CGG Services (UK) Limited

COMPETENT PERSONS REPORT

Uquo and Stubb Creek Fields, Nigeria

FOR:-

Savannah Petroleum PLC

Strand Hanson Limited

CGG Project No: BP524

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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 Petroleum 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 cash flow technique. In estimating the future cash flows 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 and Seven Energy 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 Petroleum PLC has in the Properties, as communicated by Savannah Petroleum PLC. CGG has not verified nor do they make any warrant as to Savannah Petroleum 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 Petroleum PLC.

CGG affirms that from 1st November 2019 (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 Petroleum 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 B** of the CPR.

Conditions of Usage

This report was compiled using existing data during the period 1st September 2019 to 1st November 2019. 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 Petroleum 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 Petroleum 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 Petroleum PLC and Strand Hanson Limited for the purpose of its re-admission to trading on AIM and 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 Petroleum PLC and Strand Hanson 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 the Savannah Petroleum 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: BP524				
Rev	**Date**	**Originator**	**Checked & Approved**	**Issue Purpose**
06	10/12/19	PW/TU	AJW	Final

Date	**Originator**	**Checked & Approved**
Signed:		

Prepared for:	Prepared By:
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1 EXECUTIVE SUMMARY

At the request of Savannah Petroleum PLC (Savannah) and Strand Hanson Limited, CGG Services (UK) Limited (CGG) have prepared a Competent Persons Report (CPR) on the petroleum interests held by Savannah Petroleum PLC (Savannah) in Nigeria, namely, the Uquo and Stubb Creek Marginal Fields and the Accugas Midstream Business. Those interests were acquired in November 2019 from Seven Energy International Limited (Seven) and Savannah's net asset interests assume completion of the Seven acquisition and the associated restructure of ownership with Frontier Oil at the Uquo Field.

The effective date for the evaluation is 1st November 2019.

1.1 Licence Interests

Savannah holds an 80% interest in the exploration, development and production of gas within the Uquo Field through its 80% owned subsidiary Seven Uquo Gas Limited (SUGL). The remaining 20% interest in SUGL is held by African Infrastructure Investment Managers (AIIM), a leading African-focused private equity firm. SUGL holds responsibility for all operations of the gas project at the Uquo Field, including control of gas-related capital investment projects and day to day gas operations.

Savannah also holds a direct 51% operated interest in the Stubb Creek Field through its 100% economic ownership of Universal Energy Resources Limited (Universal).

In addition, Savannah holds an 80% interest in the Accugas Midstream Business, which owns and operates the 200 MMscfd Uquo gas Central Processing Facility (CPF) and c. 260km pipeline network, as well as holding Gas Sales Agreements (GSA) with downstream customers. The remaining 20% of Accugas is held by AIIM.

Asset	Operator	Savannah Interest (%)	Status	Licence expiry date	Licence Area
Uquo Gas*	SUGL	80%	Production	2035	171 km^2
Stubb Creek	Universal	51%	Production	2026	42 km^2

* Interest in the Gas and Condensate only, following the restructure of ownership interests at the Uquo Field with Frontier

Table 1-1 Current Licence Details

For the Uquo Marginal Field, the licence was renewed by the Department of Petroleum Resources (DPR) for a period of 20 years on 18th June 2015. For the Stubb Creek Marginal Field, the licence was renewed by the DPR for a period of 10 years from 1st May 2016.

CGG have assumed, based on its experience and pursuant to the relevant Marginal Field Guidelines, that the DPR is likely to extend the licences beyond the above tabulated expiry dates, if there are still Reserves to be produced. These extensions would be awarded in several phases until the fields reached the end of their economic lives. The Reserves stated in this CPR therefore assume production to the end of the economic lives of the fields.

1.2 Asset Details

1.2.1 Uquo Field

The Uquo Field is producing gas from 4 wells and has been on production since Q1 2014. Production is sold under a Gas Sale Agreement to Accugas, a Midstream company in which Savannah has an 80% interest. Accugas then processes, distributes and markets the gas to two power plants and a cement factory under long-term take or pay contracts. A summary of the contracts is presented **Table 1-2**. In order to maintain the contracted production rates, Savannah plans to bring on stream 5 additional wells over the next 5 years while Accugas will install compression facilities.

1.2.2 Stubb Creek Field

The Stubb Creek Field is producing oil from 3 wells and has been on production since Q1 2015. Production is transported via pipeline to the Exxon-Mobil operated Qua Iboe Terminal. Universal plans to debottleneck the production facility in order to increase capacity from about 3,000 bopd to 5,000 bopd. A water disposal well is also planned. The Contingent Gas Resources will be developed and sold to Accugas, once the Uquo Field Reserves and Contingent Resources is not sufficient to meet the Daily Contracted Quantity (DCQ).

1.2.3 Accugas

The Accugas facilities consist of a two train 200 MMscfd Central Processing Facility (CPF) located near to the Uquo Field, and approximately 260 km of pipelines connecting the CPF to the current three Downstream gas purchasers. Total Daily Contracted Quantity (DCQ) under the three Gas Sales Agreements (GSA) in place is 189.4 MMscfd, and the GSAs have Take or Pay (ToP) provisions within them (set at 80% of DCQ).

Contract term	Calabar Power Plant	Unicem Cement Plant	Ibom Power Plant
Length of contract	20 years	20 years	10 years
Contract end	Sept 2037	Dec 2031	Dec 2023
DCQ	131.0 MMscfd	38.7 MMscfd	19.7 MMscfd
Take or Pay (ToP)	80% of DCQ	80% of DCQ	80% of DCQ
Gas price	2019 \$3.53/Mscf increasing in steps to \$5.04/Mscf in 2024 All indexed to US PPI	\$5.0/Mscf (all years)	2019 \$2.18/Mscf Thereafter escalated with US CPI

Table 1-2 Details of Accugas Gas Sales Agreements

1.3 Reserves and Resources

A summary of the Reserves and Resources associated with the Uquo and Stubb Creek Fields, both gross and net attributable to Savannah, in accordance with the 2018 Petroleum Resource Management System (PRMS), are shown in the tables below. Net attributable Reserves have been derived from the Savannah's economic model. Net attributable Contingent and Prospective Resources have been estimated by multiplying gross Resources by the respective ratio derived from the economic model.

	Gross on Licence			Net attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil (MMstb)							
Stubb Creek	7.9	15.4	25.0	1.7	3.7	6.4	Universal
Gas (Bscf)							
Uquo	301.0	500.9	721.7	240.8	400.7	577.4	SUGL
Condensate (MMstb)							
Uquo	0.4	0.7	1.0	0.3	0.5	0.8	SUGL

Notes
1. *Reserves must be discovered, recoverable, commercial, and remaining based on the development project(s) applied.*
2. *Volumes are sub-divided into Proved, Proved and Probable, and Proved, Probable and Possible to account for the range of uncertainty in the estimates, which correspond to the P90, P50 and P10 percentiles from a probabilistic analysis*
3. *Reserves are stated after the application of an economic cut-off*
4. *Full definitions of the Reserves categories can be found in Appendix B*

Table 1-3 Reserves as at 1st November 2019

	Gross on Licence			Net attributable				
	1C	2C	3C	1C	2C	3C	Risk Factor	Operator
Oil (MMstb)								
Stubb Creek	-	-	-	-	-	-		Universal
Gas (Bscf)								
Uquo	45.0	72.5	115.6	36.0	58.0	92.5	>75%	SUGL
Stubb Creek	364.9	515.3	680.3	208.0	293.7	387.8	>75%	Universal

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*
5. *Full definitions of the Contingent Resource categories can be found in Appendix B*
6. *Net attributable volumes for Stubb Creek assume an entitlement to approximately 57% of gross volumes*

Table 1-4 Contingent Resources

	Gross on Licence			Net attributable				
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Risk Factor	Operator
Gas (Bscf)								
Uquo	362.7	578.8	921.6	290.2	463.0	737.3	25-75%	SUGL
Stubb Creek	9.0	13.9	20.9	5.1	7.9	11.9	25-75%	Universal

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 a probabilistic analysis*
3. *The Prospective Resources are stated on an "unrisked" basis and before the application of an economic cut-off*
4. *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*
5. *Risk factors: low = > 75%, medium = 25% - 75%, high = <25%*
6. *Full definitions of the Prospective Resource categories can be found in Appendix B*
7. *Net attributable volumes for Stubb Creek assume an entitlement to approximately 57% of gross volumes*

Table 1-5 Prospective Resources

1.4 Economic evaluation

The Net Present Values (NPV) of future cash flows derived from the exploitation of the Reserves as at 1st November 2019 are tabulated below. The values stated are net to Savannah's interest and after deduction of

Royalties and Taxes and are based on the October 2019 Brent forward strip, as set out in **Table 6.2**, and the Gas Sales Agreement. Costs are also assumed to escalate at 2% per year from the end of 2020.

NPV10 ($USMM) of Reserves Net to Savannah			
	Proved	**Proved & Probable**	**Proved, Probable & Possible**
Uquo (gas and condensate)	139.2	227.7	322.1
Stubb Creek oil	38.1	56.7	72.0
Total	**177.2**	**284.4**	**394.1**

Table 1-6 NPV10 ($USMM) of Reserves Net to Savannah as at 1st November 2019

Sensitivities have been calculated for total NPV for variations in oil price, Capex and Opex. The results of this analysis are tabulated below.

NPV10 ($USMM) Net to Savannah			
	Uquo	**Stubb Creek**	**Total**
Base case (Proved+Probable)	227.2	56.7	**284.4**
Oil price -25%	223.2	46.7	**269.9**
Oil Price +25%	232.2	65.8	**298.0**
Capex +25%	216.7	56.0	**272.7**
Capex -15%	234.3	57.2	**291.5**
Opex +25%	214.3	55.2	**269.5**
Opex -15%	235.9	57.7	**293.7**

Table 1-7 Proved and Probable NPV10 ($USMM) Sensitivities as at 1st November 2019

The Net Present Values (NPV) of the future cash flows accruing to the Accugas Midstream Business have been extracted from Savannah's integrated economic model and are tabulated below for the base case (ToP). The model has been subject to a high level review by CGG, and found to be in reasonable agreement with the applicable fiscal and commercial terms. The values stated are for the Accugas Midstream Business (100%) and for Savannah's net 80% interest after deduction of Royalties and Taxes.

It should be noted that there are no gas Reserves or Resources associated with Accugas.

Case	Accugas (100%)	Net to Savannah
Base Case (ToP)	840.9	672.8

Table 1-8 Accugas NPV10s ($USMM)

A summary of the expected net free cashflows accruing to Savannah from the Uquo Field, Stubb Creek Field and Accugas Business is presented in the table below for the base case (ToP).

Year	**Cashflow (US$MM)**
2020	104.2
2021	128.1
2022	141.3
2023	141.3
Average	*128.7*

Table 1-9 Net Asset Free Cashflows (2020-2023) for the base case (ToP)

2 INTRODUCTION

2.1 Overview

This independent Competent Person's Report (CPR) was prepared by CGG at the request of Savannah Petroleum PLC (Savannah) and Strand Hanson Limited. The report evaluates Reserves and Resources associated with the onshore Uquo and Stubb Creek Marginal Fields in which Savannah hold interests. These fields are located near the coast in south-east Nigeria.

Frontier Oil Limited (Frontier) and Universal Energy Resources Limited (Universal), both indigenous Nigerian E&P companies, are Operators of the Uquo and Stubb Creek fields respectively.

Seven Uquo Gas Limited (SUGL) has a 100% Operating interest in the Uquo gas project (including associated condensate production). Savannah owns an 80% interest in SUGL, the remaining 20% is held by AIIM. Frontier has a 100% interest in the Uquo oil project.

Savannah has a 51% participating interest in the Stubb Creek field. The latter interest is held via a 100% interest in Universal, which in turn holds a 51% interest in the field. The remaining 49% interest in the field is held by Sinopec International Petroleum Exploration and Production Company Nigeria Limited (SIPEC).

Savannah also owns an 80% operated interest in Accugas Limited (Accugas), the owner of the Uquo Gas Processing Facility and associated pipeline network. The remaining 20% is held by AIIM. Accugas purchases Uquo gas production, which it then sells to two local power plants and a cement factory. A summary of Savannah's licence interests are tabulated below (**Table 2-1**).

Asset	Operator	Savannah Interest (%)	Status	Licence expiry date	Licence Area
Uquo Gas	SUGL	80%	Production	2035	171 km^2
Stubb Creek	Universal	51%	Production	2026	42 km^2

Table 2-1 Current Licence Details

The locations of the Uquo and Stubb Creek Fields, and the Accugas surface facilities are shown in **Figure 2.1**.

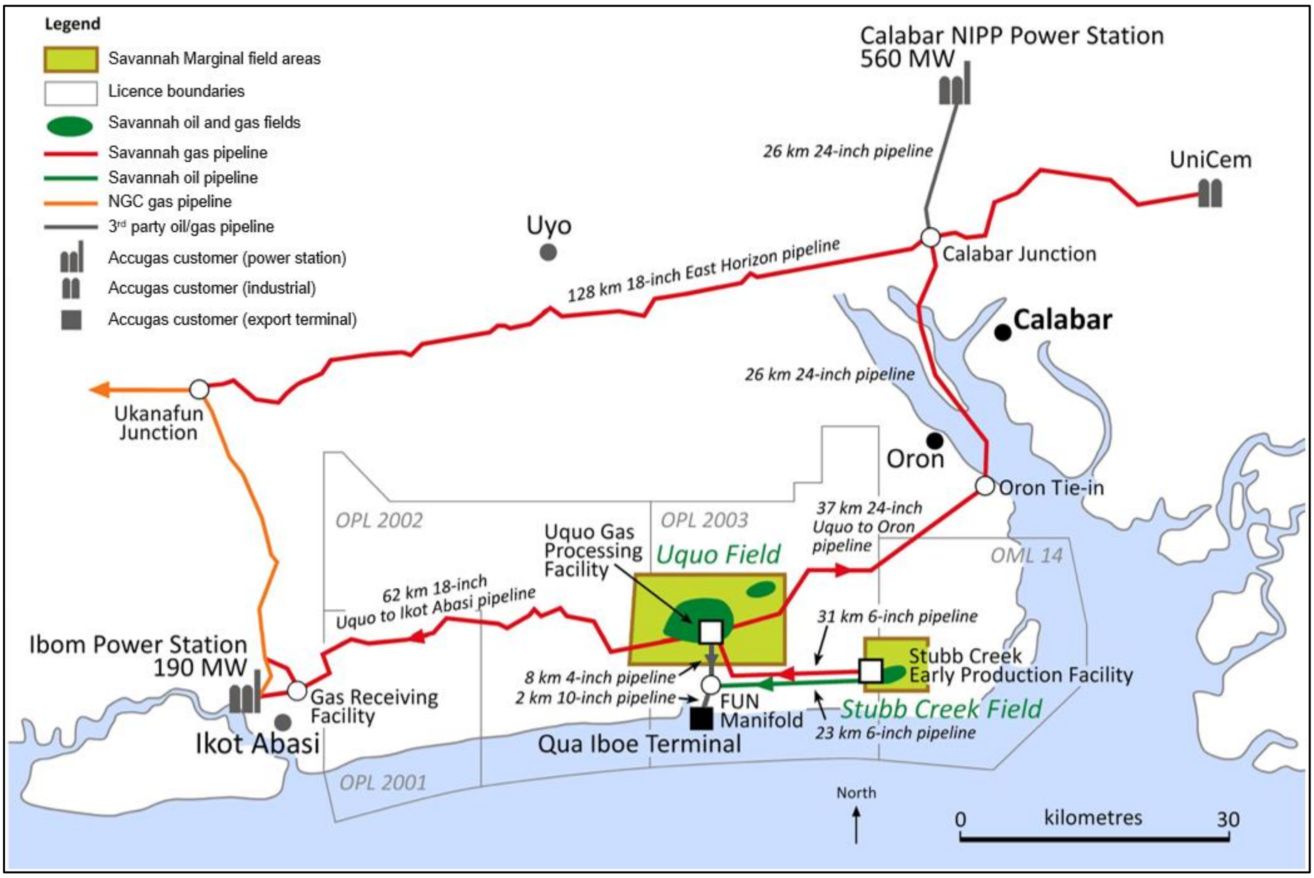


Figure 2-1 Location of Fields and Infrastructure (Source: Savannah, 2019)

2.2 Sources of Information

In completing this evaluation, CGG has reviewed information and interpretations provided by Savannah and Seven's technical teams 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
- Historical production and pressure data
- Gas sales contracts and farmout agreements
- Work plans and budgets

In conducting the evaluation, CGG have accepted the accuracy and completeness of information supplied by Savannah and Seven Energy, and have not performed any new interpretations, simulations or studies.

No site visit to the facilities has been conducted by CGG as it was not part of the work scope in the letter of engagement.

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 Manager of the Petroleum Reservoir & Economics Group at CGG. Andrew joined the company as Economics Manager in 2006. He graduated with a degree in Chemical Engineering and now has over 29 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.

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 20 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.

James Buckley

James Buckley has a BSc (Hons) in Applied Geology and Resource Management from the University of Birmingham and an MSc in Petroleum Geoscience from Royal Holloway, University of London. James has worked at CGG since graduating in 2011, predominantly working in prospect generation and reserves estimation and volumetrics. This has culminated in James participating in several North Sea Licensing Rounds. James also has experience in the geology of many other basins around the world, including the pre-salt Santos Basin on which he published a Geological Society paper in 2015. Additionally, James has been a reviewer for the 'Palaeogeography, Palaeoclimatology, Palaeoecology' Journal. James is a member of the PESGB.

Dr Christopher O. Iwobi

Chris Iwobi gained his BSc. and PhD degrees from the University of Calabar, Nigeria. He has over 29 years' experience in exploration geology including 13 years with the Nigerian Agip Oil Company in the Niger Delta. On joining Robertson's in 2005, Chris has been involved in evaluations of assets in various parts of the world including Northern Europe, North Africa, Southeast Asia, West Africa and the Middle East. He has also worked on a variety of basin-scale play fairway evaluations and screening opportunities for unconventional hydrocarbon plays. Chris is a member of the American Association of Petroleum Geologists (AAPG).

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 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 Reserves and Resources associated with the fields, CGG has used the accepted standard industry techniques of geological, engineering and economic estimation. More detailed descriptions of the workflow and methodologies employed are provided in the relevant sections of this report.

As an initial stage in the evaluation process, Seven demonstrated the seismic interpretations during a visit by CGG to their London office in October 2018. During the same visit, geological, engineering and commercial issues were also discussed face to face with Seven's technical staff.

CGG has independently validated reservoir properties, Hydrocarbon Initially in Place, Reserves, production profiles and estimates of capital and operating costs provided by Savannah and Seven. The Reserves 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.

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 Petroleum PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

3 GEOLOGY AND GEOPHYSICS

3.1 Regional geology

The Uquo and Stubb Creek Fields are located within the eastern Niger Delta, which is part of the prolific Niger Delta hydrocarbon province in Southern Nigeria. The Niger Delta is one of the world's largest Tertiary delta systems, covering an area of approximately 75,000km^2, which has historically been fed by the Niger, Benue and Cross river systems. The basin is located on the West African continental margin at the site of a triple junction that formed during continental break-up during the Cretaceous. The delta sequence consists of an upward-coarsening regressive sequence of Tertiary clastics up to 12 km thick. The dominant subsurface structures are listric normal faults, which detach close to the top of the underlying marine claystone surface at the top of the Akata Shale. These listric faults provide an array of trapping mechanisms for hydrocarbons in the subsurface, particularly within the associated rollover anticline structures. Major growth faults cross the delta from northwest to southeast, dividing the delta into a series of depobelts that have been prograding south-westwards for approximately 55 Myr (**Figure 3-1**).

The northern boundary fault for each of the depobelts marks the approximate position of the palaeo-coastline during the major progradational stages. Hydrocarbons have been located in all of the depobelts of the Niger Delta, typically in good quality sandstone reservoirs within the main deltaic sequence.

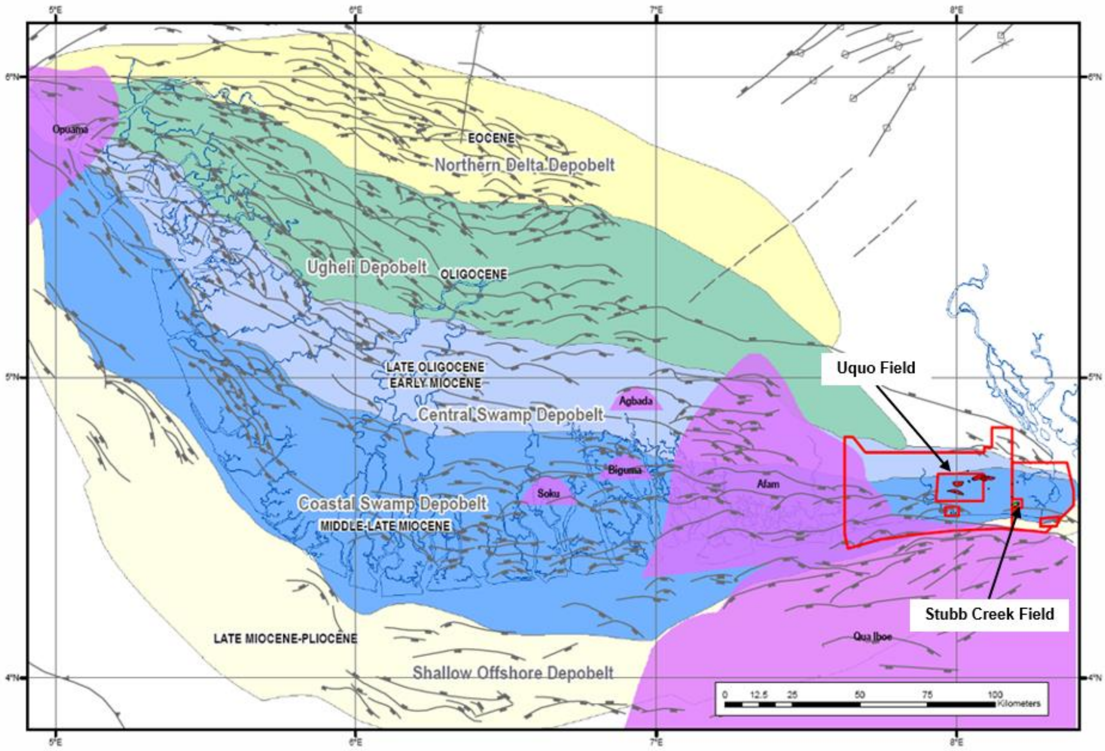


Figure 3-1 Depobelts of the Niger Delta (Source: CGG)

The stratigraphic sequence in the Niger Delta is broadly subdivided into the marine Akata Formation, paralic Agbada Formation and continental Benin Formation (**Figure 3-2**).

Hydrocarbons in the Uquo and Stubb Creek Fields have been generated from the prodelta mudstones of Akata Formation and the interbedded paralic mudstones of the Agbada Formation. Upon maturation, hydrocarbons migrated either updip through carrier beds, or vertically along fault planes into the deltaic sandstones of the Early Miocene Agbada Formation. At Uquo and Stubb Creek, the Agbada Formation is represented by the hydrocarbon-bearing “C” and “D” sands. The seal to these sands is provided by interbedded deltaic mudstones, which are thick and competent across the basin.

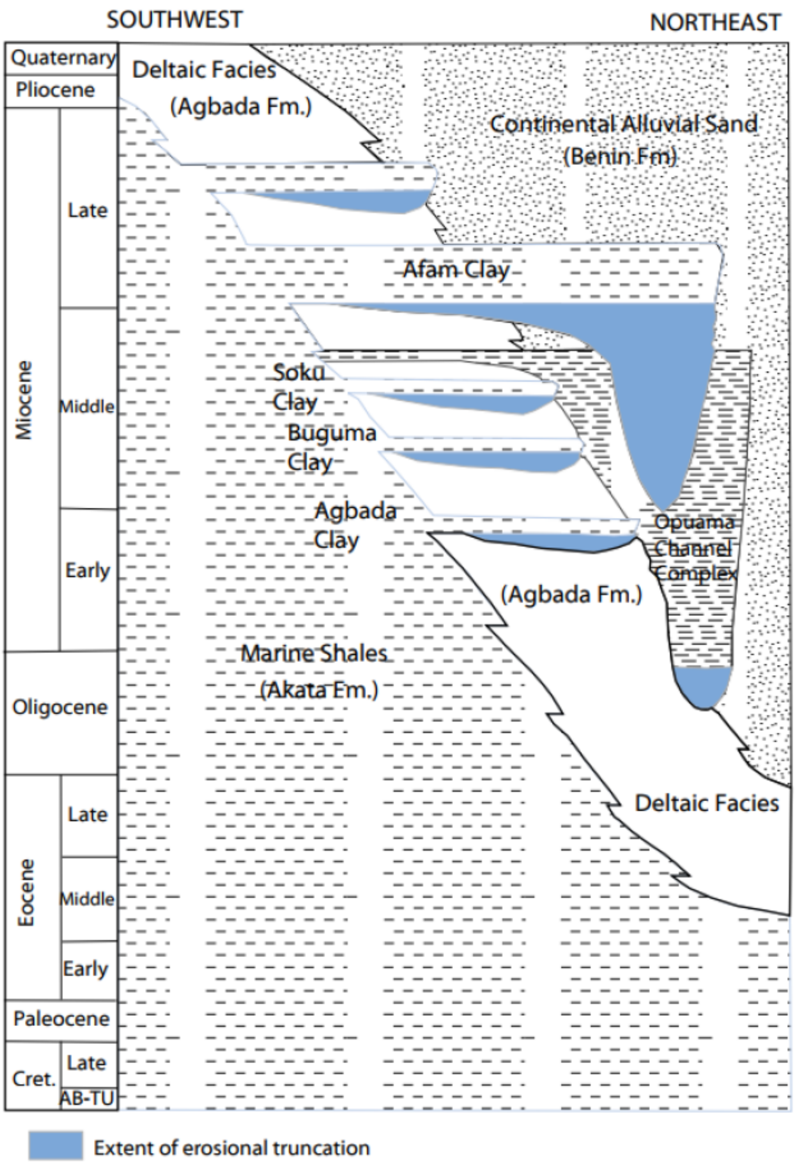


Figure 3-2 Lithostratigraphic column showing the key Tertiary sedimentary sequences in the Niger Delta (Source: Tuttle et al., U.S. Geological Survey, 1999)

3.2 Uquo Field

3.2.1 Uquo Field Summary

The Uquo Marginal Field Licence is located within OML 13, onshore Nigeria. Gas has been discovered in 12 different 'C' and 'D' sand reservoirs in the Agbada Formation.

The Uquo Field is made up of 3 main areas; Uquo-2 (Uquo-2 & 4 wells), Uquo-3 (Uquo-3, 7 & 8/8ST wells) and Uquo NE (Uquo 9/9ST well), with small volumes also present in Uquo-5 area (Uquo-1, 5 & 5ST/6 wells). The upper 'D' reservoirs contribute the greatest volumes of hydrocarbons in the Uquo area (**Figure 3-3** and **Figure 3-4).**

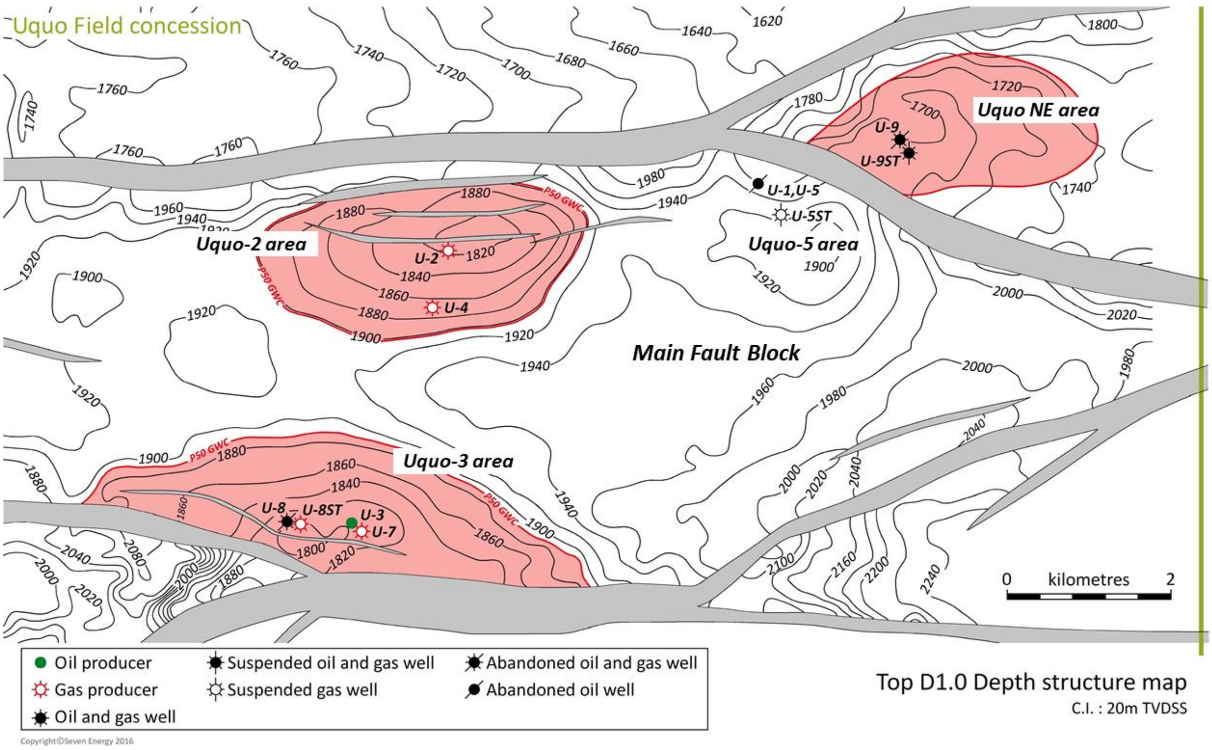


Figure 3-3 Uquo Field structure map (Source: Seven, 2017)

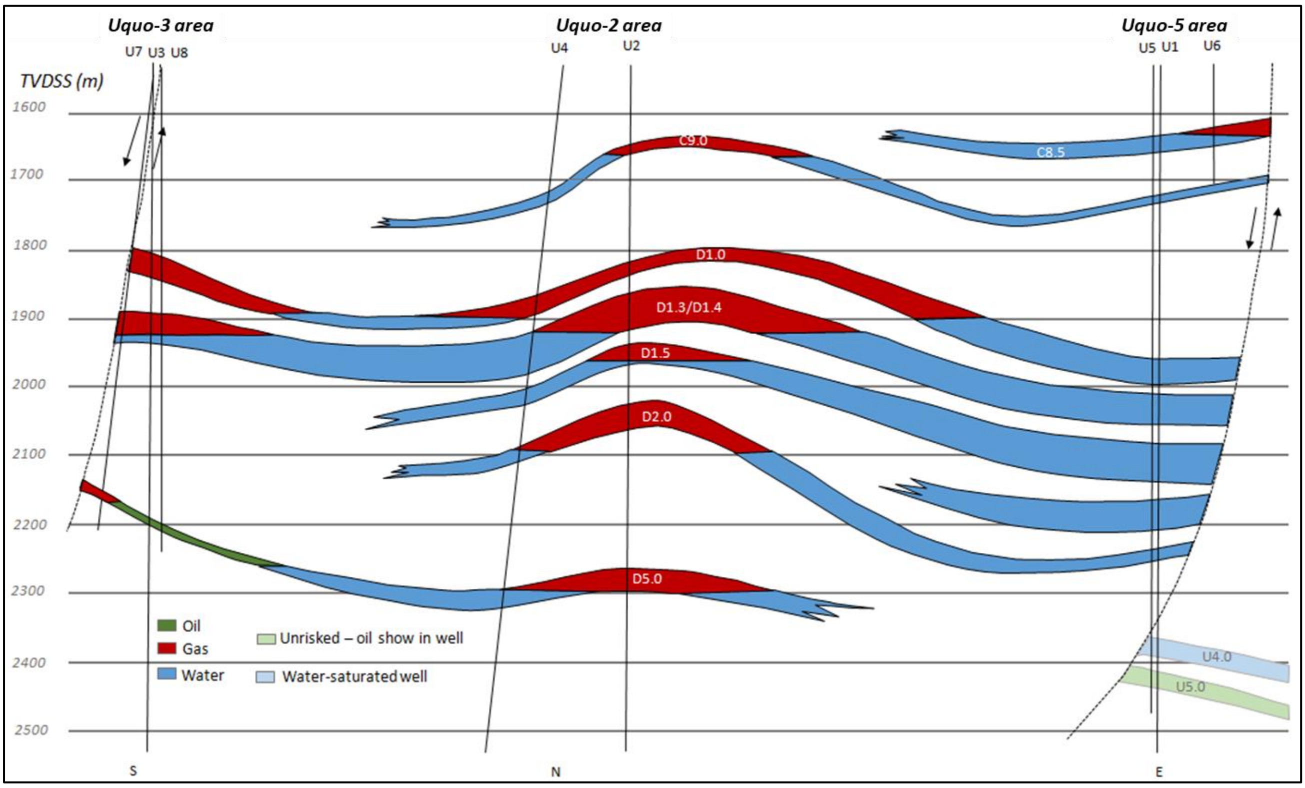


Figure 3-4 Schematic diagram showing the reservoir intervals of the Uquo Field (Source: Seven, 2017)

The Uquo Field was first drilled in 1958 by Shell Petroleum Development Company Nigeria (SPDC); the composite logs from Uquo-1 supplied by Seven suggest that this well only encountered thin gas intervals, although it was reported to have discovered oil and gas in four sands. The subsequent Uquo-2 well was drilled as an exploration well and encountered significant volumes of gas in all of the sands between C9.0 and D5.0 (7 different reservoir intervals). Another exploration well and one appraisal well were drilled in 1971/72; Uquo-3 encountered gas in the D1.0 & D1.3/D1.4 sands, and oil in the D5.0 sand, whereas Uquo-4 encountered gas throughout the D1.0 sand and in the upper part of the D2.0 sand.

Drilling activity restarted in 2008, targeting oil discovered by Uquo-1; the Uquo-5 well failed to confirm the presence of the Uquo-1 oil accumulation. The well was subsequently sidetracked (Uquo-5ST), but was terminated before reaching the target depth due to mechanical problems. However, Uquo-5ST confirmed gas in one reservoir (C8.5). In January 2010, Uquo-3 was worked-over and completed as an oil producer in the D5.0 reservoir, Uquo-2 and -4 were subsequently completed as gas producers in the D2.0 and D1.0 reservoirs, respectively. The gas accumulations were further appraised by Uquo-7, -8 and -8ST between June and September 2013. Uquo-7 and -8ST were completed in 2014 as gas producers in the D1.0 reservoir. Exploration drilling returned to the Uquo area in November 2014, resulting in the Uquo NE discovery with the Uquo-9/9ST well suspended as an oil and gas discovery. The Uquo-9/9ST well will be completed and operated as an oil producer by Frontier.

3.2.2 Uquo Field Subsurface Overview

CGG have carried out an independent analysis of the Uquo Marginal Field Licence using the 195 km^2 3D seismic volume supplied by Seven. The survey was acquired during 2006 and 2007. Around 24.5 km^2 of the licence is not covered by seismic, due to the presence of the Eket Airfield to the west of the licence. In addition, there are areas within the dataset that suffer from poor fold coverage due to the presence of villages.

The data was provided to CGG as a Kingdom™ Project; wells, horizons, faults and depth surfaces provided by Seven have been QC'd and used as a basis for generating volumetric estimates. Composite logs were supplied which contain formation depths as well as fluid contacts, which have been used to delineate the tops and bases of the reservoirs and hydrocarbon columns. The quality of the seismic data is generally good at the key reservoir levels, although the aforementioned acquisition impediments do result in a decrease in data quality in a few areas. The footwalls of most of the faults are generally poorly imaged, particularly in the deeper section, which makes the delineations of some of the gas-bearing reservoirs more uncertain. In addition, the seismic volume is a Pre-Stack Time Migration (PSTM); it is CGG's opinion that the accuracy of the tabulated volumetrics would be improved if the volume were to be re-processed to PSDM (Pre-Stack Depth Migration) which Savannah is planning to conduct in 2020.

In addition to the Kingdom™ project, Seven has provided reports to assist with CGG's G&G analysis; these include Petrophysics, Geoscience and Reservoir Engineering studies.

The Uquo Marginal Licence contains a number of different structural features due to a series of extensional faults that generally trend in an E-W direction. There are three structural culminations in the main fault block, two in the north (Uquo-2 and 5 areas) which are dip-bounded, and one dip and fault-closed structures in the south (Uquo-3 area). At the D1.0 level, Uquo 2 and Uquo 3 areas are in communication (pressure connection proven by production data) as seen in **Figure 3.5**. In the Uquo-2 area, the reservoirs are intersected by some small-offset extensional faults. CGG's Reservoir Engineering analysis suggests that this has not resulted in any compartmentalisation issues.

The Uquo 3 area has a different structural configuration, in that the reservoirs are trapped in the footwall of a large extensional fault. The rotation of the main fault block has resulted in some structural relief into which hydrocarbons have migrated and remained trapped. The southern edge of the Uquo 3 reservoirs are difficult to pick with accuracy in the deeper section, due to fault shadow effects in the seismic clearly seen in **Figure 3.5**. The majority of the gas reservoirs in the Uquo field are easy to pick; many exhibit a bright amplitude response (as exhibited in **Figure 3.6**) as a result of the presence of gas within a high-quality, porous reservoir. Many also exhibit flat spots, which help to define the contacts in some of the accumulations (if no gas-water contact has been encountered in the wells on-structure).

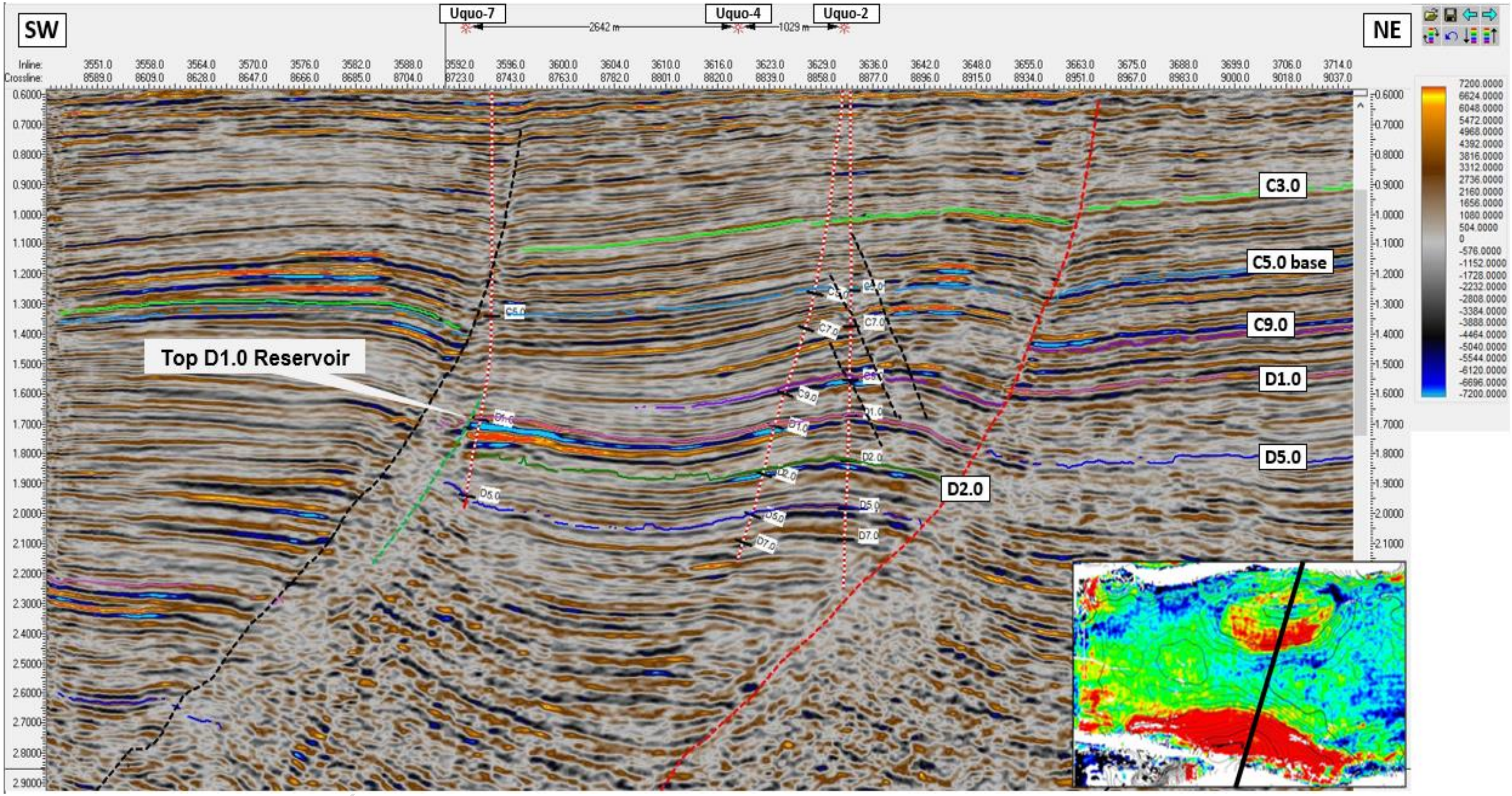


Figure 3-5 N-S line through Uquo-3 and Uquo-2 areas (Source: Seven, 2019)

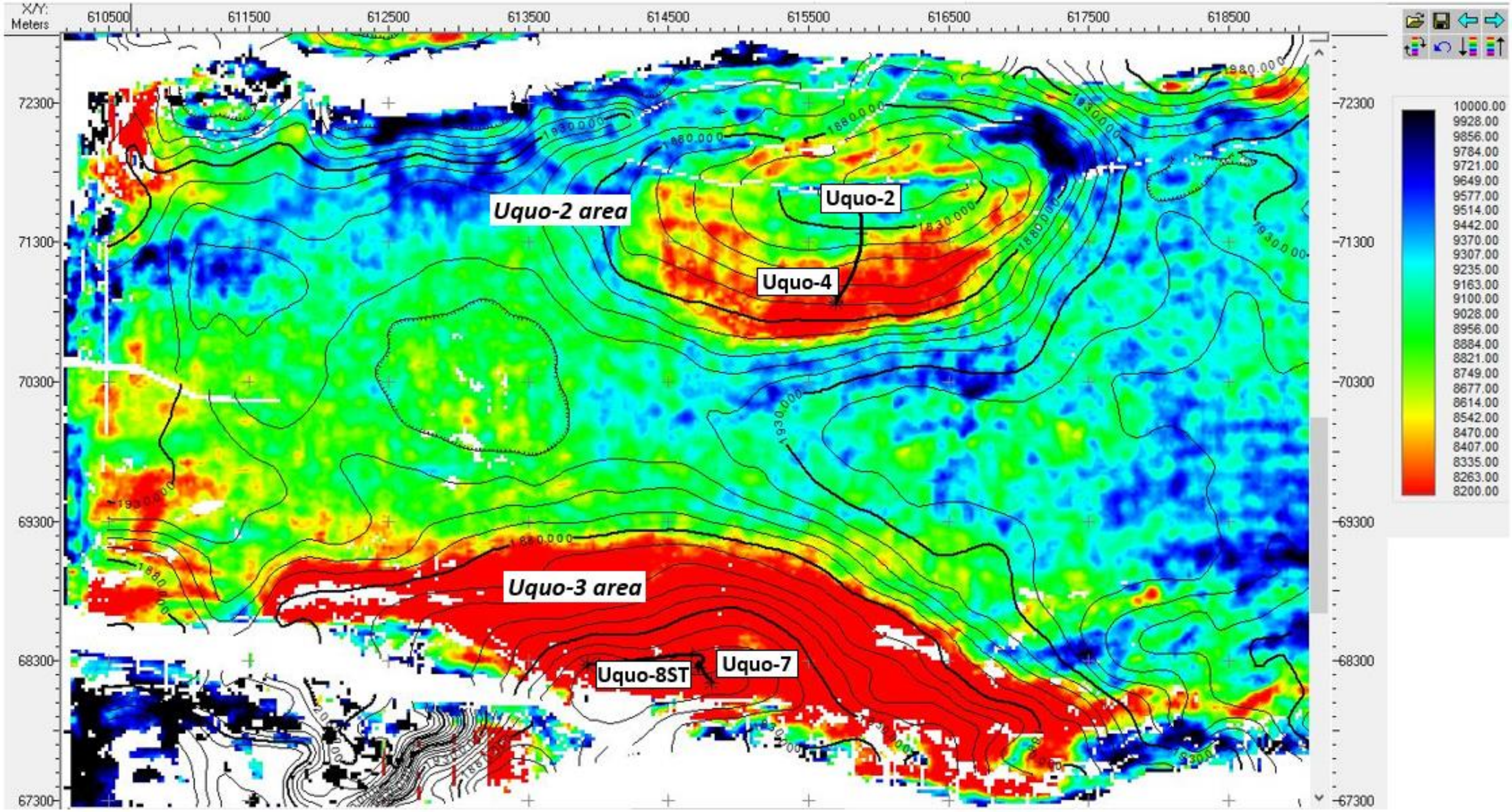


Figure 3-6 Relative Acoustic Impedance at the D1.0 level with depth contours in mSS (Source: Seven, 2017)

The Uquo-9/9ST discovery is located in a separate fault compartment, namely Uquo NE towards the North East of the main fault block. Hydrocarbons were discovered in 9 reservoirs in Uquo-9/9ST well; mainly gas except for the D1.6 and D7.0 reservoirs which encountered oil. The ultimate areal extent of the Uquo NE shallow gas discovery is unknown, as it extends outside the area of 3D seismic coverage, as shown below in **Figure 3-7**. The seismic over Uquo NE is quite poor (shown in **Figure 3-8**) in places due to an overlying village, although this is mitigated by the data provided by the exploration well on the structure (Uquo 9/9ST).

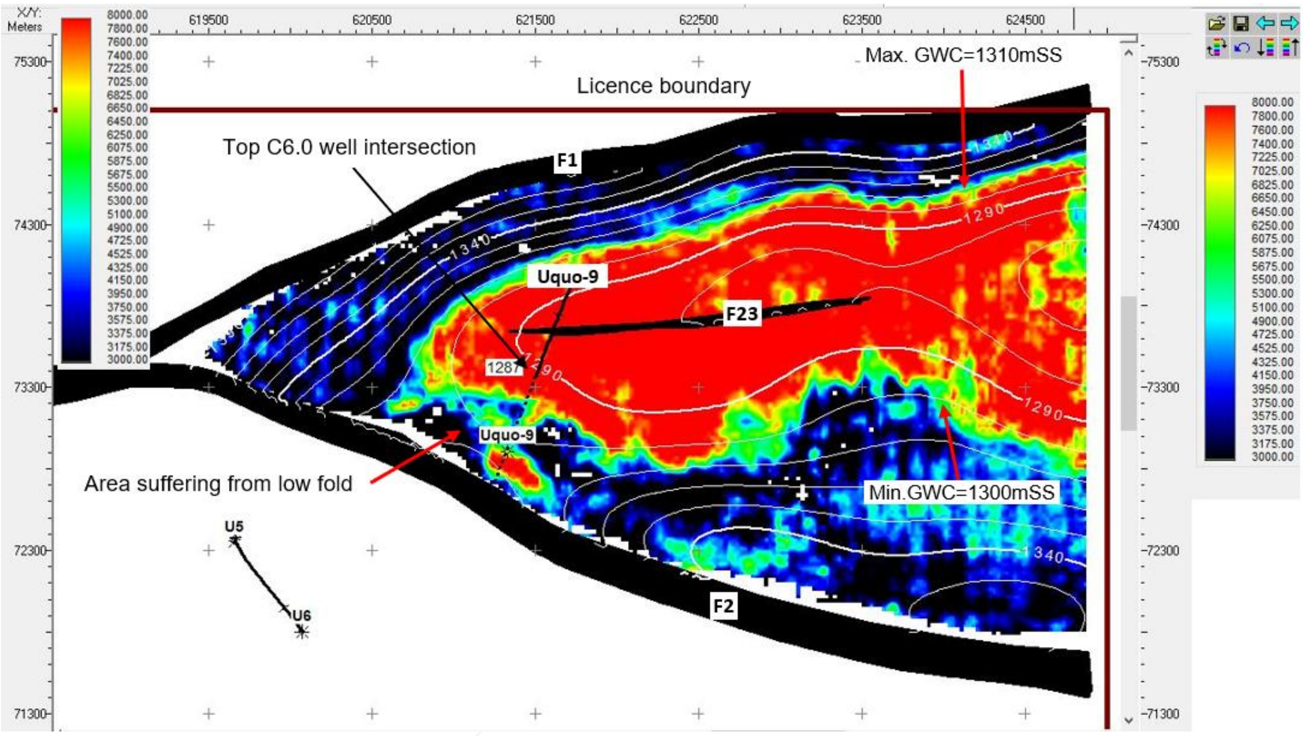


Figure 3-7 Top C6.0 reservoir RMS map (+/-8ms) – Uquo NE area (Source: Seven, 2019)

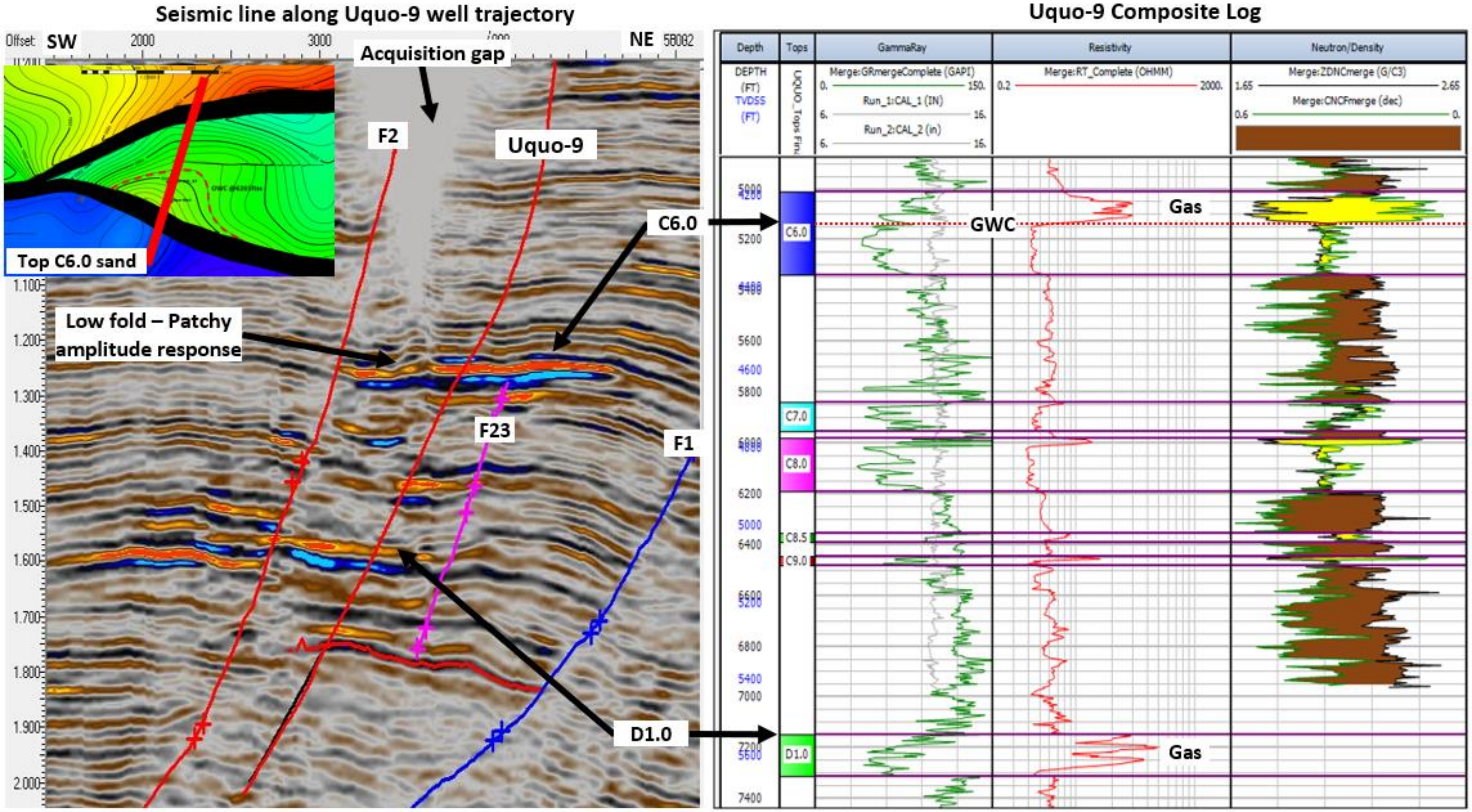


Figure 3-8 N-S seismic line through Uquo NE and Uquo-9 composite log (Source: Seven, 2019)

The Agbada C and D sand reservoirs are of high quality at the Uquo Field; NTG (Net-To-Gross) is generally in excess of 90% and porosity is usually 27% or higher. In addition to the discovered volumes, Seven have identified a series of additional prospects, as seen in **Figure 3-9.**

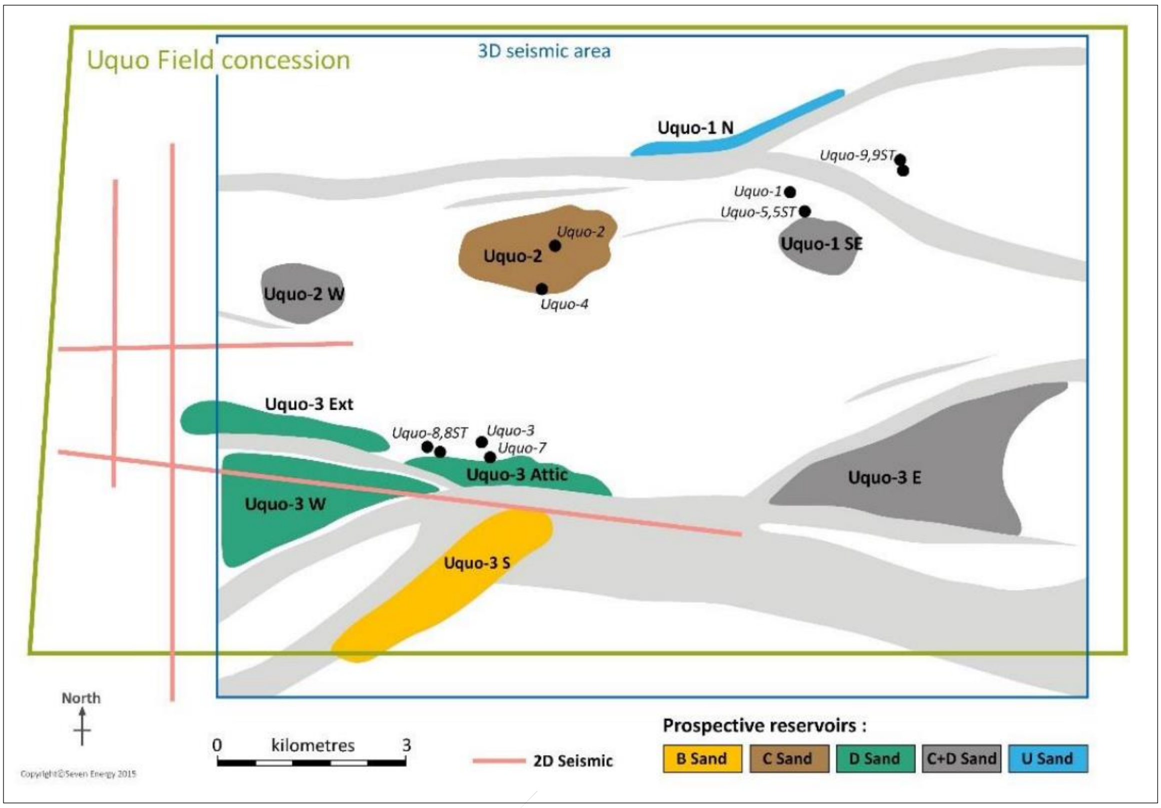


Figure 3-9 Map of prospects in the Uquo Marginal Field Licence area (Source: Seven, 2017)

The subsurface team at CGG has completed a thorough Geological and Geophysical QC of the work supplied by Seven and using the Kingdom™ project provided, have independently generated P90, P50 and P10 volumes for each reservoir. This work has been supplemented by Reservoir Engineering and Petrophysics experts who have also provided inputs for the volumetrics calculations, which were run through a probabilistic Monte Carlo analysis.

3.2.3 Uquo Field Petrophysics

The petrophysical data provided for the C and D sands in the Uquo Field and the nearby Etebi well (Seven, 2017) has been evaluated by CGG in order to obtain P10, P50 and P90 values for the reservoir properties such as the NTG, porosity and hydrocarbon saturations, which were used as inputs for the volumetric calculations. The methodology adopted for petrophysical analysis was found to be reasonable. This comprises the following computations: Volume of clay (Vcl) from GR logs using the Larionov model, porosity from density log and water saturation using the Simandoux saturation model. However, there is no density or sonic log available in Uquo-1 and Uquo-6 so effective porosity was estimated using a Vcl-porosity relationship derived from the nearby Uquo-5 well. Density and sonic logs were available only down to the top of the D sands in the Uquo-8 well, thus porosity calculations are based on the sonic logs for the C sands and a Vcl-porosity relationship was applied to the deeper reservoirs. In the well intervals in which the Vcl relationship was used in determining the porosity (Uquo-1, Uquo-6 and deeper section of Uquo-8), the Sw estimates are based on the Archie equation.

The two sets of cut-offs used in deriving the net reservoir/pay are considered to be reasonable;

- Clean sands: porosity (0.16) and Vcl (0.45)
- Shaly sand: porosity (0.10) and Vcl (0.5)
- A uniform Sw cut-off of 0.50 has been applied throughout

Fluid contacts have also been determined from the petrophysical data and these have been used in combination with the Direct Hydrocarbon Indicators (DHI's) and structural closures in determining the Minimum, Most Likely and Maximum GRV's. **Figure 3-10** presents results from the Uquo-2 well which are representative of the rock properties of the Uquo Field.

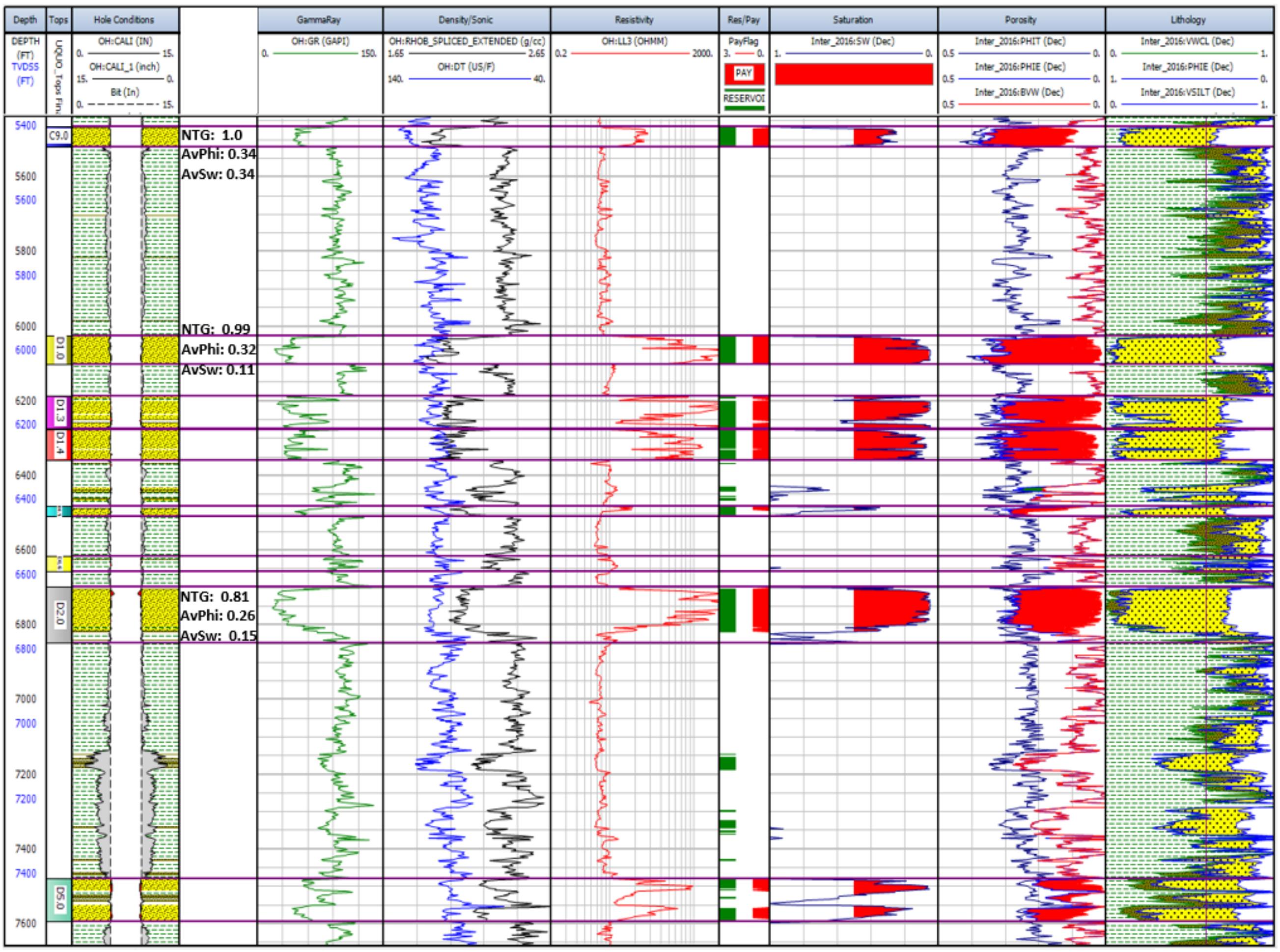


Figure 3-10 Uquo-2 Petrophysical interpretation (Source: Seven, 2019)

3.2.4 Uquo Field In-Place Volumes

The subsurface team at CGG has independently delineated each of the reservoirs/prospects below in Minimum, P50 and Maximum cases using depth surfaces provided by Seven. The horizons interpretations which have been converted to depth surfaces have been extensively QC'd by CGG and were found to be accurate. However, as mentioned in the Subsurface Overview, CGG believe that the accuracy of the volumes would be improved by reprocessing and depth migrating the 3D dataset, and subsequently re-interpreting the Gross Rock Volumes. Formation Volume Factors have also been generated by CGG; rock properties have been derived from Seven's previous work and QC'd by CGG. The inputs have been run as a probabilistic Monte Carlo analysis. A drill stem test (DST) was performed in well Uquo-3 in the gas bearing D1.3/D1.4 reservoirs. The estimated connected gas initially in-place was 21.9 Bscf, which corresponds to the low case in-place volume used.

Tables 3-1 and 3-2 tabulate the current in-place volumes as presented in Lloyd Register's CPR dated December 2017. CGG's independently estimated volumes were within an acceptable margin of error, and for consistency it was agreed with Savannah to remain with the previously quoted values.

Area	Reservoir	Gross GIIP (Bscf)		
		P90	P50	P10
Uquo-2	D1.0	183.2	216.3	254.8
	D1.3/D1.4	74.3	94.9	118.5
	D2.0	108.9	134.1	163.9
	D5.0	17.1	30.1	46.7
*Sub-Total**		*383.5*	*475.4*	*583.9*
Uquo-3	D1.0	107.0	204.0	300.0
	D1.3/D1.4	22.0	34.5	48.6
*Sub-Total**		*129.0*	*238.5*	*348.6*
Uquo NE**	C6.0	80.0	99.8	124.0
Total*		**592.5**	**813.7**	**1056.5**

* Arithmetic sum

** Uquo NE volumes are on-licence only

Table 3-1 Uquo Marginal Field GIIP

Area	Reservoir	Gross GIIP (Bscf)		
		P90	P50	P10
Uquo NE	D1.0	27.3	40.4	55.6
	D1.5	2.8	4.2	6.1
*Sub-Total**		*30.1*	*44.6*	*61.7*
Uquo-5	C8.5	11.0	14.3	18.6
Uquo-2	C9.0	17.3	35.9	65.8
Total*		**58.4**	**94.8**	**146.1**

* Arithmetic sum

Table 3-2 Uquo Marginal Field: GIIP excluded from development plan

In addition to the discovered volumes, CGG has reviewed the in-place numbers for the prospects in the Uquo Marginal Field Licence (**Figure 3-9**). **Table 3-3** tabulates Savannah's current in-place volumes as presented in Lloyd Register's CPR dated December 2017. CGG's independently estimated volumes were within an acceptable margin of error, and for consistency it was agreed with Savannah to remain with the previously quoted values.

Prospect	Unrisked Gross GIIP (Bscf)			CoS (%)
	Low	Best	High	
Uquo 1SE	55.7	84.8	139.9	50
Uquo 2	13.6	25.4	51	73
Uquo 2W	71.3	88.4	103.7	57
Uquo 3E	151.5	221.7	335.7	35
Uquo 3S	114.8	154.3	200.1	66
Uquo 3W	72.5	115.2	204.1	18
Uquo 3 Extension	10.2	15.1	22.6	14
Uquo 3 Attic	13.3	23.4	42.6	17
Uquo 3 Fault Zone	49.0	83.8	93.9	20
Uquo 1N	6.1	14.7	35.2	18
Total*	**558.0**	**826.8**	**1228.8**	

* Arithmetic sum

Table 3-3 Uquo Unrisked Prospective Resources GIIP

The Chance of Success (CoS) numbers reflect the fact that the licence is in a prolific hydrocarbon-producing basin, with hydrocarbons proven in many reservoir intervals. The principal risk in the licence area is the trap, which is amplified in areas of poor imaging. Fault seal is also key to the successful trapping of many of the prospects, which at depth is particularly poorly imaged due to fault shadows. Thus, reprocessing the seismic volume over the Uquo licence and improving the data quality would likely improve the CoS of many of the prospects. Savannah is planning to conduct this re-processing in 2020. In addition, some of the traps have an increased risk associated with them as the closures extend beyond the edge of the seismic dataset. Reservoir and source are known to be low risk in the licence area and this has been reflected in Seven's estimated CoS figures. CGG has reviewed Seven's CoS's and deem them to be reasonable estimates.

3.3 Stubb Creek Field

3.3.1 Stubb Creek Field Summary

The Stubb Creek Marginal Field is located within the area OPL 276, formerly OML 14, onshore Nigeria. The Stubb Creek Field was discovered in 1971 by SPDC, who drilled 3 exploration wells and 1 appraisal well (from 1971-1983). The first well, SC-1 well intersected a 42 m gas column within the C3 sand reservoir, while light oil was later discovered in 1971 with the SC-2 well principally within the D3 reservoir (and gas with an oil rim in the C9 reservoir). Overall, oil and gas have been discovered in 7 different 'C' and 'D' sand reservoirs in the Agbada Formation; where hydrocarbons are present, C sand reservoirs are typically gas-bearing apart from C9 reservoir, with the deeper D sand reservoirs containing oil. Outlines of the field are shown in **Figure 3-11** and **Figure 3-12.**

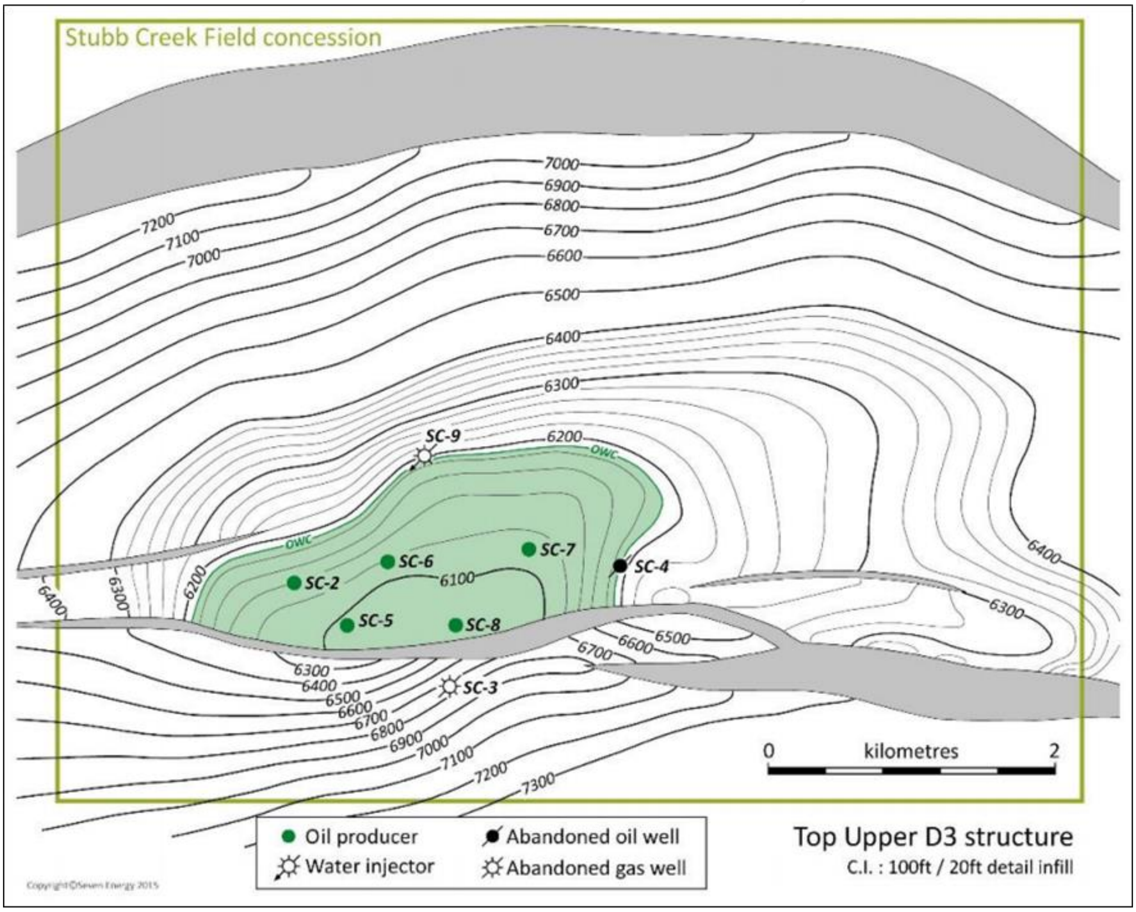


Figure 3-11 Map showing the outline of the Stubb Creek oil field at Upper D3 level (Source: Seven, 2015)

Stubb Creek was classified as a Marginal Field in 2002, with Universal becoming the Operator in 2003. Seven acquired a 62.5% interest in Universal in 2010 and full ownership in 2019, and thereby gained control over the operatorship of the field by virtue of its shareholding and management position. Between 2007 and 2009, Universal drilled 5 oil development wells, with oil production commencing in January 2015.

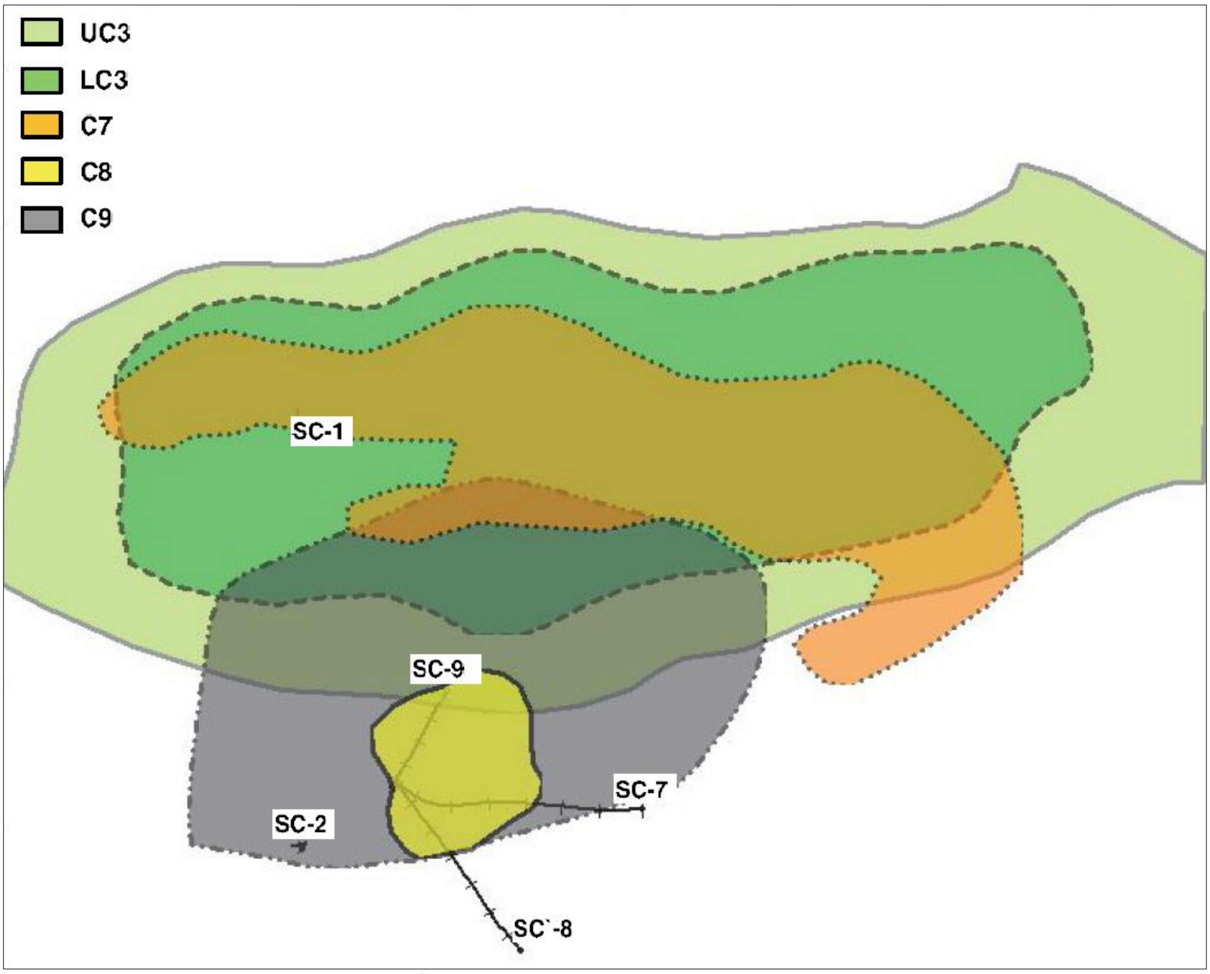


Figure 3-12 Seven Energy outlines of the C Sand gas reservoirs (Source: Seven, 2017)

3.3.2 Stubb Creek Field Subsurface Overview

CGG have carried out an independent analysis of the in-place volumes using a 3D seismic volume acquired in 2005/2006, which covers an area of 65 km^2. The data were supplied as a Kingdom™ project containing wells (with synthetic seismograms), depth grids/horizons and fault interpretations. Composite logs were supplied which contained formation tops as well as fluid contacts which were used to delineate the tops and bases of the reservoirs and hydrocarbon columns. The data quality is generally very good; gas reservoirs are easily distinguished from the background reservoir response - as would be expected in shallow, high quality gas-bearing reservoir sands. The seismic volume is a Pre-Stack Time Migration (PSTM); it is CGG's opinion that the accuracy of the volumetrics shown below would be improved if the volume were to be re-processed to PSDM (Pre-Stack Depth Migration).

In addition to the Kingdom™ project, Seven has provided reports to assist with CGG's G&G analysis; these include Geoscience and Engineering studies for both C & D reservoirs.

The Stubb Creek Field is made up of 7 different hydrocarbon-bearing intervals, all of which are located within a gently-dipping fault block which is downthrown to a major listric fault to the north. The main rollover structure is largely undeformed; however, there is significant E-W trending extensional faulting south of the SC-8 well, creating a series of gravity-driven low angle fault blocks as can be seen in **Figure 3-13**.

The hydrocarbon accumulations occur in a variety of different styles over a relatively small area; the hydrocarbons within the C3 reservoirs are trapped within the crest of the broad rollover anticline, whereas the C7 accumulation appears to be largely stratigraphic in nature. Many of the deeper reservoirs are footwall sands trapped against an extensional fault to the south, with additional structural relief created by the rollover anticline**.**

The C and D sand reservoirs of the Agbada Formation are generally of very high quality; NTG is generally in excess of 90% with porosities of 30% or higher. The C7 reservoir is anomalously poor quality, although the volumes here are relatively insignificant compared to the C3 and C9 GIIP numbers (note that the C3 accumulation appears to extend beyond the limits of the 3D seismic volume and thus may contain some upside volumes not included here). The majority of the reservoirs in the survey are easily picked out on seismic, with flat spots and amplitude anomalies clearly delineating the extent of the gas accumulations (c.f. RMS amplitude map in **Figure 3-14**). In addition to this, Seven provided Relative Acoustic Impedance (**Figure 3-15)** and Average Energy attributes which shows strong agreement with the amplitude data to support Seven’s interpretations.

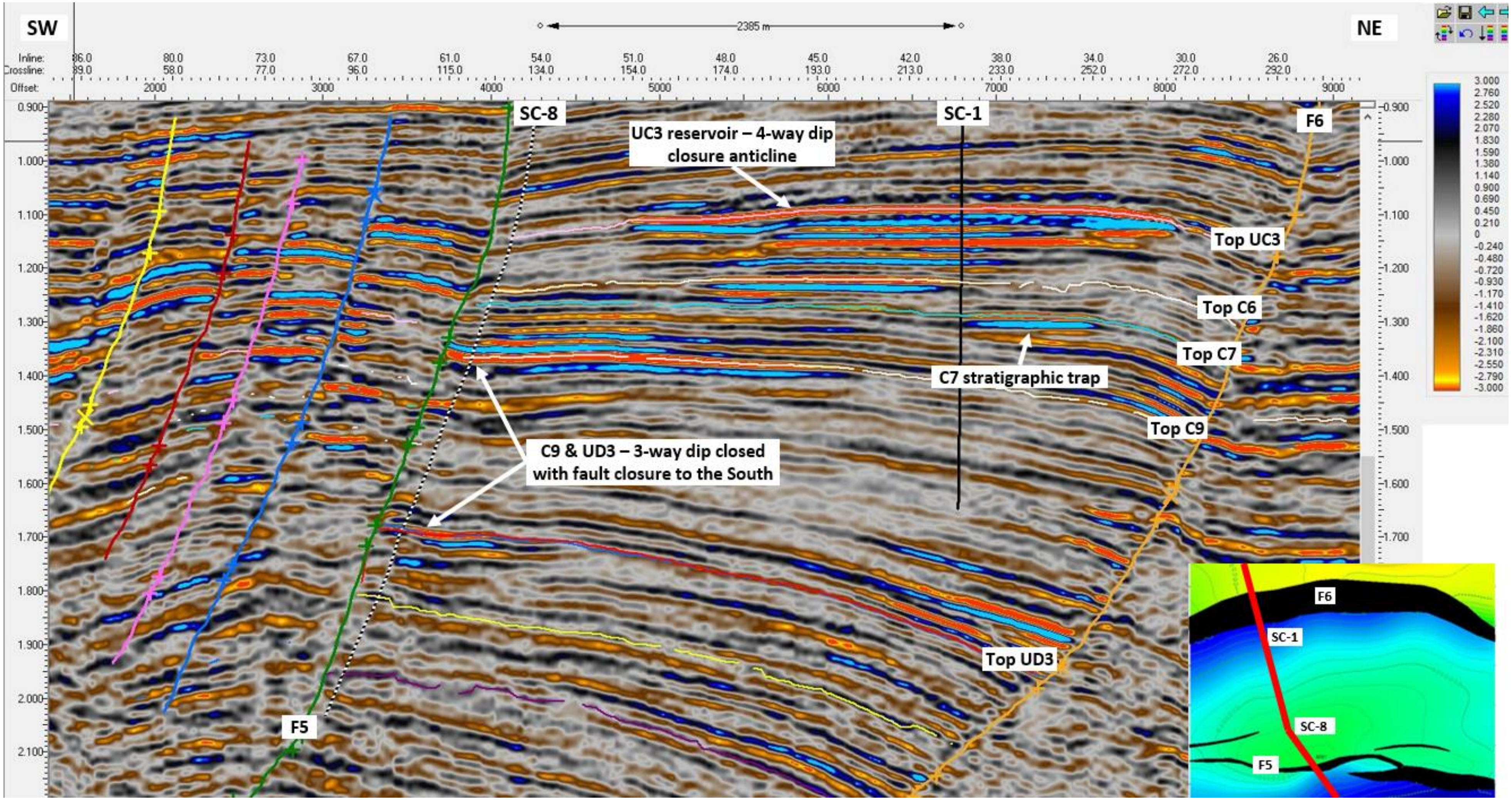


Figure 3-13 SW-NE line through Stubb Creek (Source: Seven, 2019)

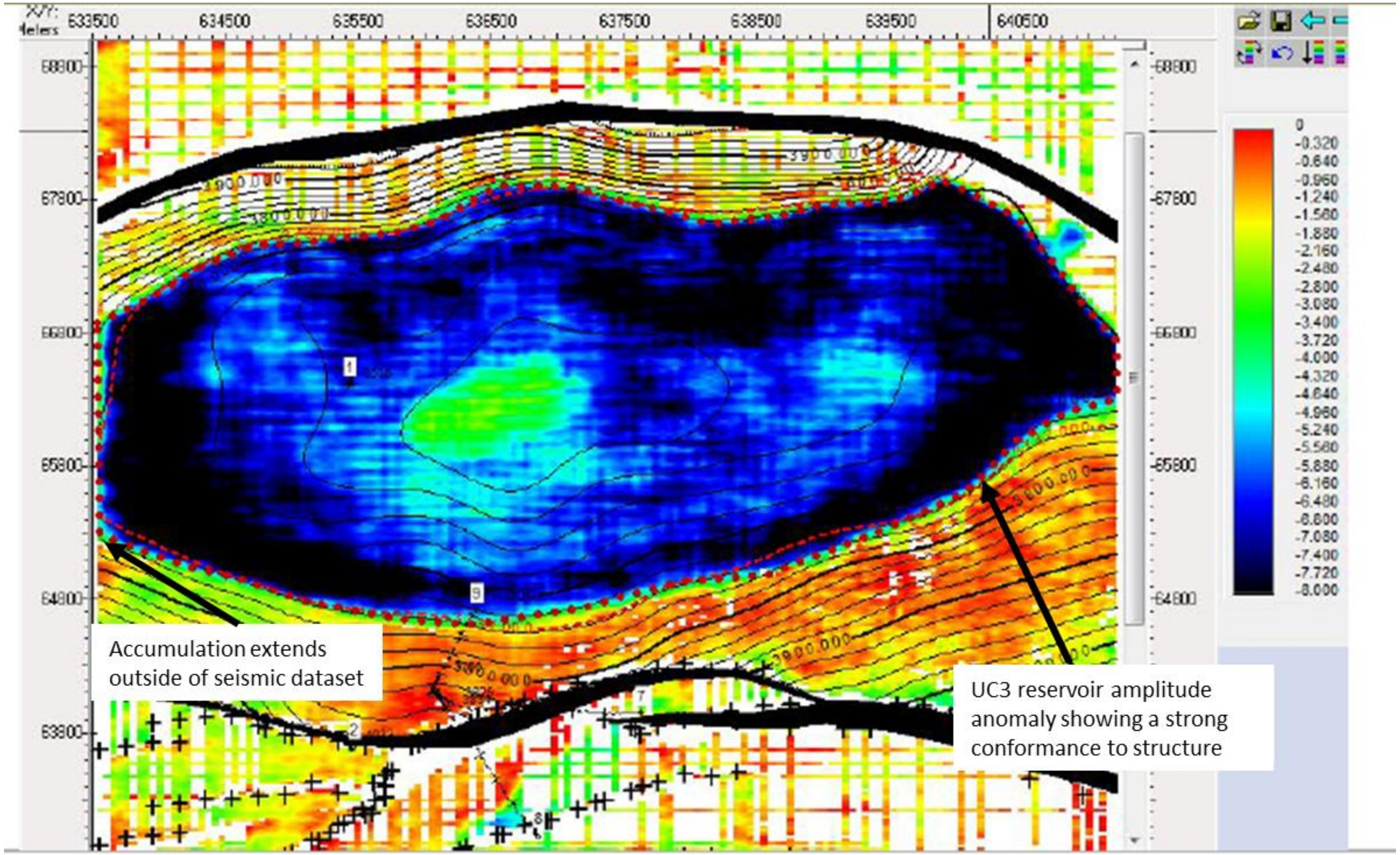


Figure 3-14 Minimum amplitude map (+/-8ms) of the UC3 reservoir (Source: Seven, 2014)

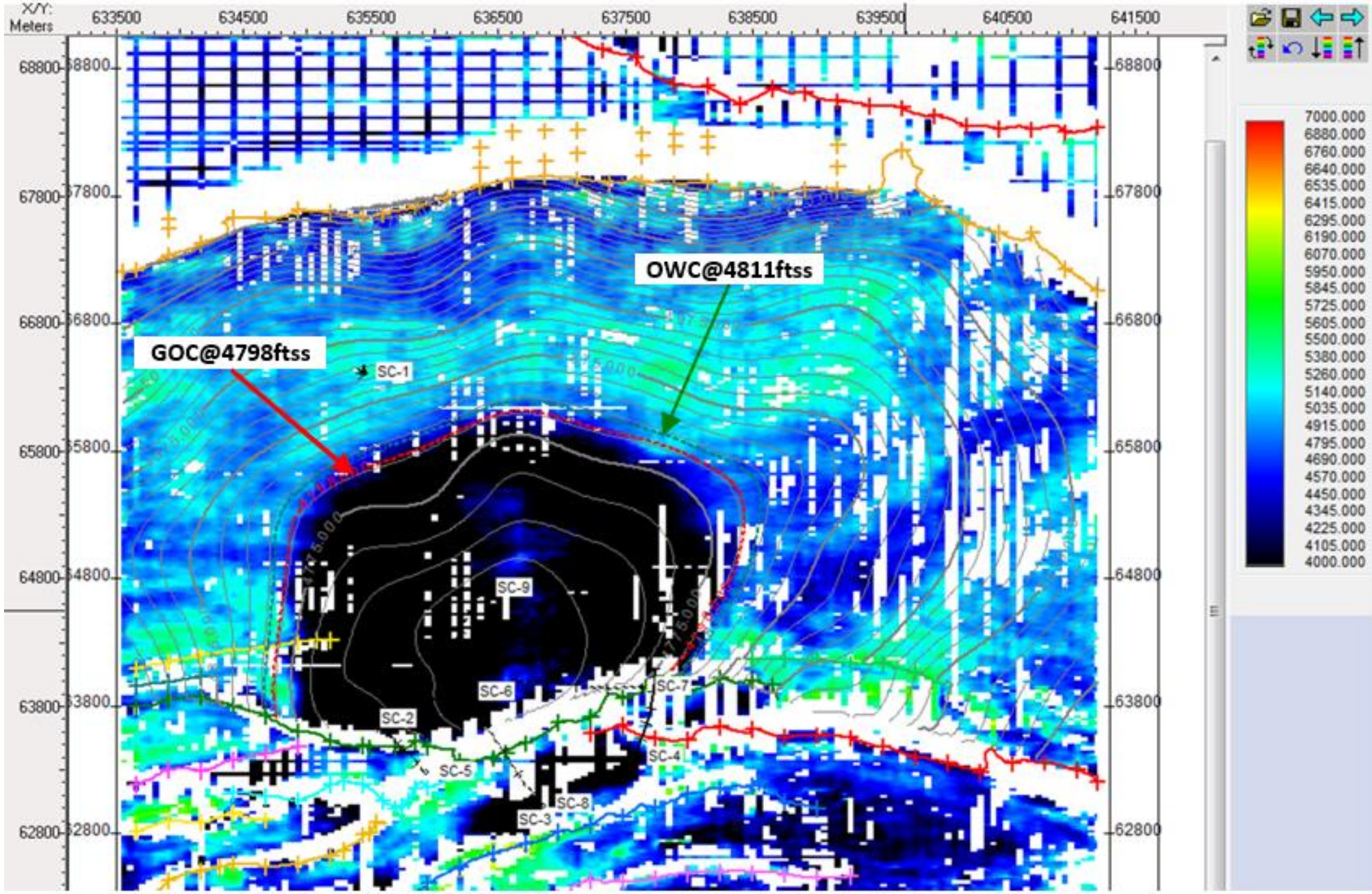


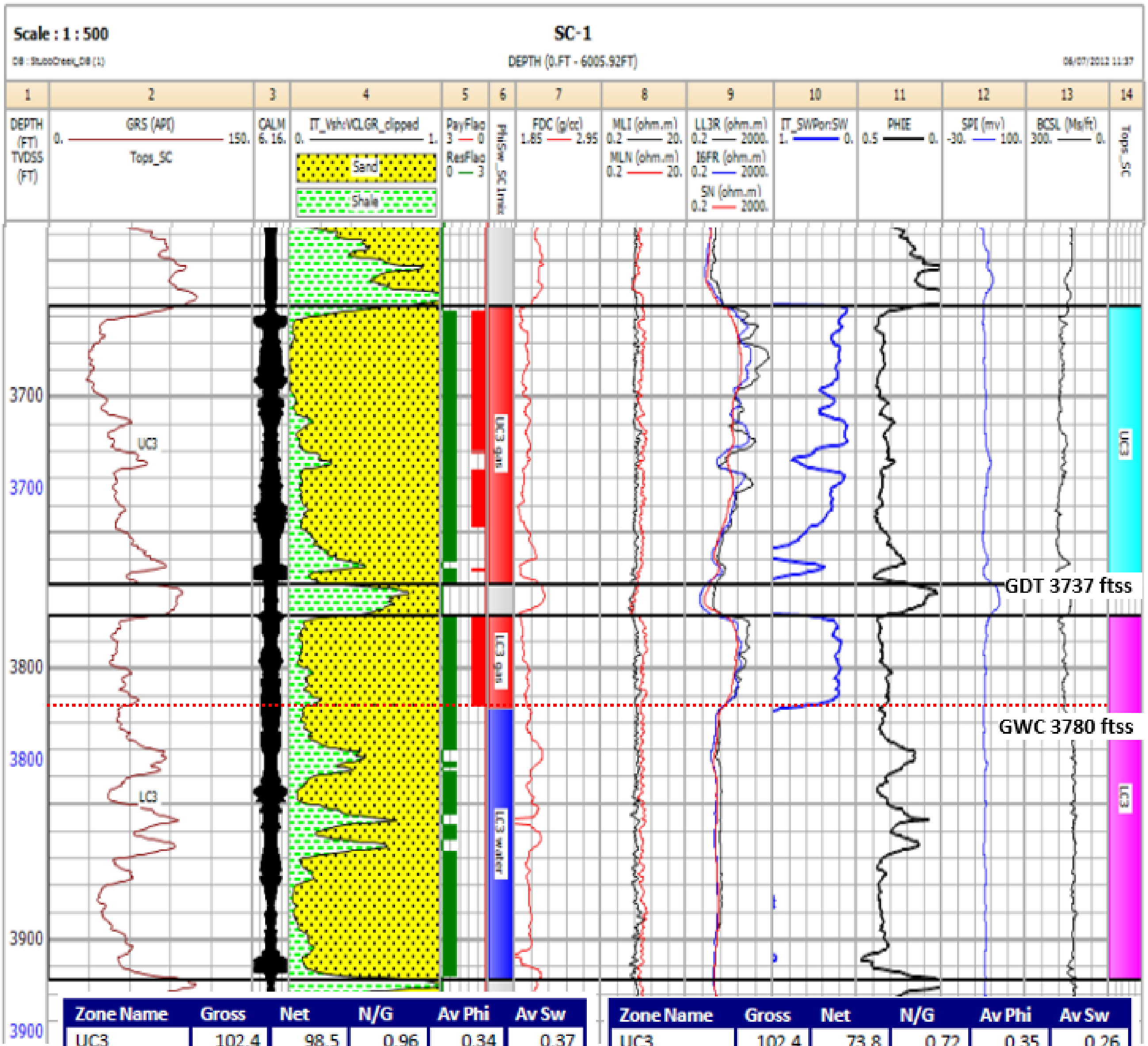
Figure 3-15 C9 Minimum Relative Acoustic Impedance map (Top+8ms) - (Source: Seven, 2014)

The oil in the Upper D3 reservoir is light and good quality; API values are c. 42° with a GOR of 751 scf/bbl. The composition of the non-associated gas in the C sand reservoirs is unknown.

The subsurface team at CGG has completed a thorough Geological and Geophysical QC of the reports supplied by Seven, and using the Kingdom™ project provided have independently generated P90, P50 and P10 volumes for each reservoir. This work has been supplemented by Reservoir Engineering and Petrophysics experts who have also provided inputs for the volumetrics calculations, which were run through a probabilistic Monte Carlo analysis.

3.3.3 Stubb Creek Field Petrophysics

CGG have evaluated the petrophysical data provided for the C and D sands in order to obtain P10, P50 and P90 values for the reservoir properties such as NTG (Net-To-Gross), porosity and hydrocarbon saturations. These were used as inputs for the volumetric calculations. The Volume of Clay (Vcl) was derived using a GR method (Larionov model); porosity was estimated based on the density log or sonic (SC-2 has no density log); while the Simandoux method was used to derive water saturation (Sw). The porosity cut-off of 0.1 and Vcl cut-off of 0.4 used to derive net reservoir intervals are considered to be reasonable. Fluid contacts have been determined from the petrophysical data and these have been used in combination with the DHI's and structural closures in determining the Minimum, P50 and Maximum GRV's. **Figure 3-16** and **Figure 3-17** present results from the petrophysical interpretation for the main gas (C3) and oil (UD3) reservoirs.



Zone Name	Gross	Net	N/G	Av Phi	Av Sw
UC3	102.4	98.5	0.96	0.34	0.37
LC3	134.0	119.0	0.89	0.33	0.78

SC-1 Net reservoir average properties (PHIE>0.1 & Vcl<0.4)

Zone Name	Gross	Net	N/G	Av Phi	Av Sw
UC3	102.4	73.8	0.72	0.35	0.26
LC3	134.0	32.8	0.25	0.34	0.24

SC-1 Net Pay reservoir average properties (PHIE>0.1, Vcl<0.4 & Sw<0.5)

Figure 3-16 SC-1 C3 Gas Reservoir Petrophysical interpretation (Source: Seven, 2018)

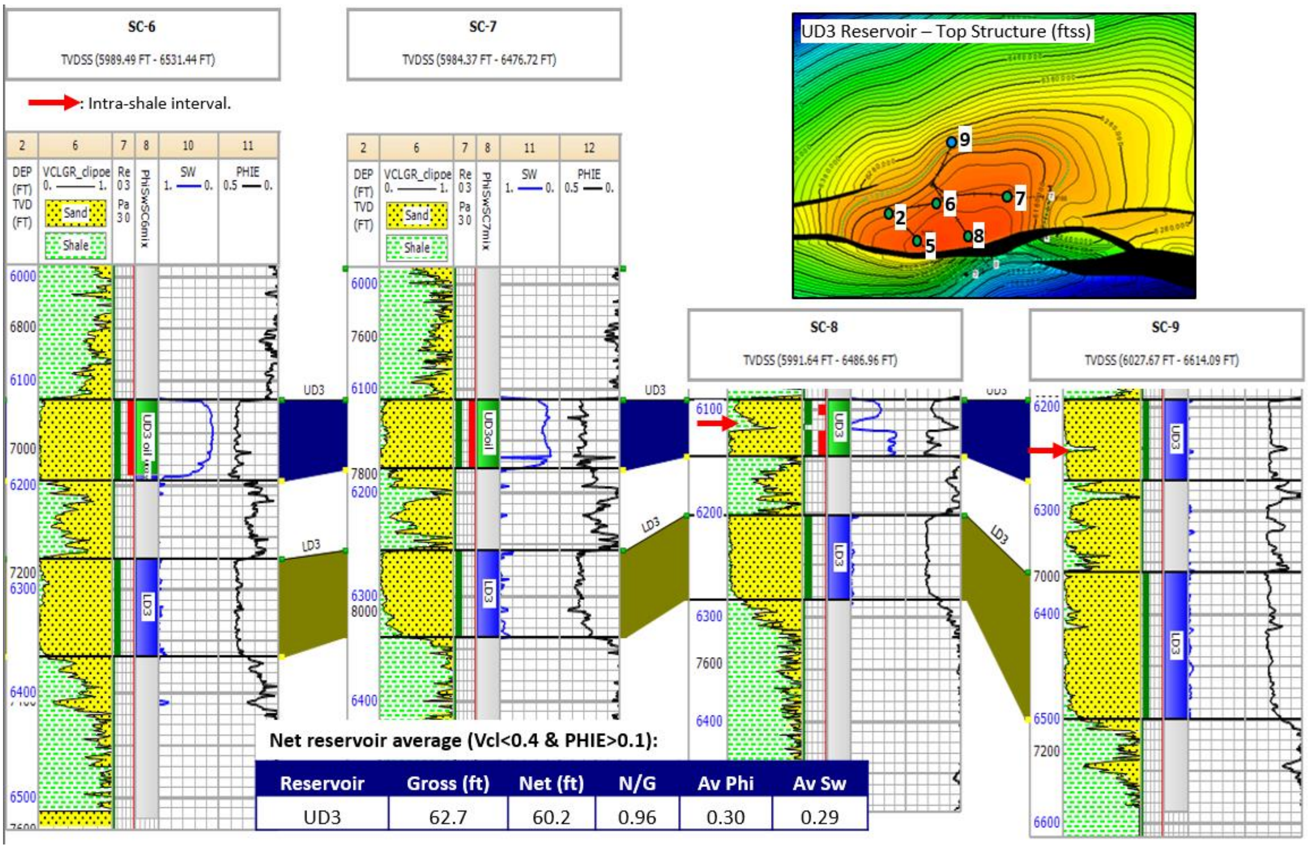


Figure 3-17 Upper D3 Oil Reservoir Petrophysical interpretation (Source: Seven, 2018)

3.3.4 Stubb Creek Field In-Place Volumes

The subsurface team at CGG has independently delineated each of the reservoirs/prospects below in Minimum, P50 and Maximum cases using depth surfaces provided by Seven. The horizons interpretations which have been converted to depth surfaces have been extensively QC'd by CGG and were found to be accurate. However, as previously mentioned, CGG believe that the accuracy of the volumes would be improved by depth migrating the 3D dataset, and subsequently re-interpreting the Gross Rock Volumes of each of the accumulations/prospects. Formation Volume Factors have also been generated by CGG; rock properties have been derived from Seven''s previous work and QC'd by CGG Petrophysics expert. The inputs have been run as a probabilistic Monte Carlo analysis.

Tables 3-4 and 3-5 tabulate in-place volumes as presented in Lloyd Register's CPR dated December 2017. CGG's independently estimated volumes were within an acceptable margin of error, and for consistency it was agreed with Savannah to remain with the previously quoted values.

Reservoir	Gross GIIP (Bscf)		
	P90	**P50**	**P10**
UC3	318.5	421.0	481.0
LC3	34.0	45.5	59.3
C6 (prospect)	13.8	19.8	27.8
C7	16.1	39.4	88.1
C8	2.6	3.9	5.6
C9	113.8	150.3	191.5
Total*	**482.4**	**656.2**	**819.9**

* Arithmetic sum, Total excludes C6 (Prospect) and C8 (too small)

Table 3-4 Stubb Creek Marginal Field GIIP

Reservoir	Gross STOIIP (MMstb)		
	P90	**P50**	**P10**
UD3	29.9	38.9	49.6
C9*	22.4	32.6	42.5
Total**	**52.3**	**71.5**	**92.1**

*C9 oil volumes not included in reserves/resources due to difficulty in producing the thin oil rim.

** Arithmetic sum

Table 3-5 Stubb Creek Marginal Field STOIIP

4 RESERVOIR ENGINEERING

The objective of this section is to provide an independent assessment of the Reservoir Engineering work performed by Savannah. The following sections summarise the analysis.

4.1 Uquo Marginal Field

4.1.1 Overview

Nine wells have been drilled on the Uquo Field to date, including:

- Four vertical wells: Uquo-1,-2,-3 and -5
- Four deviated wells: Uquo-4,-7,-8 and -9
- One sidetrack of Uquo-5 named Uquo-6
- One sidetrack of Uquo-8 named Uquo-8ST
- One side-track of Uquo-9 named Uquo-9ST

Four wells are currently producing gas and one is a marginal oil producer. The following is a brief summary of the producing wells:

- Uquo-2 is producing gas from the D2.0 reservoir in the Uquo-2 area.
- Uquo-4 is producing gas from the D1.0 reservoir in the Uquo-2 area.
- Uquo-7 and Uquo-8ST are producing gas from the D1.0 reservoir in the Uquo-3 area.
- Uquo-3 is producing oil at marginal rate from the D5.0 reservoir in the Uquo-3 area. There is an opportunity to workover this well and convert it to a gas producer in the D1.3/D1.4 reservoirs.

Savannah plans to drill up to four new wells and performs one recompletion to further develop the field Reserves. Gas from D1.0, D1.3/D1.4 and D2.0 is relatively dry (approx. 97% Methane).

Uquo has been producing gas since Q1 2014. Historical gas production is shown in **Figure 4-1**. Total Daily Contracted Quantity (DCQ) under the three Gas Sales Agreements (GSA) in place is 189.4 MMscfd, and the GSAs have Take or Pay (ToP) provisions within them (set at 80% of DCQ).

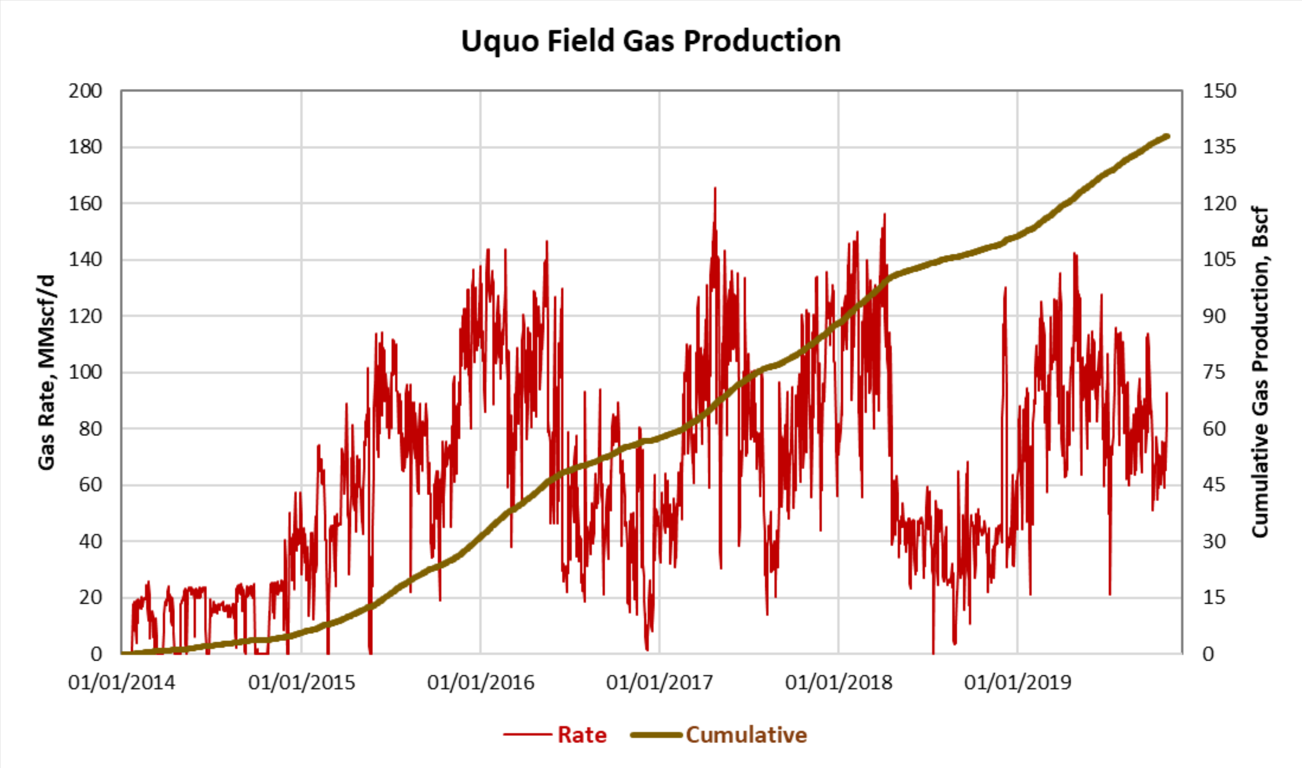


Figure 4-1 Uquo historical gas production as at 1st November 2019

4.1.2 Recoverable volumes

Material balance was used by CGG to verify the Uquo gas in-place volumes, which were estimated by the G&G volumetric method. The estimated total GIIP from material balance for the D1.0 reservoir is 431.5 Bscf. This is in reasonable agreement with the GIIP estimated using the volumetric method presented in **Table 3.1**.

Seven has performed a reservoir simulation study for the Uquo Field. The gas recovery factors estimated by the study were between 75% to 90%. **Table 4.1** shows the range of recovery factors adopted for the Uquo Field. These are based on a high permeability gas reservoir with depletion drive and assuming compression, and are deemed to be reasonable by CGG.

Case	Low	Best	High
Recovery Factor (%)	75.3	79.5	82.3

Table 4-1 Summary of Uquo Field gas recovery factors

Table 4.3 shows a summary of the Gross Technical Reserves calculation. The cumulative production as of 31st October, 2019 is 138.0 Bscf gas and 0.190 MMstb of condensate. Four new gas wells and one recompletion are planned in this field. Economic Reserves net to Savannah derived from the economic model are presented in the Executive Summary.

Area	Reservoir	Well(s)	Comment
Uquo-2	C9.0	-	Contingent Category, not in the development plan
	D1.0	Uquo-4, New Well 1	Producing, new well is planned for 2020
	D1.3/D1.4	WO or New Well 2	Possible recompletion of the new well from D5.0 reservoir
	D2.0	Uquo-2	Producing
	D5.0	New Well 3	
Uquo-3	D1.0	Uquo-7 & Uquo-8ST	Producing
	D1.3/D1.4	WO or New Well 4	Recompletion of well Uquo-3
Uquo NE	C6.0	New Well 5	
	D1.0, D1.5	-	Contingent Category, not in the development plan
Uquo-5	C8.5	-	Contingent Category, not in the development plan

Table 4-2 Summary of Uquo field Gas reservoirs and producing/planned wells

Area	Reservoir	Low	Best	High
Uquo-2	D1.0	183.2	216.3	254.8
	D1.3/D1.4	74.3	94.9	118.5
	D2.0	108.9	134.1	163.9
	D5.0	17.1	30.1	46.7
Uquo-3	D1.0	107.0	204.0	300.0
	D1.3/1.4	22.0	34.5	48.6
Uquo NE	C6.0*	80.0	99.8	124.0
GIIP (Bscf)	**Total****	**592.5**	**813.7**	**1,056.5**
Recovery Factor (%)		75.3	79.5	82.3
EUR (Bscf)		446.5	647.0	870.1
Cum. Prod. (as of 31st Oct. 2019) (Bscf)		138.0	138.0	138.0
Gas Reserves Total (Bscf)		**308.5**	**509.0**	**732.1**
Condensate Reserves Total (MMstb)		0.42	0.69	0.99

* Uquo NE volumes are on-licence only

** Arithmetic sum

Table 4-3 Summary of Uquo Gross Technical Reserves as at 1st November 2019

Figure 4-2 shows 1P, 2P and 3P gas production profiles for Uquo Field based on remaining Low, Best and High case technical reserves respectively as shown in **Table 4-3**. A downtime factor of 7%, equivalent to 25 days per year, is assumed for maintenance and incorporated into the forecasted profiles.

Annual production rates for the Uquo Field are tabulated in **Appendix A.**

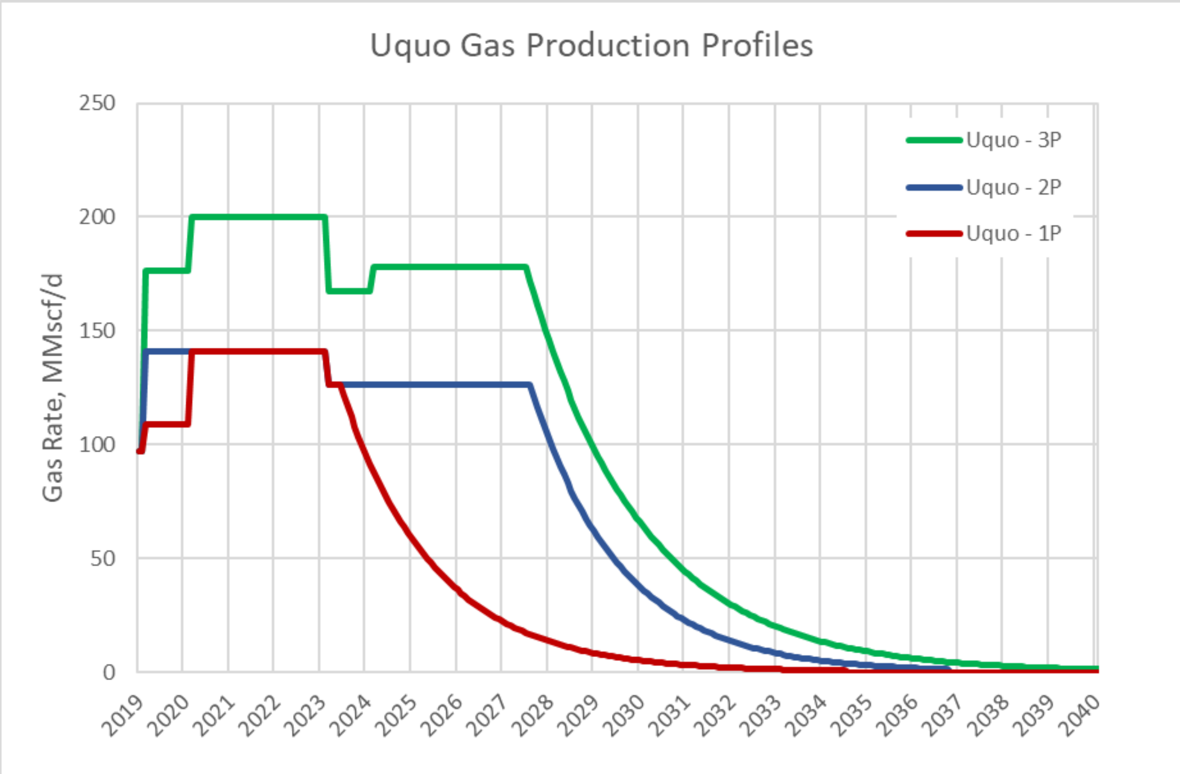


Figure 4-2 Uquo field production forecast profiles (Reserves cases)

Table 4-4 shows a summary of the Gross Contingent Resources. The Contingent Resources are estimated by Material Balance calculation and presented in **Table 3-2**. CGG deem the resulting recovery factors to be reasonable for the expected drive mechanism and fluid properties

Area	Reservoir	Contingent Resources		
		Low/1C	Best/2C	High/3C
Uquo NE	D1.0	27.3	40.4	55.6
	D1.5	2.8	4.2	6.1
Uquo-5	C8.5	11.0	14.3	18.6
Uquo-2	C9.0	17.3	35.9	65.8
Total GIIP (Bscf)		**58.4**	**94.8**	**146.1**
Recovery Factor (%)		77.0	76.4	79.1
Contingent Resources (Bscf)		**45.0**	**72.5**	**115.6**

Table 4-4 Summary of Uquo Gross Contingent Resources

Table 4-5 shows a summary of the Unrisked Gross Prospective Resources in the Uquo Field Licence. The Prospective Resources are estimated by multiplying the recovery factors by the in-place volumes described **Table 3-3**. Recovery factors ranging from 65% to 75% were used.

Prospective Resources	Low/1U	Best/2U	High/3U
GIIP (Bscf)	**558.0**	**826.8**	**1,228.8**
Recovery Factor (%)	65	70	75
Gas Resources (Bscf)	**362.7**	**578.8**	**921.6**

Table 4-5 Summary of Uquo Gross Unrisked Gross Prospective Resources

4.2 Stubb Creek Marginal Field

4.2.1 Overview

Stubb Creek field is producing from three oil wells, the three wells which are on production are: SC-6, SC-7 and SC-8 SS (Short String). Historical oil production since start-up is shown in **Figure 4-3**. Maximum production recorded is 3,491 bopd (gross at separator level) with three wells on-stream. Average production from each well is c. 1,000 bopd.

The processing capacity is capped at 3,000 bopd and it is planned to carry out some debottlenecking in order to increase the production capacity to 5,000 bopd. The upgrade will enable two more wells, namely SC-2 and SC-5, to be put on-stream. These two wells (SC-2 and SC-5) are already drilled and completed in the Upper D3 reservoir.

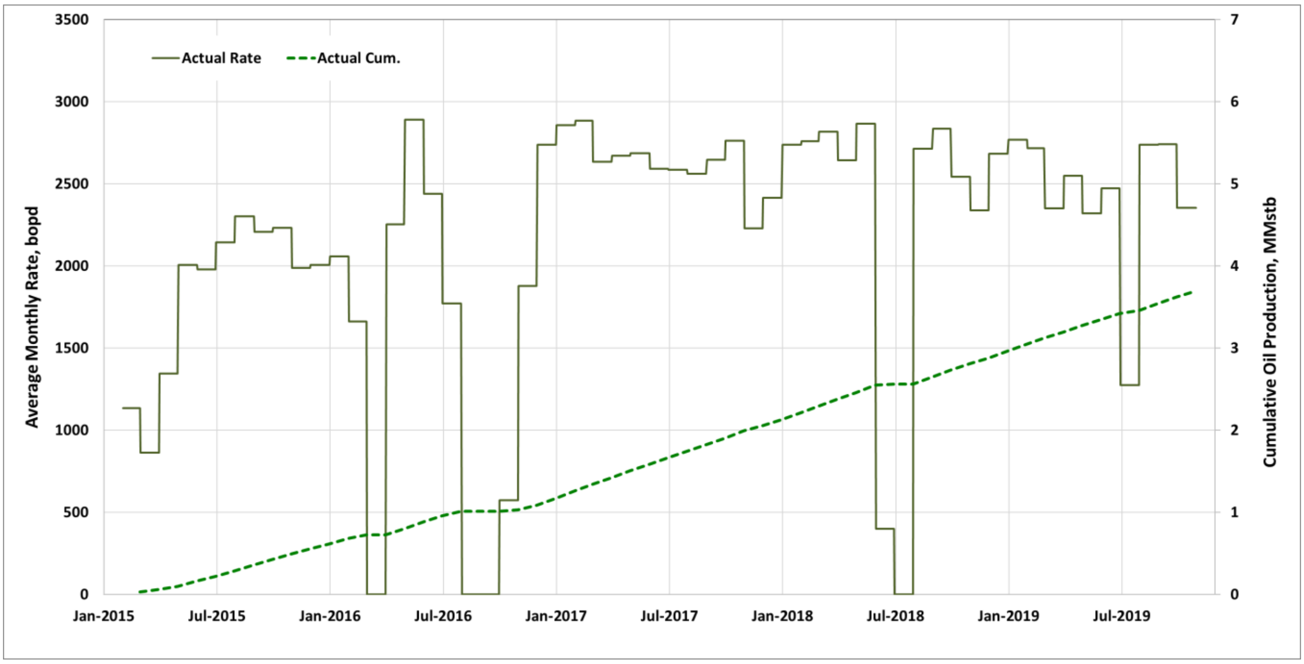


Figure 4-3 Stubb Creek field historical oil production as at 1st November 2019

4.2.2 Drive mechanism

Initial reservoir pressure for the Upper D3 reservoir was 2,719.8 psia at datum depth of 6,189.2 ftss. A static pressure survey has been carried out in December 2015, June 2016 and June 2017. The table below shows the summary of the pressure data at datum depth of 6,189.2 ftss.

Date	Pressure, psia
31/01/2015	2,719.8
31/12/2015	2,712.5
30/06/2016	2,708.8
30/06/2017	2,705.0

Table 4-6 Summary of Stubb Creek Pressure data

The drive mechanism for the UD3 reservoir is strong aquifer drive, which is confirmed by bottom hole pressure surveys on the available wells and the Campbell plot shown in **Figure 4-4**.

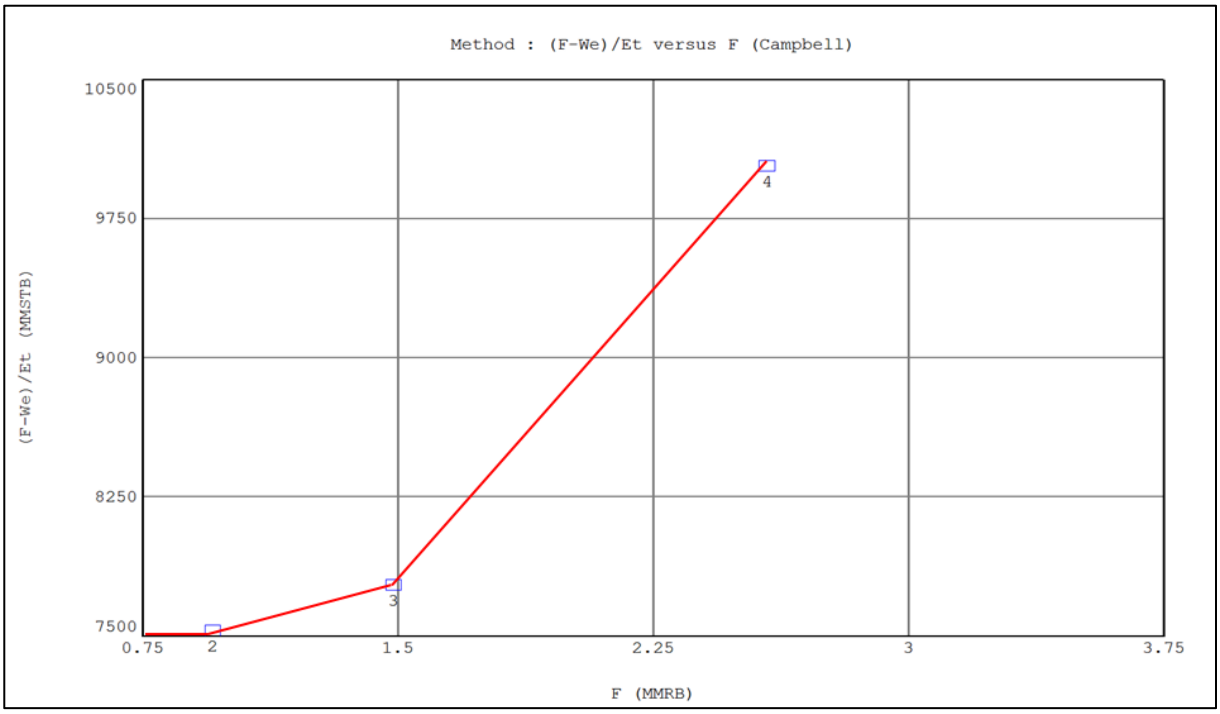


Figure 4-4 Campbell Plot to identify UD3 drive mechanism

Pressure transient analysis performed by Schlumberger for well SC-5, DST-2, test interval: 6,652-6,680 ftMD indicated permeability of 1,420 mD. Another Schlumberger well test report was reviewed for the test interval: 6,693 – 6,738 ftMD at SC-5 well and indicated permeability of 4,900 mD.

Due to high reservoir permeability and strong water drive mechanism the anticipated recovery factors are as shown in **Table 4-7**. CGG deem these recovery factors to be in agreement with regional analogue fields[1].

Case	Low	Best	High
Recovery Factor (%)	40.0	50.0	58.0

Table 4-7 Summary of Stubb Creek field oil recovery factors

The cumulative production as of 31st October, 2019 is 3.70 MMstb of oil.

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[1] SPE 119722 Developing marginal fields in Niger Delta, Uwaga et. Al., Shell Nigeria

4.2.3 Recoverable volumes

Material balance was used to determine the Low, Best and High in-place volumes for the UD3 reservoir. The estimated STOIIP using the material balance method was found to be in a reasonable agreement with the G&G volumetric estimated STOIIP. Therefore, CGG has utilised the G&G volumetrics to estimate the Gross Oil Technical Reserves presented in **Table 4-9**. Economic entitlement Reserves net to Savannah derived from the economic model are presented in the Executive Summary.

	Low	**Best**	**High**
STOIIP (MMstb)	**29.9**	**38.9**	**49.6**
Recovery Factor (%)	40	50	58
EUR (MMstb)	12.0	19.5	28.8
Cumulative Production (as of 31st Oct. 2019)	3.7	3.7	3.7
Reserves (MMstb)	**8.3**	**15.8**	**25.1**
GOR (scf/stb)	751		
Solution gas (Bscf)	6.2	11.8	18.8

Table 4-8 Summary of Stubb Creek Field Gross Technical Reserves as at 1st November 2019

Figure 4-5 shows the forecast production profiles for the Stubb Creek Field. The well performance of the producing wells is used to generate production profiles with different plateau rates in each case. It is assumed that the debottlenecking of the production facility will take place in 2021 and the production will increase to 5,000 bopd (Proved +Probable case) by July 2021.

Since production inception, there was minimal downtime due to production facility maintenance or wells' deliverability. However, a downtime factor of 7%, equivalent to 25 days per year, is assumed for maintenance and incorporated into the forecasted profiles.

It is also assumed that after the debottlenecking of the production facility, a pre-downtime rate value of 4,500, 5,000, and 5,500 bopd of processing capacity will be achieved for the 1P, 2P, and 3P scenarios, respectively. This rate will be achieved by opening all the available wells namely SC-2, SC-5, SC-6, SC-7 and SC-8SS.

It should be noted that 12ft of oil exists in the C9.0 reservoir, however due to the limited thickness of the oil leg CGG believes recovery would be challenging. Therefore, no oil Reserves or Resources have been attributed for the C9.0 reservoir.

Annual production rates for the Stubb Creek Field are tabulated in **Appendix A**.

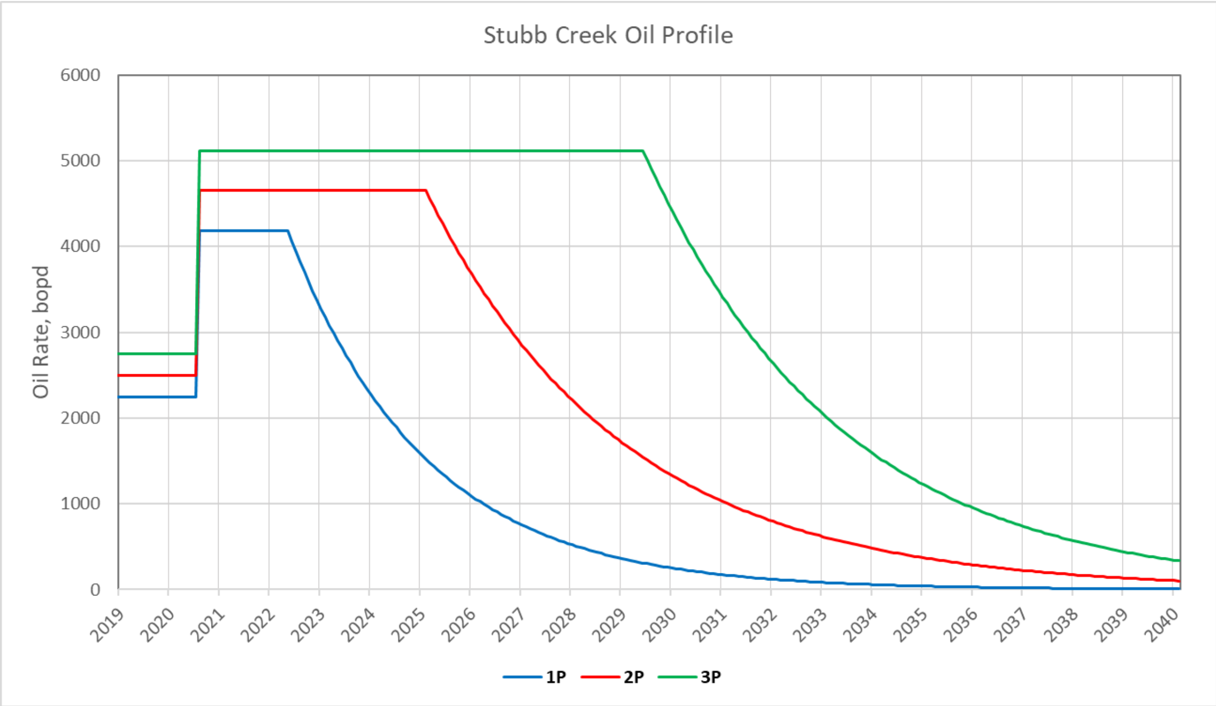

Figure 4-5 Stubb Creek production forecast profiles

A summary of the Gross Gas Contingent Resources is shown in Table 4-9. The Contingent Gas Resources are calculated by multiplying in-place volumes estimated in Table 3.4 by a range of recovery factors based on simulation studies and analogue fields.

Contingent Resources	Low/1C	Best/2C	High/3C
GIIP (Bscf)	**482.4**	**656.2**	**819.9**
Recovery Factor (%)	76	78.5	83
Gas Resources (Bscf)	**364.9**	**515.3**	**680.3**

Table 4-9 Summary of Stubb Creek Field Gross Contingent Resources

A summary of Unrisked Gas Prospective Resources is shown below in **Table 4-10**. The Prospective Resources are calculated by multiplying in-place volumes estimated in **Table 3-4** by a range of recovery factors based on analogue fields.

Prospective Resources	Low/1U	Best/2U	High/3U
GIIP (Bscf)	**13.8**	**19.8**	**27.8**
Recovery Factor (%)	65	70	75
Gas Resources (Bscf)	**9.0**	**13.9**	**20.9**

Table 4-10 Summary of Stubb Creek Field Gross Unrisked Prospective Resources

Figure 4-6 shows Reserves and Contingent Resources profiles for the Uquo and Stubb Creek fields.

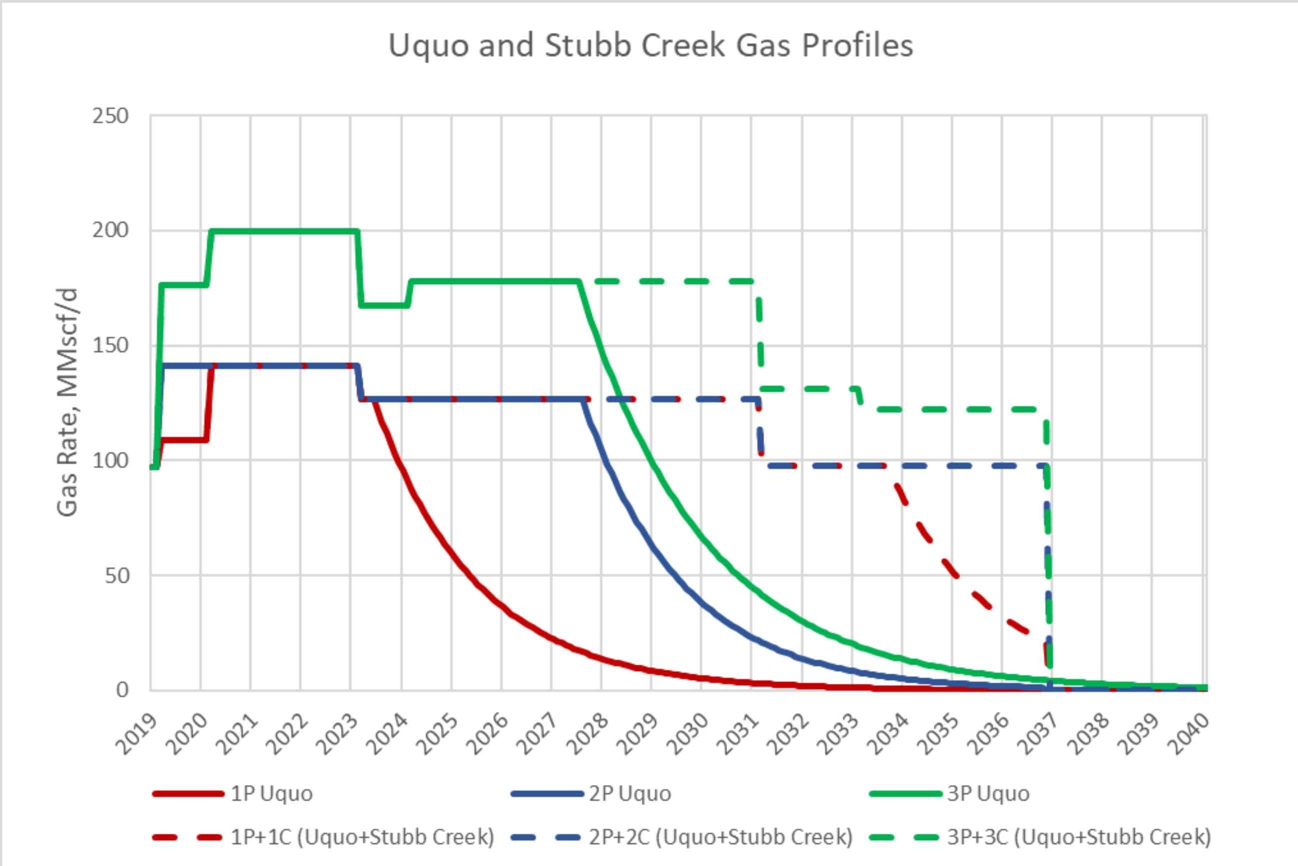

Figure 4-6 Uquo and Stubb creek Fields production forecast profiles (Reserves and Contingent Resources cases)

Annual production rates for all cases are tabulated in **Appendix A**.

5 FACILITES AND COSTS

This section presents details of the existing facilities and future development plans for the Uquo, Stubb Creek Fields, and Accugas Midstream Business. All costs are presented in 2019 terms.

5.1 Uquo Field

5.1.1 Existing facilities

Dedicated in-field flowlines transport produced gas individually from the producing wells owned by SUGL to a Central Processing Facility (CPF) owned by Accugas. The gas from the Uquo Field is relatively dry (approximately 97% methane).

5.1.2 Development plans

The proposed development plan for Uquo consists of drilling four additional gas wells, and the recompletion of one well (Uquo-3). An existing well will also be subject to a work-over.

Table 5.1 presents the work plan assumed for the 1P, 2P and 3P Reserves cases. All Reserves cases assume the same work elements but with different timings.

Year	1P	2P	3P	1C	2C	3C
2020	1 gas well and 1 recompletion	1 gas well and 1 recompletion	1 gas well and 1 recompletion			
2021	1 gas well	1 gas well	1 gas well			
2022	2 gas wells	1 gas well	1 gas well			
2023		1 gas well	1 gas well			
2024				2 gas wells		
2025						
2026						
2027						
2028					1 gas well	1 gas well
2029					1 gas well	1 gas well

Table 5-1 Uquo – Reserves and Contingent Resources Well Schedules

The estimated cost of each gas well is $18MM, comprising $15MM for the well itself and $3MM for the flowlines. The recompletion of Uquo-3 is estimated to be $7.2MM. The total cost is estimated to be approximately $80MM for each Reserves case.

An additional two wells costing $18MM each are assumed for the Contingent Resources cases.

These cost estimates have been reviewed by CGG, and are deemed to be reasonable.

5.1.3 Operating costs

Operating costs for Uquo Field are assessed to be $6.5MM per year, with an additional $8.5MM in 2020 for the Uquo-7 workover.

5.1.4 Decommissioning costs

Decommissioning costs for the Reserves cases are estimated to be $20MM (2019 terms) for plugging and abandoning the wells, and removing the flowlines.

5.2 Stubb Creek Field

5.2.1 Existing facilities

Dedicated in-field flowlines from each well transport production to a 3,000 bopd Early Production Facility (EPF). From the EPF crude is transported via a 23 km 6 inch pipeline to the FUN manifold, and then to the Qua Iboe Terminal. A 31 km 6 inch pipeline has also been constructed to transport produced associated gas to the Uquo CPF, which is now operational and preventing flaring.

5.2.2 Development plans

The proposed Oil development plan for Stubb Creek consists of:

- De-bottlenecking the existing production facility, to increase gross capacity from 3,000 to 5,000 bopd (2021)
- Bringing on stream the two wells already drilled (2021)
- Drilling a water disposal well (2021)

The latter may be needed, based on evidence of strong aquifer support, although there is no water production at the current time.

Total capex for the above development plan is estimated to be $28MM comprising $15MM for the water well and $13MM for the production facility upgrade and water handling facilities.

For the Contingent Resources gas cases, six new wells are assumed, with an estimated total cost of $108MM.

Year	1C	2C	3C
2025	1 gas well		
2026			
2027	1 gas well		
2028	2 gas wells		
2029	1 gas well		
2030	1 gas well	1 gas well	1 gas well
2031			
2032		1 gas well	
2033			1 gas well
2034		1 gas well	
2035			1 gas well
2036		1 gas well	

Table 5-2 Stubb Creek - Contingent Gas Resources Wells Schedule

These cost estimates have been reviewed by CGG, and are deemed to be reasonable.

5.2.3 Operating costs

Operating costs for the oil operations are $6.5MM per year, and an additional $2MM per year for the Contingent Resources gas case. There is also a crude handling charge of $1.37/bbl for use of the Qua Iboe Terminal.

5.2.4 Decommissioning

Decommissioning costs for the Reserves case are estimated to be $6MM (2019 terms) for plugging and abandoning the wells, and removing the flowlines and production facility.

5.3 Accugas

Accugas owns and operates the midstream gas facilities associated with the Uquo and Stubb Creek Fields. The principal assets comprise the Uquo CPF and the export pipelines.

The Uquo CPF, which is owned and operated by Accugas, consists of two process trains; each with a nameplate capacity of 100 MMscfd. The CPF provides the following services:

- hydrocarbon and water dew-point control,
- condensate stabilisation,
- crude processing,
- power generation

Gas from the CPF is currently exported through the following pipelines owned and operated by Accugas:

- a 62 km 18 inch pipeline via the Ikot Abasi Gas Receiving Facility to the Ibom power station
- a 63 km 24 inch pipeline via the Oron Tie-in to the Calabar Junction and then to the Calabar power station and the Unicem plant

Condensate is exported from the CPF via an 8 km 4 inch oil pipeline to the FUN manifold and then via a 2 km 10 inch oil pipeline to the Exxon Mobil operated Qua Iboe Terminal. Accugas also owns the 128 km East Horizon gas pipeline, which was originally constructed as the main export pipeline to Calabar. The FUN manifold is owned by a JV of the Uquo, Stubb Creek and Qua Iboe Marginal Field Operators.

Locations and details of the CPF and the pipelines are provided in **Figure 5-1**.

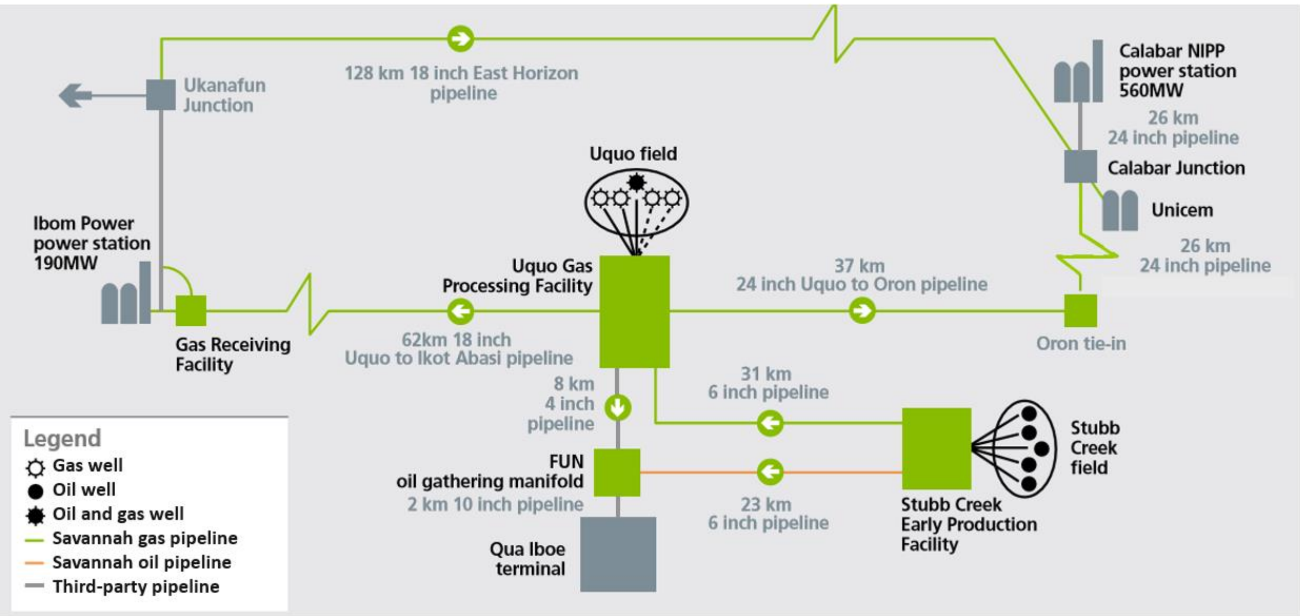

Figure 5-1 Uquo, Stubb Creek, Accugas and associated Infrastructure

5.3.1 Development costs

The CPF currently processes gas from the Uquo Field, but in the future it is planned to install compression facilities and to process gas from other fields, including Stubb Creek.

The planned capex for Accugas totals $105MM comprising $59MM for pipelines, $45MM for compression and $0.7MM of other costs. Compression is planned for 2023 (two stages) for the Proved case, 2026 (1st stage) and 2027 (2nd stage) for the Proved+Probable case, and 2025 (1st stage) and 2027 (2nd stage) for the Proved+Probable+Possible case

5.3.2 Operating costs

Operating costs are estimated at $20MM in 2020, reducing to $15MM thereafter without non-recurring costs incurred in 2020. In addition, there is a crude handling charge of $1.37/bbl for use of the Qua Iboe Terminal. Accugas will also charge a processing fee of $4.25/bbl to Frontier on any future oil production, although this has not been included in the valuation at this stage.

5.3.3 Decommissioning costs

Decommissioning costs for the Reserves case are estimated to be $79MM (2019 terms) for removal of the facilities and land re-instatement.

6 ECONOMIC EVALUATION

6.1 Methodology

Net Present Values (NPVs) and economic Reserves have been calculated using Savannah's Excel™ integrated economic model of the Uquo and Stubb Creek Marginal Fields, and the Accugas Midstream business. 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 licences.

6.2 Paying and Revenue interests

Savannah has an 80% participating interest in the Uquo gas project via an 80% interest in SUGL.

Savannah has a 51% participating interest in the Stubb Creek Marginal Field via a 100% interest in UERL. The company's paying interest in the field is 20% for oil and 50% for gas, and the profit interest is 35% for oil and 60% for gas.

Savannah has an 80% participating interest in the Accugas Midstream Business.

6.3 Fiscal terms

It is assumed that the current Nigerian Marginal Field tax terms apply to Uquo and Stubb Creek Fields.

Accugas is assumed to be subject to standard Nigerian Corporate Income Tax.

The key features of the fiscal regime for Uquo and Stubb Creek assumed in the model are tabulated below.

Oil Royalty	0 – 2,000 bpd	2.5%
	2,001 – 5,000 bpd	2.5%
	5,001 – 10,000 bpd	7.5%
	10,001 – 15,000 bpd	12.5%
	> 15,001 bpd	18.5%
Gas Royalty	7%	
Overriding Royalty (oil)	0 – 2,000 bpd	2.5%
	2,001 – 5,000 bpd	3.0%
	5,001 – 10,000 bpd	5.5%
	10,001 – 15,000 bpd	7.5%
	> 15,001 bpd	TBD
Education tax	2.0%	
NDDC levy	3.0%	
Petroleum Profits Tax (PPT)	85% (Uquo tax holiday to end Nov 2018, Stubb Creek 65.75% to end 2019)	
CIT	30%	
Capital allowances	100% on exploration, development and the first two appraisal wells. 20% for years 1-4, then 19% for year 5 on other capex. Capital allowances used in any given year are restricted to 85% of assessable profit.	
Profit Investment Allowance (PIA)	5.0%	

Table 6-1 Summary of Fiscal Terms

Taxes have been adjusted to allow for brought forward capital allowances and tax losses.

6.4 Oil prices

Oil production from Stubb Creek is sold to ExxonMobil at the Qua Iboe terminal. It is assumed that the price achieved is at a $1.25/bbl premium to Brent based on historic sales for 2018 and 2019. Condensate is commingled with processed crude and sold at the same premium to Brent.

The Brent price assumed is based on the forward Brent strip as of 29th October 2019 until the end of 2026 and thereafter escalated at 2% per year. The Brent price assumed by year is tabulated below.

Year	$/bbl
2019	60.2
2020	59.3
2021	57.4
2022	56.9
2023	57.1
2024	57.7
2025	58.2
2026	58.9
2027	+2% pa

Table 6-2 Brent oil price assumed (nominal)

6.5 Gas prices

Gas from the Uquo Field is sold to Accugas under the Upstream GSA (Gas Sales Agreement). The contract runs until the end of December 2028, and thereafter extendable to the end of Uquo Field life. The DCQ (Daily Contracted Quantity) is 189.4 MMscfd with a ToP of 80% of the DCQ. The yearly base gas price for each year of the contract is tabulated below. The base price A transfers to base price B at the later of two years from the effective date or after cumulative production under the agreement has reached 110 Bscf.

Year	Base Price A (unindexed) $/Mscf	Base Price B (unindexed) $/Mscf
2019	1.25	-
2020	1.31	-
2021	1.37	1.57
2022	1.44	1.64
2023	1.51	1.72
2024	1.58	1.80
2025	1.58	1.80
2026	1.58	1.80
2027	1.58	1.80
2028	1.58	1.80

Table 6-3 Details of Upstream Gas Sales Agreement

These prices are adjusted by a "Weighted Average Index" based on the PPI-US/CPI-US adjustment calculated under the Downstream GSAs. The upstream nominal gas price assumed in the economic model is tabulated below.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gas Price ($/mcf)	1.28	1.37	1.61	1.69	1.80	1.82	2.31	2.35	2.39	2.42

Table 6-4 Upstream nominal gas price assumed in the economic model

Accugas sells processed gas under Downstream GSAs to the Ibom and Calabar power plants, and to the Unicem cement factory. The key terms of each GSA are tabulated below.

Contract term	Calabar Power Plant	Unicem Cement Plant	Ibom Power Plant
Length of contract	20 years	20 years	10 years
Contract end	Sept 2037	Dec 2031	Dec 2023
DCQ	131.0 MMscfd	38.7 MMscfd	19.7 MMscfd
Take or Pay (ToP)	80% of DCQ	80% of DCQ	80% of DCQ
Gas price	2019 $3.53/Mscf increasing in steps to $5.04/Mscf in 2024 All indexed to US PPI	$5.0/Mscf (all years)	2019 $2.18/Mscf Thereafter escalated with US CPI

Table 6-5 Details of Downstream Gas Sales Agreements

The average downstream nominal gas price assumed by year across the three contracts in the economic model is tabulated below.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gas Price ($/mcf)	3.88	4.07	4.27	4.52	4.98	5.06	5.13	5.21	5.30	5.38

Table 6-6 Downstream average nominal gas price assumed in the economic model

6.6 Other assumptions

The following assumptions have also been used by CGG.

Parameter	Value
Discount Rate	10%
Discount Methodology	Monthly
Cost /Price Inflation	2% per annum
Valuation Date	1st November 2019

Table 6-7 Economic Parameters

6.7 Economic results

6.7.1 Upstream Assets

The Net Present Values (NPV) of future cash flows derived from the exploitation of the reserves are tabulated below. The values stated are net to Savannah's interest and after deduction of Royalties and Taxes. The NPVs of Uquo are based on the gas sold under the GSAs and its associated condensate, while Stubb Creek is solely based on oil production.

NPV10 ($USMM) of Reserves Net to Savannah			
	Proved	**Proved & Probable**	**Proved, Probable & Possible**
Uquo (gas and condensate)	139.2	227.7	322.1
Stubb Creek oil	38.1	56.7	72.0
Total	**177.2**	**284.4**	**394.1**

Table 6-8 NPV10 ($USMM) of Reserves Net to Savannah as at 1st November 2019

Sensitivities have been calculated for total NPV for variations in oil price, capex and opex. The results of this analysis are tabulated below for the Proved & Probable case.

NPV10 ($USMM) Net to Savannah			
	Uquo	**Stubb Creek**	**Total**
Base case (Proved+Probable)	227.2	56.7	**284.4**
Oil price -25%	223.2	46.7	**269.9**
Oil Price +25%	232.2	65.8	**298.0**
Capex +25%	216.7	56.0	**272.7**
Capex -15%	234.3	57.2	**291.5**
Opex +25%	214.3	55.2	**269.5**
Opex -15%	235.9	57.7	**293.7**

Table 6-9 Proved+Probable NPV10 ($USMM) Sensitivities as at 1st November 2019

6.7.2 Midstream Assets (Accugas)

The Net Present Values (NPV) of the future cash flows accruing to the Accugas Midstream Business have been extracted from Savannah's integrated economic model and are tabulated below for the base case (ToP). The model has been subject to a high level review by CGG, and found to be in reasonable agreement with the applicable fiscal and commercial terms. The values stated are for the Accugas Midstream Business (100%) and for Savannah's net 80% interest after deduction of Royalties and Taxes.

Case	Accugas (100%)	Net to Savannah
Base Case (ToP)	840.9	672.8

Table 6-10 Accugas NPV10s ($USMM)

The values stated assume that the ToP volumes detailed in the respective gas sales agreements described in Section 6.5 are sold to the respective downstream buyers. These sales volumes are initially sourced from Uquo, with additional feedstock expected to come from Stubb Creek, and potentially other sources such as third party gas fields.

It should be noted that there are no gas Reserves or Resources associated with Accugas.

7 APPENDIX A: PRODUCTION PROFILES

Gross Production Profiles: Uquo Field

	Uquo Field											
	Condensate (bopd)			Gas (MMscf/d)			Condensate (bopd)			Gas (MMscf/d)		
	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2019	131.6	131.6	131.6	96.9	96.9	96.9	-	-	-	-	-	-
2020	147.6	191.7	239.6	108.7	141.1	176.4	-	-	-	-	-	-
2021	191.7	191.7	271.2	141.1	141.1	199.7	-	-	-	-	-	-
2022	191.7	191.7	271.2	141.1	141.1	199.7	-	-	-	-	-	-
2023	191.7	191.7	271.2	141.1	141.1	199.7	-	-	-	-	-	-
2024	153.1	171.7	227.3	112.7	126.5	167.4	18.6	-	-	13.7	-	-
2025	96.5	171.7	241.6	71.0	126.5	177.9	56.5	-	-	41.6	-	-
2026	59.4	171.7	241.6	43.7	126.5	177.9	36.6	-	-	26.9	-	-
2027	36.6	171.7	241.6	26.9	126.5	177.9	22.3	-	-	16.4	-	-
2028	22.5	160.2	224.4	16.6	118.0	165.2	13.5	11.5	17.2	10.0	8.5	12.7
2029	13.9	102.8	155.5	10.2	75.7	114.5	8.2	69.0	86.1	6.1	50.8	63.4
2030	8.5	62.1	104.5	6.3	45.8	76.9	5.0	75.9	110.1	3.7	55.9	81.1
2031	5.3	37.6	70.2	3.9	27.7	51.7	3.1	46.3	75.6	2.2	34.1	55.6
2032	3.2	22.7	47.2	2.4	16.7	34.7	1.9	28.2	50.9	1.4	20.8	37.5
2033	2.0	13.7	31.7	1.5	10.1	23.3	1.1	17.2	34.3	0.8	12.6	25.3
2034	1.2	8.3	21.3	0.9	6.1	15.7	0.6	10.5	23.1	0.4	7.7	17.0
2035	0.4	5.0	14.3	0.3	3.7	10.5	-	6.4	15.6	-	4.7	11.5
2036	-	3.0	9.6	-	2.2	7.1	-	3.9	10.5	-	2.9	7.7
2037	-	1.3	6.5	-	1.0	4.8	-	0.9	6.6	-	0.7	4.8
2038	-	-	4.3	-	-	3.2	-	-	-	-	-	-
2039	-	-	2.9	-	-	2.1	-	-	-	-	-	-
2040	-	-	2.0	-	-	1.4	-	-	-	-	-	-

Gross Production Profiles: Stubb Creek Field

	Stubb Creek Field											
	Oil (bopd)			Gas (MMscf/d)			Condensate (bopd)			Gas (MMscf/d)		
	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2019	2,250	2,500	2,750	1.7	1.9	2.1	-	-	-	-	-	-
2020	2,250	2,500	2,750	1.7	1.9	2.1	-	-	-	-	-	-
2021	3,218	3,575	3,933	2.4	2.7	3.0	-	-	-	-	-	-
2022	4,185	4,650	5,115	3.1	3.5	3.8	-	-	-	-	-	-
2023	3,832	4,650	5,115	2.9	3.5	3.8	-	-	-	-	-	-
2024	2,700	4,650	5,115	2.0	3.5	3.8	-	-	-	-	-	-
2025	1,871	4,650	5,115	1.4	3.5	3.8	27.7	-	-	13.8	-	-
2026	1,296	4,148	5,115	1.0	3.1	3.8	111.6	-	-	55.8	-	-
2027	897	3,214	5,115	0.7	2.4	3.8	166.3	-	-	83.1	-	-
2028	622	2,491	5,115	0.5	1.9	3.8	199.8	-	-	99.9	-	-
2029	431	1,930	5,115	0.3	1.4	3.8	220.4	-	-	110.2	-	-
2030	298	1,495	4,873	0.2	1.1	3.7	233.0	49.6	39.8	116.5	24.8	19.9
2031	207	1,159	3,845	0.2	0.9	2.9	240.7	129.5	141.2	120.3	64.7	70.6
2032	143	898	2,977	0.1	0.7	2.2	187.7	120.3	118.2	93.9	60.1	59.1
2033	99	696	2,304	0.1	0.5	1.7	190.6	149.7	165.5	95.3	74.9	82.7
2034	69	539	1,784	0.1	0.4	1.3	183.4	167.6	178.7	91.7	83.8	89.3
2035	48	418	1,381	0.0	0.3	1.0	123.0	178.4	200.1	61.5	89.2	100.0
2036	33	324	1,069	0.0	0.2	0.8	76.3	185.0	214.4	38.2	92.5	107.2
2037	23	251	828	0.0	0.2	0.6	37.5	143.1	167.4	18.8	71.6	83.7
2038	16	194	641	0.0	0.1	0.5	-	-	-	-	-	-
2039	11	151	496	0.0	0.1	0.4	-	-	-	-	-	-
2040	8	117	384	0.0	0.1	0.3	-	-	-	-	-	-

8 APPENDIX B: 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.

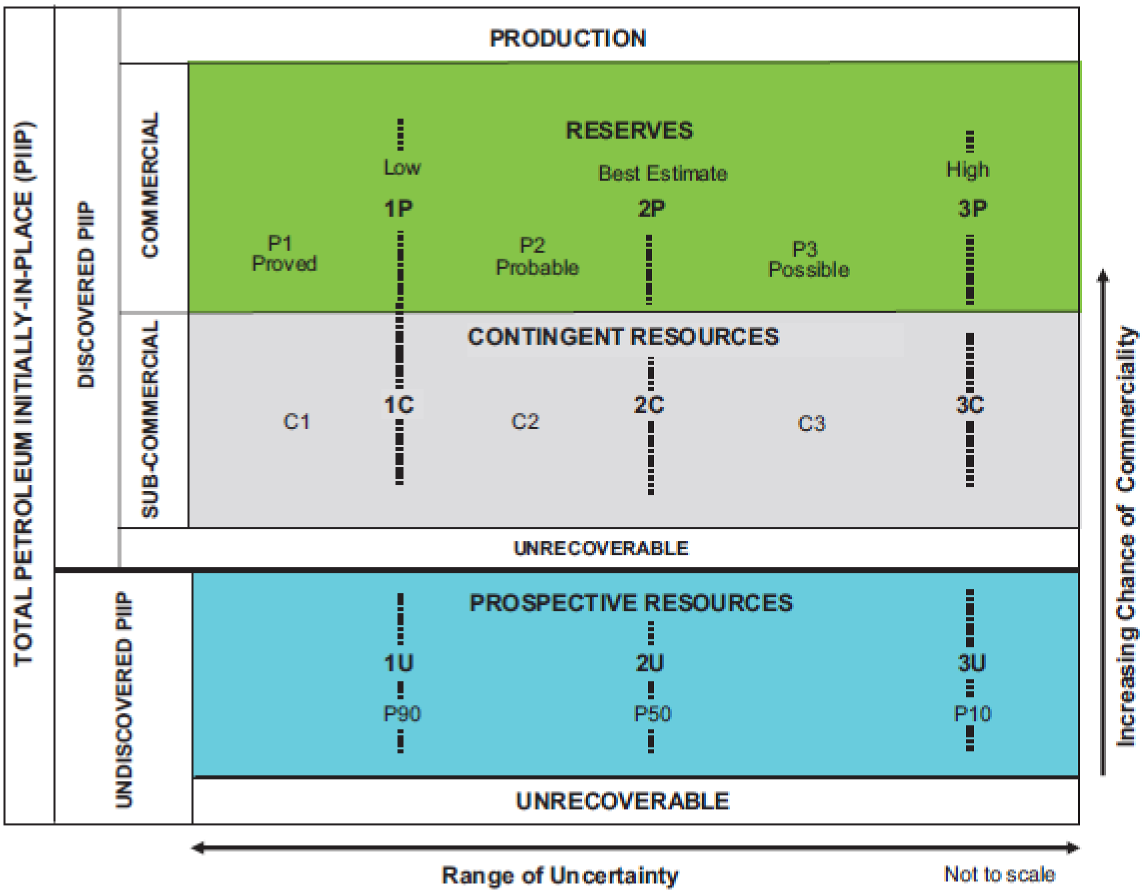

Figure 8-1 Resources Classification Framework

(Source: SPE Petroleum Resources Management System 2018)

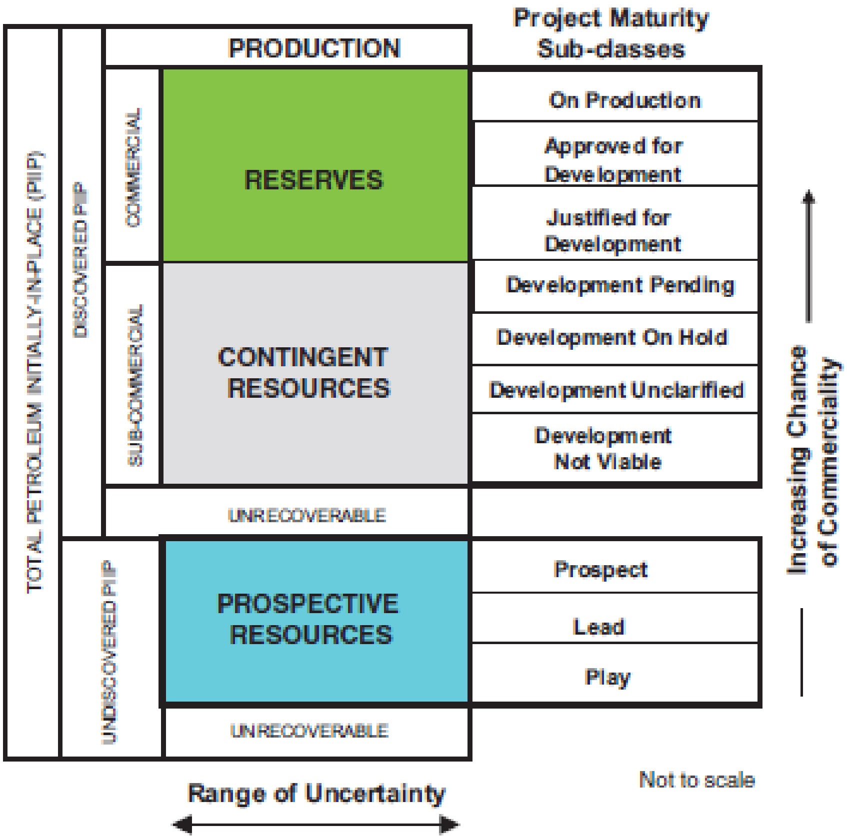

Figure 8-2 Resources Classification Framework: Sub-classes based on Project Maturity

(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 (see Section 3.2, Production Measurement).

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 Reources

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 C: NOMENCLATURE

1-D, 2-D, 3-D	1-, 2-, 3-dimensions	ftMD	feet measured depth
1P	proved	ftss	feet subsea
2P	proved + probable	G & A	general & administration
3P	proved + probable + possible	G & G	geological & geophysical
acre	43,560 square feet	g/cm^3	grams per cubic centimetre
AOF	absolute open flow	Ga	billion (10^9) years
API	American Petroleum Institute	GIIP	gas initially in place
av.	Average	GIS	Geographical Information Systems
AVO	Amplitude vs. Off-Set	GOC	gas-oil contact
bbl	barrel	GOR	gas to oil ratio
bbl/d	barrels per day	GR	gamma ray (log)
BHP	bottom hole pressure	GWC	gas-water contact
BHT	bottom hole temperature	H_2S	hydrogen sulphide
boe	barrel of oil equivalent	ha	hectare(s)
Bscf	billion standard cubic feet	HI	hydrogen index
Bscm	billion standard cubic metres	HP	high pressure
Btu	British thermal unit	Hz	hertz
BV	bulk volume	IDC	intangible drilling costs
c.	circa	IOR	improved oil recovery
CCA	conventional core analysis	IRR	internal rate of return
CD-ROM	compact disc with read only memory	kg	kilogram
cgm	computer graphics meta file	km	kilometre
CNG	compressed natural gas	km^2	square kilometres
CO_2	carbon dioxide	kWh	kiloWatt-hours
DHC	dry hole cost	LoF	life of field
DHI	direct hydrocarbon indicators	LP	low pressure
DPT	deeper pool test	LST	lowstand systems tract
DROI	discounted return on investment	LVL	low-velocity layer
DST	drill-stem test	M & A	mergers & acquisitions
DWT	deadweight tonnage	m	metre
E & P	exploration & production	M	thousand
E	East	m/s	metres per second
e.g.	for example	Ma	million years (before present)
EAEG	European Association of Exploration	Mbbl/d	thousands of barrels per day
	Geophysicists	Mbbl/d	thousands of barrels per day
EOR	enhanced oil recovery	mbdf	metres below derrick floor
ESP	Electrical Submersible Pump	mbsl	metres below sea level
et al.	and others	mD	millidarcies
EUR	estimated ultimately recoverable	MD	measured depth

mdst.	mudstone
MFS	maximum flooding surface
mg/gTOC	units for hydrogen index
mGal	milligals
MHz	megahertz
MJ	megajoule
ml	millilitres
mls	miles
MM	million
MMbbl	million bbls of oil
MMboe	million bbls of oil equivalent
MMscfd	million standard cubic feet per day
MMscm	million standard cubic metres
mmsl	metres below mean sea level
MMstb	million stock tank barrels
MMt	million tons
mN/m	interfacial tension measured unit
MPa	megapascals
Mscfd	thousand standard cubic feet per day
Mscm	thousand standard cubic metres
msec	millisecond(s)
MSL	mean sea level
mSS	metres subsea
MWh	MegaWatt-hours
N	north
NaCl	sodium chloride
NFW	new field wildcat
NGL	natural gas liquids
no.	number (not #)
NPV	net present value
Ø	porosity
OAE	oceanic anoxic event
OI	oxygen index
OWC	oil-water contact
P & A	plugged & abandoned
pbu	pressure build-up
perm.	permeability
PESGB	Petroleum Exploration Society of Great Britain
pH	-log H ion concentration
phi	unit grain size measurement
plc	public limited company
por.	Porosity
poroperm	porosity-permeability
ppm	parts per million
PRMS	Petroleum Resource Management System (SPE)
psia	pounds per square inch absolute
RFT	repeat formation test
ROI	return on investment
ROP	rate of penetration
RT	rotary table
S	South
SCAL	special core analysis
scf	standard cubic feet
scm	standard cubic metre*
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
TD	total depth
TDC	tangible drilling costs
Therm	105 Btu
Tscf	trillion standard cubic feet
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWT	two-way time
US$	US dollar
US$MM	Millions of US dollars
UV	ultra-violet
VDR	virtual dataroom
W	West
WD	water depth
WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
wt%	percent by weight
XRD	X-ray diffraction (analysis)