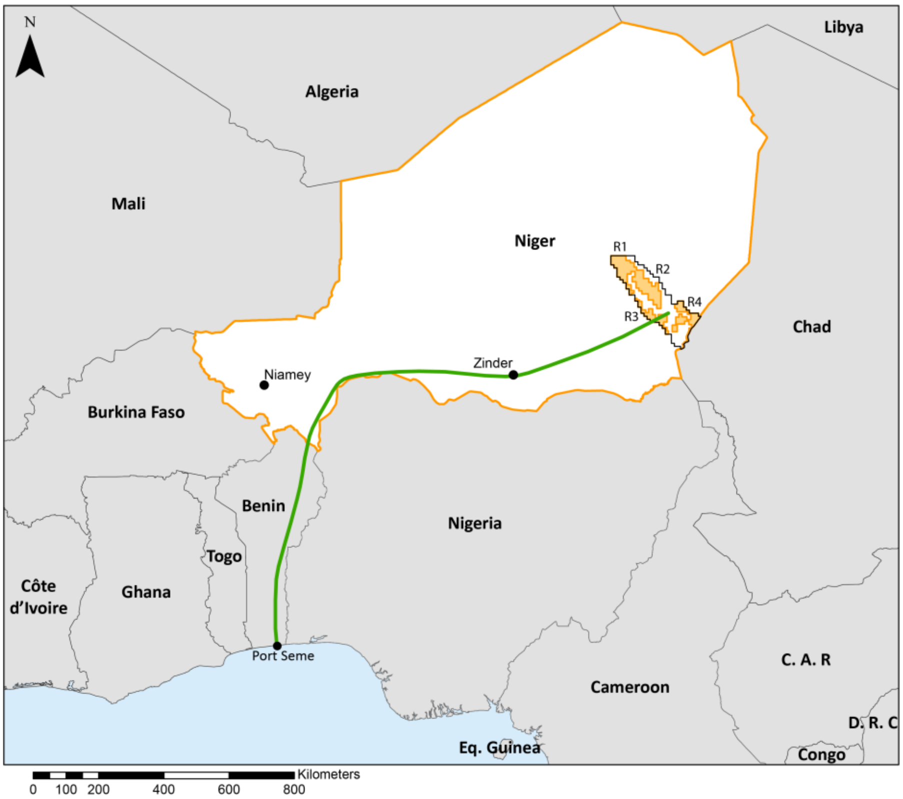


Figure 6-4 Proposed Route of Niger to Benin Export Pipeline *(Source: Savannah, 2021)*

7 INDICATIVE ECONOMICS

7.1 Methodology

Net Present Values (NPVs) have been calculated using Savannah's Excel™ economic model of the R1234 PSC. The model has been subject to a high-level review by CGG, and found to be in agreement with the fiscal and commercial terms applicable to the contract area.

7.2 Input assumptions

The previous R1/R2 and R3/R4 Licence Areas were originally subject to separate Production Sharing Contracts (PSCs) between Savannah Energy Niger (the Contractor) and the Republic of Niger. Savannah has agreed with the Ministry of Petroleum to amalgamate the four licence areas (covered by the previous R1/R2 PSC and the R3/R4 PSC) into a single PSC. The new PSC (being a R1234 PSC) will be valid for up to 10 years from the date of signing the agreement. Savannah has a 95% Contractor interest in the PSC.

The key terms of the amalgamated PSC as understood by CGG are presented in the following sections.

7.2.1.1 Signature bonus:

A signature bonus of US$1.0MM will be payable on signing the amalgamated PSC.

7.2.1.2 Royalties:

There is an oil royalty of 12.5% levied on the gross sales revenue less pipeline transportation costs.

7.2.1.3 Cost Oil:

Exploration, capital, and operating costs can be recovered from 70% of gross revenues less royalties. Unrecovered costs in any year can be carried forward. There are approximately US$190MM of historic costs available for recovery at the valuation date.

7.2.1.4 Profit oil:

Profit oil is shared between the State and Savannah depending on the value of an R-factor as shown in **Table 7-1**. The R-factor is calculated as follows:

(cumulative cost and profit oil less exploitation costs)/ (cumulative exploration and capital costs)

R-Factor	Contractor	State
< 1.0	60%	40%
1.0 – 1.49	55%	45%
1.5 -1.99	50%	50%
> 2.0	45%	55%

Table 7-1 Profit Oil rates

7.2.1.5 Corporation tax:

No corporation tax is payable in Niger.

7.2.1.6 State participation:

The state has back-in rights to 15% of the Contractor's share of profit oil.

7.2.2 Oil prices

It is understood from Savannah that currently, production from the ARB is sold to the SORAZ refinery at a government agreed fixed price of US$42 per barrel. When the CNPC Niger-Benin export pipeline is completed, it is expected that the domestic price will achieve parity with the price of exported crude. It is therefore assumed that at this point the refinery gate price achieved by Savannah will be equivalent to the Brent price less a discount of US$9.5 per barrel to account for the expected export and domestic pipeline transportation costs. Production start-up is currently expected post-completion of the Niger-Benin export pipeline.

The base Brent price assumption in the evaluation assumes prices of US$75/bbl, US$70/bbl and US$65/bbl in 2022, 2023 and 2024 respectively. Beyond 2024, the price is escalated at 2% per year.

Sensitivity cases at fixed prices of US$50/bbl, US$60/bbl, US$70/bbl, US$80/bbl, US$90/bbls and US$100/bbl have also been analysed, with the price inflated at 2% per year from January 2022.

7.2.3 Other

Other assumptions used by CGG in the economic evaluation are tabulated below.

Parameter	Value
Discount Factor	10%
Discount Methodology	Monthly
Cost Inflation	2% per annum
Discount Date	1st October 2021

Table 7-2 Other assumptions

7.3 Results

Indicative economics have been determined for the 2C resource case. The economics presented are net to Savannah's 95% interest.

Case	2C
NPV0 (US$MM)	443.3
NPV10 (US$MM)	150.2
NPV10/bbl (US$)	6.4

Notes

1. *NPVs are based on net economic production to Savannah of 23 MMstb and post 15% government back-in right*

Table 7-3 Indicative economics (net Savannah) for Discoveries

NPV10 sensitivities have also been performed on costs and oil price. The results of this analysis are tabulated below.

The break-even refinery gate oil price, which would enable Savannah to generate a 10% IRR on the development would be approximately US$30/bbl, assuming costs at this oil price level would be reduced by at least 20% from those prevailing at US$60/bbl. CGG has assessed this assumption and considers it to be reasonable.

As a further sensitivity, the economics of tying-in a 20 MMstb prospect to the Amdigh facilities have also been evaluated. On the basis of minimal modifications to the facilities, this analysis yielded an incremental unrisked NPV10 of approximately US$100MM net to Savannah.

Case	2C
Base case	150.2
+15% factor on costs	122.3
-15% factor on costs	176.7
Oil price - US$50/bbl	70.4
Oil price - US$60/bbl	142.0
Oil price - US$70/bbl	197.4
Oil price - US$80/bbl	498.9
Oil price - US$90/bbl	297.3
Oil price - US$100/bbl	344.0
Production volume +25%	214.1
Year 1 production 2,500 bopd	156.9

Table 7-4 Sensitivities for Indicative Economics (NPV10 net to Savannah, US$MM)

8 APPENDIX A: DEFINITIONS

8.1 Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in June 2018, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (June 2018) are presented below.

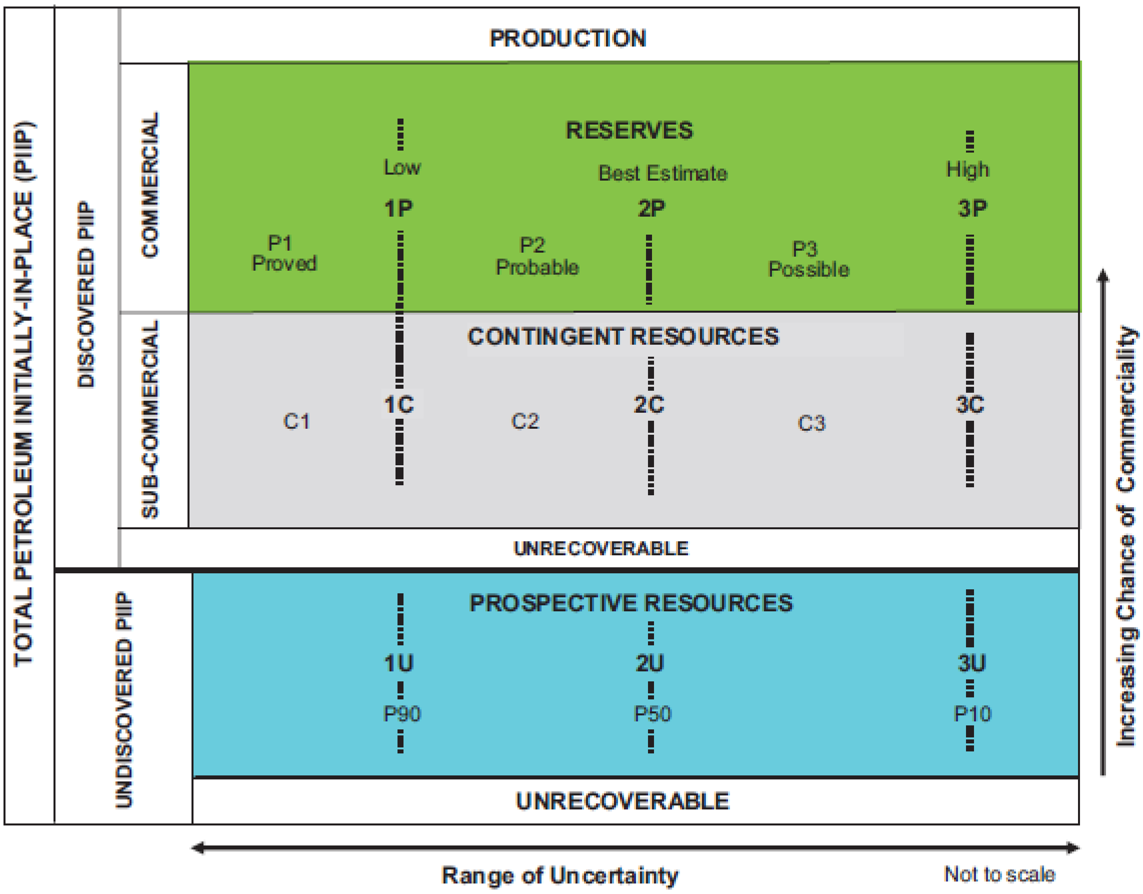


Figure 8-1 Resources Classification Framework

(Source: SPE Petroleum Resources Management System 2018)

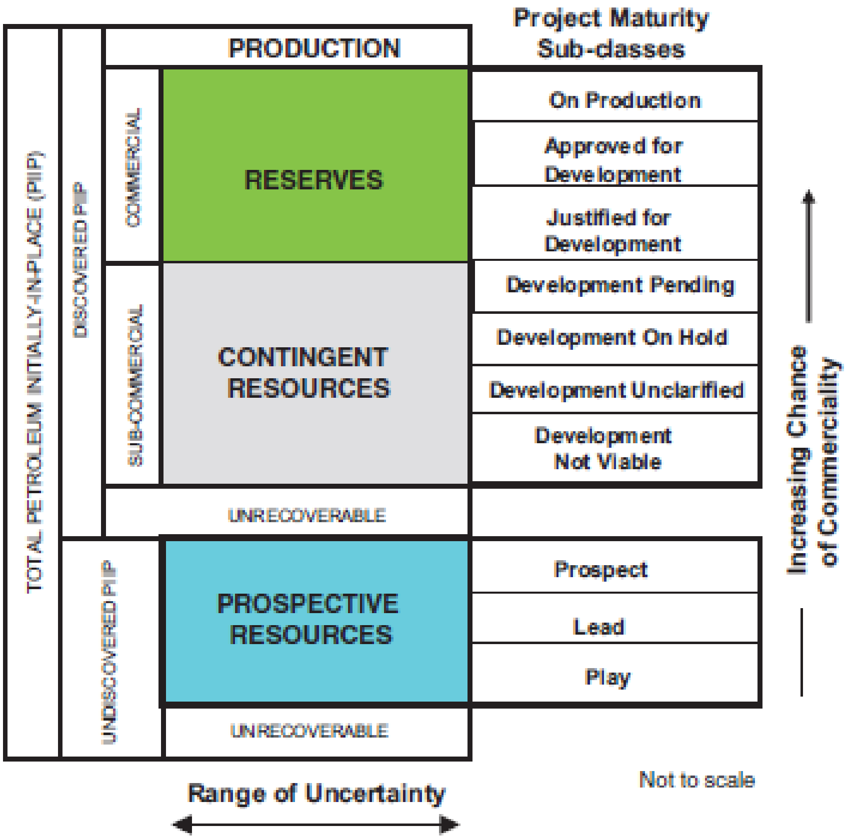


Figure 8-2 Resources Classification Framework: Sub-classes based on Project Maturity

(Source: SPE Petroleum Resources Management System 2018)

8.1.1 Total Petroleum Initially-In-Place

Total Petroleum Initially-In-Place (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

8.1.2 Discovered Petroleum Initially-In-Place

Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.

8.1.3 Undiscovered Petroleum Initially-In-Place

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

8.2 Production

Production is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage.

8.3 Reserves

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

8.3.1 Developed Producing Reserves

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

8.3.2 Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe reserves with minor costs to access.

8.3.3 Undeveloped Reserves

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

(1) From new wells on undrilled acreage in known accumulations,

(2) From deepening existing wells to a different (but known) reservoir,

(3) From infill wells that will increase recovery

(4) Where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.

8.3.4 Proved Reserves

Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions.

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

8.3.5 Probable Reserves

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

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

8.3.6 Possible Reserves

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

When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Standalone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

8.4 Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies.

Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

1C denotes low estimate scenario of Contingent Resources

2C denotes best estimate scenario of Contingent Resources

3C denotes high estimate scenario of Contingent Resources

8.4.1 Contingent Resources: Development Pending

Contingent Resources Development Pending is discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. It is project maturity sub-class of Contingent Resources.

8.4.2 Contingent Resources: Development Un-Clarified/On Hold

Contingent Resources ((Development Un-Clarified / On Hold) are a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status.

The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

8.4.3 Contingent Resources: Development Unclarified

A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development.

This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

8.4.4 Contingent Resources: Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.

The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.

8.5 Prospective Resources

Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

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

For Prospective Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1U/2U/3U quantities, respectively.

1U denotes low estimate scenario of Prospective Resources

2U denotes best estimate scenario of Prospective Resources

3U denotes high estimate scenario of Prospective Resources

8.5.1 Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

8.5.2 Lead

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

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

8.5.3 Play

A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.

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

8.5.4 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place that is assessed, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

9 APPENDIX B: NOMENCLATURE

1D, 2D, 3D	1-, 2-, 3-dimensions
1P	proved
2P	proved + probable
3P	proved + probable + possible
API	American Petroleum Institute
av.	Average
bbl	barrel
bbl/d	barrels per day
BHP	bottom hole pressure
BHT	bottom hole temperature
boe	barrel of oil equivalent
Bscf	billion standard cubic feet
BV	bulk volume
c.	circa
CO_2	carbon dioxide
DHI	direct hydrocarbon indicators
DST	drill-stem test
E & P	exploration & production
E	East
e.g.	for example
EOR	enhanced oil recovery
ESP	Electrical Submersible Pump
et al.	and others
EUR	estimated ultimately recoverable
ftMD	feet measured depth
ftss	feet subsea
G & A	general & administration
G & G	geological & geophysical
g/cm^3	grams per cubic centimetre
Ga	billion (10^9) years
GIIP	gas initially in place
GOC	gas-oil contact
GOR	gas to oil ratio
GR	gamma ray (log)
GWC	gas-water contact
H_2S	hydrogen sulphide
HI	hydrogen index
IOR	improved oil recovery
IRR	internal rate of return
kg	kilogram
km	kilometre
km^2	square kilometres
LST	lowstand systems tract
LVL	low-velocity layer
M & A	mergers & acquisitions
m	metre
M	thousand
m/s	metres per second
Ma	million years (before present)
Mbbl/d	thousands of barrels per day
mD	millidarcies
MD	measured depth
MM	million
MMbbl	million bbls of oil
MMboe	million bbls of oil equivalent
MMscfd	million standard cubic feet per day
MMstb	million stock tank barrels
Mscfd	thousand standard cubic feet per day
msec	millisecond(s)
MSL	mean sea level
mSS	metres subsea
N	north
NaCl	sodium chloride
no.	number (not #)
NPV	net present value
Ø	porosity
OWC	oil-water contact
P & A	plugged & abandoned
perm.	permeability
pH	-log H ion concentration
plc	public limited company
por.	Porosity
ppm	parts per million
PRMS	Petroleum Resource Management System (SPE)
psi	pounds per square inch
RFT	repeat formation test
RT	rotary table
S	South
SCAL	special core analysis
scf	standard cubic feet
SPE	Society of Petroleum Engineers
SS	sub-sea
ST	sidetrack (well)
stb	stock tank barrel
std. dev.	standard deviation
STOIIP	stock tank oil initially in place
Sw	water saturation
Tscf	trillion standard cubic feet
TD	total depth
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWT	two-way time
US$	US dollar
US$MM	Millions of US dollars
VDR	virtual dataroom

- 1 boe = 6000 scf

- 1 scm = 35.3147 scf