TETRA TECH
RPS ENERGY

Competent Person's Report
NORTH SÈMÈ FIELD, OFFSHORE BENIN

H7 and H8 Reservoirs

Prepared for:

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793- TA000069
17 April 2025
FINAL_V1

Document status

Version	Purpose of document	Authored by	Reviewed by	Approved by	Review date
Draft V1	Initial Draft	DJO, SR, AT	GT	GT	25th March 2025
Draft V2	Client Comment	DJO	Lime (LH)		
Draft V3	Summary CPR	DJO	GT	GT	4th April 2025
Draft V4	Client Comment	DJO	GT	GT	11th April 2025
Final	Final Document	DJO	GT	GT	15th April 2025
Final V1	Final Document (Additional Cient Comment & Clarification)	DJO	GT	GT	17th April 2025

Approval for issue

G Taylor		17th April 2025

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EVALUATION OF H7 AND H8 RESERVOIRS, SÈMÈ NORTH FIELD, OFFSHORE BENIN

In response to a request by Lime Petroleum Holding AS ("Lime"), and the Letter of Engagement dated 19 March 2025 with Lime (the "Agreement"), Tetra Tech RPS Energy Ltd ("Tetra Tech RPS Energy") has completed an independent evaluation of the following Assets:

- H7 and H8 Reservoirs of the Sèmè North Field, Offshore Benin

This report is issued by Tetra Tech RPS Energy under the appointment by Lime Petroleum Holding A.S on behalf of Akrake Petroleum Benin S.A (Akrake) and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

We have estimated Contingent Resources as of 1st January 2025. All Reserves and Resources definitions and estimates shown in this report are based on the PRMS and reported to the SEC regulations. The work was undertaken by a team of petroleum engineers, geoscientists and economists and is based on data supplied by Lime. Our approach has been a combination of an independent seismic interpretation and depth conversion, with audit and review of previous Geological studies and Lime's indicated re-development project and associated costs.

In estimating Reserves, we have used standard geoscience and petroleum engineering techniques. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of recoverable volumes, based on predicted field performance and contracted gas sales.

We have taken the working interest that Akrake has in the Fields as presented by Lime. We have not investigated, nor do we make any warranty as to Lime or Akrake interest in the Assets.

A site visit was not conducted.

The Net Entitlement Resources for both Akrake and Lime's holding company of Rex International Holding Limited (Rex) as of 1st January 2025 are summarised in Table 1-2, Table 1-3, Table 1-4 and Table 1-5 for oil and gas respectively.

QUALIFICATIONS

Tetra Tech RPS Energy is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. David Offer, Principal Geologist has supervised this evaluation, and the report has been reviewed and approved by Mr Gordon Taylor, Technical Director, for Tetra Tech RPS Energy as the Competent Person. Mr Taylor is a Chartered Geologist with over 40 of years' experience in upstream oil and gas and a Fellow of the Geological Society, a Chartered Engineer in the UK and a Member of the Institute of Materials, Minerals and Mining, a Certified Petroleum Geologist through the Division of Professional Affairs of the of the American Association of Petroleum Geologists, and a member of the Society of Petroleum Engineers.

Mr David Offer has over 25 years of experience in upstream oil and gas. Other Tetra Tech RPS Energy employees involved in this work hold at least a bachelor's degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering. A full listing of all qualifications and professional memberships of employees associated with this report can be found in Section 10, Table 10-1.

BASIS OF OPINION

The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognized uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, Tetra Tech RPS Energy is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Reserves are based on data provided by Lime. We have accepted, without independent verification, the accuracy and completeness of this data.

The report represents Tetra Tech RPS Energy's best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This report was provided for the sole use of Lime and their corporate advisors on a fee basis.

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Yours sincerely, for Tetra Tech RPS Energy Ltd

Gordon Taylor, CGeol, CEng
Technical Director

Name	Role	Signature
David Offer	Project Manager / Geologist	
Simon Russel	Geophysics	
David Walker	Facilities / Cost Engineer	
Joseph Tan	Economist	
Adam Turner	Reservoir Engineering	

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1 EXECUTIVE SUMMARY

In response to a request by Lime Petroleum Holding AS ("Lime") on behalf of Akrake Petroleum Benin AS (Akrake), and the Letter of Engagement dated 19th March 2025 with Lime (the "Agreement"), Tetra Tech RPS Energy Ltd ("RPS") has completed an independent evaluation of the H7 and H8 reservoirs of the Sèmè North Field, Block 1, Dahomey Basin, Gulf of Guinea (Figure 1-1), offshore Benin in which Akrake has an interest.

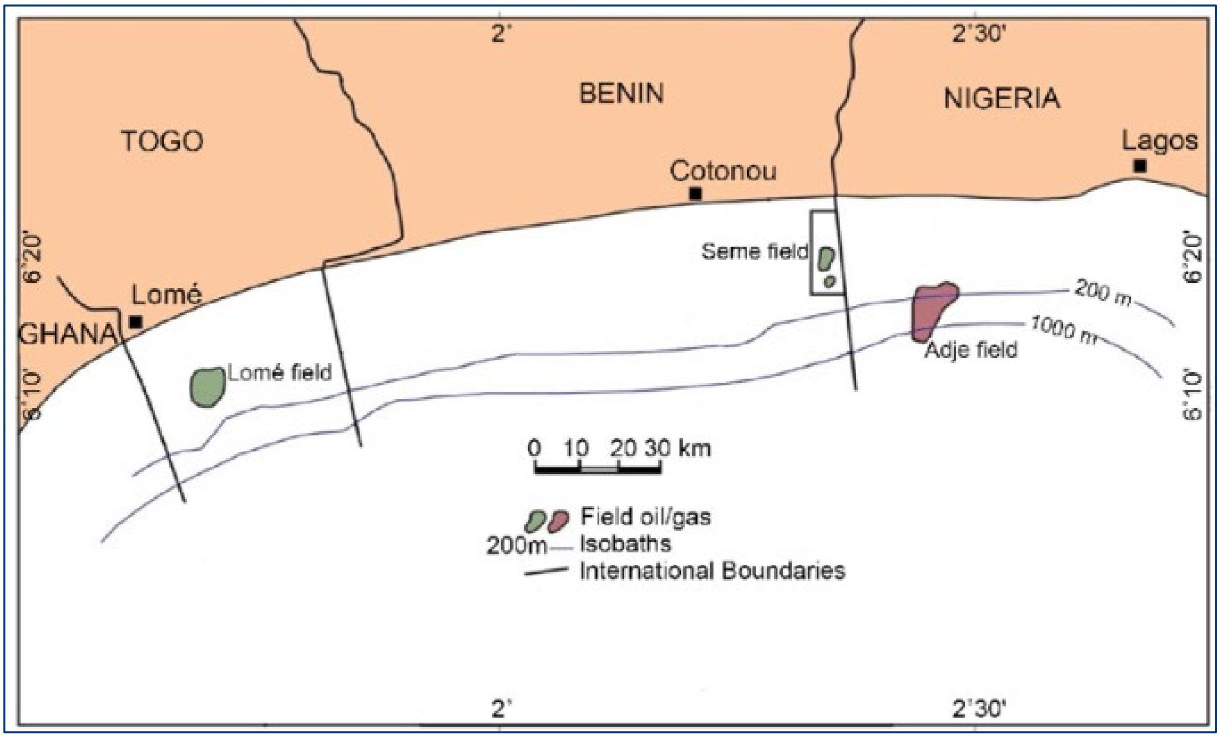

Figure 1-1: Seme Field Location Map (*After d'Almeida et al 2021*)[1]

In December 2023, the Government of Benin granted a consortium comprised of Akrake Petroleum Bénin S.A (Akrake) and Octogone E&P S.A Research Authorisation to explore Block 1 and the Sèmè field. Akrake are the current licence operator with 76% interest. Akrake is a special purpose company, set up to assess the Sèmè North Field's development potential. Akrake is owned 100% by Lime Petroleum Holding A.S, (Lime). Lime is 80.14% owned by its parent company Rex International Holding Limited (Rex).

RPS previously completed a CPR of the H6, H7 and H8 reservoirs of the Sèmè North Field, Block 1, Dahomey Basin, Gulf of Guinea, offshore Benin for Lime on behalf of Akrake in August 2024 (Report Number 793-TA000023). The August CPR evaluated the deep H7 and H8 reservoirs, which have been revised for this CPR, and also the shallower H6 reservoirs, which are not included in this CPR, but which Lime plan to redevelop in Q2 2025.

The aim of the report is to revise the independent resource evaluation the H7 and H8 of the Sèmè North Field, Block 1, Dahomey Basin and supply a CPR for the inclusion of documents submitted to the Singapore Stock Exchange.

Although the deeper H7 and H8 reservoirs are known to contain hydrocarbons, they will be re-evaluated as part of the H6 redevelopment in Q2 2025. Lime has no firm plans to develop these reservoirs at the present and therefore both the H7 and H8 reservoirs are considered to be **Contingent Resources – Development Unclarified**.

[1] d'Almeida. G,A,F, Kaki. C, Amelina. S (2021) Structural Modelling of the Top Turonian Reservoir in the Northern Seme Oilfield (Benin, West-Aftrica). Open Journal of Geology, Vol 11, pp 682-695.

1.1 Geological Review

The Sèmè field is located in the Dahomey Basin, in shallow waters twelve miles off-shore in the Gulf of Guinea, Republic of Benin (Benin). At its peak in 1984 Sèmè produced 7,627 stb/d from the Abekotu Formation, (H6) reservoir, although hydrocarbons were also discovered, but never produced from the older, underlying H7 and H8 reservoirs. Lime will be drilling a new production well into the H6 reservoir in Q2 2025. As part of this drilling campaign, they will drill the H7 and H8 reservoirs again.

The Upper H6 Reservoir sands were deposited by prograding fan deltas, which have subsequently been re-worked by marginal marine or shallow marine processes. The lower part of the Abekotu Formation is characterised by overlapping fans pro-grading towards the south east.

Overlying the Abekotu is a series of unconformities and sub-marine canyons that are significant challenges to seismic imaging, interpretation and depth conversion.

The H8 Reservoir sands are thought to have been deposited as a fan-delta environment, this was later reworked by rising sea levels resulting in the deposition of the H7 shoreface and stacked, wave dominated deltaic shelf sands.

Lime supplied RPS with previous subsurface reports, seismic, logs and well tops and in a project constructed by previous operator SApetro in Schlumberger's Petrel™ geomodelling software. This model was focussed on the previously produced H6 reservoir and no significant digital well data for the H7 and H8 reservoirs were available for review. RPS undertook its own independent seismic interpretation and depth conversion, which along with an audit of previous petrophysical and geological report data and an audit of the Lime supplied static model, was used as the basis of RPS's independent volume estimation.

Probabilistic volumes were estimated using Logitech's REP™ software. The volume estimation inputs are based upon RPS ranges around the accepted petrophysical parameters supplied by Lime see (Section 4.2.3). The resultant RPS estimated pre-production in-place estimates are given in Table 1-1 for the H7 and H8 reservoirs.

Reservoir	Hydrocarbon	HCIIP		
		P90	P50	P10
H7 (H7.1 & H7.2)	**Oil (MMstb)**	42	86	150
H8	**Gas (Bscf)**	62	105	167

Table 1-1: Gross Hydrocarbons Initially In-Place (HCIIP) for North Sèmè Field[2]

1.2 Reservoir Engineering Review

After the North Sèmè field discovery in 1968 by Union Oil, the field was developed by Saga Petroleum. Between 1982 and 1998, the field produced approximately 16.8 MMstb of oil from the H6 reservoir from 10 vertical wells. Following this initial development, SApetro drilled an additional three infill wells between 2012 and 2014. However, these wells were never brought onstream, although the deeper H7 and H8 reservoirs tested hydrocarbons.

Lime Petroleum Holding AS ("Lime") on behalf of Akrake Petroleum Benin AS (Akrake) are now proposing a redevelopment of the Field as two phases (Section 1.3).

RPS has been provided with previous study reports, many well reports of varying age and quality, production data for the wells in the previous development, a legacy history-matched model and Lime's dynamic forecast model of the field.

[2] This report is focussed upon the Contingent H7 and H8 reservoirs and therefore the H6 reservoir HCIIP are not mentioned.

RPS has audited the forecasting methodology employed by Lime for each of the reservoirs, namely:

- H7 – Oil decline curve results based on DSTs
- H8 – Gas decline curve results based on DSTs with field gas constraint

The methodology employed by Lime is deemed to be sound, and RPS has therefore used a similar approach, rescaling to the RPS-estimated in-place volumes and notional recovery factors. There remains a significant level of uncertainty in the forecasts, which will be narrowed as development progresses.

1.3 Proposed Redevelopment

Lime are in the process of redeveloping the North Sèmè field. The proposed redevelopment consists of two phases;

Phase 1 is a combined long term (1 year) production test of the previously produced H6 reservoir and appraisal of the lower, unproduced H7 and H8, reservoirs. Lime proposes to do this by drilling a high angle appraisal well (AK1 Figure 1-2) that will test the H7 and H8 reservoirs before plugging back and completing the H6 for long term test / production. This well is due to be drilled in Q2 2025.

A second horizontal well (AK2 Figure 1-2) will be drilled in the west of the field in the H6 reservoir, which will also be placed on long term test / production via a MOPU. The exact position of this well will be dependent upon the results of the AK1 well.

All wells will be fitted with ESP and intelligent completions (Autonomous Inflow Control (AICD)) to limit the produced water. First oil is expected from the H6 reservoirs in Q3 2025.

Phase 2 comprises two parts and is contingent upon the appraisal results of the lower H7 and H8 reservoirs drilled in Phase 1. The first part will be to develop H7 using three horizontal wells with 'fish bone' completions fitted and ESPs. First oil from H7 is planned for Q1 2027, with the development wells being drilled back to back with the second (Phase 1) H6 development well. A further exploration well will also be drilled in Block 1 outside of the current North Sèmè field.

The second part, of Phase 2, will be to develop H8 by drilling two horizontal 'fish bone' wells and installing wet gas processing on the MOPU with a pipeline to shore. A gas processing plant will be constructed on-shore to supply indigenous gas for a power station. First gas is planned for Q1 2029.

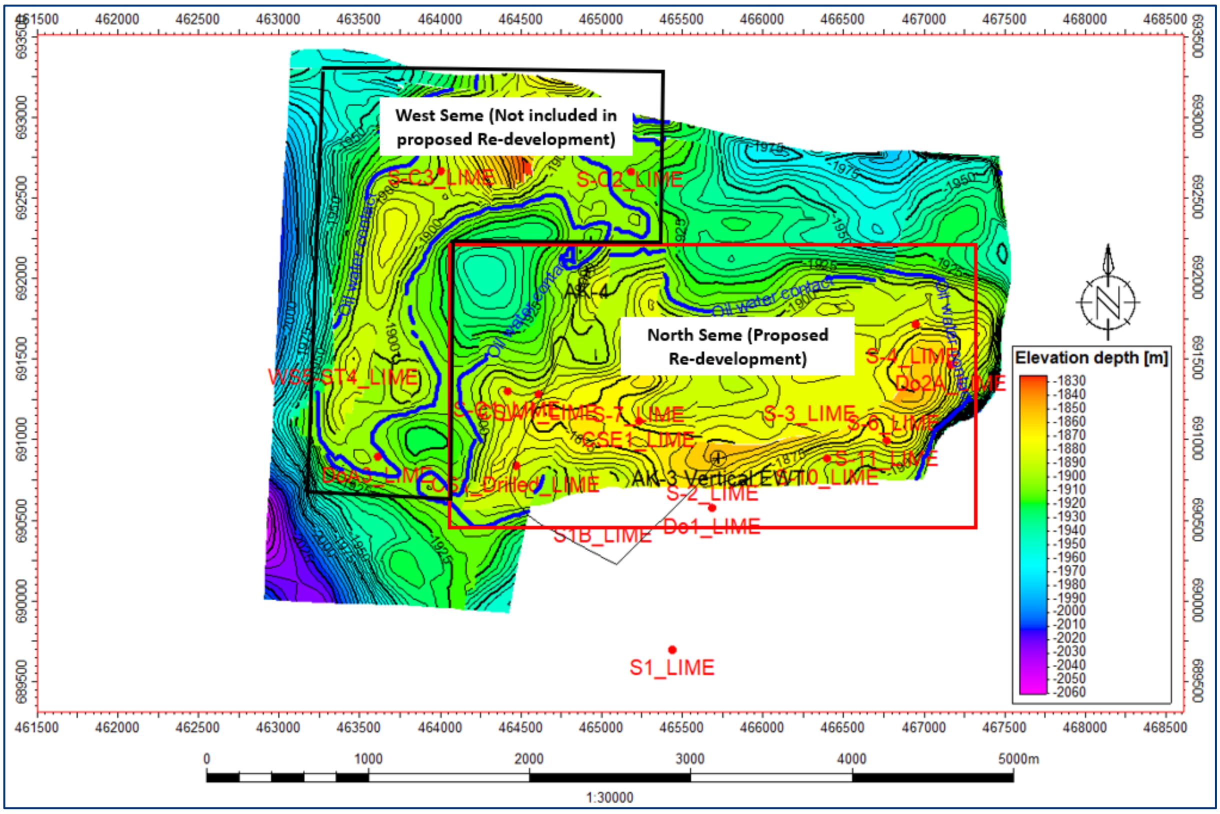

Figure 1-2: Top H6 Depth Map Showing Sèmè Field and the North Sèmè Proposed Re-development Area

RPS monthly Gross production forecasts for each reservoir are shown in Figure 1-3 and Figure 1-4 for oil/condensate and gas, respectively.

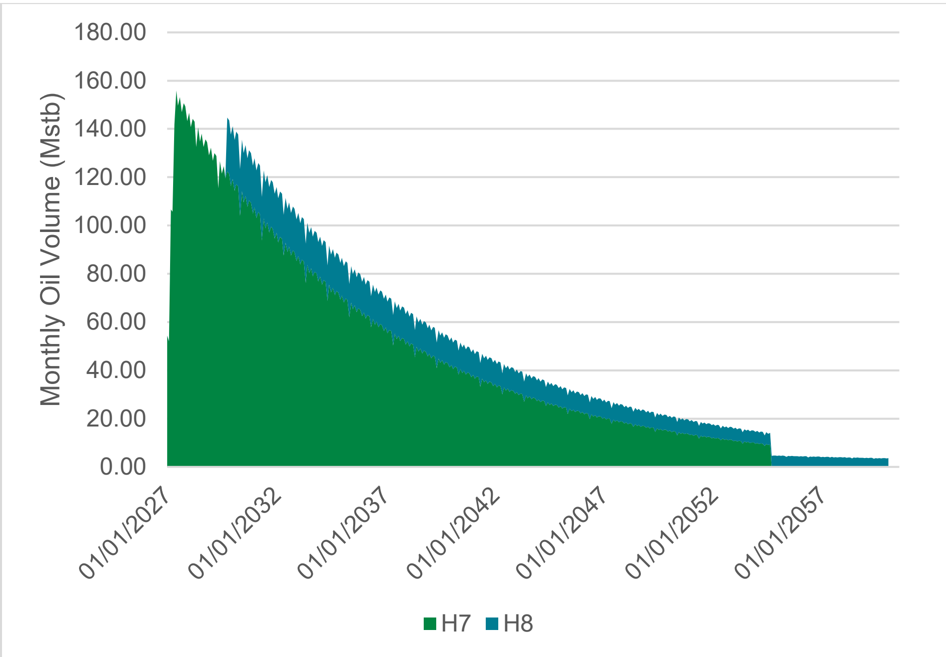

Figure 1-3: H7 and H8 Monthly Oil and Condensate (Gross) Production

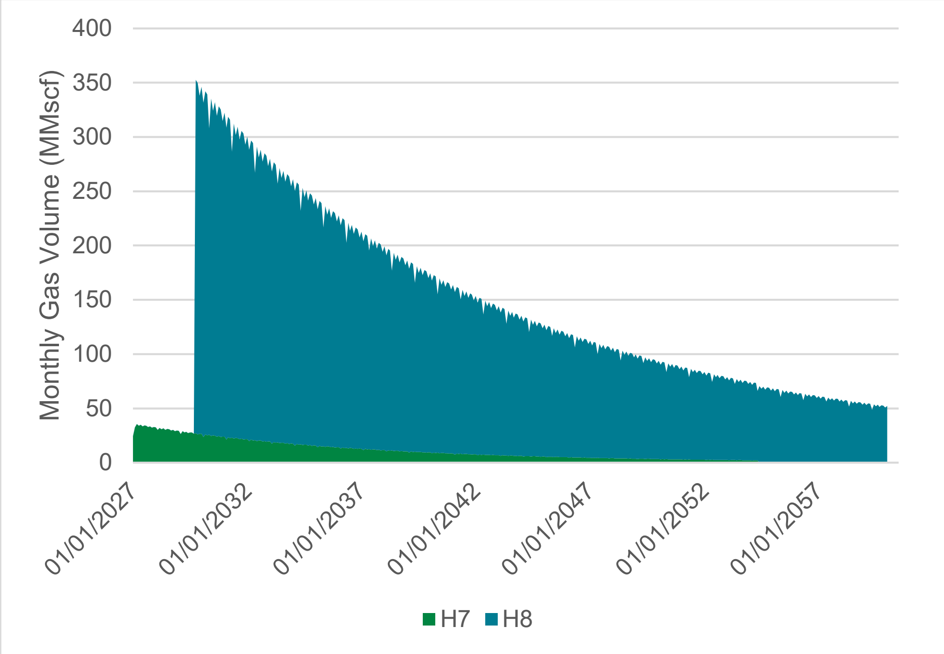

Figure 1-4: H7 and H8 Monthly Gas (Gross) Production

The H7 and H8 reservoirs are known to contain hydrocarbons having a total of seven well penetrations. However, they have never been developed and are part of Lime's Phase 2 development plan (Section 1.1). The development of both the H7 and H8 reservoirs are contingent on the findings of the new well (AK1) due to be drilled in Q2 2025 and the agreement to continue production past the initial 1 year test period currently proposed for the Phase 1 redevelopment of the H6 reservoir.

Therefore, RPS considers the H7 and H8 reservoirs as **Contingent Resources – Development Unclarified**.

SUMMARY OF OIL CONTINGENT RESOURCES

As of 1 January 2025

BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (MMstb)			Lime (Akrake) Net Entitlement Resources[2] (MMstb)			Rex Net Entitlement Resources[2] (MMstb)		
	1C[3]	2C	3C	1C[3]	2C	3C	1C[3]	2C	3C
H7 (H7.1 & H7.2)	-	13.4	30.8	-	8.2	11.5	-	6.6	9.2

Notes:
[1] Gross field Contingent Resources (100% basis) after economic limit test
[2] Companies working interest share (Akrake 76%, REX 60.91%) in the PSC of the net field Resources after economic limit test, within the PSC terms.
[3] Negative incremental NPV

Table 1-2: North Sèmè Oil Contingent Resources – Development Unclarified.

SUMMARY OF GAS CONTINGENT RESOURCES

As of 1 January 2025
BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (Bscf)			Lime (Akrake) Net Entitlement Resources[2] (Bscf)			Rex Net Entitlement Resources[3] (Bscf)		
	1C[4]	2C	3C	1C[4]	2C	3C	1C[4]	2C	3C
H8 – Free Gas (H8.1A, H8.1B, H8.2A & H8.2B)	-	28.6	39.1	-	18.1	17.4	-	14.5	13.9
H7 Associated Gas (H7.1 & H7.2)	-	3.1	7.0	-	1.9	3.1	-	1.6	2.5
Total[5]	**-**	**31.7**	**46.1**	**-**	**20.1**	**20.5**	**-**	**16.1**	**16.4**

Notes:
[1] Gross field Contingent Resources (100% basis) after economic limit test
[2] Net Entitlement to Akrake's working interest of 76%, which excludes the Benin Government Share under the PSC after the ELT
[3] Net Entitlement to Rex (Rex owns 80.14% of Akrake's Net Entitlement), which excludes the Benin Government Share under the PSC after the ELT
[4] Negative incremental NPV
[5] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Resources are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Resources may be a very conservative assessment and the total 3C Resources a very optimistic assessment.

Table 1-3: North Sèmè Gas Contingent Resources – Development Unclarified.

SUMMARY OF CONDENSATE CONTINGENT RESOURCES

As of 1 January 2025
BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (MMstb)			Lime (Akrake) Net Entitlement Resources[2] (MMstb)			Rex Net Entitlement Resources[3] (MMstb)		
	1C[4]	2C	3C	1C[4]	2C	3C	1C[4]	2C	3C
H8 – (H8.1A, H8.1B, H8.2A & H8.2B)	-	2.0	3.5	-	1.2	1.3	-	1.0	1.0

Notes:
[1] Gross field Contingent Resources (100% basis) after economic limit test
[2] Net Entitlement to Akrake's working interest of 76%, which excludes the Benin Government Share under the PSC after the ELT
[3] Net Entitlement to Rex (Rex owns 80.14% of Akrake's Net Entitlement), which excludes the Benin Government Share under the PSC after the ELT
[4] Negative incremental NPV

Table 1-4: North Sèmè Condensate Contingent Resources – Development Unclarified.

SUMMARY OF CONTINGENT RESOURCES (BOE)

As of 1 January 2025

BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (MMBoe)[6]			Lime (Akrake) Net Entitlement Resources[2] (MMBoe)[6]			Rex Net Entitlement Resources[3] (MMBoe)[6]		
	1C[4]	2C	3C	1C[4]	2C	3C	1C[4]	2C	3C
H7	-	13.9	32.0	-	8.6	12.0	-	6.9	9.6
H8	-	6.7	10.0	-	4.2	4.2	-	3.4	3.4
Total[5]	**-**	**20.7**	**42.0**	**-**	**12.8**	**16.2**	**-**	**10.2**	**13.0**

Notes:

[1] Gross field Contingent Resources (100% basis) after economic limit test. Economic limit in 2039 for 2C and 3C

[2] Net Entitlement to Akrake's working interest of 76%, which excludes the Benin Government Share under the PSC after the ELT

[3] Net Entitlement to Rex (Rex owns 80.14% of Akrake's Net Entitlement), which excludes the Benin Government Share under the PSC after the ELT

[4] Negative incremental NPV

[5] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Resources are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Resources may be a very conservative assessment and the total 3C Resources a very optimistic assessment.

[6] Conversion rate of 6,000 standard cubic feet per boe

Table 1-5: North Sèmè BOE Contingent Resources – Development Unclarified

2 INTRODUCTION

RPS was requested by Lime Petroleum Holding A.S (Lime), on behalf of Beninese petroleum company, Akrake Petroleum Benin S.A (Akrake), to complete a Competent Persons Report (CPR) for the undeveloped H7 and H8 reservoirs of the Sèmè North Field.

The aim of this report is to revise the independent resource evaluation of the H7 and H8 reservoirs of the Sèmè North Field, Block 1, Dahomey Basin and supply a summary CPR for the inclusion of documents submitted to the Singapore Stock Exchange.

RPS previously completed a CPR of the H6, H7 and H8 reservoirs of the Sèmè North Field, Block 1, Dahomey Basin, Gulf of Guinea, offshore Benin for Lime on behalf of Akrake in August 2024 (Report Number 793-TA000023). Much of the technical evaluation of the August CPR has been used as the basis of this report and is explained within this document.

The August CPR included a review of previous petrophysical and geological studies and a new seismic interpretation and depth conversion of the overburden, overlying the produced Abekotu Formation reservoir H6 and the undeveloped Albian Formation H7 and H8 reservoirs.

The previously developed H6 reservoir, which Akrake plan to redevelop in Q2 2025 is not included in this report.

2.1 The Asset

Akrake has a 76% working interest in the Block 1 Production Sharing Contract (PSC) and is the operator of the joint venture in Block 1, Off-shore Benin. Octogone E&P S.A and the Benin Government hold the remaining share in the Block 1 PSC.

The current acreage of Block 1 is 536.8 km^2 (Figure 2-1) although the focus of the re-development is the shut in North Sèmè field, which covers 62km^2.

The current PSC was signed by Akrake and Octogone on the 20th of December 2023. Currently it covers exploration of Block 1, but not production. Akrake contacted the Beninese State Minister of Energy and Mines, who issued a letter of comfort on the 17th May 2024, stating that the Benin Government would issue the PSC partnership Authorisation of Exploitation upon submission of an application demonstrating the existence of one or more commercial hydrocarbon deposits.

The current PSC contains the commitment to drill three wells within Block 1 and reprocess seismic data. Should these wells not be drilled a forfeiture cost of US$2.5 Million is payable to the Benin Government.

Asset	Country	Licence	Operator	Operator Working Interest	Development Status	Licence Expiry Data	Licence Area	Partners	Mineral Deposit
Block 1	Benin	Exploration PSC only	Akrake (Issuer – Rex)	76% (Issuer 60.91%)	Re-Development	Yet to be agreed	536.8 km2	Octogone (9%) Government of Benin (15%)	Oil and Gas

Table 2-1: Summary of Akrake Assets

This report is issued by RPS under the appointment by Lime, on behalf of Akrake, and is produced as part of the services detailed therein and subject to the terms and conditions of the Agreement. RPS has no percentage interest in Block 1, the operator the partners or any Holding company (Rex & Lime) associated with this asset.

A glossary of terms used in this report is given in Appendix A.

2.1.1 Exploration and Production History

The Sèmè field is located in the Dahomey Basin, twelve miles off-shore in shallow waters of the Gulf of Guinea, Benin (Figure 2-1). At its peak in 1984 Sèmè produced 7,627 BOPD.

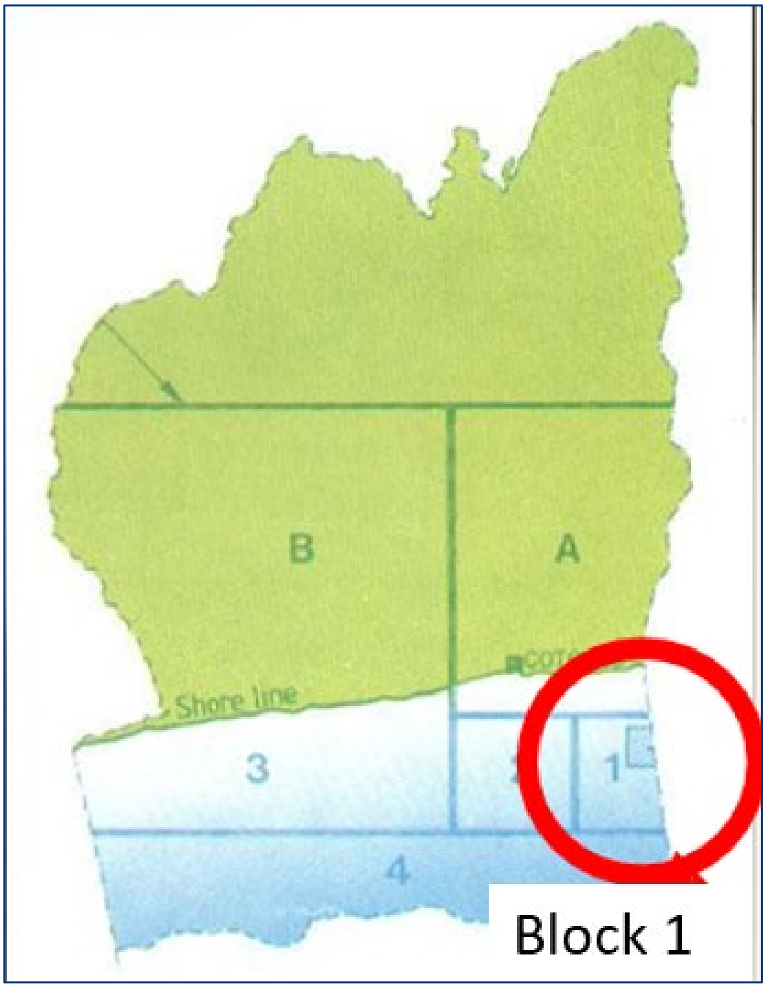

Figure 2-1: Block 1 (Sèmè North) Location Map[3]

Exploration for oil and gas started in Benin in 1964 with Union Oil of California in both offshore and onshore areas. The first well, DO1, was spudded in 1967 and discovered the Sèmè Field. This showed hydrocarbons in multiple oil pay zones in the Abeokuta (H6) and Albian (H7 & H8) sandstones. Further appraisal of the Sèmè area by Union, between 1967 and 1973, lead to the drilling of a further nine wells in the Sèmè area.

However, after two partial relinquishments of their licence Union exited the Sèmè licence after its licence expiry in 1975. In 1976 a development feasibility was conducted leading to Saga Petroleum A.S entering into agreement with the Republic of Benin, operating under the name Project Petrolier de Sèmè (PPS), in order to develop the Sèmè oil field.

Production started on the 1st of October 1982 with a daily rate of approximately 8,000 barrels oil produced from three predrilled wells targeting the H6 reservoir as part of the initial development phase. Saga continued to develop the Sèmè field, drilling five additional development wells between 1982 and 1985 and shooting 2D and 3D seismic surveys in 1983. However, the Saga development contract was cancelled in August 1985, at which point Pan Ocean

[3] *After LIME Seme North – RC2 FDP Casebook (10.06.2024_RPS (002)*

(Panoco) took over as operator but exited the licence in October 1986 leaving PPS to operate the field on its own until 1988.

In May 1988 Ashland took over operatorship of Sèmè and drilled two more development wells, S10 and S11 in 1991, but exited the licence the following year in 1992, at which point a Beninese company called APIC became operator until the field was shut in in 1997.

South Atlantic Petroleum (SApetro) of Nigeria, took over the licence in 2004, shooting a new 3D survey and conducting several subsurface studies. Spurred on by the studies SApetro drilled an appraisal well, Perle-C1 in 2013 and a further 3 development wells only to leave the concession in 2014 with-out any production.

In December 2023, the Government of Benin granted a consortium comprised of Akrake Petroleum Bénin S.A (Akrake) and Octogone E&P S.A Research Authorisation to explore Block 1 and the Sèmè field. Akrake is a special purpose company 100% owned by Lime Petroleum Holding A.S, (Lime). Rex International Holding Limited (RIH) owns 80.14% of Lime.

3 BASIS OF OPINION

The evaluation presented in this report reflects our (RPS) informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Reserves are based on data provided by Lime. We have accepted, without independent verification, the accuracy of the data.

The report represents RPS' best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available.

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This report is issued by RPS under the appointment by Lime, on behalf of the majority licence holder Akrake, and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

3.1 Methodology

Our approach has been to audit the geoscience, engineering, cost and commercial data Recoverable volumes were derived by applying a range of recovery factors to the in-place volume estimates.

All Reserves and Resources definitions and estimates shown in this report are based on the 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resource Management System ("PRMS") v1.03. A summary of PRMS is presented in Appendix B.

3.2 Audit Methodology

As noted above, our approach has been to conduct a combined independent seismic interpretation and depth conversation, audit of existing North Sèmè Field petrophysical, geological and engineering data and Lime's redevelopment plan. Our evaluation is based on the 2019 SPE Reserves Auditing Standards, which describe an audit as follows:

A reserves audit is the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or reserves information prepared by others and the rendering of an opinion about:

1. *the appropriateness of the methodologies employed,*
2. *the adequacy and quality of the data relied upon,*
3. *the depth and thoroughness of the reserves estimation process,*
4. *the classification of reserves appropriate to the relevant definitions used, and*
5. *the reasonableness of the estimated reserves quantities and/or the Reserves Information.*

The term "reasonableness" cannot be defined with precision but should reflect a quantity and/or value difference of not more than plus or minus 10%, or the subject reserves information does not meet minimum recommended audit standards.

This tolerance can be applied to any level of reserves or reserves information aggregation, depending upon the nature of the assignment, but is most often limited to proved reserves information. A separate predetermined and disclosed tolerance may be appropriate for other reserves classifications. Often a reserves audit includes a detailed review of certain critical assumptions and independent assessments with acceptance of other information less critical to the reserves estimation. Typically, a reserves audit letter or report is prepared, clearly stating the assumptions made. A reserves audit should be of sufficient rigor to determine the appropriate reserves classification for all reserves in the property set evaluated and to clearly state the reserves classification system being utilised. In contrast to the term "audit" as used in a financial sense, a reserves audit is generally less rigorous than a reserves report.

4 NORTH SÈMÈ FIELD SUBSURFACE REVIEW

The North Sèmè field is located within the Sèmè field, Block 1, Dahomey Basin, Gulf of Guinea. It was initially discovered in 1964 with the drilling of the DO1 well by Union Oil. First Oil started on 1st October 1982 following an initial development by Project Petrolier de Sèmè, supported by Saga Petroleum A.S.

The field passed between several operators (Section 2.1.1) and was eventually shut in in 1997, but re-appraised by SApetro in 2004, who drilled three new wells, but relinquished the licence prior to any production.

4.1 Subsurface and In-place Resource Evaluation

The database required for the geophysical, petrophysical and geological evaluation comprises a Petrel model called Sèmè PetrelModel2015, well log data and a series of previous operator geological reports. The Petrel model and most well data is focused upon the previously developed H6 reservoirs, with only seven wells out of the twenty two drilled on the Field reaching the H7 & H8 reservoir level (DO-1, DO-2A, DO-A3, S-3, S-10, S-11 and S-9). Therefore, the majority of the data was used to aid the geophysical interpretation of the overburden and give an understanding of the validity of previous geological studies on the H7 and H8 reservoirs.

Some field data has been mis-placed in the Field's history and there was very little data supplied for the H7 and H8 reservoirs. RPS has therefore relied on the previous Sèmè field geological report (1994 Beicip Franlab (Beicip) report prepared for Projet Petrolier de Sèmè). The Beicip report indicates that the H8 layer is subdivided further into a lower H8.2 and an upper H8.1, whilst the H7 layer is sub-dived into a lower H7.2 and an upper H7.1. RPS could only verify these tops based on figures in the above 1994 Beicip report as no digital well data across these layers are available.

4.1.1 Geophysical Review

RPS completed an independent seismic interpretation of the available seismic and velocity data for the Sèmè field. This covered the developed H6 and undeveloped H7 and H8 reservoirs.

4.1.1.1 Geophysical Database

The database required for the geophysical evaluation comprises processed 3D surface seismic data, well log data containing velocity information and well tops.

3D Seismic

Lime related that the BeninSEGY data is a reprocessed and merged dataset comprising the Western 1983 and Fugro 2007 (DLT_00183_03) surveys and is regarded as the best dataset for interpretation. The cube covers an area of ~48km^2 centred of the Sèmè North field wells, primarily focussed on the main, previously produced, H6 reservoir. RPS note that the BeninSEGY data could be significantly improved through the application of a modern reprocessing and depth imaging scheme.

No acquisition or processing reports were available.

Although the available reports indicate that VSP and checkshot surveys were run over many of the wells this information was either focussed on the previously developed H6 reservoirs or often missing. The evaluation has therefore been performed without any *bona fide* checkshot survey data, instead RPS generated synthetic seismograms and velocity logs from DT sonic logs in CS-1, CSW, CSE1 and Do2A wells (Figure 4-1).

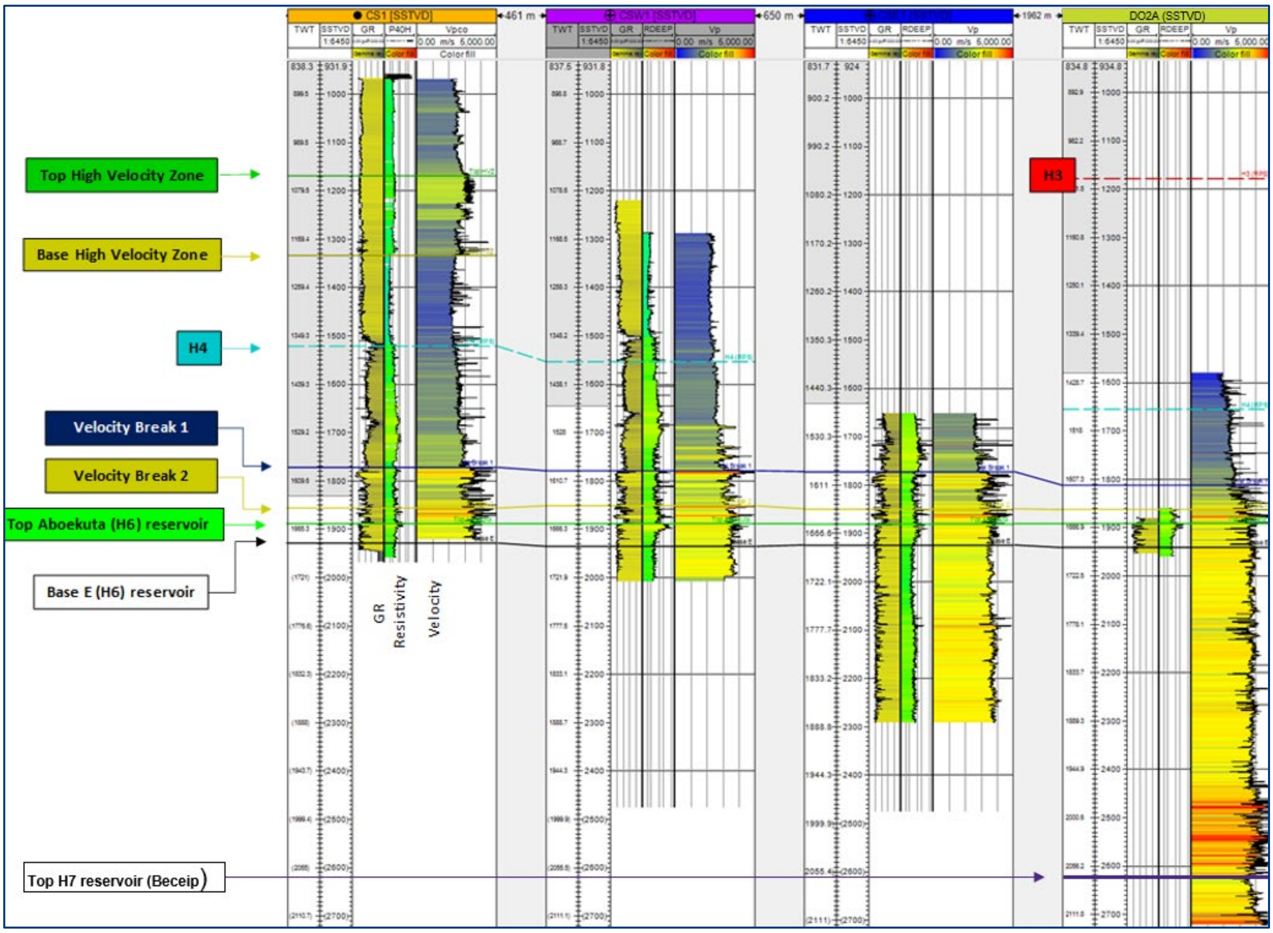

Figure 4-1: Well Data with useful Sonic Logs (converted to Velocity Logs). Also shown: GR, Resistivity Logs and a selection of Well Tops. Flattened on Top Abeokuta in TVDSS

4.1.1.2 Geophysical Audit

RPS completed an independent seismic interpretation, in time, using the overburden horizons to help understand the impact of the overburden geology on the developed H6 and deeper, under -developed, H7 and H8 structure. As more data was available for the overlying H6 reservoir, this was used as an initial focus to aid the depth conversion of the more data scarce H7 and H8 reservoirs. A series of depth conversion methods was investigated for the H6 reservoir, but due to the paucity of well penetrations a single pseudo velocity to Top H7 was used for the H7 reservoir (Figure 4-2). The top H8 reservoir (Figure 4-3) was created using a well top derived isopach from the H7 seismically derived map.

4.1.2 Geological Review

The H7 and H8 reservoirs have been drilled and tested, but the digital data appears to have been lost after SApetro relinquished the Operating licence. Subsequently no digital well log data or maps for these reservoirs were supplied by Lime and all reference to H8 is taken from the 1994 Beicip Franlab (Beicip) report prepared for Projet Petrolier de Sèmè.

Without log or pressure data RPS cannot verify the petrophysical, or geological assumptions made by Beicip. RPS reviewed the Beicip[4] report, and it was considered reasonable and logical and therefore fit for use for the In-place estimation at this stage in the Field's life.

RPS understand that Lime will be redrilling the H7 and H8 reservoirs in Q2 2025, at which point more data will be gathered to aid additional evaluation of these reservoirs.

4.1.2.1 H7

The H7 reservoir has been separated, by Beicip[4], into, an upper, H7-1 and a, lower, H7-2. The reservoirs are separated by a series of shales, sands and carbonates interpreted as a flood plain deposit. The depositional nature of these shales and carbonates, suggest that it is highly likely that H7 will be compartmentalised. Additionally similar field wide shales are reported in the produced H6 reservoirs where they form production barriers. However, without additional information RPS cannot opine further on possible compartmentalisation of the H7.

Based on the well tops and information provided, seven wells penetrated the H7 reservoir; DO-1, DO-2A, DO-A3, S-3, S-9, S10 and S11. Well tops and well parameters cannot be verified by RPS due to the lack of well log information. All values shown in Table 4-1 are taken from the 1994 Beicip[4] report. A full range used in the independent in-place estimation can be found in Table 4-4 and Table 4-5.

Reservoir	Average Thickness (m)	Average Porosity (%)	Average NTG (%)	Average Sw (%)
H7-1	21	14	76	61
H7-2	42	13	35	63

Table 4-1: Beicip Estimated H7 Reservoir Parameters

4.1.2.2 H8

Beicip split the H8 reservoir into, an upper, H8-1 and a, lower, H8-2. These were further subdivided into A and B layers (Table 4-2), which are separated by a series of shale bodies, interpreted by Beicip to be field-wide.

Based on the well tops and information provided, seven wells penetrated the H7 reservoir; DO-1, DO-2A, DO-A3, S-3, S-9, S10 and S11. Well tops and well parameters cannot be verified by RPS due to the lack of well log information. All values shown in Table 4-2 are taken from the 1994 Beicip[4] report.

Beicip report that core data from the S-10 well shows no signs of marine fauna or glauconite and has been interpreted at a continental fluvial depositional setting. The seals between reservoirs being interpreted as mud dominated flood-plain deposits. These could potentially cause vertical seals within H8. However, without log data RPS cannot fully opine upon this, other than to say that this is highly likely based on the reported depositional model and the production data observations in H6 reservoir, which shows similar field wide shales between the reservoir sands.

[4] *Beicip-Franlab (1994): Geological Study and Reserve Evaluation of the Seme Oil Field*

Reservoir	Average Thickness (m)	Average Porosity (%)	Average NTG (%)	Average Sw (%)
H8-1A	30	16	81	56
H8-1B	24	14	53	73
H8-2A	12	14	72	69
H8-2B	40	12	14	71

Table 4-2: Beicip Estimated H8 Reservoir Parameters

A full range used in the independent in-place estimation can be found in Table 4-6, Table 4-7, Table 4-8 & Table 4-9.

4.2 Volumetric Estimation

RPS estimated in-place volumes for the North Sèmè Field reservoirs. The volumetric estimation is based upon RPS' geophysical maps (Section 4.1.1) and RPS' assessment of information taken from the 1994 Beicip Franlab (Beicip) report prepared for Projet Petrolier de Sèmè.

RPS estimated the North Sèmè In-place volumes stochastically using Logicom's REP software (REP). RPS input values are summarised in in-place.

4.2.1 Top and Base Surfaces

The RPS seismic interpretation (Section 4.1.1.1) generated top surface maps of the H7 reservoir. Isopachs were generated for each of the reservoirs and the intervening shale 'barriers' from the RPS audited tops supplied in the Beicip[5] report. These were added H7 seismically derived maps to generate a series of Top and Base reservoir surfaces for the H7 and H8 hydrocarbon bearing reservoirs (Figure 4-2 and Figure 4-3).

The seismic provided in the static model, was limited to the producing H6 area. However, the underlying H7 and H8 reservoirs extend past the limit of the available seismic towards the south of the Field Structure (Figure 4-2 and Figure 4-3). Therefore, the approximate 'missing data' was digitised directly into REP from maps in the Beicip report.

Due to the uncertainty in the depth conversion (Section 4.1.1) caused by variable velocity in the overburden and the missing velocity data, RPS applied a +/- 20% uncertainty to the H7 and H8 reservoir surfaces.

[5] *Beicip-Franlab (1994): Geological Study and Reserve Evaluation of the Seme Oil Field*

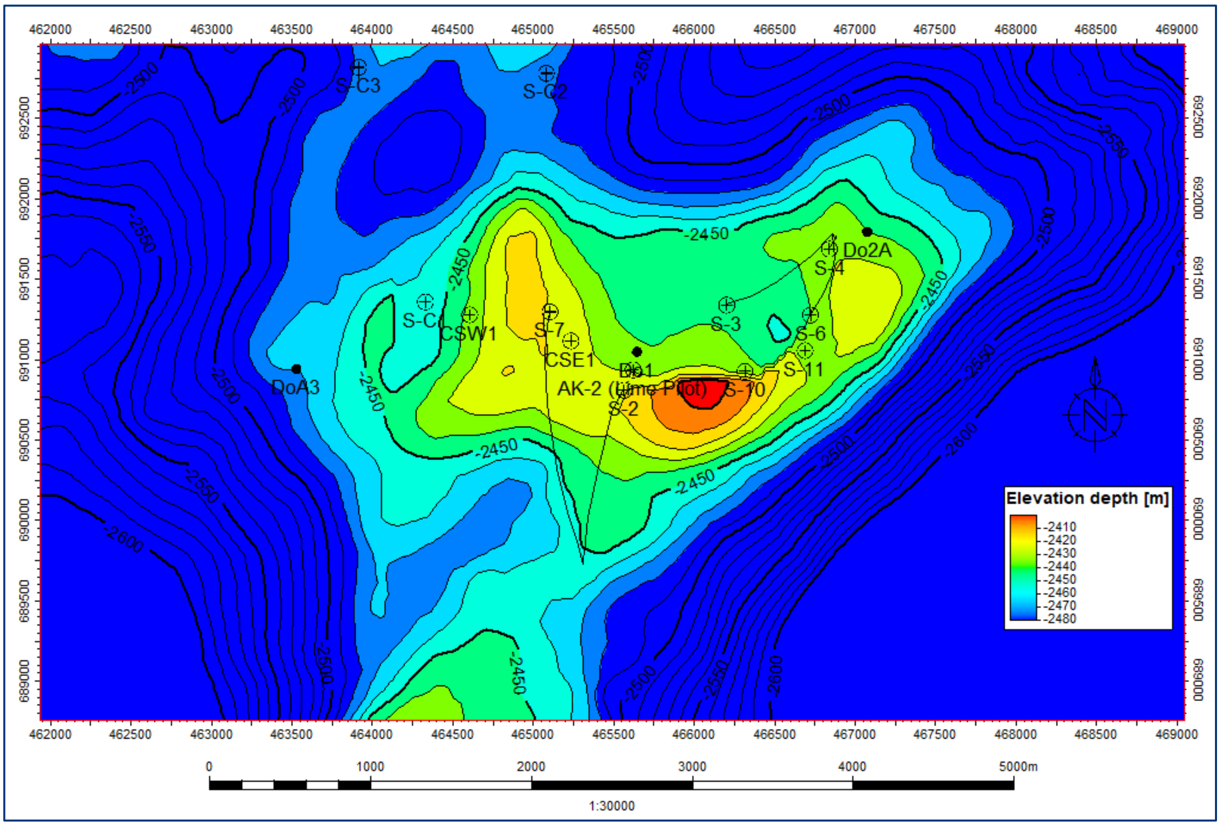

Figure 4-2: RPS H7.1 Top Surface

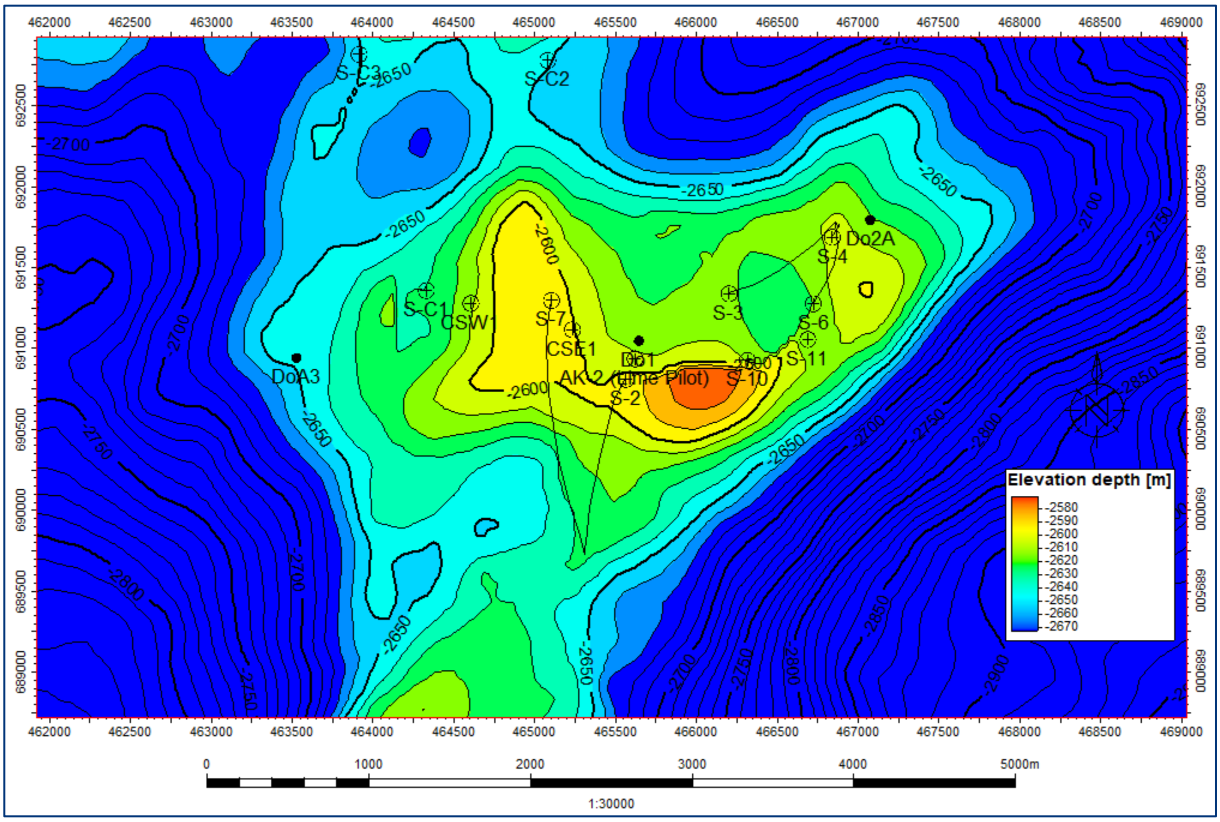

Figure 4-3: RPS H8.1 Top Surface

4.2.2 Contacts

In order to estimate the H7 and H8 in-place volumes the water contacts interpreted by Beicip[6] were used as a P50 +/- range estimated by RPS to account for the greater uncertainty due to limited well penetration (Table 4-3).

Reservoir	Hydrocarbon Contact	Low	Best	High
H7.1	Oil Water Contact	2455	2465	2475
H7.2	Oil Water Contact	2544	2554	2564
H8.1A	Gas Water Contact	2645	2650	2655
H8.1B	Gas Water Contact	2663	2668	2673
H8.2A	Gas Water Contact	2685	2690	2690
H8.2B	Gas Water Contact	2715	2720	2725

Table 4-3: Applied Hydrocarbon Contacts (m TVDss)

4.2.2.1 Reservoir Parameters for In-place Volume Estimation

RPS based its reservoir parameter range on those estimated by Beicip[6] in order to estimate the In-Place for the H7 and H8 reservoirs.

Parameter	Distribution	P_{90}	P_{50}	P_{10}
NTG (%)	Normal	54.5	74.0	91.5
Porosity (%)	Normal	13.0	14.0	15.0
Water Saturation (%)	Normal	40.0	50.0	60.0
Bo (v/v)	Single		1.15	

Table 4-4: Summary of Input Reservoir Parameters for H7.1 Volumetrics

Parameter	Distribution	P_{90}	P_{50}	P_{10}
NTG (%)	Normal	15.8	35.2	55.1
Porosity (%)	Normal	12.0	13.0	14.0
Water Saturation (%)	Normal	40.0	50.0	60.0
Bo (v/v)	Single		1.15	

Table 4-5: Summary of Input Reservoir Parameters for H7.2 Volumetrics

Parameter	Distribution	P_{90}	P_{50}	P_{10}
NTG (%)	Normal	64.7	79.4	92.9
Porosity (%)	Normal	14.0	17.0	20.0
Water Saturation (%)	Normal	45.0	55.0	65.0
Bo (v/v)	Single		154	

Table 4-6: Summary of Input Reservoir Parameters for H8.1A Volumetrics

[6] *Beicip-Franlab (1994): Geological Study and Reserve Evaluation of the Seme Oil Field*

Parameter	Distribution	P_{90}	P_{50}	P_{10}
NTG (%)	Normal	29.9	54.8	79.0
Porosity (%)	Normal	10.0	14.0	18.0
Water Saturation (%)	Normal	55.0	62.5	70.0
Bo (v/v)	Single		154	

Table 4-7: Summary of Input Reservoir Parameters for H8.1B Volumetrics

Parameter	Distribution	P_{90}	P_{50}	P_{10}
NTG (%)	Normal	54.9	69.9	84.4
Porosity (%)	Normal	11.0	13.0	15.0
Water Saturation (%)	Normal	55.0	62.5	70.0
Bo (v/v)	Single		154	

Table 4-8: Summary of Input Reservoir Parameters for H8.2A Volumetrics

Parameter	Distribution	P_{90}	P_{50}	P_{10}
NTG (%)	Normal	6.09	15.3	25.1
Porosity (%)	Normal	10.0	12.0	14.0
Water Saturation (%)	Normal	55.0	62.5	70.0
Bo (v/v)	Single		154	

Table 4-9: Summary of Input Reservoir Parameters for H8.2B Volumetrics

4.2.3 RPS In-place Volume Estimates

RPS estimated in-place volumes for the lower oil reservoirs; H7.1 and H7.2 are summarised in Table 4-10 and for the gas reservoir, H8, in Table 4-11. Due to limited appraisal drilling RPS has estimated the in-place for the full Sèmè Field Structure. RPS has not segmented these volumes and a large amount of structural and petrophysical uncertainty remains.

	STOIIP (MMstb)		
	P90	P50	P10
H7.1	24	41	67
H7.2	18	45	83
Arithmetic Total	**42**	**86**	**150**
Probabilistic Total	**55**	**88**	**134**

Table 4-10: Gross Pre-Production STOIIP for all Oil Bearing Lower Reservoirs

	GIIP (Bscf)		
	P90	P50	P10
H8.1A	48	76	116
H8.1B	7	15	27
H8.2A	4	7	10
H8.2B	3	7	14
Arithmetic Total	**62**	**105**	**167**
Probabilistic Total	**77**	**108**	**149**

Table 4-11: Gross Pre-Production GIIP for H8 Reservoirs

5 Reservoir Engineering Assessment

RPS has been provided with previous study reports, many well reports of varying age and quality, a legacy history-matched model and Lime's dynamic forecast model of the field.

RPS has reviewed the forecasting methodology employed by Lime for each of the reservoirs, namely:

- H7 – Oil decline curve results based on DSTs
- H8 – Gas decline curve results based on DSTs with field gas constraint

5.1 H7 Reservoir – Oil

The H7 reservoir has not been produced to date, but has been tested a number of times. The Lime Phase 2, development plan includes three horizontal fishbone wells with ESPs (Section 1.3).

In order to provide profiles for the H7 reservoir, RPS has used exponential decline curves. The initial rates are based on reported DST rates from vertical wells for the H7 reservoir with an uplift due to the proposed completions strategy and are summarised in Table 5-1. No Aquifer support is expected and the Recovery factors are assumed to be 15-20-25% across the Low, Mid and High cases, respectively.

		Initial Oil Rates (stb/d)	
	Low	**Best**	**High**
Vertical Well	300	500	900
Uplift due to completions strategy	2	3.5	5
Initial Rate for DCA	600	1750	4500

Table 5-1: Initial Rates used in DCA for North Sèmè H7 Reservoir

The resulting production profiles are shown in Figure 5-1 and summarised in Table 5-2. Gas profiles are generated based on a constant GOR of approximately 228 scf/stb.

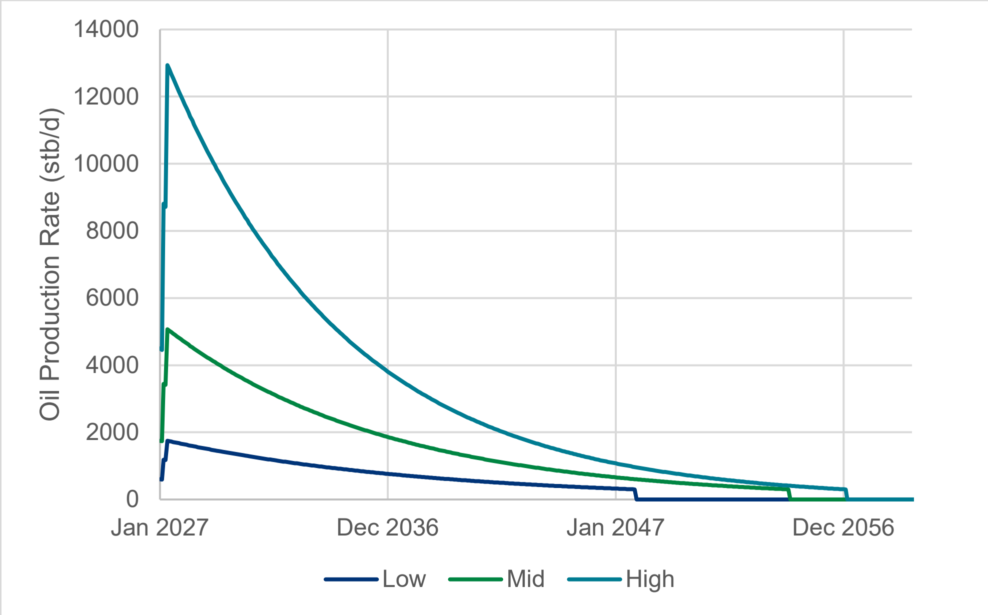

Figure 5-1: North Sèmè H7 Oil Production Profiles for Low, Mid and High Cases

	OIL (MMstb/d)		
	Low	**Best**	**High**
STOIIP – Arithmetic Total (MMstb)	42	86	150
Total Production (MMstb)	6.3	17.2	37.5
Recovery Factor	15%	20%	25%

Table 5-2: Technical Forecast Volume Summary for North Sèmè H7 Reservoir

5.2 H8 Reservoir – Gas

The H8 reservoir has not been produced to date but has been tested a number of times. The Lime development plan includes two horizontal H8 fishbone wells (Section 1.3).

In order to provide profiles for the H8 reservoir, RPS has used exponential and hyperbolic decline curves as the H8. The initial rates are based on reported DST rates from vertical wells for the H8 reservoir with an uplift due to the proposed completions strategy. As there are only two development wells, there is risk of compartmentalisation in the reservoir and RPS therefore applied a factor to the connected GIIP of 70-80-100% across the Low, Mid and High cases, respectively. Recovery factors are assumed to be 60-70-80% across the Low, Mid and High cases.

	GAS (MMscf/d)		
	Low	**Best**	**High**
Vertical Well	1	1.5	2
Uplift due to completions strategy	2	3.5	5
Initial Rate for DCA	2	5.25	10

Table 5-3: Initial Rates used in DCA for North Sèmè H6 Reservoir

The resulting unconstrained gas potential curves are shown in Figure 5-2. Lime plan to use the gas production to deliver a flat 12 MMscf/d of gas in the assumed gas contract, after accounting for the associated gas production from the H6 and H7 reservoirs. The productivity of the wells is sufficient to reach this production target only in the High case and a reduction in the constant gas rate (Plateau) would be required over Lime's currently assumed 10 year period for the Base case gas contract. The resulting constrained production profiles are shown in Figure 5-3 and summarised in Table 5-4. Condensate profiles have been generated using a constant CGR based on the range of oil rates reported in the DST results, 47.6-68.4-89.3 stb/MMscf in the Low, Mid, High cases, respectively.

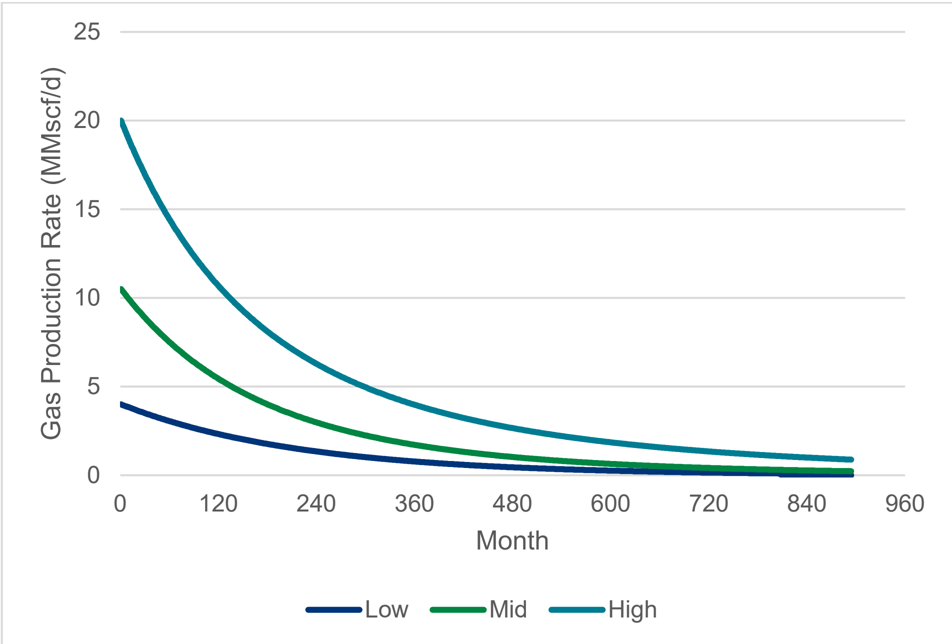

Figure 5-2: North Sèmè H8 Unconstrained Gas Production Profiles for Low, Mid and High Cases

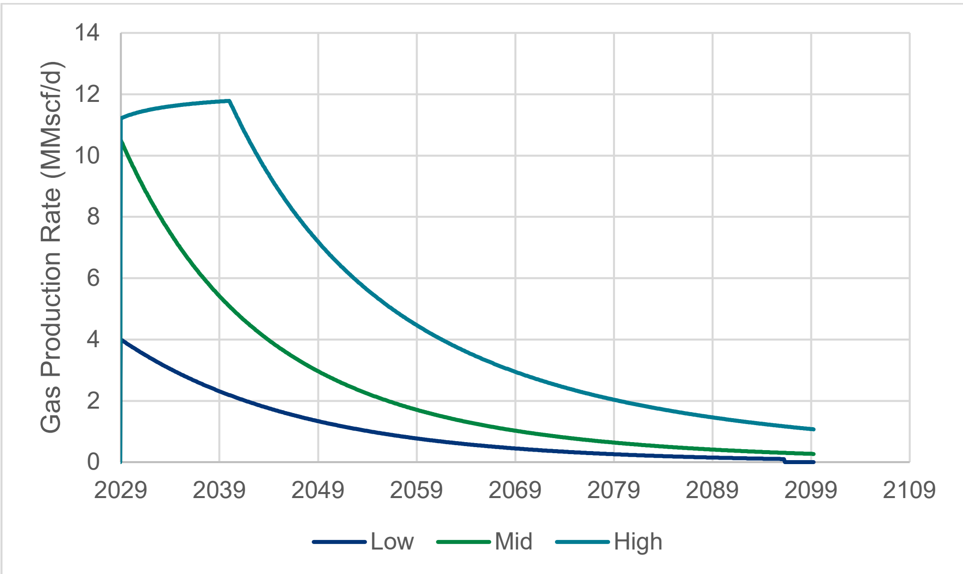

Figure 5-3: North Sèmè H8 Gas Production Profiles for Low, Mid and High Cases

	GAS (MMscf/d)		
	Low	Best	High
GIIP - Arithmetic Total (Bscf)	62	105	167
Connected GIIP Ratio	70.0%	85.0%	100.0%
Connected GIIP (Bscf)	43.4	89.25	167
Total Production (Bscf)	26.0	62.5	133.6
Recovery Factor of Connected GIIP	60.0%	70.0%	80.0%

Table 5-4: Technical Forecast Volume Summary for North Sèmè H8 Reservoir

6 H7 and H8 Capex and Opex Review

RPS evaluated both the Phase 1 and Phase 2 development costs supplied by Lime. The initial development plan is outlined in Section 1.3 and all costs relating to this.

The development of the H7 and H8 reservoirs is part of the Phase 2 development. Phase 2 comprises two parts and is contingent upon the appraisal results of the lower reservoirs drilled in Phase 1. The first part will be to develop H7 using three horizontal 'fish bone' wells, fitted with intelligent completions and ESPs. First oil from H7 is planned for Q3 2026, with the development wells being drilled back to back with the second (Phase 1) H6 development well.

The second part, of Phase 2, will be to develop H8 by drilling two horizontal 'fish bone' wells and installing wet gas processing on the MOPU. This will involve installation of gas dehydration and compression on the MOPU. A new gas line will be installed to shore with final gas export to a local gas fired power station. A gas processing plant will be constructed onshore to supply indigenous gas to the power station.

RPS in general has accepted the Operator's Capex estimates with the following modifications.

- The Operator's estimate of the new gas line to shore in RPS's opinion was too low. RPS has increased this to US$15m with 25% (US$3.75m) contingency

- The new facilities costs do not appear to include contingency. RPS has applied a 25% contingency to the Phase 2 facilities costs

The Phase 2 Capex is shown in Table 6-1.

Phase 2 Capex	US$ million
Drilling Capex: 3 x Horizontal Oil Wells (in H7)	60
Drilling Capex: 2 x Horizontal Gas Wells (in H8)	40.0
15 MMscfd Electrically Driven Gas Compressor Package (1 MX x 2)	3.0
15 MMscfd Glycol Contactor, Regen Skid and Gas Separator	2.0
RPS Applied Contingency on Compression and Glycol Packages	1.25
Gas Export Pipeline	15
Gas Export Pipeline Contingency	3.75
Total Phase 2 Capex	**125**

Table 6-1: Phase 2 Capex

The operating costs have been provided by the operator and reviews and accepted by RPS. The Phase 2 Opex is shown in Table 6-2.

Phase 2 Opex	US$ / day
FSO Lease Rate	46,500
MOPU	50,500
Supply Vessel	17,500
G&A	8,500
Total Phase 2 Opex	**120,000**

Table 6-2: Phase 2 Opex

7 Production and Cost Profiles

The full field Phase 1 and Phase 2 cost profiles are shown in **Figure 7-1** below. The Phase 2 wells, gas handling and pipeline costs are contingent.

Year	EXPLORATION CAPEX			DEVELOPMENT CAPEX					DECOMM	OPERATING EXPENSES			TARIFFS			Financing		
	Drilling	Seimic	Other	PM	Phase 1 wells	Phase 2 wells	MOPU – FSO – Flowline	Gas handling + pipeline	Abandonment Cost	Lease	Interests	Office	Oil Tariff	Gas Tariff	General Tariff	Draw down		
	$MM	$MM	$MM	$MM	$MM	$MM	$MM	$MM	$MM	$MM	$MM	$MM	$/bbl	$/mcf		77.26	Interest	
jan. 24											-						-	
feb. 24																	-	
mar. 24																	-	
apr. 24																	-	
mai. 24																	-	
jun. 24																	-	
jul. 24				0.42													-	
aug. 24				0.42													-	
sep. 24				0.42													-	
okt. 24				0.42													-	
nov. 24				0.42													-	
des. 24				0.42													-	
jan. 25				0.42													-	
feb. 25				0.42													-	
mar. 25				0.42													-	
apr. 25				0.42							0.55	0.23				59.46	0.55	
mai. 25				0.42	4.80						0.55	0.23				59.46	0.55	
jun. 25				0.42	8.00		6.00				0.55	0.23				59.46	0.55	
jul. 25				0.42	8.00		4.00			3.29	0.55	0.23				59.46	0.55	
aug. 25				0.13	10.00					3.29	0.55	0.23				59.46	0.55	
sep. 25				0.13	10.00					3.18	0.55	0.23				59.46	0.55	
okt. 25				0.13	1.90					3.29	0.55	0.23				59.46	0.55	
nov. 25				0.13						3.18	0.55	0.23				59.46	0.55	
des. 25				0.13						3.29	0.55	0.23				59.46	0.55	
jan. 26				0.13						3.29	0.55	0.23				59.46	0.55	
feb. 26				0.13						2.97	0.55	0.21				59.46	0.55	
mar. 26				0.13						3.29	0.55	0.23				59.46	0.55	
apr. 26				0.13						3.18	-	0.23					-	
mai. 26				0.13						3.29	-	0.23					-	
jun. 26										3.18	-	0.23					-	
jul. 26					10.00					3.29	-	0.23					-	
aug. 26					10.00					3.29	-	0.23					-	
sep. 26				0.42						3.18	-	0.26					-	
okt. 26				0.42						3.29	-	0.26					-	
nov. 26				0.42		10.00				3.18	-	0.26					-	
des. 26				0.42		11.00				3.29	-	0.26					-	
2027				5.00		42.00		13.16		37.78	-	3.10					-	
2028				5.00				11.84		37.78	-	3.10					-	
2029						42.00				37.78	-	3.10						
2030										37.78	-	3.10						
2031										37.78	-	3.10						
2032										37.78	-	3.10						
2033										37.78	-	3.10						
2034										37.78	-	3.10						
2035									-	37.78	-	3.10						
2036										37.78	-	3.10						
2037										37.78	-	3.10						
2038										37.78	-	3.10						
2039										37.78	-	3.10						
2040									30.00	-	-							
2041																		
2042																		
2043																		
2044																		
2045																		
2046																		
2047																		
2048																		
2049																		
2050																		
Totals	-	-	-	18.33	62.70	105.00	10.00	25.00	30.00	549.30	6.54	45.23	-	-	-	713.52	6.54	-

Figure 7-1 Phase 1 and Phase 2 Cost Profile

8 Economic Evaluation

8.1 Contractual Rights Overview

In December 2023, Akrake signed a production sharing contract ("PSC") for operatorship and a 76 percent working interest in Block 1, Benin. The remainder of the working interest is held by the government of Benin holding 15 per cent and Octogone Trading, an integrated energy and commodities company trading throughout West Africa, holding 9 per cent.

8.2 Fiscal Overview

Block 1 PSC fiscal terms applied for this evaluation are as follows:

- Ad Valorem Fee (Royalty):
  - Oil rate: 10%
  - Gas rate: 3%
- Cost Recovery Ceiling
  - EWT phase: 100.0%
  - Exploitation phase: 70.0%
- Profit Oil to State (Tax oil)
  - Oil Allocation Rate to Government

	R Factor	Rate (%)
Less than	1.5	45%
Between	1.5 and 2	50%
Between	2 and 2.5	55%
Greater than	2.5	60%
Historical	1.0	

- Profit Oil allocation between Contractor Group
  - Akrake Petroleum: 76%
  - Octogone E&P: 9%
  - National Operator: 15%

8.3 Petroleum Pricing Basis

Oil and gas price assumptions applied in RPS commercial evaluation are summarised in Table 8-1.

Year	RPS Q1 2025 Brent Oil Price (US$/stb) MOD	Realised Gas Price (US$/Mscf) MOD
2025	75.0	6.00
2026	75.0	6.18
2027	73.0	6.30
2028	73.0	6.43
2029	73.0	6.56
2030	73.0	6.69
2031	73.0	6.82
2032	75.0	6.96
2033	78.0	7.10
2034	84.5	7.24
2035	86.2	7.39
2036	87.9	7.53
2037	89.6	7.68
2038	91.4	7.84
2039	93.3	7.99
2040	95.1	8.15

Table 8-1: Oil and Gas Price Assumptions

8.4 Cashflow Analysis

The Economic Limit Test ("ELT") performed for the determination of Reserves and Resources is based on RPS's estimates of recoverable volumes, a review of the Company's estimates of Capex, Opex, and Abex; and inclusion of other financial information and assumptions.

The PSC is assumed to reach its economic limit when the cumulative value of its net cash flow (excluding Abex) before tax ceases to increase. All projects to be classified as Reserves must be economic under defined conditions[7]. RPS has therefore assessed the future economic viability of each case on the basis of its pre-tax undiscounted Net Cash Flow MOD.

An annual inflation rate of 2 per cent has been built into the ELT.

The effective date of this report is 1st January 2025.

[7] *PRMS 2018: 3.1.2.1 Economic determination of a project is tested assuming a zero percent discount rate (i.e., undiscounted). A project with a positive undiscounted cumulative net cash flow is considered economic.*

9 Contingent Resources

The H7 and H8 reservoirs are known to contain hydrocarbons having a total of seven well penetrations. However, they have never been developed and are part of Lime's Phase 2 development plan (Section 1.3). The development of both the H7 and H8 reservoirs is contingent on the findings of the new well (AK1) due to be drilled in Q2 2025 and the agreement to continue production past the initial 1 year test period currently proposed for the Phase 1 redevelopment of the H6 reservoir.

Therefore, RPS considers the H7 and H8 reservoirs as **Contingent Resources – Development Unclarified.**

The Full Field Gross Resources and the Net Entitlement Resources of the contingent resource are shown in Table 9-1, Table 9-2**,** Table 9-3, Table 9-4 & Table 9-5.

RPS estimate a risk factor development of 40% for the Gas and Condensate 50% for the Oil (Table 9-5).

SUMMARY OF OIL CONTINGENT RESOURCES

As of 1 January 2025

BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (MMstb)			Lime (Akrake) Net Entitlement Resources[2] (MMstb)			Rex Net Entitlement Resources[3] (MMstb)		
	1C[4]	2C	3C	1C[4]	2C	3C	1C[4]	2C	3C
H7 (H7.1 & H7.2)	-	13.4	30.8	-	8.2	11.5	-	6.6	9.2

Notes:

[1] Gross field Contingent Resources (100% basis) after economic limit test

[2] Net Entitlement to Akrake's working interest of 76%, which excludes the Benin Government Share under the PSC after the ELT

[3] Net Entitlement to Rex (Rex owns 80.14% of Akrake's Net Entitlement), which excludes the Benin Government Share under the PSC after the ELT

[4] Negative incremental NPV

Table 9-1: North Sèmè Oil Contingent Resources – Development Unclarified.

SUMMARY OF GAS CONTINGENT RESOURCES

As of 1 January 2025

BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (Bscf)			Lime (Akrake) Net Entitlement Resources[2] (Bscf)			Rex Net Entitlement Resources[3] (Bscf)		
	1C[4]	2C	3C	1C[4]	2C	3C	1C[4]	2C	3C
H8 – Free Gas (H8.1A, H8.1B, H8.2A & H8.2B)	-	28.6	39.1	-	18.1	17.4	-	14.5	13.9
H7 Associated Gas (H7.1 & H7.2)	-	3.1	7.0	-	1.9	3.1	-	1.6	2.5
Total[5]	**-**	**31.7**	**46.1**	**-**	**20.1**	**20.5**	**-**	**16.1**	**16.4**

Notes:

[1] Gross field Contingent Resources (100% basis) after economic limit test

[2] Net Entitlement to Akrake's working interest of 76%, which excludes the Benin Government Share under the PSC after the ELT

[3] Net Entitlement to Rex (Rex owns 80.14% of Akrake's Net Entitlement), which excludes the Benin Government Share under the PSC after the ELT

[4] Negative incremental NPV

[5] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Resources are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Resources may be a very conservative assessment and the total 3C Resources a very optimistic assessment.

Table 9-2: North Sèmè Gas Contingent Resources – Development Unclarified.

SUMMARY OF CONDENSATE CONTINGENT RESOURCES

As of 1 January 2025

BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (MMstb)			Lime (Akrake) Net Entitlement Resources[2] (MMstb)			Rex Net Entitlement Resources[3] (MMstb)		
	1C[4]	2C	3C	1C[4]	2C	3C	1C[4]	2C	3C
H8 – (H8.1A, H8.1B, H8.2A & H8.2B)	-	2.0	3.5	-	1.2	1.3	-	1.0	1.0

Notes:

[1] Gross field Contingent Resources (100% basis) after economic limit test

[2] Net Entitlement to Akrake's working interest of 76%, which excludes the Benin Government Share under the PSC after the ELT

[3] Net Entitlement to Rex (Rex owns 80.14% of Akrake's Net Entitlement), which excludes the Benin Government Share under the PSC after the ELT

[4] Negative incremental NPV

Table 9-3: North Sèmè Condensate Contingent Resources – Development Unclarified.

SUMMARY OF CONTINGENT RESOURCES (BOE)

As of 1 January 2025

BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (MMBoe)[6]			Lime (Akrake) Net Entitlement Resources[2] (MMBoe)[6]			Rex Net Entitlement Resources[2] (MMBoe)[6]		
	1C[4]	2C	3C	1C[4]	2C	3C	1C[4]	2C	3C
H7	-	13.9	32.0	-	8.6	12.0	-	6.9	9.6
H8	-	6.7	10.0	-	4.2	4.2	-	3.4	3.4
Total[5]	**-**	**20.7**	**42.0**	**-**	**12.8**	**16.2**	**-**	**10.2**	**13.0**

Notes:

[1] Gross field Contingent Resources (100% basis) after economic limit test. Economic limit in 2039 for 2C and 3C

[2] Net Entitlement to Akrake's working interest of 76%, which excludes the Benin Government Share under the PSC after the ELT

[3] Net Entitlement to Rex (Rex owns 80.14% of Akrake's Net Entitlement), which excludes the Benin Government Share under the PSC after the ELT

[4] Negative incremental NPV

[5] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Resources are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Resources may be a very conservative assessment and the total 3C Resources a very optimistic assessment.

[6] Conversion rate of 6,000 standard cubic feet per boe

Table 9-4: North Sèmè BOE Contingent Resources – Development Unclarified.

Category	Gross Attributable to Licence (MMstb/Bscf)[1]	Net Attributable to Akrake [2] (MMstb/Bscf)	Net Attributable to Akrake [2] Change from Previous Update [5] (%)	Net Attributable to Issuer (Rex) [3] (MMstb/Bscf)	Net Attributable to Issuer (Rex) [3] Change from Previous Update [5] (%)	Risk Factors [6]	Remarks (Economic Limit)
RESERVES							
Oil							
1P	N/A	N/A	N/A	N/A	N/A		
2P	N/A	N/A	N/A	N/A	N/A		
3P	N/A	N/A	N/A	N/A	N/A		
Natural Gas							
1P	N/A	N/A	N/A	N/A	N/A		
2P	N/A	N/A	N/A	N/A	N/A		
3P	N/A	N/A	N/A	N/A	N/A		
Natural Gas Liquids							
1P	N/A	N/A	N/A	N/A	N/A		
2P	N/A	N/A	N/A	N/A	N/A		
3P	N/A	N/A	N/A	N/A	N/A		
CONTINGENT RESOURCES							
Oil							
1C	0.0	0.0	N/A	0.0	N/A	50%	N/A [4]
2C	13.4	8.2	N/A	6.6	N/A	50%	2039
3C	30.8	11.5	N/A	9.2	N/A	50%	2039
Natural Gas							
1C	0.0	0.0	N/A	0.0	N/A	40%	N/A [4]
2C	31.7	20.1	N/A	16.1	N/A	40%	2039
3C	46.1	20.5	N/A	16.4	N/A	40%	2039
Natural Gas Liquids							
1C	0.0	0.0	N/A	0.0	N/A	40%	N/A [4]
2C	2.0	1.2	N/A	1.0	N/A	40%	2039
3C	3.5	1.3	N/A	1.0	N/A	40%	2039

Notes: [1] - Gross Field Contingent Resources (100%) after Economic Limit Test (ELT)
[2] - Net Entitlement to Akrake's working interest of 76%, which excludes the Benin Government Share under the PSC after the ELT
[3] - Net Entitlement to Rex (Rex owns 80.14% of Akrake's Net Entitlement), which excludes the Benin Government Share under the PSC after the ELT
[4] - Negative incremental NPV.
[5] - Previous evaluation was not conducted by RPS
[6] - Applicable to Resources. "Risk Factor" for Contingent Resources means the estimated chance , or probability, that the volumes will be commercially extracted

1P: Proved
2P: Proved + Probable
3P: Proved + Probable + Possible
1C: Low Estimate Contingent Resource
2C: Best Estimate Contingent Resource
3C: High Estimate Contingent Resource

MMstb: Millions of Stock Tank Barrels
Bscf: Billions of Standard Cubic Feet
N/A: Not Applicable

Name of Qualified Person: Gordon Taylor
Date: 17-Apr-25

Professional Society Membership: Fellow, Geological Society, Chartered Geologist (C.Geol)
Member, Institute Materials, Minerals & Mining, Chartered Engineer (C.Eng)

Table 9-5: Summary of Oil and Gas Contingent Resources for North Sèmè as of January 1, 2025

10 Consultant's Information

RPS confirms the following:

- The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical, and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Reserves are based on data provided by Lime. We have accepted, without independent verification, the accuracy and completeness of this data.

- The report represents RPS's best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available.

- RPS has been remunerated on a fee basis, not dependent on the findings of this report or connected to asset or client financial performance, past or future, in any way.

- RPS confirms that there is no conflict of interest related to this work. Furthermore, the management and employees of RPS are independent of Lime as well as Rex International Holding Limited (Rex), Rex's substantial shareholders, advisors and their associates and they have no interest in any of these assets evaluated nor related with the analysis carried out as part of this report.

- RPS confirms also that neither it nor its management, employees and their respective associates have any interest in Lime, Rex, Rex's subsidiaries or associated companies and will not receive benefits other than renumeration paid to RPS in connection with the preparation of this report.

- All staff and associates working on this evaluation meet the professional qualifications requirements of a Qualified Reserves Auditor as specified in the SPE Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (June 2019):

  - A minimum of 10 years practical experience in petroleum engineering or petroleum geology or similar.

  - Have at least a bachelor's or advanced degree in Petroleum Engineering, Geology, or other discipline of engineering or physical science.

  - Has received and is maintaining in good standing, a registered or certified professional licence or equivalent thereof from an appropriate governmental authority or professional organisation.

  - A summary of experience and relevant qualifications is provided in Table 10-1.

- The Competent person (Mr Gordon Taylor) has not been found in breach of any relevant rule of law and is not;
  - Denied or disqualified from membership of;
  - The subject of any sanctions that would prohibit his certification of this report by;
  - The subject of any disciplinary proceedings or the subject of any investigation which may lead to disciplinary proceedings by;

  Any relevant regulatory authority of professional association.

Name	Role	Years of Experience	Qualifications	Professional Memberships
Gordon Taylor	Competent Person	>40	BSc. Geological Science Birmingham University MSc Foundation Engineering Birmingham University	Chartered Geologist Fellow, Geological Society of London Chartered Engineer Member, IMMM Certified Geologist Division Professional Affairs, AAPG Member, SPE
David Offer	Project Manager and Geoscience Lead	>25	BSc (*Hons*) Exploration and Mining Geology. University of Wales, College of Cardiff. MSc Industrial Mineralogy University of Leicester	Fellow, Geological Society of London Member – Geoscience Energy Society of Great Britain
Adam Turner	Reservoir Engineering Lead	>15	BE Chemical Engineering University of Bath MS Petroleum Engineering Herriot-Watt University	Member - SPE
Joseph Tan	Economics Lead	>20	BEng (Hons.) Petroleum Engineering, Universiti Teknologi Malaysia, 2001	Member – SPE Member – South East Asia Petroleum Exploration Society (SEAPEX) Member and Malaysia Section Lead – Association of International Energy Negotiators (AIEN)
David Walker	Costs/Facilities Lead	>20	MEng Chemical Process Engineering University of Sheffield	
Simon Russell	Geophysical Lead	>25	BSc Geological and Earth Sciences Durham University PhD Geophysics and Seismology University of Durham	

Table 10-1: Summary of Consultant Personnel

11 Data Sources

Key data sources used in the preparation of this report;

Seme Field Re-Development_REX(23.09.2023).pdf

LISTE DES DONNEES TRANSMIS A Rex_lime_Octogone CE 30 11 2023.doc

8-Petrophysical evaluation by GEOPARTNER for SAPETRO 2010.pdf

BEICIP-FRANLAB_ Volume I,MARCH 1994 VERSION ANGLAISE .pdf

BENIN BASIN EVALUATION REPORT SAGA 1984.pdf

ETUDE GEOLOGIQUE ET EVALUATION DES RESERVES DU CHAMP PETROLIER DE SEME OFFSHORE BENIN BEICIP FRANLAB VOLUME 1 MARS 1994 VERSION FRANCAISE.pdf

GEOLOGICAL AND GEOPHYSICAL REVIEW SAPETRO,block 1 2011.pdf

Nord-Seme-Petrophysical Evaluation Report-LS-corr 2016.pdf

SEME FIELD MANAGEMENT AND RESERVOIR SIMULATION STUDY VOLUME III RESERVOIR SIMULATION FINAL REPORT MAY 1998 SSI.pdf

SEME OIL FIELD PROJECT SEME FIELD RESERVOIR STUDY STATUS REPORT FOR GEOLOGY AND PETROPHYSICS SSI JUNE 1987.pdf

Well trajectories for;

AK-2.las

AK-3.las

AK-4.las

23-05-2024 AG AKRAKE PETROLEUM AU SUJET DE VOTRE DEMANDE DE LETTRE DE CONFORT.pdf

Seme North - RC2 FDP Casebook (10.06.2024)_RPS.xlsx

BeninSegY.sgy

DLT_00183_01.sgy

DLT_00183_02.sgy

DLT_00183_03.sgy

DLT_00183_04.sgy

Benin-seme-dynamic model-Benin Ministry Presentation--JB .ppt

PetrelStatic2015

Post-Drill Forecast2015Model

Pre-Drill Model – Forecast 2014Model

SEME History Match 2013 Model

SEME run WW4a Pre-drilled Model_Forecast 2010

Production and DST data

PVT STUDY REPORT FOR SAPETRO CSE-1 PVT2009-015.pdf

Appendix A: Glossary

1C	The low estimate of Contingent Resources. There is estimated to be a 90% probability that the quantities actually recovered could equal or exceed this estimate
2C	The best estimate of Contingent Resources. There is estimated to be a 50% probability that the quantities actually recovered could equal or exceed this estimate
3C	The high estimate of Contingent Resources. There is estimated to be a 10% probability that the quantities actually recovered could equal or exceed this estimate
1P	The low estimate of Reserves (proved). There is estimated to be a 90% probability that the quantities remaining to be recovered will equal or exceed this estimate
2P	The best estimate of Reserves (proved+probable). There is estimated to be a 50% probability that the quantities remaining to be recovered will equal or exceed this estimate
3P	The high estimate of Reserves (proved+probable+possible). There is estimated to be a 10% probability that the quantities remaining to be recovered will equal or exceed this estimate
1U	The unrisked low estimate of Prospective Resources
2U	The unrisked best estimate of Prospective Resources
3U	The unrisked high estimate of Prospective Resources
AVO	Amplitude versus Offset
B	Billion
bbl(s)	Barrels
bbls/d	Barrels per day
Bcm	Billion cubic metres
B_g	Gas formation volume factor
B_{gi}	Gas formation volume factor (initial)
B_o	Oil formation volume factor
B_{oi}	Oil formation volume factor (initial)
B_w	Water volume factor
Boe	Barrels of oil equivalent
stb/d	Barrels of oil per day
BHP	Bottom hole pressure
Bscf	Billions of standard cubic feet
Bwpd	Barrels of water per day
Condensate	A mixture of hydrocarbons which exist in gaseous phase at reservoir conditions but are produced as a liquid at surface conditions
cP	Centipoise
Eclipse	A reservoir modelling software package
E_{gi}	Gas Expansion Factor
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
FBHP	Flowing bottom hole pressure
FTHP	Flowing tubing head pressure
Ft	Feet
FWHP	Flowing well head pressure

FWL	Free Water Level
GDT	Gas Down To
GIIP	Gas Initially in Place
GOC	Gas oil Contact
GOR	Gas/oil ratio
GRV	Gross rock volume
GWC	Gas water contact
IPR	Inflow performance relationship
IRR	Internal rate of return
KB	Kelly Bushing
k_a	Absolute permeability
k_h	Horizontal permeability
Km	Kilometres
LPG	Liquefied Petroleum Gases
M	Metres
m^3	Cubic metres
m^3/d	Cubic metres per day
Ma	Million years
M	Thousand
M$	Thousand US dollars
MBAL	Material balance software
Mbbls	Thousand barrels
mD	Permeability in millidarcies
MD	Measured depth
MDT	Modular formation dynamics tester tool
MM	Million
MMbbls	Million barrels
MMscf/d	Millions of standard cubic feet per day
MMstb	Million stock tank barrels (at 14.7 psi and 60° F)
MMt	Millions of tonnes
MM$	Million US dollars
MPa	Mega pascals
m/s	Metres per second
Msec	Milliseconds
Mt	Thousands of tonnes
mV	Millivolts
NTG or N:G	Net to gross ratio
NGL	Natural Gas Liquids
NPV	Net Present Value
OWC	Oil water contact
P90	There is estimated to be at least a 90% probability (P_{90}) that this quantity will equal or exceed this low estimate
P50	There is estimated to be at least a 50% probability (P_{50}) that this quantity will equal or exceed this best estimate

P10	There is estimated to be at least a 10% probability (P_{10}) that this quantity will equal or exceed this high estimate
PDR	Physical data room
Petrel	A geoscience and reservoir engineering software package
Petroleum	Naturally occurring mixtures of hydrocarbons which are found beneath the Earth's surface in liquid, solid or gaseous form
Phi	Porosity
p_i	Initial reservoir pressure
PI	Productivity index
Ppm	Parts per million
Psi	Pounds per square inch
Psia	Pounds per square inch (absolute)
Psig	Pounds per square inch (gauge)
p_{wf}	Flowing bottom hole pressure
PSDM	Pre-stack depth migrated seismic data
PSTM	Pre-stack time migrated seismic data
PVT	Pressure volume temperature
Rb	Barrel(s) at reservoir conditions
Rcf	Reservoir cubic feet
REP™	A Monte Carlo simulation software package
RF	Recovery factor
RFT	Repeat formation tester
RKB	Relative to kelly bushing
rm^3	Reservoir cubic metres
SCADA	Supervisory control and data acquisition
SCAL	Special Core Analysis
Scf	Standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	Standard cubic feet per day
scf/stb	Standard cubic feet per stock tank barrel
SGS	Sequential Gaussian Simulation
SIBHP	Shut in bottom hole pressure
SIS	Sequential Indicator Simulation
sm^3	Standard cubic metres
S_o	Oil saturation
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
S_{orw}	Residual oil saturation relative to water
sq. km	Square kilometers
Stb	Stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	Stock tank barrels per day
STOIIP	Stock tank oil initially in place
S_w	Water saturation
S_{wc}	Vonnate water saturation
$	United States Dollars

T	Tonnes
THP	Tubing head pressure
Tscf	Trillion standard cubic feet
TVDSS	True vertical depth (sub-sea)
TVT	True vertical thickness
TWT	Two-way time
US$	United States Dollar
VDR	Virtual data room
VLP	Vertical lift performance
V_{sh}	Shale volume
VSP	Vertical Seismic Profile
W/m/K	Watts/metre/° K
WC	Water cut
WUT	Water Up To
Z	A measure of the "non-idealness" of gas
ϕ	Porosity
μ	Viscosity
μ_g	Viscosity of gas
μ_o	Viscosity of oil
μ_w	Viscosity of water

Appendix B: Summary of Reporting Guidelines

PRMS is a fully integrated system that provides the basis for classification and categorization of all petroleum reserves and resources.

B.1 Basic Principles and Definitions

A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. Quantities of petroleum and associated products can be reported in terms of volumes (e.g., barrels or cubic meters), mass (e.g., metric tonnes) or energy (e.g., Btu or Joule). These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

B.1.1 Petroleum Resources Classification Framework

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

The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

Figure A.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

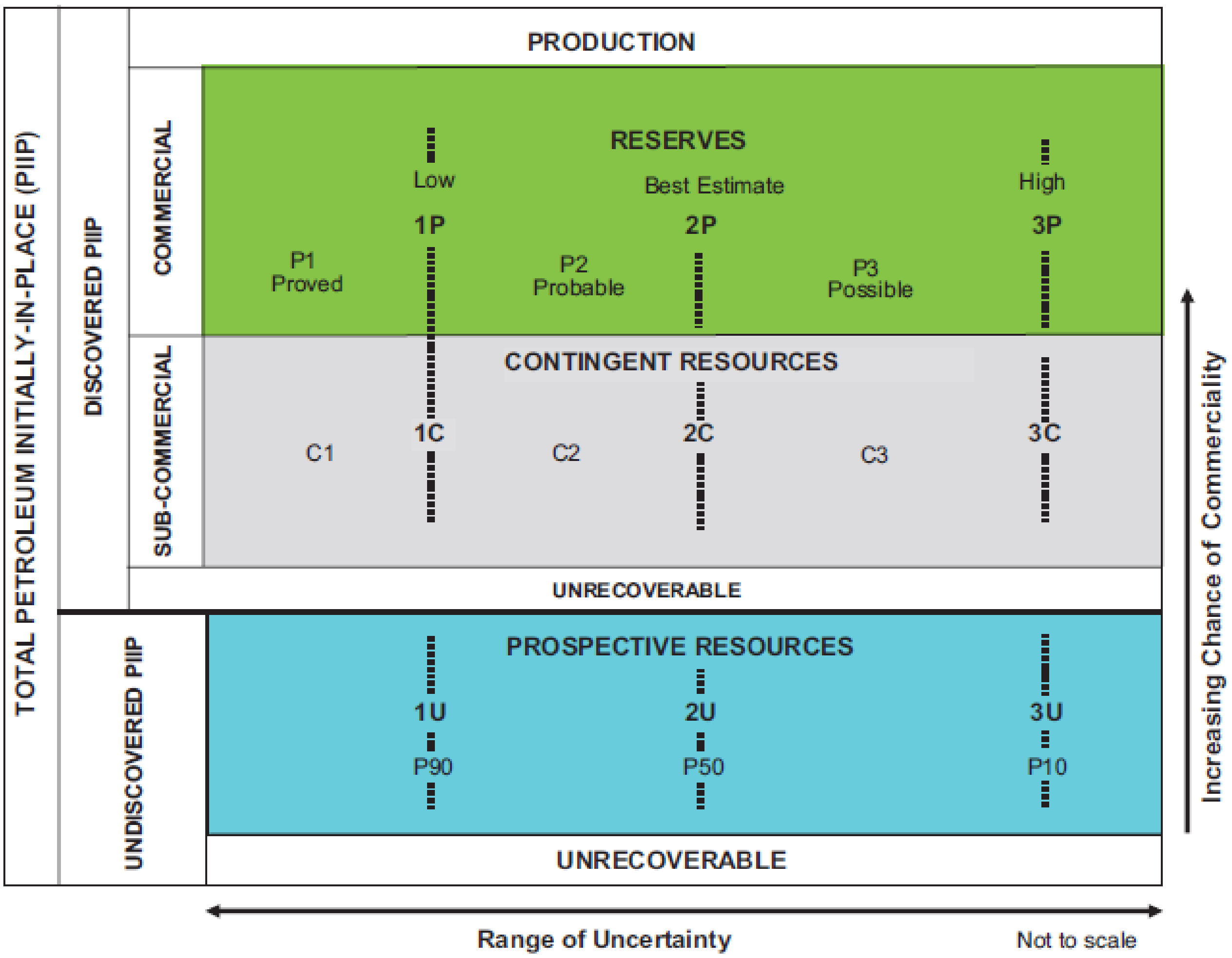

Figure B. 1: Resources classification framework

The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

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

- **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.
- **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before 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 PRMS 2018 Section 3.2, Production Measurement).

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

- **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) (see PRMS 2018 Section 3.2.2), 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.

Reserves are further categorized in accordance with the range of uncertainty and should be sub- classified based on project maturity and/or characterized by development and production status.

- **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.
- **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
- **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.
- **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, 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 because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

  The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

  Other terms used in resource assessments include the following:

- **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
- **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

Whenever these terms are used, the conditions associated with their usage must be clearly noted and documented.