Year End 2022 Reserves Audit

Abu Sennan Concession, Egypt

as of 31 December 2022

Prepared For:	United Oil and Gas
By:	ERCE
Date:	April 2023

Independent Energy Experts

Approved by: Paul Taylor, Head of Reserves and Resources

Date released to client: 24/04/2023

Table of Contents

List of Tables

List of Figures

24/04/2023

United Oil and Gas,

200 Strand,
London,
WC2R 1DJ

Ref: Year End 2022 Reserves Audit – Abu Sennan Concession

Dear Sir,

In accordance with your instructions, ERC Equipoise Ltd (ERCE) has conducted an audit ("the Audit") of the hydrocarbon Reserves in the Abu Sennan Concession (the "Concession") onshore Egypt, where United Oil and Gas. ("UOG" or the "Company") holds petroleum interests.

The effective date (the "Effective Date") of the Audit is 31 December 2022. In the preparation of this report (the Report) ERCE was provided with data and information up to the Effective Date by the operator of the concession, Kuwait Energy (KE). For the purposes of determining the economic limit associated with the Reserves, ERCE has used a price forecast advised by the operator as of 31st December 2022. United Oil and Gas has confirmed that no new data or information that would impact ERCE's opinions within the report have been acquired since the Effective Date.

ERCE has carried out this work in accordance with the June 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Appendix A of the report. The full text can be downloaded from:-

https://www.spe.org/en/industry/petroleum-resources-management-system-2018/

Nomenclature that may be used in the report is summarised in Appendix B.

Use of the report

The report is produced solely for the benefit of and on the instructions of United Oil and Gas, and not for the benefit of any third party. Any third party to whom the client discloses or makes available this report shall not be entitled to rely on it or any part of it.

United Oil and Gas agrees to ensure that any publication or use of this report which makes reference to ERCE shall be published or quoted in its entirety and United Oil and Gas shall not publish or use extracts of this report or any edited or amended version of this report, without the prior written consent of ERCE. In the case that any part of this report is delivered in digital format, ERCE does not accept any responsibility for edits carried out by the client or any third party or otherwise after such material has been sent by ERCE to the client.

Disclaimer

ERCE has made every effort to ensure that the interpretations, conclusions and recommendations presented in this report are accurate and reliable in accordance with good industry practice. ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees.

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes. In applying these procedures and tests, nothing came to the attention of ERCE that would suggest that information provided by United Oil and Gas was not complete and accurate. ERCE reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this report.

The accuracy of any Reserves and production estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment. While Reserves and production estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

Revenue projections presented in this report are based in part on forecasts of market prices, currency rates, inflation, market demand and government policy which are subject to many uncertainties and may, in future, differ materially from the forecasts utilised herein. Present values of revenues documented in this report do not necessarily represent the fair market value of the Reserves evaluated herein.

No site visits were undertaken in the preparation of this report.

Professional Qualifications

ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment. ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this report and ERCE will receive no other benefit for the preparation of this report.

Neither ERCE nor the Qualified Reserves Auditor (QRA as defined under PRMS) who is responsible for authoring this report, nor any Directors of ERCE have at the date of this report, nor have had within the previous two years, any shareholding in United Oil and Gas Ltd .

Consequently, ERCE, the QRA and the Directors of ERCE consider themselves to be independent of the Company, its directors and senior management.

ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

The preparation of this report has been supervised by Mr. Paul Taylor, Head of Reserves and Resources at ERCE. Mr. Taylor is a Qualified Reserves Auditor and has over 30 years of experience in the evaluation of oil and gas fields, preparation of development plans and assessment of Reserves and resources. He holds a MEng degree in Chemical Engineering from Nottingham University. He is a Chartered Petroleum Engineer with the UK Engineering Council, a member of the Energy Institute, a Professional Engineer with the Association of Professional Engineers and Geoscientists of Alberta (APEGA) in Canada and is a member of and has served on the Board of Directors of the Society of Petroleum Evaluation Engineers.

Yours faithfully

Mr. Paul Taylor, CEng, P.Eng.

Head of Reserves and Resources, ERCE

1. Executive Summary

1.1. ERCE Audit Basis

At the request of United Oil and Gas (UOG), ERCE Limited (ERCE) has performed an audit of the Reserves of the Abu Sennan concession located in the Western Desert of Egypt. ERCE has undertaken this Audit in accordance with the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" approved by the SPE Board on 25 June 2019 (the "SPE Audit Standards"). 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%. ERCE has been provided with the production and cost forecasts used by the operator of the concession, Kuwait Energy (KE), for estimating Reserves and the economic models used for evaluating the Reserves; ERCE has audited the KE production and cost forecasts, and the economic models and provided an opinion on their reasonableness.

The Abu Sennan Concession comprises the assets presented in Table 1.1. United Oil and Gas holds a 22% Working Interest in the concession. The Operator is Kuwait Energy Egypt (KE) through the East Abu Sennan Petroleum Company, which is a 50:50 joint venture (JV) between the Egyptian General Petroleum Corporation (EGPC) and the Contractor Group, with the Contractor Group represented by the operator.

Table 1.1: Audited Fields

Concession	Company Working Interest	Partners	Licence	Area (km2)	Fields	Expiry	Options for Extension
Abu Sennan	22%	Kuwait Energy Egypt (25% WI), GlobalConnect Ltd (25% WI) Dover Investments Ltd (Dover) (28%)	Al Ahmadi	18	ZZ, Al Ahmadi	Mar-32	5 years
			Abu Sennan-01 (AS-1)	18	Al Jahraa	Feb-32	5 years
			Abu Sennan-02 (AS-2)	15	El Salmiya	Mar-32	5 years
			Abu Sennan-03 (AS-3)	12	ASA	Jul-33	5 years
			Abu Sennan-04 (AS-4)	18	ASH	Apr-35	5 years
			Abu Sennan-05 (AS-5)	30	Al Jahraa SE	Jul-36	5 years
	22%	Kuwait Energy Egypt (39% WI), GlobalConnect Ltd (25% WI), Dover Investments Ltd (Dover) (14%)	Abu Sennan-06 (AS-6)	9	ASZ	Mar-39	5 years
			Abu Sennan-07 (AS-7)	13	ASD	May-41	5 years
			Abu Sennan-08 (AS-8)	12	ASX	Oct-41	5 years

Except for the ZZ and Al Ahmadi fields, which are shut in and with no further plans of development presented by the operator, all other fields in the Concession have been assessed as part of the Audit. ERCE's assessment included the review of hydrocarbon in place estimates, Technically Recoverable Resources (TRR) and Reserves at the Effective Date. ERCE's audit opinion relates to whether the Reserves in aggregate, can be considered fair and reasonable.

1.2. Conclusions

In adhering to the definition of an audit proposed by the SPE Audit Standards ERCE has concluded the following:

- ERCE has concluded the Reserves estimation methodology appropriate and in line with standard petroleum evaluation techniques and industry practice;
- The adequacy and high quality of the data relied upon by United Oil and Gas and KE enabled ERCE to complete a satisfactory audit.
- ERCE considers the production and cost estimates prepared by United Oil and Gas and KE for the Abu Sennan Concession fields to be in aggregate fair and reasonable across all Reserves categories.
- The Reserves estimates and economic results presented in this report are based on ERCE's evaluation of the audited production and cost estimates.

1.3. Reserves Summary

The oil and gas Reserves attributable to United Oil and Gas in Abu Sennan as of 31 December 2022 are shown in Table 1.2 and Table 1.3. Reserves are reported on a field gross, working interest and a Company net entitlement basis. Table 1.4 displays oil equivalent Reserves based on an energy equivalent conversion factor of 5.0 Mscf/boe, advised by KE.

Table 1.2: UOG Estimated Oil Reserves as of 31 December 2022

Field Gross Oil Reserves	Units	1P	2P	3P
Developed	MMstb	2.9	8.0	14.4
Undeveloped	MMstb	-	1.9	9.1
Total	MMstb	2.9	9.9	23.6
Working Interest Oil Reserves	**Units**	**1P**	**2P**	**3P**
Developed	MMstb	0.6	1.8	3.2
Undeveloped	MMstb	-	0.4	2.0
Total	MMstb	0.6	2.2	5.2
Net Entitlement Oil Reserves		**1P**	**2P**	**3P**
Developed	MMstb	0.3	0.8	1.4
Undeveloped	MMstb	-	0.2	0.6
Total	MMstb	0.3	0.9	1.9

Table 1.3: UOG Estimated Gas Reserves as of 31 December 2022

Field Gross Gas Reserves	Units	1P	2P	3P
Developed	Bscf	0.0	1.5	7.1
Undeveloped	Bscf	-	0.8	6.5
Total	Bscf	0.0	2.3	13.6
Working Interest Gas Reserves	**Units**	**1P**	**2P**	**3P**
Developed	Bscf	0.0	0.3	1.6
Undeveloped	Bscf	-	0.2	1.4
Total	Bscf	0.0	0.5	3.0
Net Entitlement Gas Reserves		**1P**	**2P**	**3P**
Developed	Bscf	0.0	0.1	0.7
Undeveloped	Bscf	-	0.1	0.5
Total	Bscf	0.0	0.2	1.2

Notes:

1. 1P gas volumes are small and round to zero. The Reserves quantities are 0.01 Bscf Gross Reserves, 0.002 Bscf Working Interest Reserves and 0.001 Bscf Net Entitlement Reserves

Table 1.4: UOG estimated Oil Equivalent Reserves as of 31 December 2022

	Units	Field Gross Reserves		
		1P	2P	3P
Oil	MMboe	2.9	9.9	23.6
Sales Gas	MMboe	0.0	0.5	2.7
Total	MMboe	2.9	10.4	26.3
	Units	**Working Interest Reserves**		
		1P	**2P**	**3P**
Oil	MMboe	0.6	2.2	5.2
Sales Gas	MMboe	0.0	0.1	0.6
Total	MMboe	0.6	2.3	5.8
	Units	**Net Entitlement Reserves**		
		1P	**2P**	**3P**
Oil	MMboe	0.3	0.9	1.9
Sales Gas	MMboe	0.0	0.0	0.2
Total	MMboe	0.3	1.0	2.2

Notes to Table 1.2, Table 1.3 and Table 1.4:

1. Company Working Interest Reserves are based on the working interest share of the field gross Reserves and are prior to deduction of royalties
2. Company Net Entitlement Reserves are based on Company share of total Cost and Profit Revenues
3. Gas volumes have been converted to oil equivalent volumes using a conversion factor of 5000 scf = 1 boe advised by the operator
4. Totals may not sum exactly due to rounding

A summary of the changes in Gross Field Reserves in barrels of oil equivalent (MMboe) since 31 December 2021 is shown in Table 1.5. The reconciliation for oil and gas volumes is presented in Table 1.6 and Table 1.7.

Table 1.5: Reconciliation of Reserves as of 31 December 2022 with Reserves as of 31 December 2021

	Gross Field Reserves (MMboe)		
	1P	2P	3P
Reserves as at 31 December 2021	4.3	13.3	30.1
Reserves Additions Through Exploration	-	-	-
2022 Production	-2.0	-2.0	-2.0
Revisions	0.6	-0.9	-1.8
Reserves as at 31 December 2022	2.9	10.4	26.3

Table 1.6: Reconciliation of Oil Reserves as of 31 December 2022 with Reserves as of 31 December 2021

	Gross Field Oil Reserves (MMstb)		
	1P	2P	3P
Reserves as at 31 December 2021	3.8	11.7	25.0
Reserves Additions Through Exploration	-	-	-
2022 Production	-1.7	-1.7	-1.7
Revisions	0.8	0.0	0.3
Reserves as at 31 December 2022	2.9	9.9	23.6

Table 1.7: Reconciliation of Gas Reserves as of 31 December 2022 with Reserves as of 31 December 2021

	Gross Field Gas Reserves (Bscf)		
	1P	2P	3P
Reserves as at 31 December 2021	2.4	8.4	25.1
Reserves Additions Through Exploration	-	-	-
2022 Production	-0.3	-0.3	-0.3
Revisions	-2.1	-5.8	-11.2
Reserves as at 31 December 2022	0.0	2.3	13.6

Notes to Table 1.5, Table 1.6 and Table 1.7:

1. Gas volumes have been converted to oil equivalent volumes using a conversion factor of 5000 scf = 1 boe advised by the operator
2. Production data has been provided by the operator to end of October 2022. November and December Best Estimate production estimates have been used in deriving this table
3. Gas Reserves have reduced largely due to pipeline pressure constraints
4. Oil Reserves have been replaced or slightly increased due to data acquired (production, drilling and reprocessed seismic) and forecast updates particularly in the ASD and ASH fields
5. Totals may not sum exactly due to rounding

Based on the economic evaluation of the Reserves Table 1.8 presents the post-tax Net Present Values (NPV) in millions of US$ as of 31 December 2022 at discount rates ranging from 0% to 15% attributable to the UOG.

Table 1.8: Summary of Post-tax NPV (US$ MM) Net to UOG as of 31st December 2022

Discount Rate (%)	1P	2P	3P
0.0%	10.8	38.8	92.8
7.5%	9.9	30.9	67.0
10.0%	9.6	29.0	61.4
12.5%	9.4	27.2	56.6
15.0%	9.2	25.7	52.6

2. Introduction

As detailed in the covering letter of the report, United Oil and Gas (UOG) has engaged ERCE to carry out a Reserves audit for the Abu Sennan Concession, onshore Egypt.

In adhering to the definition of the audit, ERCE has focused on: “(1) the appropriateness of the methodologies employed, (2) the adequacy and quality of the data relied upon, (3) the depth and thoroughness of the resources estimation process, (4) the classification of resources appropriate to the relevant definitions used, and (5) the reasonableness of the estimated resources quantities and/or the resources information”.

ERCE has assessed the remaining Technically Recoverable Resources (TRR) for the all the development projects presented by the operator in the different fields.

Audited remaining TRR were then used for Reserves estimation based on the operator’s economic model. The estimation of Reserves has been based on forecasts of production and costs aggregated at Concession level and reviewed at the Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P) levels. These are detailed further in the report.

In accordance with the PRMS guidelines, the Cessation of Production (CoP) date used to estimate Reserves is defined as the end of the last period that the operating cash flow is positive, or the end of the technical field life, whichever occurs soonest. In cases where the existing production licences are due to expire prior to the estimated cessation of field production date, it has been assumed that the licences will be extended.

In all tables Reserves totals are aggregated by arithmetic summation as recommended in the PRMS reporting guidelines. However, as such the summed 1P may be a conservative estimate and the summed 3P may be an optimistic estimate due to portfolio effects.

ERCE has used standard petroleum evaluation techniques in the preparation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbons. Our methodology adheres to the PRMS guidelines (summarised in Appendix A of this report).

The accuracy of estimates of forecast volumes of oil and gas production is a function of the quality and quantity of available data and of engineering interpretation and judgment. While estimates of TRR presented herein are considered reasonable, these estimates should be accepted with the understanding that additional data and/or reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

2.1. Data Provided

All the data and information used in the preparation of this Audit were made available by the operator. The dataset included, among others, geological, petrophysical, engineering data, reports, interpretations and details of UOG's licence interests. A narrative of operator's methodology and estimates as of the Effective Date was provided in technical presentations given during an initial meeting. A summary of the operator's estimates of in place and recoverable volumes has been included in the economic model, also provided to ERCE. The operator has provided well by well production data through to end October 2022 for all the fields.

ERCE has relied on the accuracy and completeness of the information provided by the operator in the preparation of this report and has taken all reasonable care to present the information accurately.

Meetings were held with the operator's technical staff (via video conference) to review the data provided and to discuss the audit. No site visit was undertaken in the preparation of this report.

2.2. ERCE Methodology

ERCE has reviewed the data supplied by the operator for the Abu Sennan concession, reviewed the methodology behind the estimates of STOIIP and calculated independent estimates of petrophysical parameters and STOIIP. ERCE has accepted the operator's estimates of STOIIP as reasonable over the low, best and high range of uncertainty.

The estimates of remaining Technically Recoverable Resources (TRR) in producing fields have been based on Decline Curve Analysis (DCA). Estimates of Undeveloped Reserves are based on hydrocarbon in place and recovery efficiency estimates, analogue production type curves and historic well performance analysis. These TRR estimates reflect the wellhead volumes of oil and natural gas which are forecast to be produced and have been cut-off at the earlier of either the end of the licence expiry (including its renewal option) or at the minimum technical production rate.

The minimum technical production rate is estimated by the operator at well level to be in the range between 60 and 6 stb/d depending on artificial lift method. This has been applied at well level during decline analysis and before the aggregation of the combined production from all the fields. No economic cut off has been applied and no allowance has been made for fuel and flare requirements or gas shrinkage at this stage. The aggregated totals were derived using arithmetic summation to allow a simple comparison. Following this work ERCE has accepted the operator's aggregated estimates of TRR as reasonable and has used them for Reserves estimation.

In evaluating the range of uncertainty in the operator's estimates of TRR, ERCE has reviewed the low to high range of TRR for each project in the concession and also the ratios of the low/best estimate and high/best estimates. Based on analogous field developments at a similar stage of maturity ERCE accepts that the range of uncertainty applied in the operator's production forecasts is reasonable and may be somewhat conservative in the low case. ERCE notes that in some cases the high case estimates are significantly higher than the best estimate due to larger in place volume estimates coupled with higher estimates of recovery factor and subsequently higher well counts required to develop these resources. Based on these reviews ERCE has adopted the operator's production forecasts as reasonable estimates of the TRR in aggregate.

The production forecasts adopted have been used along with reviewed costs and economic model in deriving the Reserves estimates reported.

3. Concession Overview

The Abu Sennan concession is located in the hydrocarbon-producing Western Desert region, Egypt (Figure 3.1). UOG has a 22% working interest (WI) in the concession operated by Kuwait Energy Egypt (25% WI), with GlobalConnect Ltd (25% WI) and Dover Investments (28% WI) as the other partners in the Contractor Group. The Abu Sennan 6 concession has a different working interest structure with United Oil and Gas having a 22% WI, Kuwait Energy Egypt (39% WI), GlobalConnect Ltd having (25% WI), and Dover Investments (14% WI).

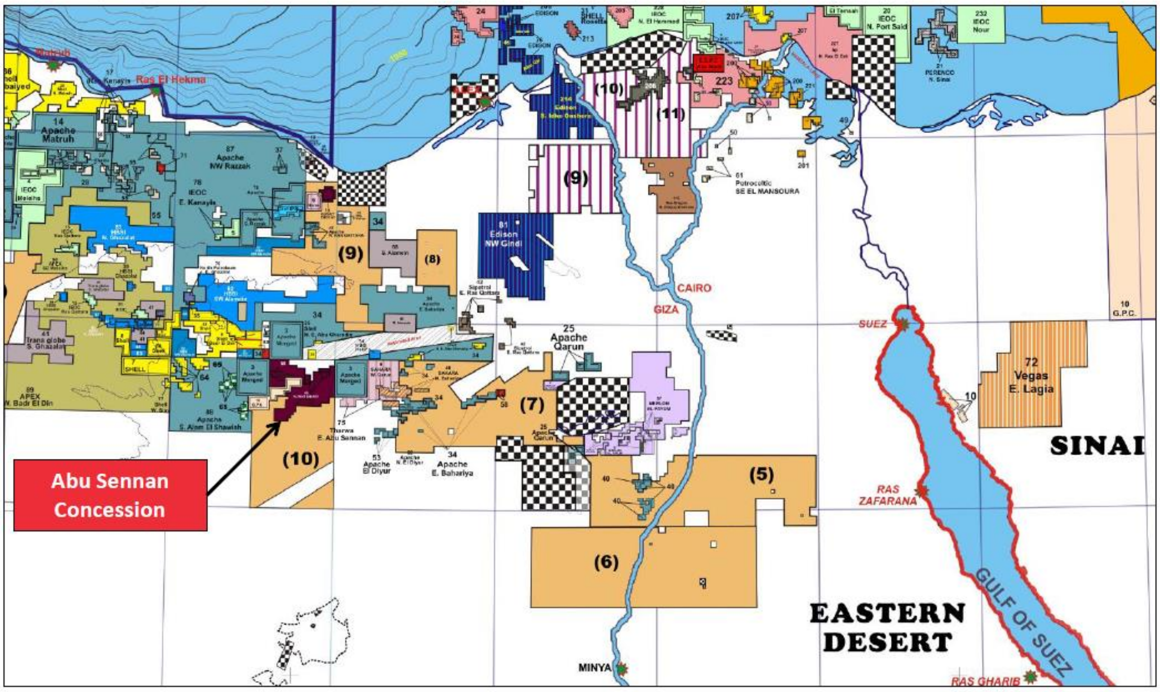

Figure 3.1: Location of the Abu Sennan concession (source: Kuwait Energy)

The original exploration licence expired in May 2016, but a 5-year extension (3 years plus two 1-year extensions at the Contractor Group's option) covering the rest of the concession area was granted with a starting date of 10 September 2018. At the Effective Date, the development of the area is in the first extension period (First Exploration Phase). Commitments for the Initial Exploration Phase and the First Exploration Phase have been fulfilled, with the drilling of two exploration wells (Wells ASZ-1X & ASD-1X) and one commitment well (Well ASX-1X) respectively. The remaining commitment for the Second Exploration Phase has been fulfilled with the drilling of exploration well ASV-1X in Q2 2022.

At the time of writing, the Concession comprises nine development leases covering the ten commercial discoveries that have been made, as well as a 644 km2 Exploration Licence (Figure 3.2).

The development licences are operated by KE through the East Abu Sennan Petroleum Company, a 50:50 joint venture (JV) between EGPC and the Contractor Group, with the

Contractor Group represented by KE. Whilst KE is the Operator, all decisions require approval from both JV parties.

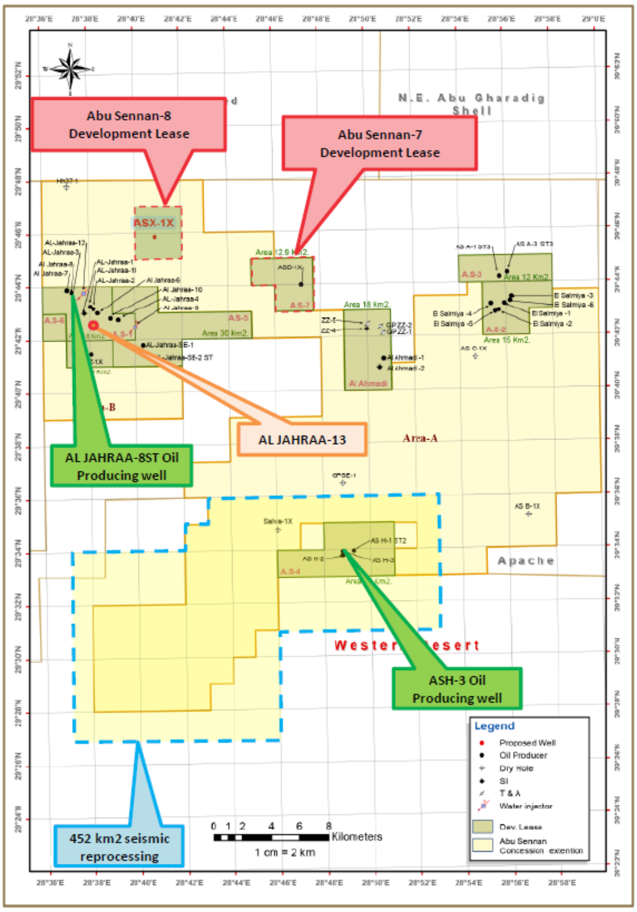

Figure 3.2: Map of the Abu Sennan Concession and Development Leases

First oil from the Concession was in July 2012 and cumulative oil production was 14.2 MMstb as of 31October 2022. At the same date, cumulative gas production was 17.6 Bscf.

In October 2022, there were 23 wells on production in the Concession, which were delivering a monthly average oil rate of 3,880 stb/d and average gas rate of 1.34 MMscf/d on a gross basis. The production history of the Concession is shown in Figure 3.3 with a breakdown by field.

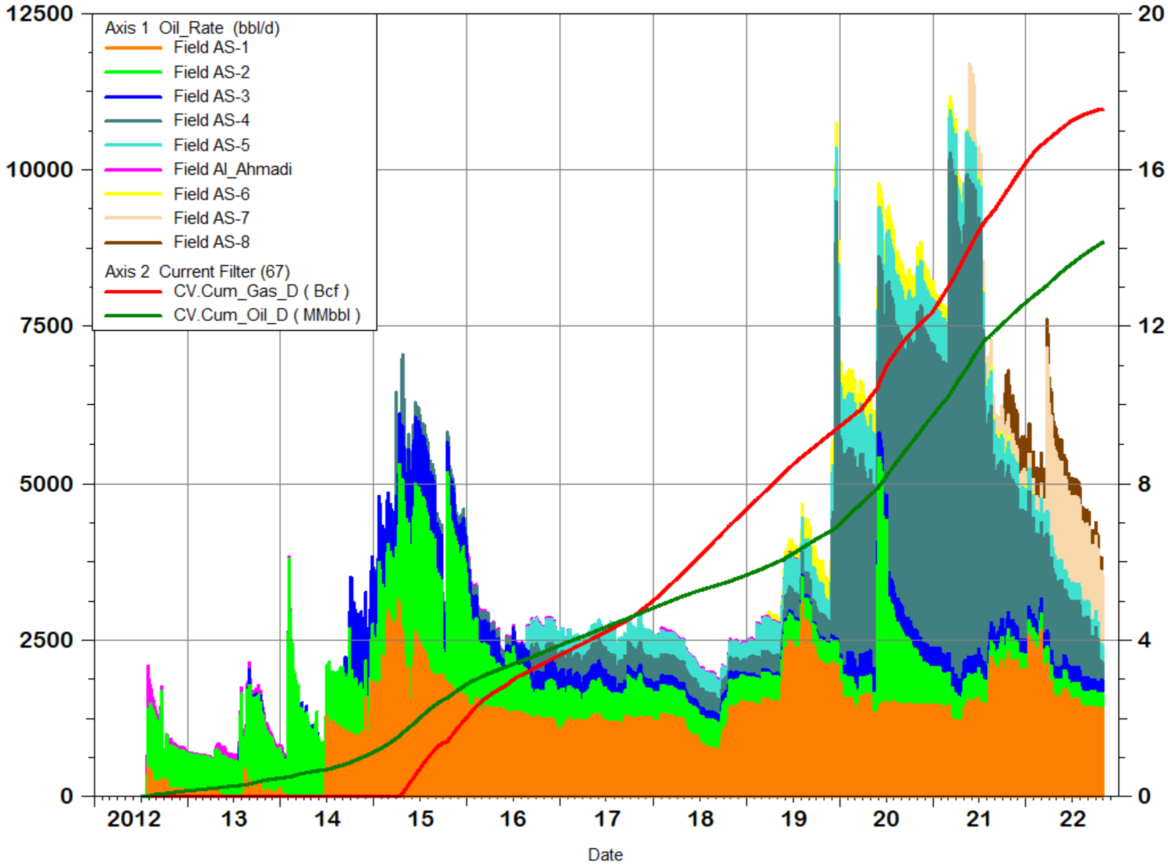

Figure 3.3: Abu Sennan Production History

4. Geology

The Abu Sennan concession lies in the Egyptian Western Desert (Figure 4.1). The concession has two main geological provinces, the Abu Sennan sub-basin in the north and the Mubarak / Agnes High in the south. The Abu Sennan sub-basin is a half graben developed along east-west trending normal faults and displays evidence of structural inversion. The north west of the concession is bounded by the north east – south west trending Abu Gharadig anticline.

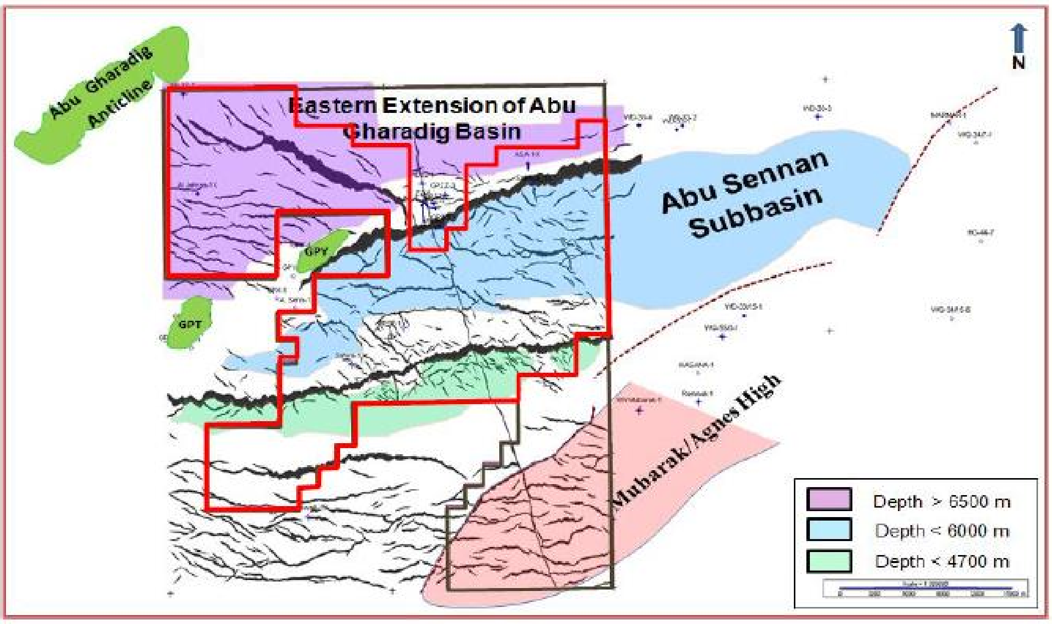

Figure 4.1: Geological Setting of the Abu Sennan concession (source Kuwait Energy)

The stratigraphy of the Western Desert is shown in Figure 4.2. The discovered reservoirs within the Abu Sennan concession are Cretaceous in age and consist of interbedded marine shales and sandstones, with carbonates also observed. The reservoir members are the Abu Roash Formation, Alam El Bueib and the Upper and Lower Bahariya formations. The Abu Roash is subdivided into seven members (AR-A through AR-G) and the producing members are the AR-C, AR-D, AR-E and AR-G. The early Cretaceous sandstones, composed of stacked and braided sands, of the Kharita formation underlain by the Bahariya Formation.

The Abu Roash AR-C and AR-E members typically have moderate porosities ranging from 12% to 16%, while the Bahariya Formations often have porosities in the 9% to 14% range.

The reservoir traps are typically structural, fault bounded dip closures and horst blocks. Seals are provided by the marine mudstone units, typically of the Abu Roash formation, and intra formation shales are also observed as seals.

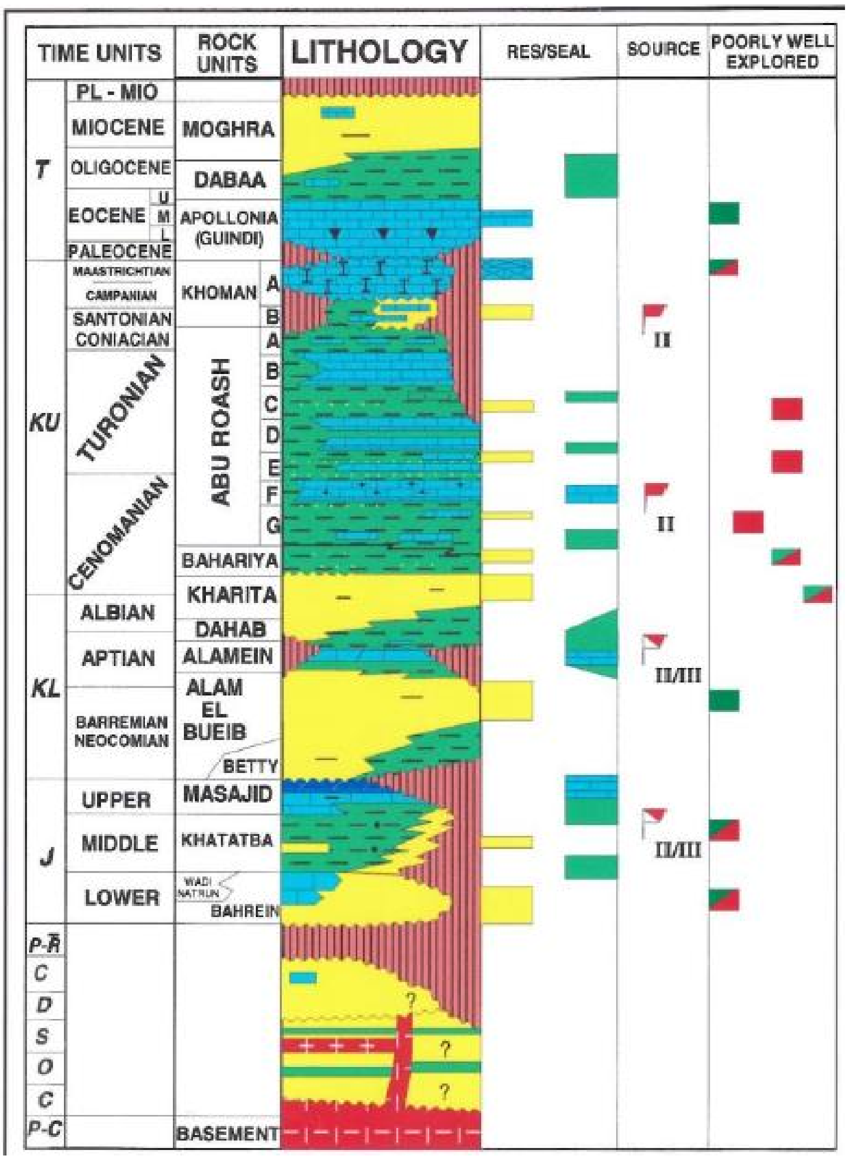

Figure 4.2: Stratigraphy of the Western Desert (source Kuwait Energy)

4.1. Hydrocarbons in Place

ERCE has reviewed the data supplied by the operator for the Abu Sennan concession and calculated independent estimates of STOIIP. ERCE has reviewed the provided geological data confirming the reservoir maps tie the well formation tops and logs. Fluid contacts have been checked for consistency with well logs. Gross rock volume calculations have been checked through the geological model workflows and also confirmed with independent calculations using top and base structure maps and representative petrophysical sums and averages. For areas not covered by full geological modelling, the operator has estimated volumes based on structural mapping and ranges of fluid contacts combined with average petrophysical properties. ERCE has used a similar methodology to check these estimates.

On the basis of this work ERCE has accepted the operator’s estimates of STOIIP across the low, best estimate and high range of uncertainty as reasonable for the Abu Sennan Concession.

Table 4.1 shows the operator's probabilistic Low/Best/High HIIP range for the Abu Sennan concession.

Table 4.1: HIIP Estimates

Abu Sennan		STOIIP (MMstb)		
Field	Reservoir	Low	Best	High
Al Jahraa & AL Jahraa SE	A/R "E" Al Jahraa-1	0.68	0.68	0.68
	A/R "E" (Al Jahraa SE)	1.50	2.70	4.00
	A/R "C"	15.70	24.20	33.90
	A/R "D"	3.05	3.05	3.05
	A/R"G"	0.95	1.30	1.79
	Lower Bahariya	4.16	5.71	7.84
	A/R"E" Al Jahraa-7	0.63	0.63	1.34
	A/R"E" Al Jahraa-8&3	0.93	1.20	1.51
	Upper Baharyia Al Jahraa-7	0.19	0.40	0.80
	Upper Baharyia Al Jahraa-8&13	0.55	1.04	1.88
	Lower Bahariya Sand II Al Jahraa-7	0.06	0.17	0.45
El Salmiya	A/R "C" (Salmiya-1,4&5)	3.00	4.00	5.50
	A/R "C" (Salmiya-3)	0.71	0.71	0.71
	A/R "C" (Salmiya-2)	0.00	0.00	0.00
	A/R "E" (Salmiya-2&6&5)	3.52	4.92	6.42
	Lower Bahariya	0.53	1.40	5.65
	ARG	0.35	0.63	1.12
	Kharita(El Salmiya-2, 6&5ST)	5.00	5.50	6.00
ASA	A/R "C"	0.91	1.51	2.31
	A/R "E"	3.40	3.85	5.10
ASH	AEB	11.60	12.70	13.80
ASZ	A/R"C"	1.70	3.24	6.03
ASD	A/R"C"	4.38	5.71	7.21
	A/R "D"	0.15	0.25	0.44
	A/R "E"	6.49	9.20	11.93
	Lower Bahariya	1.24	1.62	2.04
	Kharita	0.05	0.07	0.10
ASX	A/R"C"	1.01	1.73	2.90
	A/R "E"	0.06	0.12	0.23
	Upper Baharyia	0.22	0.29	0.37
	Lower Bahariya	0.09	0.14	0.18
Total		72.81	98.67	135.29

Notes to Table 4.1:

1 GIIP volumes are solution gas in place based on the STOIIP volumes and the gas oil ratio of the crude

2 Al Ahmadi and ZZ field not included in this table as no Reserves have been estimated for these accumulations

5. Al Jahraa and Al Jahraa SE Field

Al Jahraa field was discovered in 2011 and Al Jahraa SE was discovered in 2016. Al Jahraa SE is a smaller accumulation to the south east of the main Al Jahraa pool. 15 wells have been drilled to date, which includes two in the Al Jahraa SE accumulation. Oil is found in the Abu Roash members: AR-C, AR-D, AR-E, AR-G, and the Upper and Lower Bahariya reservoirs. The most significant reservoir is the AR-C at depths around 2,750-3,050 m TVDSS. The reservoirs contains light oil with a Gas Oil Ratio (GOR) around 400 scf/stb in the Abu Roash and a higher GOR in the Bahariya members.

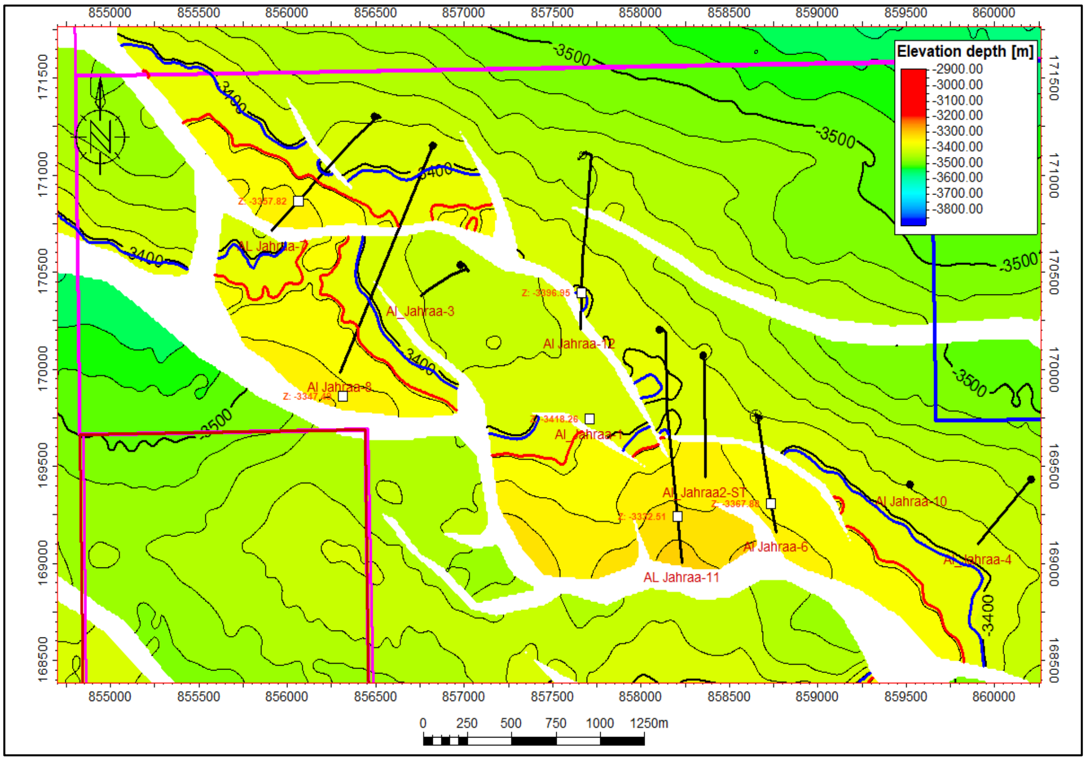

Figure 5.1: Top Lower Bahariya Resevoir

Al Jahraa field is an NW-SE strike elongated anticline with fault bound trapping control. AR-C reservoir was discovered by Al Jahraa-2 and brought on production via a sidetrack, Al Jahraa-2ST, with two additional development Wells Al Jahraa-3 and -4, in 2016. The reservoir started up at around 1,000 stb/d. AR-D was also perforated by Al Jahraa-2ST in 2015.

Two additional wells, Al Jahraa-6 and -10 were drilled and started-up on the structure in September and December 2018 respectively. Al Jahraa-6 discovered oil in the Lower Bahariya as well as targeting the AR-C and AR-D. The Lower Bahariya was perforated and started-up at 500 stb/d but with a high GOR. Production was constrained by flaring until 2020 when the pipeline connecting Al Ahmadi to the GPC gas processing facility was moved to connect to the Al Jahraa fields. Al Jahraa-10 targeted the AR-C with initial rates around 130 stb/d.

AR-D was perforated and acidized in March 2019 and comingled with AR-C, increasing production around 200 stb/d

The Al Jahraa SE-1 well was drilled in 2016 and found oil in the AR-C at lower pressure, suggesting communication with the main Al Jahraa pool. Communication is assumed through the aquifer because the two pools are mapped to have separate closures and the Well Al Jahraa-9, drilled in 2017 between the two pools, found water in the AR-C.

The aquifer provides limited pressure support so that a water injection project was commenced in July 2018 with the conversion of Al Jahraa-9 to a water injection well. The well ramped up injection to 2,000 stb/d, and in 2019, a further water injector was drilled, Al Jahraa-12, just north of the main pool with start-up in March 2020 at around 1,000 stb/d.

In 2020, Al Jahraa-2ST was re-perforated in the AR-C and AR-D in May, and Al Jahraa-1 was converted to a Lower Bahariya water injector in June.

In 2022, Al Jahraa -13 has completed on Lower Bahariya and put on production in January, with an initial oil rate of 600 stb/d. In June, Al Jahraa-14 has been drilled and completed in AR-C reservoir with rate of 40 BOPD and 19% water cut.

At the end of October 2022, the field was producing at an oil rate of 1,655 stb/d. The cumulative oil production is 5.7 MMstb, while the cumulative gas sales is 1.4 Bscf.

Current further development plans include one infill well and seven well recompletions across different reservoirs. A further three wells will be drilled to develop the high case Reserves.

6. Other Fields

6.1. El Salmiya

Six wells have been drilled in the El Salmiya field with oil discovered: AR-C, AR-E and AR-G; and the Lower Bahariya and Kharita reservoirs at depths around 3,200 – 3,800 m TVDSS. The oil is volatile with a high GOR of approximately 1,900-2,500 scf/stb in all horizons except the AR-E where the oil is 33° API and GOR is 200-300 scf/stb.

The field is a heavily compartmentalised and faulted anticlinal structure with at least two separate pools in each of the AR-C and Kharita reservoirs.

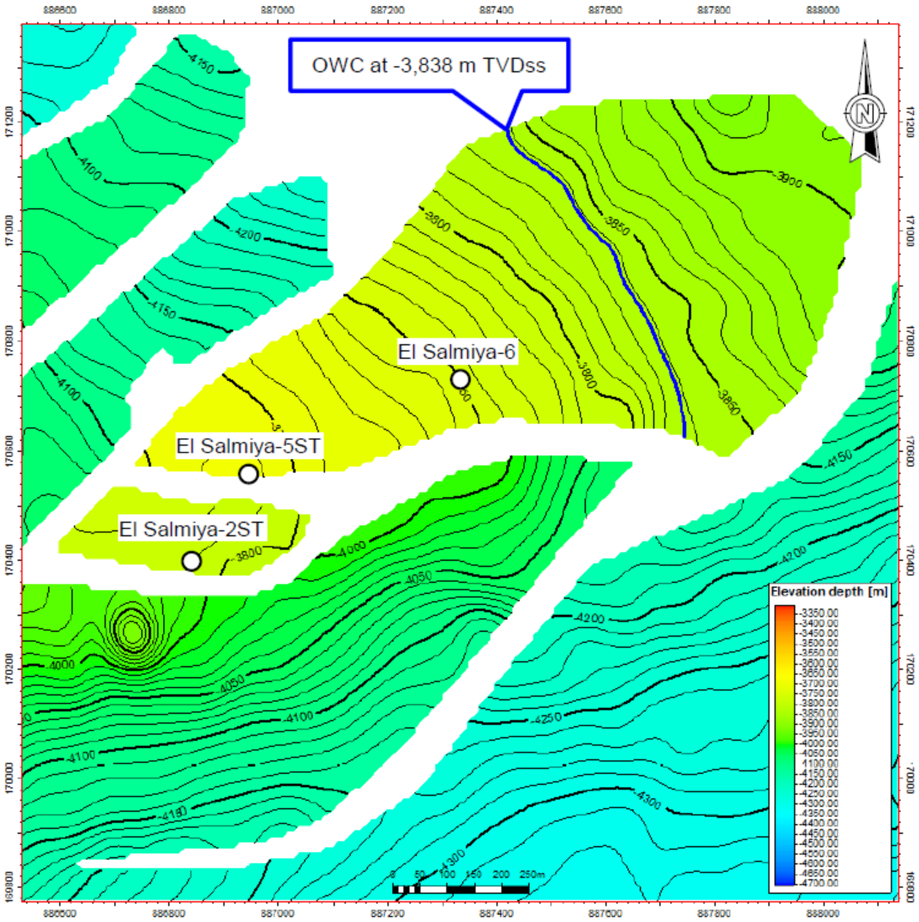

Figure 6.1: El Salmiya, Top Kharita Depth Map (source KE)

Field production was initially constrained until the gas export pipeline was installed connecting El Salmiya gas plant to the GPC gas processing facility in 2015. With the production rate unconstrained, the pressure depletion increased significantly demonstrating the compartmentalised nature of the reservoir.

In 2020, KE drilled Well El Salmiya-5ST finding hydrocarbons in the AR-C, AR-E, discovering oil in the AR-G and in Kharita. Initial testing produced rates of 6,200 stb/d of oil and 23.6 MMscf/d of gas from Kharita and 1,250 stb/d oil from the AR-E. The well was completed in

Kharita with an initial rate of 4,000 stb/d before being choked back to 1,500 stb/d and 7 MMscf/d gas.

At end of October 2022, the oil and gas production rates from El Salmiya were 218 stb/d and 0.5 MMscf/d respectively from two producers. The cumulative oil production is 2.7 MMstb, while the cumulative sales gas is 11.4 Bscf.

Current plans include three well recompletions across different reservoirs. A further two wells will be drilled to develop the high case Reserves.

6.2. ASA

ASA is a tilted fault structure to the north of El Salmiya developed by two wells both of which have been sidetracked. Oil was found in AR-C and AR-E at depths of around 3,000 mTVDSS. The oil is light with a GOR around 400 scf/stb. By 2020, Well ASA-3ST was producing from AR-E and ASA-1ST3 was re-perforated in the AR-C and AR-E reservoirs in February 2020.

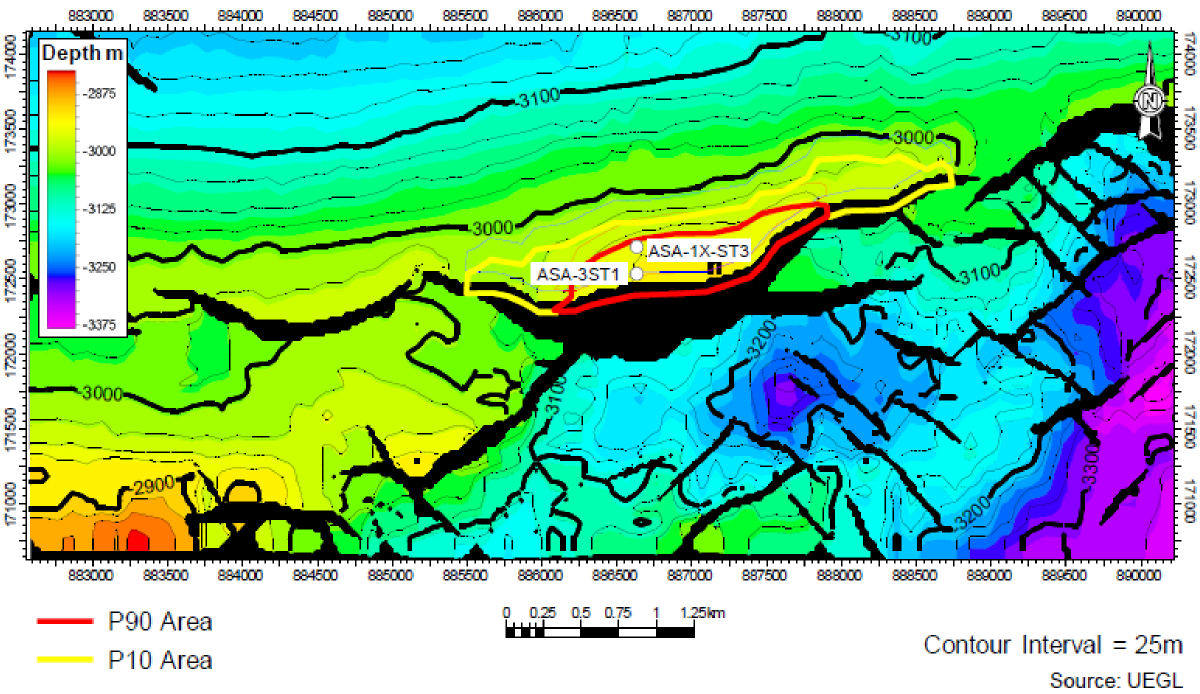

Figure 6.2: ASA Field, Top AR-E reservoir (Sources KE)

At end of October 2022, the oil and gas production rate from ASA were 194 stb/d from the two producers completed on AR-E reservoir. The cumulative oil production is 0.95 MMstb.

6.3. ASH

The ASH-1X exploration well was drilled in 2015 and discovered light oil with a GOR of around 1,750 scf/stb in Alam El Bueib (AEB) formation at a depth of approximately 3,700 mTVDss (Figure 6.3). The well encountered the Oil Water Contact (OWC) and produced at more than 1,000 stb/d which quickly declined due to increasing water cut. The well was subsequently sidetracked up-dip in 2016 and steadily produced at 300-400 stb/d. In 2020 a tubing leak occurred. The tubing string was replaced in October 2020 and a sucker rod pump (SRP) was installed. The well was fracture stimulated in 2021, increasing the rate from 160 to 1200 stb/d.

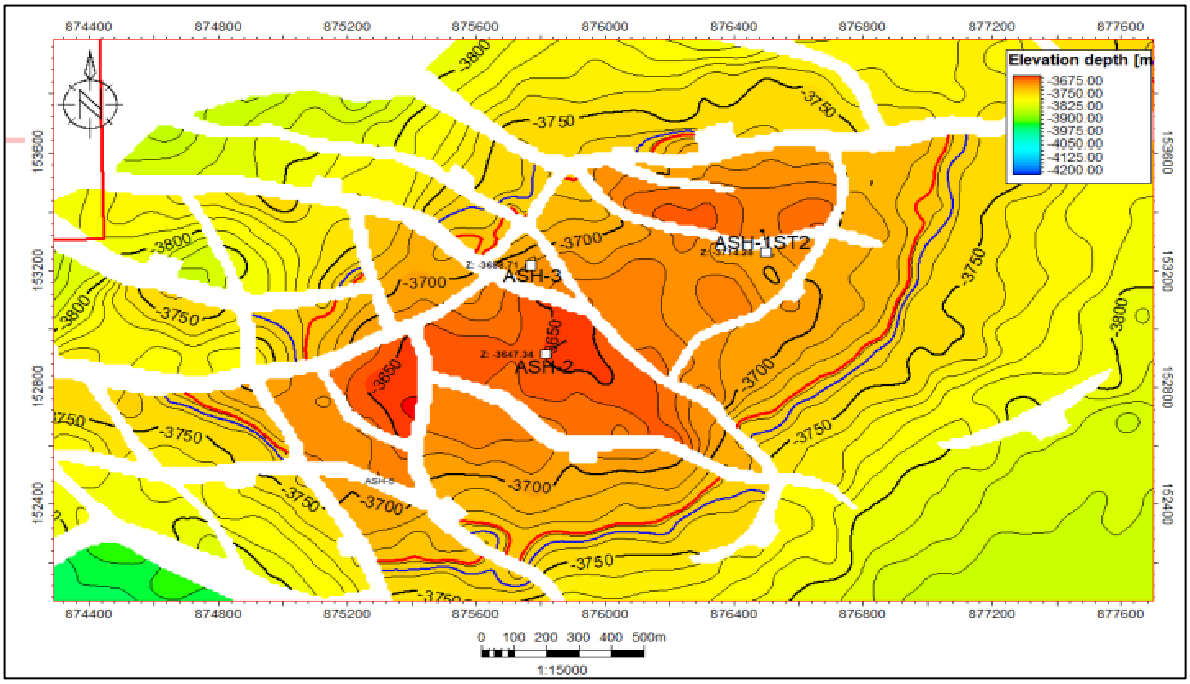

Figure 6.3: Top AEB Reservoir, ASH Field

The ASH-2 well was drilled in Q4 2019 finding 50 m of net pay in AEB formation 1km south west of ASH-1X. The well was found close to initial pressure and with a deeper OWC. Production tests in late 2019 achieved 7,000 stb/d with a GOR of 1,100-1,300 scf/stb. The well was put on production with an initial rate of 3,000 stb/d of oil, constrained by gas flaring restrictions.

In 2021, Well ASH-3 was drilled and put on production in March, with an initial oil rate of 3600 stb/d.

At the end of October 2022, the oil and gas production rates from ASH were 251 stb/d and 0.3 MMscf/d from two producers completed on the AEB reservoir. The cumulative oil production is 3.9 MMstb, while the cumulative sales gas is 2.6 Bscf.

Current plans include three infill wells, targeting the AEB reservoir.

6.4. ASZ

Exploration Well ASZ-1X discovered oil in a fault block south of the Al Jahraa field. The well found 3.4m of net pay in AR-C reservoir. The field came on production in April 2019, tied-in to the Al Jahraa facilities, and reached a rate of 400 stb/d which remained stable through much of 2020, declining as water cut increased. In February 2022, Well ASZ-1X has been shut in with cumulative oil production of 0.24 MMstb.

6.5. ASX

The ASX field was discovered in 2021 through exploratory Well ASX-1X (Figure 6.4) in the Abu Sennan-8 development lease. The well found 4.5m of net pay in AR-E reservoir and 2.5m of net pay in AR-C reservoir. The field came on production in October 2021 after the well was completed in AR-C with initial rate of 860 stb/d. In October 2022 the oil production rate was 226 stb/d with cumulative oil production of 0.15 MMstb.

.

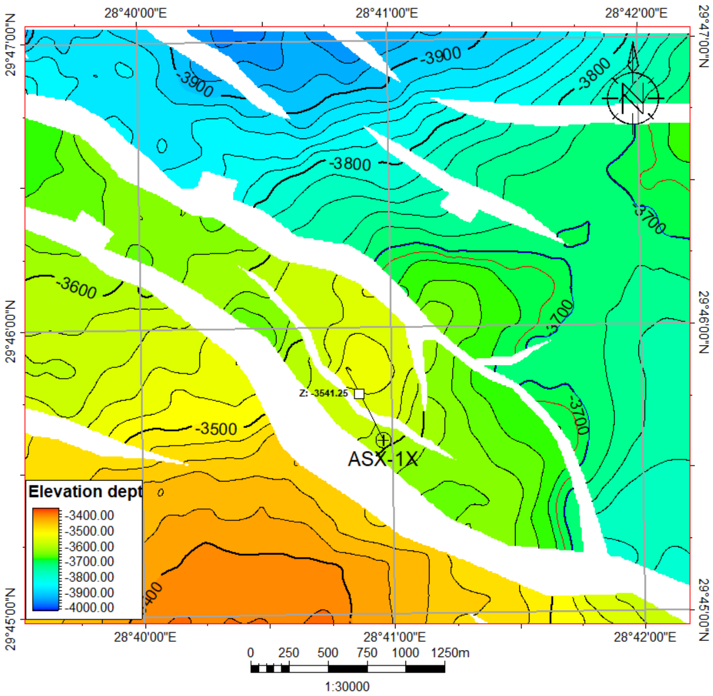

Figure 6.4: Top AR-E Reservoir, ASX Field

6.6. ASD

The ASD-1X exploration well discovered oil in May 2021 in what is now the Abu Sennan-7 development lease (Figure 6.5). The well found oil in AR-C, AR-E and Lower Bahariya reservoirs, with net pay of 6.5, 3.4 and 14.1 m respectively. The well was put on production in May 2021 perforated in the AR-C, AR-E and Lower Bahariya.

In 2022, Well ASD-2 has been drilled and completed in ARE reservoir. The well has been on production since March, with initial rate of 2,350 stb/d. As of the end of October 2022 the well is producing around 990 stb/d.

At the end of July 2022, the field produces at rate of 1,134 stb/d with cumulative oil production of 0.4 MMstb.

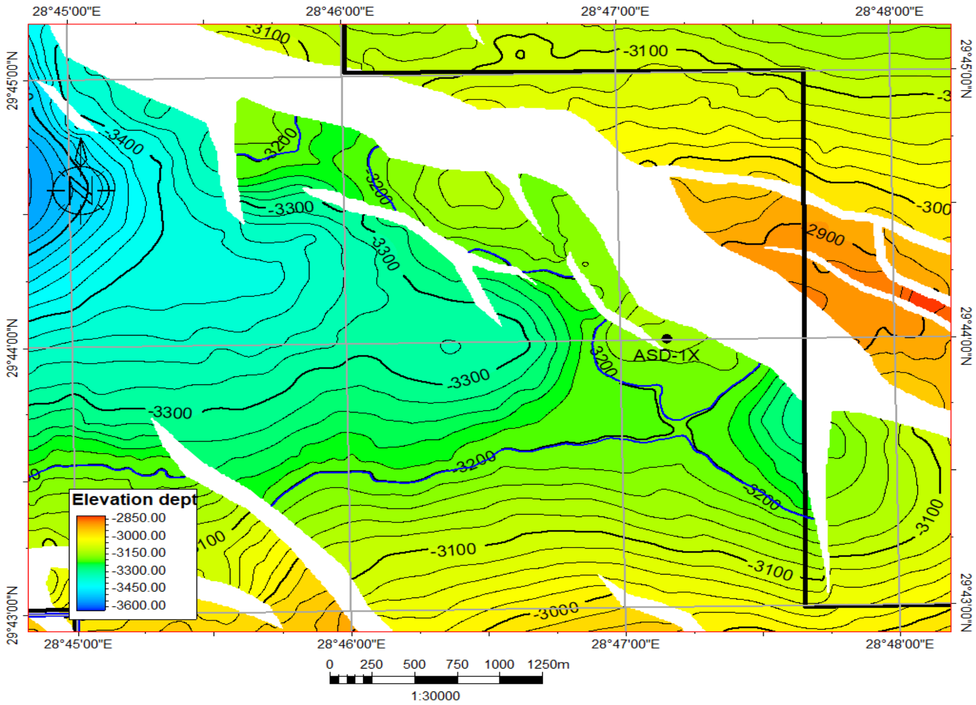

Figure 6.5: AR-C Structure Map

Current plans include one more infill well, targeting the AR-E and AR-C reservoirs and two recompletions on different reservoirs.

6.7. ZZ and Al Ahmadi

The ZZ (formerly GP ZZ) and Al Ahmadi fields have proven to contain smaller volumes than expected prior to drilling. Each field has one production well. The ZZ has not produced since 2018 and the Al Ahmadi has not produced since July 2019. In total the ZZ and Al Ahmadi fields have produced a total of 0.07 MMstb of oil and 2.1 Bscf of sales gas.

There are no Reserves associated with these developments.

7. Reserves

7.1. Development Plans

The future development of the Abu Sennan concession has been assessed from the operator's technical material, where development opportunities are described, and resource estimates provided. ERCE has reviewed the future activities presented in these documents and cross checked them against the estimates included in the economic model. ERCE has then verified the classification of the projects according to their maturity as Developed Reserves (both producing and non-producing) and Undeveloped Reserves.

Developed Reserves are attributable to the current stock of 23 producing wells: 12 wells in Al Jahraa and Al Jahraa SE, two wells in El Salmiya, three wells in ASH, two wells in ASA, one well in ASZ, one well in ASX and two well in ASD. These Reserves are calculated at the earlier of the economic limit and the technical Cessation of Production of the concession.

Developed non-producing Reserves have been assigned to a number of behind pipe opportunities identified by the Operator. Approximately 32 interventions, mostly recompletions, for the existing wells are expected to provide additional resources, categorised as Developed (non-producing).

Undeveloped Reserves have been assigned to future infill drilling projects. In the 2P case, the operator is planning to drill four production wells in the Abu Sennan concession over the period 2023-2025 as follows:

- One well in Al Jahraa
- Two wells in ASH
- One well in ASD

In the 1P, 2P and 3P cases, a different well count is planned by the operator to develop the range of resources. Table 7.1 shows the drilling schedule by year and by Reserves category.

Table 7.1: Planned Drilling Schedule

Year	Production Wells			Water Injection Wells		
	1P	2P	3P	1P	2P	3P
2023	--	2	3	--	--	--
2024	--	2	6	--	--	--
2025	--	--	--	--	--	--
Total	--	4	9	--	--	--

7.2. Production Forecasts and Recovery

ERCE's forecasts of production for the current producing wells have been derived using Decline Curve Analysis (DCA) on a well-by-well level, rolled-up and compared to an overall field level DCA. Production data were available up to end of October 2022. The DCA incorporated a range of varying declines to account for the forecast uncertainty. Decline analysis was carried out on calendar rates and as such field production forecasts implicitly account for operating efficiency (OE). Secondary phase production volumes were estimated either using a constant GOR value derived from historic production data or by estimating a GOR trend as appropriate. As described in Section 4.1, the operator's estimates of remaining TRR were found fair and reasonable and ERCE has accepted these forecasts at all levels of confidence.

ERCE's gross Developed plus Undeveloped TRR estimates for the fields in the Abu Sennan concession are presented in Table 7.2.

Table 7.2: Abu Sennan Fields TRR Estimates and Recovery Factors

Field	Operator Best Estimate STOIIP (MMstb)	Cum. Prod. at 31 Oct. 2022 (MMstb)	RF to 31 Oct. 2022	TRR Estimate (MMstb)			TRR best est. RF
				Low	Best	High	
Al Jahraa & Al Jahraa SE	40.23	5.73	14%	8.25	12.14	16.68	30%
El Salmiya	17.16	3.11	18%	3.28	4.14	6.18	24%
ASA	5.36	0.88	16%	1.13	1.26	1.49	23%
ASH	12.70	4.32	34%	4.33	4.84	7.30	38%
ASZ	3.24	0.24	7%	0.24	0.24	0.26	8%
ASD	16.85	0.41	2%	1.54	2.74	5.24	16%
ASX	2.28	0.15	7%	0.22	0.28	0.59	12%
Al Ahmadi	0.80	0.07	9%	0.07	0.07	0.07	9%

Notes

1. Cumulative based on actual production to 31 October 2022

The production forecast for the developed plus undeveloped TRR proposed by the operator and accepted by ERCE is shown in Figure 7.1.

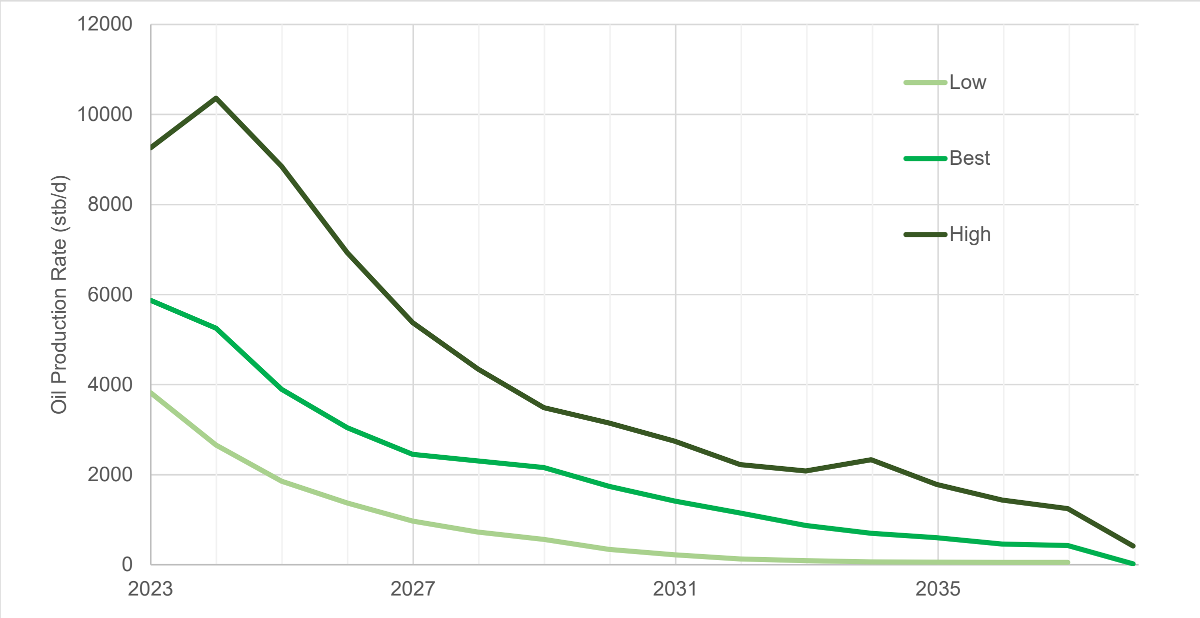

Figure 7.1: Production Forecast

7.3. Reserves Estimation

The technical production profiles described in Section 7.2 have been used as input (sales profiles) for Reserves estimation. The fuel gas at El Salmiya has been advised as 0.2 MMscf/d. The remaining gas is sold as "wet" gas with no shrinkage.

Reserves have been estimated to the earliest of the economic cut-off dates and the end of the technical profile.

The Developed Reserves have been based on the existing well stock. Infill wells have been classified as Undeveloped Reserves due to their status as of the Effective Date.

A summary of the gross Reserves is presented in Table 9.4 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

8. Facilities and Costs

The operator has provided forecasts of annualised CAPEX and OPEX for the Abu Sennan and Abu Sennan Extension areas, in addition to a list of actual expenditure for the period 2016-2022 and the 2023 Work Plan and Budget. ERCE has reviewed these forecasts, to establish:

- The CAPEX and OPEX allocations for wells and facilities are consistent with the practical requirements to support the production profiles in each scenario

- Estimates of CAPEX and OPEX are consistent with the historical expenditures for similar works (where available)
- Estimates of CAPEX and OPEX are proportionate when benchmarked against industry analogues

ERCE raised queries with the operator wherever there were apparent potential discrepancies, and all such queries were fully resolved by KE. ERCE therefore accepts the operator's cost forecasts based on the information available.

8.1. CAPEX Assumptions

The following capital costs were assumed (gross, 2023 basis):

- Production well drilled in El Salmiya (single completion): 5.6 $mm
- Production well drilled in ASH (single completion): 4.0 $mm
- Production well drilled in other fields (single completion): 3.9 $mm
- Facilities upgrades total (excluding extension): 2.7 $mm
- Facilities upgrades total (extension): 0.9 $mm
- Well workovers (each): 0.3 $mm
- Well hydraulic fracturing (each): 0.7 $mm

The CAPEX values are shown in Table 8.1 and Table 8.2:

Table 8.1: Abu Sennan (excluding extension) CAPEX forecasts

Year	Total CAPEX (Developed)			Total CAPEX (Dev.+Undev.)		
	1P	2P	3P	1P	2P	3P
	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
2023	1.60	1.70	1.70	1.60	7.30	12.20
2024	0.70	-	-	0.70	8.30	25.60
2025	0.30	0.70	0.70	0.30	1.25	0.95
2026	-	0.30	-	-	1.00	0.70
2027	-	-	-	-	0.30	0.30
2028	-	-	-	-	-	0.90
2029	-	0.30	0.30	-	0.30	0.90
2030	-	-	-	-	-	-
2031	-	-	-	-	-	-
2032	-	0.30	0.30	-	0.30	0.30
2033	-	-	0.70	-	-	0.70
2034	-	-	-	-	-	-

Table 8.2: Abu Sennan Extension CAPEX forecasts

Year	Total CAPEX (Developed)			Total CAPEX (Dev.+Undev.)		
	1P	2P	3P	1P	2P	3P
	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
2023	0.60	0.60	0.30	0.60	5.58	5.33
2024	-	-	-	-	0.02	0.02
2025	0.30	-	-	0.30	0.25	-
2026	0.30	0.30	-	0.30	0.25	0.25
2027	-	-	-	-	-	-
2028	0.30	0.30	-	0.30	0.25	-
2029	-	-	-	-	-	-
2030	-	-	-	-	-	-
2031	-	-	0.30	-	-	0.25
2032	-	0.30	-	-	0.25	-
2033	-	-	-	-	-	-
2034	-	-	-	-	-	-
2035	-	-	0.60	-	-	0.50
2036	-	-	-	-	-	-
2037	-	-	-	-	-	-

8.2. OPEX Assumptions

The following operating costs were assumed (gross, 2022 basis):

- Fixed field OPEX (excluding extension): 10.20 $mm/year
- Fixed field OPEX (extension): 1.80 $mm/year
- Variable OPEX (including extension): 3.95 $/stb

The OPEX values are shown in Table 8.3 and Table 8.4:

Table 8.3: Abu Sennan (excluding extension) OPEX forecasts

Year	Total OPEX (Developed)			Total OPEX (Dev.+Undev.)		
	1P	2P	3P	1P	2P	3P
	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
2023	13.83	14.35	14.36	13.83	15.44	17.81
2024	13.14	14.19	14.14	13.14	15.51	19.66
2025	12.36	13.73	14.21	12.36	14.43	19.14
2026		13.54	14.26		13.83	17.65
2027		13.02	13.85		13.09	16.23
2028		12.78	13.56		12.79	15.31
2029		12.61	13.61		12.61	14.94
2030		12.09	13.44		12.09	14.41
2031		11.91	13.25		11.91	13.96
2032			13.09			13.63
2033			13.23			13.63
2034			12.90			13.33
2035			12.43			13.03
2036			12.01			12.40
2037						11.99

Table 8.4: Abu Sennan Extension OPEX forecasts

Year	Total OPEX (Developed)			Total OPEX (Dev.+Undev.)		
	1P	2P	3P	1P	2P	3P
	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
2023	2.66	2.89	3.26	2.66	3.48	4.08
2024	2.34	2.55	2.93	2.34	3.10	3.85
2025	2.24	2.48	2.67	2.24	2.85	3.38
2026	2.14	2.38	2.48	2.14	2.63	3.04
2027	2.17	2.19	2.34	2.17	2.35	2.77
2028		2.16	2.23		2.27	2.56
2029		2.40	2.14		2.47	2.40
2030		2.20	2.45		2.29	2.65
2031		2.07	2.54		2.48	2.70
2032			2.24		2.30	2.37
2033			2.10		2.13	2.60
2034			2.02		2.26	2.46
2035			2.78		2.07	3.14
2036			2.63			2.92
2037			2.45			2.69
2038			2.27			2.47
2039			2.18			2.34
2040			2.10			2.23
2041						2.15
2042						2.08

9. Economic Evaluation

ERCE has undertaken economic evaluation of Abu Sennan based on the production and cost profiles, the fiscal regime in Egypt (Concession Agreement) and several commercial assumptions listed below. All estimates are presented on a gross, net working interest and a net entitlement basis.

ERCE has reviewed the operator's economic model and ensured it follows the Concession contractual terms and calculates the CoP (Cessation of Production). ERCE has estimated the Reserves at the 1P/2P/3P levels of uncertainty, for both Developed and Undeveloped scenarios for Abu Sennan as of the effective date of 31 December 2022.

9.1. Fiscal Regime

Upstream activities in the Abu Sennan Area in the Western Desert, Egypt, are subject to the terms of the Abu Sennan Concession Agreement. UOG holds a 22% WI in the Abu Sennan Concession.

In Abu Sennan, the Contractor is allowed a recovery of its costs and expenses of up to 30% of revenues from petroleum produced. Capital expenditures are allowed to be depreciated at a rate of 20% per annum, with operating costs to be recovered in the year incurred. The unrecovered costs can be carried forward until fully recovered. The excess Cost Recovery Petroleum not recovered is due to EGPC.

The remaining 70% of petroleum revenues are divided between EGPC (82.1%) and the Contractor (17.9%).

Bonuses will be due to the EGPC when 30-day average production rates cross certain thresholds. The operator has advised that some of these bonuses have been achieved and paid out.

Table 9.1: Status of Bonuses

30-day average production rate (stb/d)	Bonus (US$MM)	Status
3000	0.50	Achieved and paid
5000	1.00	Achieved and paid
10000	1.50	Achieved and paid
25000	2.00	Not Achieved

The operator has provided gross unrecovered historical cost balances to be used for the evaluation.

Table 9.2: Cost Recovery balances and additions

Year	Unrecovered Costs (US$ Thousand)	
	Original	Extension
Opening balance as of 1/1/2023	75,832	255
2023 addition	13,851	4,073
2024 addition	10,665	3,634
2025 addition	7,240	3,386
2026 addition	4,402	2,690
2027 addition	1,369	775

The Contractor's Egyptian income tax is paid out of EGPC's share of the petroleum produced and is considered income to the Contractor.

Different licences within Abu Sennan expire at different times (expiries range between 2032 and 2039), with five year extensions available.

9.2. Commercial Assumptions

The following commercial parameters were assumed in the modelling of discounted cash flows and in determining the economic Reserves for the evaluated fields.

The economic evaluation has used an oil price forecast advised by the operator as shown in Table 9.3. It is based on the Sproule Consultant's YE 2022 forecast with a reduction in the 2023 estimate from $90 to $87. The forecast is within 10% of the ERCE YE 2022 oil price forecast and so has been accepted.

Table 9.3: ERCE Assumed Brent Price Assumptions

KEC Oil Price Assumptions ($/bbl)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032+
Real (Constant $, 2023)	87.0	84.5	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1
Nominal ($ of the day)	87.0	87.0	82.0	83.6	85.3	87.0	88.8	90.5	92.3	+2.0% pa

- ERCE has assumed a crude oil discount of US$0.85/stb for production in Abu Sennan, on guidance from the operator.
- The economic evaluation has used the operator's assumption of a long-term flat realised Gas Price of US$3.10/Mscf in 2023 and beyond
- Capital and operating costs have been determined in 2023 real terms and inflated at a 2% inflation rate.

9.3. Economic Results

The economic results and subsequent Reserves volumes can be found in Table 9.4. Cash flow tables for the Reserves cases are included in Appendix 3.

Reserves are presented at different levels of uncertainty and are based on combination of the 1P/2P/3P estimates (Developed and Developed + Undeveloped) for cumulative production to the economic limit. We present the Net Present Values discounted at 0%, 7.5%, 10% and 12.5% p.a. at the various levels of uncertainty as of 31 December 2022. The NPV calculations are based on the terms of the Concession Agreement and are shown in US dollars after tax. Though NPVs form an integral part of fair market value estimations, without consideration for other economic criteria they are not to be construed as ERCE's opinion of fair market value.

Cash flow tables for each of the Developed and Undeveloped cases in the Proved, Proved plus Probable and Proved plus Probable plus Possible categories can be found in Appendix 3.

Table 9.4: Results of the Economic Evaluation

Cluster/Asset	Category	Economic Limit (Year)	Gross Reserves Oil (MMstb)	Gross Reserves Gas (Bscf)	Gross Reserves Total (MMboe)	Net Working Interest Reserves Oil (MMstb)	Net Working Interest Reserves Gas (Bscf)	Net Working Interest Reserves Total (MMboe)	Net Entitlement Reserves Oil (MMstb)	Net Entitlement Reserves Gas (Bscf)	Net Entitlement Reserves Total (MMboe)	Net NPV 0% (US$MM)	Net NPV 7.5% (US$MM)	Net NPV 10% (US$MM)	Net NPV 12.5% (US$MM)	Net NPV 15% (US$MM)
Abu Sennan																
Abu Sennan	1P Dev.	2025	2.2	0.0	2.2	0.5	0.0	0.5	0.2	0.0	0.2	8.6	7.9	7.7	7.5	7.4
	2P Dev.	2031	6.7	1.5	7.0	1.5	0.3	1.5	0.6	0.1	0.7	26.6	21.4	20.1	18.9	17.9
	3P Dev.	2036	11.5	7.1	13.0	2.5	1.6	2.8	1.1	0.7	1.2	52.7	36.0	32.4	29.3	26.8
	1P Undev.		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2P Undev.		0.9	0.8	1.1	0.2	0.2	0.2	0.1	0.1	0.1	3.2	2.8	2.7	2.6	2.5
	3P Undev.		7.2	6.5	8.5	1.6	1.4	1.9	0.5	0.5	0.6	23.1	20.0	19.1	18.3	17.6
	1P Dev. + Undev.	2025	2.2	0.0	2.2	0.5	0.0	0.5	0.2	0.0	0.2	8.6	7.9	7.7	7.5	7.4
	2P Dev. + Undev.	2031	7.6	2.3	8.0	1.7	0.5	1.8	0.7	0.2	0.8	29.8	24.2	22.8	21.5	20.4
	3P Dev. + Undev.	2037	18.8	13.6	21.5	4.1	3.0	4.7	1.6	1.2	1.8	75.8	56.0	51.5	47.7	44.4
Abu Sennan Extension	1P Dev.	2027	0.6	0.0	0.6	0.1	0.0	0.1	0.1	0.0	0.1	2.2	2.0	1.9	1.9	1.8
	2P Dev.	2031	1.3	0.0	1.3	0.3	0.0	0.3	0.1	0.0	0.1	5.0	4.2	3.9	3.7	3.5
	3P Dev.	2040	2.9	0.0	2.9	0.6	0.0	0.6	0.2	0.0	0.2	11.0	7.4	6.7	6.1	5.6
	1P Undev.		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2P Undev.		1.1	0.0	1.1	0.2	0.0	0.2	0.1	0.0	0.1	3.9	2.5	2.3	2.0	1.8
	3P Undev.		1.9	0.0	1.9	0.4	0.0	0.4	0.1	0.0	0.1	6.1	3.7	3.2	2.8	2.5
	1P Dev. + Undev.	2027	0.6	0.0	0.6	0.1	0.0	0.1	0.1	0.0	0.1	2.2	2.0	1.9	1.9	1.8
	2P Dev. + Undev.	2035	2.3	0.0	2.3	0.5	0.0	0.5	0.2	0.0	0.2	8.9	6.7	6.2	5.7	5.3
	3P Dev. + Undev.	2042	4.8	0.0	4.8	1.1	0.0	1.1	0.4	0.0	0.4	17.1	11.0	9.9	8.9	8.2

10. Appendix 1: SPE PRMS Guidelines

This report references the SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Reserves and Resources Classification System and Definitions, as revised in June 2018 (PRMS). The full text of the PRMS document can be viewed at:

https://secure.spee.org/sites/spee.org/files/prmgmtsystem_final_2018.pdf.

Definitions of the Key PRMS Reserves and Resource classes, categories and a glossary of related terms can be found at the above address.

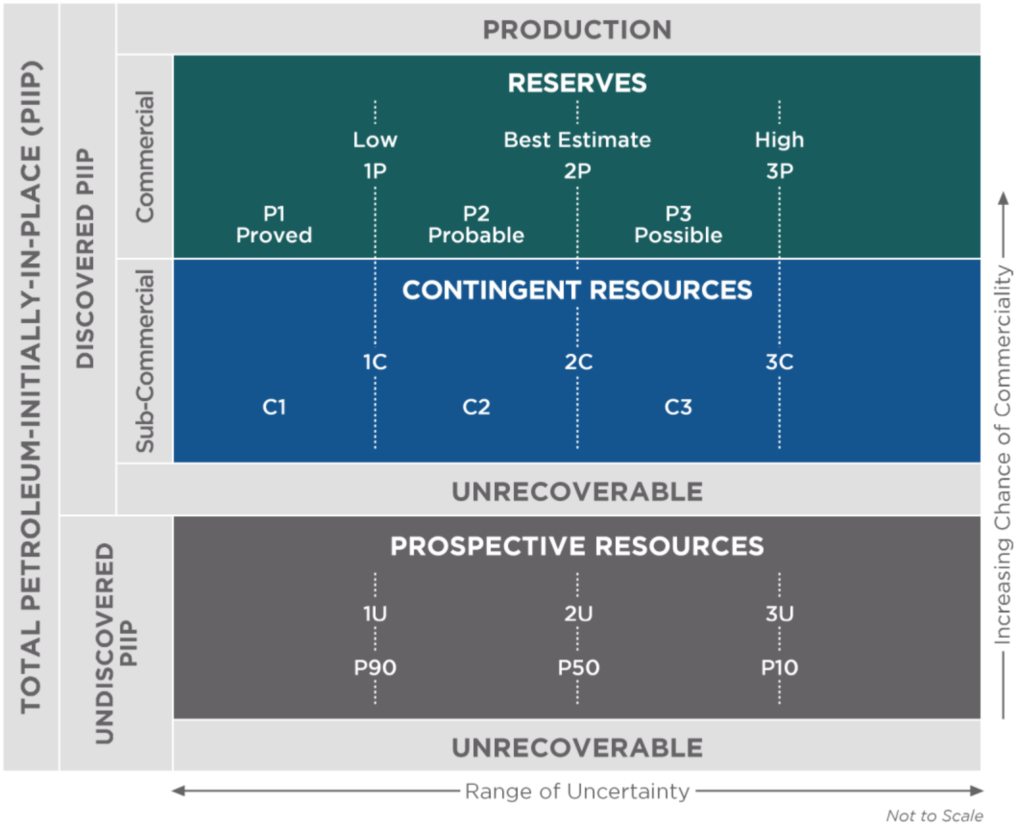

Figure A: PRMS Resources classification framework

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 1.1)

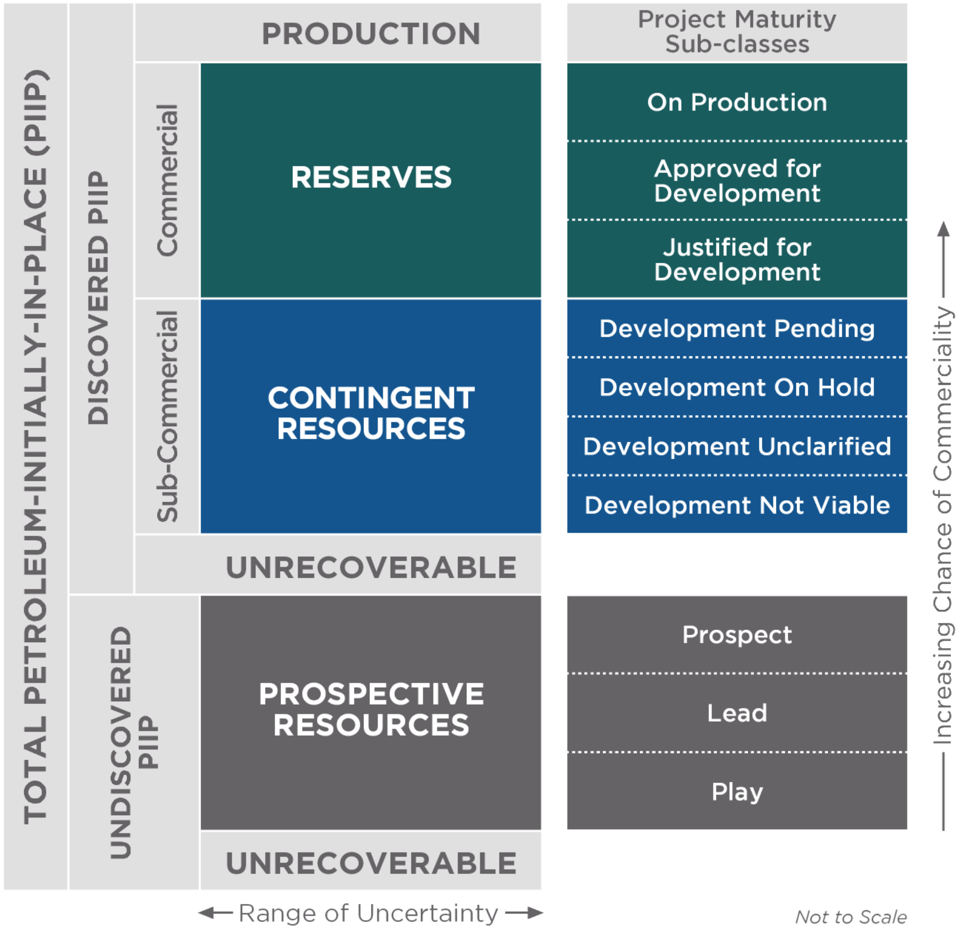

Figure B: PRMS Resources sub-classes

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 2.1)

Table 1: PRMS Recoverable Resources Classes and Sub-Classes

Classes/Sub-classes	Definition	Guidelines
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 based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market- related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

Classes/Sub-classes	Definition	Guidelines
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The Key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

Classes/Sub-classes	Definition	Guidelines
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub- classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Classes/Sub-classes	Definition	Guidelines
Development on Hold	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.
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.
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.
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.

Classes/Sub-classes	Definition	Guidelines
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.
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.
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.

Table 2: PRMS Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (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, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: PRMS Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and 2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates 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. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Table 4: Glossary of Terms Used in PRMS

Term	Definition
1C	Denotes low estimate of Contingent Resources.
2C	Denotes best estimate of Contingent Resources.
3C	Denotes high estimate of Contingent Resources.
1P	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2P	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
3P	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
1U	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	Denotes the unrisked high estimate qualifying as Prospective Resources.
Abandonment, Decommissioning, and Restoration (ADR)	The process (and associated costs) of returning part or all of a project to a safe and environmentally compliant condition when operations cease. Examples include, but are not limited to, the removal of surface facilities, wellbore plugging procedures, and environmental remediation. In some instances, there may be salvage value associated with the equipment removed from the project. ADR costs are presumed to be without consideration of any salvage value, unless presented as "ADR net of salvage."
Accumulation	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	The process of summing well, reservoir, or project-level estimates of resources quantities to higher levels or combinations, such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Appraisal	The phase that may follow successful exploratory drilling. Activities to further evaluate the discovery, such as seismic acquisition, geological studies, and drilling additional wells may be conducted to reduce technical uncertainties and commercial contingencies.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway. A project maturity sub-class of Reserves.
Analog	Method used in resources estimation in the exploration and early development stages (including improved recovery projects) when direct measurement is limited. Based on evaluator's assessment of similarities of the analogous reservoir(s) together with the development plan.

Analogous Reservoir	Reservoirs that have similar rock properties (e.g., petrophysical, lithological, depositional, diagenetic, and structural), fluid properties (e.g., type, composition, density, and viscosity), reservoir conditions (e.g., depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide insight and comparative data to assist in estimation of recoverable resources.
Assessment	See Evaluation.
Associated Gas	A natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as gas cap gas or solution gas.
Basin-Centered Gas	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas-saturated reservoirs, and lack of a down dip water leg.
Barrel of Oil Equivalent (BOE)	The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil.
Basis for Estimate	The methodology (or methodologies) and supporting data on which the estimated quantities are based. (Also referenced as basis for the estimation.)
Behind-Pipe Reserves	Reserves that are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion before the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling and completing a new well including hook-up to allow production.
Best Estimate	With respect to resources categorization, the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C1	Denotes low estimate of Contingent Resources. C1 is equal to 1C.
C2	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves.
C3	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves.
Chance	Chance equals 1-risk. Generally synonymous with likelihood. (See Risk)
Chance of Commerciality	The estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the chance of geologic discovery and the chance of development. For Contingent Resources and Reserves, it is equal to the chance of development.
Chance of Development	The estimated probability that a known accumulation, once discovered, will be commercially developed.

Chance of Geologic Discovery	The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.
Coalbed Methane (CBM)	Natural gas contained in coal deposits. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. [Also called coal-seam gas (CSG) or natural gas from coal (NGC).]
Commercial	A project is commercial when there is evidence of a firm intention to proceed with development within a reasonable time-frame. Typically, this requires that the best estimate case meet or exceed the minimum evaluation decision criteria (e.g., rate of return, investment payout time). There must be a reasonable expectation that all required internal and external approvals will be forthcoming. Also, there must be evidence of a technically mature, feasible development plan and the essential social, environmental, economic, political, legal, regulatory, decision criteria, and contractual conditions are met. .
Committed Project	Project that the entity has a firm intention to develop in a reasonable time-frame. Intent is demonstrated with funding/financial plans, but FID has not yet been declared (See also Final Investment Decision.)
Completion	Completion of a well. The process by which a well is brought to its operating status (e.g., producer, injector, or monitor well). A well deemed to be capable of producing petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir.
Completion Interval	The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
Concession	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an entity. The entity is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned. (Also called a license.)
Condensate	A mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from NGLs in two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensate.
Confidence Level	A measure of the estimated reliability of a result. As used in the deterministic incremental method, the evaluator assigns a relative level of confidence (high/moderate/low) to areas/segments of an accumulation based on the information available (e.g., well control and seismic coverage). Probabilistic and statistical methods use the 90% (P90) for the high confidence (low value case), 50% (P50) for the best estimate (moderate value case), and 10% (P10) for the low (high value case) estimate to represent the chances that the actual value will equal or exceed the estimate.

Constant Case	A descriptor applied to the economic evaluation of resources estimates. Constant-case estimates are based on current economic conditions being those conditions (including costs and product prices) that are fixed at the evaluation date and held constant, with no inflation or deflation made to costs or prices throughout the remainder of the project life other than those permitted contractually.
Consumed in Operations (CiO)	That portion of produced petroleum consumed as fuel in production or lease plant operations before delivery to the market at the reference point. (Also called lease fuel.)
Contingency	A condition that must be satisfied for a project in Contingent Resources to be reclassified as Reserves. Resolution of contingencies for projects in Development Pending is expected to be achieved within a reasonable time period.
Contingent Project	A project that is not yet commercial owing to one or more contingencies that have not been resolved.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.
Continuous-Type Deposit	A petroleum accumulation that is pervasive throughout a large area and that generally lacks well-defined OWC or GWC. Such accumulations are included in unconventional resources. Examples of such deposits include “basin-centered” gas, tight gas, tight oil, gas hydrates, natural bitumen, and oil shale (Kerogen) accumulations.
Conventional Resources	Resources that exist in porous and permeable rock with buoyancy pressure equilibrium. The PIIP is trapped in discrete accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down dip contact with an aquifer and is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
Cost Recovery	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the production stream. The contractor normally receives an entitlement interest share in the petroleum production and is exposed to both technical and market risks.
Crude Oil	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature (excludes retrograde condensate). Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Cumulative Production	The sum of petroleum quantities that have been produced at a given date. (See also Production). Production is measured under defined conditions to allow for the computation of both reservoir voidage and sales quantities and for the purpose of voidage also includes non-petroleum quantities.
Current Economic Conditions	Economic conditions based on relevant historical petroleum prices and associated costs averaged over a specified period. The default period is 12 months. However, in the event that a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified and used as the basis of constant-case resources estimates and associated project cash flows.

Defined Conditions	Forecast of conditions to exist and impact the project during the time period being evaluated. Forecasts should account for issues that impact the commerciality, such as economics (e.g., hurdle rates and commodity price); operating and capital costs; and technical, marketing, sales route, legal, environmental, social, and governmental factors.
Deposit	Material laid down by a natural process. In resources evaluations, it identifies an accumulation of hydrocarbons in a reservoir. (See Accumulation.)
Deterministic Incremental Method	An assessment method based on defining discrete parts or segments of the accumulation that reflect high, moderate, and low confidence regarding the estimates of recoverable quantities under the defined development plan.
Deterministic Method	An assessment method based on discrete estimate(s) made based on available geoscience, engineering, and economic data and corresponds to a given level of certainty.
Deterministic Scenario Method	Method where the evaluator provides three deterministic estimates of the quantities to be recovered from the project being applied to the accumulation. Estimates consider the full range of values for each input parameter based on available engineering and geoscience data, but one set is selected that is most appropriate for the corresponding resources confidence category. A single outcome of recoverable quantities is derived for each scenario.
Developed Reserves	Reserves that are expected to be recovered from existing wells and facilities. Developed Reserves may be further sub-classified as Producing or Non- Producing.
Developed Producing Reserves	Developed Reserves that are expected to be recovered from completion intervals that are open and producing at the effective date. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Reserves that are either shut-in or behind-pipe. (See also Shut-In Resources and Behind-Pipe Reserves.)
Development On Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class of Contingent Resources.
Development Not Viable	A discovered accumulation for which there are contingencies resulting in there being no current plans to develop or to acquire additional data at the time due to limited commercial potential. A project maturity sub-class of Contingent Resources.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class of Contingent Resources.
Development Plan	The design specifications, timing, and cost estimates of the appraisal and development project(s) that are planned in a field or group of fields. The plan will include, but is not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation, regulations, and marketing. The plan is often executed in phases when involving large, complex, sequential recovery and/or extensive areas.

Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. This sub-class requires appraisal or study 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. A project maturity sub-class of Contingent Resources.
Discovered	A petroleum accumulation where one or several exploratory wells through testing, sampling, and/or logging have demonstrated the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for technical recovery. (See also Known Accumulation.)
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.
Discovered Unrecoverable	Discovered petroleum in-place resources that are evaluated, as of a given date, as not able to be recovered by the commercial and sub-commercial projects envisioned.
Dry Gas	Natural gas remaining after hydrocarbon liquids have been removed before the reference point. It should be recognized that this is a resources assessment definition and not a phase behavior definition. (Also called lean gas.)
Economic	A project is economic when it has a positive undiscounted cumulative cash flow from the effective date of the evaluation, the net revenue exceeds the net cost of operation (i.e., positive cumulative net cash flow at discount rate greater than or equal to zero percent).
Economic Interest	Interest that is possessed when an entity has acquired an interest in the minerals in-place or a license and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return.
Economic Limit	Defined as the time when the maximum cumulative net cash flow (see Net Entitlement) occurs for a project.
Economically Not Viable Contingent Resources	Those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions. May also be subject to additional unsatisfied contingencies.
Economically Viable Contingent Resources	Those quantities associated with technically feasible projects where cash flows are positive under reasonable forecast conditions but are not Reserves because it does not meet the other commercial criteria
Economically Producible	Refers to the situation where the net revenue from an ongoing producing project exceeds the net expenses attributable to a certain entity’s interest. The ADR costs are excluded from the determination.
Effective Date	Resource estimates of remaining quantities are “as of the given date” (effective date) of the evaluation. The evaluation must take into account all data related to the period before the "as of date.”

Entitlement	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license.
Entity	A legal construct capable of bearing legal rights and obligations. In resources evaluations, this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
Established Technology	Methods of recovery or processing that have proved to be successful in commercial applications.
Estimated Ultimate Recovery (EUR)	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities that have been already produced. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
Evaluation	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. (Also called assessment.)
Evaluator	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including its resources and attributed value estimates.
Exploration	Prospecting for undiscovered petroleum using various techniques, such as seismic surveys, geological studies, and exploratory drilling.
Field	In conventional reservoirs, a field is typically an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities. For unconventional reservoirs without hydrodynamic influences, a field is often defined by regulatory or ownership boundaries as necessary.
Final Investment Decision (FID)	Project approval stage when the participating companies have firmly agreed to the project and the required capital funding.
Flare Gas	The total quantity of gas vented and/or burned as part of production and processing operations (but not as fuel).
Flow Test	An operation on a well designed to demonstrate the existence of recoverable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test). May also demonstrate the potential of certain completion techniques, particularly in unconventional reservoirs.
Fluid Contacts	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.

Forecast Case	A descriptor applied to a scenario when production and associated cash-flow estimates are based on those conditions (including costs and product price schedules, inflation indexes, and market factors) forecast by the evaluator to reasonably exist throughout the evaluation life (i.e., defined conditions). Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Gas Balance	In gas production operations involving multiple working interest owners, maintaining a statement of volumes attributed to each, depending on each owner's portion received. Imbalances may occur that must be monitored over time and eventually balanced in accordance with accepted accounting procedures.
Gas Cap Gas	Free natural gas that overlies and is in contact with crude oil in the reservoir. It is a subset of associated gas.
Gas Hydrates	Naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure or clathrate. At conditions of standard temperature and pressure, one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Gas hydrates are included in unconventional resources, but the technology to support commercial maturity has yet to be developed.
Gas/Oil Ratio	Ratio that is calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil ratio, Rs ; produced gas/oil ratio, Rp ; or another suitably defined ratio of gas production to oil production.
Geostatistical Methods	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of large quantities of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates.
High Estimate	With respect to resources categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
Hydrates	See Gas Hydrates.
Hydrocarbons	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon molecules.
Improved Recovery	The extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes, and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called enhanced recovery.)
Injection	The forcing, pumping, or natural flow of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.

Justified for Development	A development project that has reasonable forecast commercial conditions at the time of reporting and there are reasonable expectation that all necessary approvals/contracts will be obtained. A project maturity sub-class of Reserves.
Kerogen	The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.)
Known Accumulation	An accumulation that has been discovered.
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. A project maturity sub-class of Prospective Resources.
Learning Curve	Demonstrated improvements over time in performance of a repetitive task that results in efficiencies in tasks to be realized and/or in reduced time to perform and ultimately in cost reductions.
Likelihood	Likelihood (the estimated probability or chance) is equal (1- risk). (See Probability and Risk.)
Low/Best/High Estimates	Reflects the range of uncertainty as a reasonable range of estimated potentially recoverable quantities.
Low Estimate	With respect to resources categorization, this is a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Lowest Known Hydrocarbons (LKH)	The deepest documented occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, core data, or other conclusive and reliable evidence.
Market	A consumer or group of consumers of a product that has been obtained through purchase, barter, or contractual terms.
Marketable Quantities	Those quantities of hydrocarbons that are estimated to be producible from petroleum accumulations and that will be consumed by the market. (Also referred to as marketable products.)
Mean	The sum of a set of numerical values divided by the number of values in the set.
Measurement	The process of establishing quantity (volume, mass, or energy content) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
Mineral Lease	An agreement in which a mineral owner (lessor) grants an entity (lessee) rights. Such rights can include (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of the lease; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and/or (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer).

Monte Carlo Simulation	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum quantities).
Multi-Scenario Method	An extension of the deterministic scenario method. In this case, a significant number of discrete deterministic scenarios are developed by the evaluator, with each scenario leading to a single deterministic outcome. Probabilities may be assigned to each discrete input assumption from which the probability of the scenario can be obtained; alternatively, each outcome may be assumed to be equally likely.
Natural Bitumen	The portion of petroleum that exists in the semi-solid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other non- hydrocarbons. Natural bitumen has a viscosity greater than 10,000 mPa·s (or 10,000 cp) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural bitumen generally requires upgrading before normal refining.
Natural Gas	Portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in a reservoir, and which is gaseous at atmospheric conditions of pressure and temperature. Natural gas may include some amount of non- hydrocarbons.
Natural Gas Liquids (NGLs)	A mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects: (1) NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates.
Net Entitlement	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license. Under the terms of PSCs, the producers have an entitlement to a portion of the production. This entitlement, often referred to as “net entitlement” or “net economic interest” is estimated using a formula based on the contract terms incorporating costs and profits.
Net Pay	The portion (after applying cutoffs) of the thickness of a reservoir from which petroleum can be produced or extracted. Value is referenced to a true vertical thickness measured.
Net Revenue Interest	An entity’s revenue share of petroleum sales after deduction of royalties or share of production owing to others under applicable lease and fiscal terms. (See also Entitlement and Net Entitlement)
Netback Calculation	Term used in the hydrocarbon product price determination at reference point to reflect the revenue of one unit of sales after the costs associated with bringing the product to a market (e.g., transportation and processing) are removed.
Non-Hydrocarbon Gas	Associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium that are present in naturally occurring petroleum accumulations.
Non-Sales	That portion of estimated recoverable or produced quantities that will not be included in sales as contractually defined at the reference point. Non-sales include quantities CiO, flare, and surface losses, and may include non- hydrocarbons.

Oil Sands	Sand deposits highly saturated with natural bitumen. Also called “tar sands.” Note that in deposits such as the western Canada oil sands, significant quantities of natural bitumen may be hosted in a range of lithologies, including siltstones and carbonates.
Oil Shales	Shale, siltstone, and marl deposits highly saturated with Kerogen. Whether extracted by mining or in-situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil). (Often called Kerogen shale.)
On Production	A project maturity sub-class of Reserves that reflects the operational execution phase of one or multiple development projects with the Reserves currently producing or capable of producing. Includes Developed Producing and Developed Non-Producing Reserves.
Overlift/Underlift	Production entitlements received that vary from contractual terms resulting in overlift or underlift positions. This can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed upon by the parties. At any given financial year- end, a company may be in overlift or underlift. Based on the production matching the company’s accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year and not on the production entitlement for the year.
P1	Denotes Proved Reserves. P1 is equal to 1P.
P2	Denotes Probable Reserves.
P3	Denotes Possible Reserves.
Penetration	The intersection of a wellbore with a reservoir.
Petroleum	Defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content of petroleum can be greater than 50%.
Petroleum Initially-in-Place (PIIP)	The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs, as of a given date. Crude oil in-place, natural gas in-place, and natural bitumen in-place are defined in the same manner.
Pilot Project	A small-scale test or trial operation used to assess technology, including recovery processes, for commercial application in a specific reservoir.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects. A project maturity sub-class of Prospective Resources.
Pool	An individual and separate accumulation of petroleum in a reservoir within a field.

Possible Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. 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), 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.
Primary Recovery	The extraction of petroleum from reservoirs using only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
Probability	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. PRMS convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)
Probabilistic Method	The method of estimation of resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
Probable Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Production	The cumulative quantities of petroleum that have been recovered at a given date. Production can be reported in terms of the sales product specifications, but project evaluation requires that all production quantities (sales and non-sales), as measured to support engineering analyses requiring reservoir voidage calculations, are recognized.
Production Forecast	A forecasted schedule of production over time. For Reserves, the production forecast reflects a specific development scenario under a specific recovery process, a certain number and type of wells and particular facilities and infrastructure. When forecasting Contingent or Prospective Resources, more than one project scope (e.g., wells and facilities) is frequently carried to determine the range of the potential project and its uncertainty together with the associated resources defining the low, best, and high production forecasts. The uncertainty in resources estimates associated with a production forecast is usually quantified by using at least three scenarios or cases of low, best, and high, which lead to the resources classifications of, respectively, 1P, 2P, 3P and 1C, 2C, 3C or 1U,2U and 3U.
Production-Sharing Contract (PSC)	A contract between a contractor and a host government in which the contractor typically bears the risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership of petroleum in the ground is retained by the host government; however, the contractor normally receives title to the prescribed share of the quantities as they are produced. (Also termed production-sharing agreement (PSA).

Project	A defined activity or set of activities that provides the link between the petroleum accumulation's resources sub-class and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, an incremental development in a larger producing field, or the integrated development of a group of several fields and associated facilities (e.g. compression) with a common ownership. In general, an individual project will represent a specific maturity level (sub-class) at which a decision is made on whether or not to proceed (i.e., spend money), suspend, or remove. There should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Property	A defined portion of the Earth's crust wherein an entity has contractual rights to extract, process, and market specified in-place minerals (including petroleum). In general, defined as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.
Prospect	A project associated with an undrilled potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class of Prospective Resources.
Prospective Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.
Proved Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. 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 a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
Pure Service Contract	Agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific time period. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor's reimbursement is fixed by the contract's terms with little exposure to either project performance or market factors. No Reserves or Resources can be attributed to these activities.
Qualified Reserves Auditor	A reserves evaluator who (1) has a minimum of ten years of practical experience in petroleum engineering or petroleum production geology, with at least five years of such experience being in responsible charge of the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor's or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer's license or a registered or certified professional geologist's license, or the equivalent, from an appropriate governmental authority or professional organization. (see SPE 2007 "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information")

Qualified Reserves Evaluator	A reserves evaluator who (1) has a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years of such experience being in the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor's or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer's license or a registered or certified professional geologist's license, or the equivalent, from an appropriate governmental authority or professional organization. (modified from SPE 2007 "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information")
Range of Uncertainty	The range of uncertainty of the in-place, recoverable, and/or potentially recoverable quantities; may be represented by either deterministic estimates or by a probability distribution. (See Resources Categories.)
Raw Production	All components, whether hydrocarbon or other, produced from the well or extracted from the mine (hydrocarbons, water, impurities such as non-hydrocarbon gases, etc.).
Reasonable Certainty	If deterministic methods for estimating recoverable resources quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. Typically attributed to Proved Reserves or 1C Resources quantities.
Reasonable Expectation	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur. (Differs from reasonable certainty, which applies to resources quantity technical confidence, while reasonable expectation relates to commercial confidence.).
Recoverable Resources	Those quantities of hydrocarbons that are estimated to be producible by the project from either discovered or undiscovered accumulations.
Recovery Efficiency	A numeric expression of that portion (expressed as a percentage) of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage. It is estimated using the recoverable resources divided by the hydrocarbons initially in-place. It is also referenced to timing; current and ultimate (or estimated ultimate) are descriptors applied to reference the stage of the recovery. (Also called recovery factor.)
Reference Point	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions before custody transfer (or consumption). Also called point of sale, terminal point, or custody transfer point.
Report	The presentation of evaluation results within the entity conducting the assessment. Should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.
Reserves	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: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.

Reservoir	A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, or fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs).
Resources	Term used to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring in an accumulation on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional or unconventional. (See Total Petroleum Initially-in-Place.)
Resources Categories	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability and contractual changes). The resource quantity uncertainty range within a single resources class is reflected by either the 1P, 2P, 3P, Proved, Probable, Possible, or 1C, 2C, 3C or 1U, 2U, 3U resources categories.
Resources Classes	Subdivisions of resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project's estimated likelihood of commerciality.
Resources Type	Describes the accumulation and is determined by the combination of the type of hydrocarbon and the rock in which it occurs.
Revenue-Sharing Contract	Contracts that are very similar to the PSCs with the exception of contractor payment in these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Risk	The probability of loss or failure. Risk is not synonymous with uncertainty. Risk is generally associated with the negative outcome, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring.
Risk and Reward	Risk and reward associated with oil and gas production activities are attributed primarily from the variation in revenues cause by technical and economic risks. The exposure to risk in conjunction with entitlement rights is required to support an entity's resources recognition. Technical risk affects an entity's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors.
Risk Service Contract (RSC)	Agreements that are very similar to the production-sharing agreements in that the risk is borne by the contractor but the mechanism of contractor payment is different. With a RSC, the contractor usually receives a defined share of revenue rather than a share of the production.

Royalty	A type of entitlement interest in a resource that is free and clear of the costs and expenses of development and production to the royalty interest owner. A royalty is commonly retained by a resources owner (lessor/host) when granting rights to a producer (lessee/contractor) to develop and produce that resource. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at discretion of the royalty owner.
Sales	The quantity of petroleum and any non-hydrocarbon product delivered at the custody transfer point (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities.
Shale Gas	Although the terms shale gas and tight gas are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight gas production
Shale Oil	Although the terms shale oil and tight oil are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight oil production
Shut-In Resources	Resources planned to be recovered from (1) completion intervals that are open at the time of the estimate, but which have not started producing; (2) wells that were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons that can be remediated at a limited cost compared to the cost of the well.
Split Classification	A single project should be uniquely assigned to a sub-class along with its uncertainty range, For example, a project cannot have quantities categorized as 1C, 2P, and 3P. This is referred to as “split classification.” If there are differing commercial conditions, separate sub-classes should be defined.
Split Conditions	The uncertainty in recoverable quantities is assessed for each project using resources categories. The assumed commercial conditions are associated with resource classes or sub-classes and not with the resources categories. For example, the product price assumptions are those assumed when classifying projects as Reserves, and a different price would not be used for assessing Proved versus Probable reserves. That would be referred to as “split conditions.”
Stochastic	Adjective defining a process involving or containing a random variable or variables or involving likelihood or probability, such as a stochastic simulation.
Sub-Commercial	A project subdivision that is applied to discovered resources that occurs if either the technical or commercial maturity conditions of project have not yet been achieved. A project is sub-commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time-frame. Sub-commercial projects are classified as Contingent Resources.

Sunk Cost	Money spent before the effective date and that cannot be recovered by any future action. Sunk costs are not relevant to future business decisions because the cost will be the same regardless of the outcome of the decision. Sunk costs differ from committed (obligated) costs, where there is a firm and binding agreement to spend specified amounts of money at specific times in the future (i.e., after the effective date).
Synthetic Crude Oil	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, Kerogen from oil shales, or processing of other substances such as natural gas or coal. Synthetic crude oil may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil.
Taxes	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical Forecast	The forecast of produced resources quantities that is defined by applying only technical limitations (i.e., well-flow-loading conditions, well life, production facility life, flow-limit constraints, facility uptime, and the facility's operating design parameters). Technical limitations do not take into account the application of either an economic or license cut-off. (See also Technically Recoverable Resources).
Technical Uncertainty	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by the range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Technically Recoverable Resources	Those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial or accessibility considerations.
Technology Under Development	Technology that is currently under active development and that has not been demonstrated to be commercially viable. There should be sufficient direct evidence (e.g., a test project/pilot) to indicate that the technology may reasonably be expected to be available for commercial application.
Tight Gas	Gas that is trapped in pore space and fractures in very low-permeability rocks and/or by adsorption on Kerogen, and possibly on clay particles, and is released when a pressure differential develops. It usually requires extensive hydraulic fracturing to facilitate commercial production. Shale gas is a sub-type of tight gas.
Tight Oil	Crude oil that is trapped in pore space in very low-permeability rocks and may be liquid under reservoir conditions or become liquid at surface conditions. Extensive hydraulic fracturing is invariably required to facilitate commercial maturity and economic production. Shale oil is a sub-type of tight oil.
Total Petroleum Initially-in-Place	All estimated quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
Uncertainty	The range of possible outcomes in a series of estimates. For recoverable resources assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)

Unconventional Resources	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined OWC or GWC (also called "continuous-type deposits"). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility.Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).
Undeveloped Reserves	Those quantities expected to be recovered through future investments: (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, or (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.
Undiscovered Petroleum Initially-in-Place	That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
Unrecoverable Resources	Those quantities of discovered or undiscovered PIIP that are 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.
Upgrader	A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil. While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Wet Gas	Natural gas from which no liquids have been removed before the reference point. The wet gas is accounted for in resources assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resources assessment definition and not a phase behavior definition.
Working Interest	An entity's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.

11. Appendix 2: Nomenclature

3D	three dimensional
ABEX	abandonment cost
API	American Petroleum Institute
bbl	barrel (42 US gallons)
Bg	gas formation volume factor, in scf/rcf
BH	bottom hole
BHA	bottom hole assembly
Bo	oil formation volume factor, in rb/stb
Bscf	thousands of millions of standard cubic feet
C&P	cased and perforated
CAPEX	capital cost
CGR	condensate gas ratio
CO_2	carbon dioxide
CoP	cessation of production
COS	geological chance of success
CPI	computer processed interpretation
d	day
DCA	decline curve analysis
DST	drill stem test
Eg	gas expansion factor
ELT	economic limit test
FBHP	flowing bottom hole pressure
FDP	field development plan
ft	feet
FTHP	flowing tubing head pressure
FVF	formation volume factor
FWL	free water level
GDT	gas down to
GEF	gas expansion factor
GIIP	gas initially in place
GOC	gas oil contact

GOR	gas oil ratio
GRV	gross rock volume
GSA	gas sales agreement
GWC	gas water contact
H_2S	hydrogen sulphide
HIIP	hydrocarbons initially in place
kh	permeability thickness
km	kilometres
Kr	relative permeability
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LTC	long term compression
m	metre
M MM	thousands and millions respectively
MD	measured depth
md or mD	millidarcy
MDRKB	measured depth below Kelly Bushing
MDT	modular dynamic tester
MSL	mean sea level
mss	metres subsea
N_2	nitrogen
NAG	non-associated gas
NPV xx	net present value at xx discount rate
NTG	net to gross ratio
ODT	oil down to
OPEX	operating cost
OWC	oil water contact
P90	low case (probabilistic) estimate (there should be a 90% probability of exceeding this estimate)
P50	mid or best case (probabilistic) estimate (there should be a 50% probability of exceeding this estimate)
P10	high case (probabilistic) estimate (there should be a 10% probability of exceeding this estimate)
Pb	saturation, or bubble point, pressure
PBU	pressure-build-up

Phi	porosity
Phie	effective porosity
Phit	total porosity
PI	productivity index, in stb/d/psi for oil or MMscf/d/psi or Mscf/d/psi for gas
POD	plan of development
PSA	production sharing agreement
PSC	production sharing contract
psi	pressure, measured in pounds per square inch
psia	absolute pressure, measured in pounds per square inch
psig	gauge pressure which is the pressure above atmospheric pressure, measured in pounds per square inch
PSDM	post stack depth migration
PSTM	post stack time migration
PVT	pressure volume temperature experiment
rb	reservoir barrels
RCA	routine core analysis
rcf	cubic feet at reservoir conditions
RFT	repeat formation tester
Rs	solution gas oil ratio
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
stb	stock tank barrel (42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit)
STOIIP	stock tank oil initially in place
Sw	water saturation
Swc	connate water saturation
TD	total depth
THP	tubing head pressure
TVD	true vertical depth
TVDSS	true vertical depth sub-sea
TWT	two way time
WGR	water gas ratio
WOR	water oil ratio
WUT	water up to

12. Appendix 3: Summary of HIIP, EUR and Recovery Factor

Table 12.1: Summary of HCIIP, EUR and Recovery Factor

Field	Reservoir	HIIP (MMboe)			Cum Production (31 Dec. 2022)			Remaining Technically Recoverable Resources (MMboe)			EUR (MMboe)			RF%		
		1P	2P	3P	MMbbls	Bscf	MMboe	1P	2P	3P	1P	2P	3P	1P	2P	3P
ZZ	Abu Roash "G"	0.58	0.74	0.88	0.03	1.30	0.29	-	-	-	0.29	0.29	0.29	49.6	38.9	32.7
	L. Bahariya	0.16	0.21	0.26	0.01	-	0.01	-	-	-	0.01	0.01	0.01	6.3	4.8	3.8
Al Ahmadi	Abu Roash "G"	0.12	0.16	0.20	0.01	-	0.01	-	-	-	0.01	0.01	0.01	9.6	7.2	5.8
	Lower Bahariya	1.08	1.35	1.62	0.02	0.77	0.17	-	-	-	0.17	0.17	0.17	16.2	12.9	10.8
Al Jahraa & AL Jahraa SE	A/R "E" Al Jahraa-1	0.74	0.74	0.74	0.07	-	0.07	-	-	-	0.07	0.07	0.07	10.0	10.0	10.0
	A/R "E" (Al Jahraa SE)	1.63	2.93	4.34	0.31	-	0.31	0.03	0.08	0.12	0.33	0.39	0.42	20.4	13.2	9.8
	A/R "C"	16.85	25.97	36.38	4.29	-	4.29	2.19	5.11	8.23	6.48	9.40	12.51	38.5	36.2	34.4
	A/R "D"	3.34	3.34	3.34	0.40	-	0.40	0.03	0.04	0.50	0.43	0.44	0.91	12.9	13.2	27.1
	A/R"G"	1.03	1.41	1.94	-	-	-	0.07	0.24	0.32	0.07	0.24	0.32	6.9	16.9	16.4
	Lower Bahariya	5.84	8.01	11.00	0.64	1.44	0.93	0.02	0.50	0.71	0.95	1.43	1.64	16.3	17.8	14.9
	A/R"E" Al Jahraa-7	0.68	0.68	1.46	0.11	-	0.11	0.01	0.01	0.04	0.12	0.12	0.15	17.4	18.0	10.2
	A/R"E" Al Jahraa-8&3	1.01	1.30	1.64	-	-	-	0.07	0.25	0.38	0.07	0.25	0.38	7.1	18.9	23.2
	Upper Baharyia Al Jahraa-7	0.24	0.51	1.02	-	-	-	-	-	0.21	-	-	0.21	-	-	20.1
	Upper Baharyia Al Jahraa-8	0.70	1.33	2.41	-	-	-	0.08	0.16	0.43	0.08	0.16	0.43	11.1	12.0	17.9
	Lower Bahariya Sand II Al Jahraa-7	0.11	0.31	0.81	-	-	-	0.01	0.05	0.19	0.01	0.05	0.19	8.9	15.9	23.3
El Salmiya	A/R "C" (Salmiya-1,4&5)	4.20	6.24	9.35	0.57	1.68	0.91	0.17	0.42	1.21	1.07	1.32	2.11	25.5	21.2	22.6
	A/R "C" (Salmiya-3)	0.99	0.99	0.99	0.18	0.45	0.27	-	-	-	0.27	0.27	0.27	26.7	26.7	26.7
	A/R "E" (Salmiya-2&6&5)	3.77	5.26	6.87	0.25	-	0.25	0.32	0.84	1.60	0.57	1.09	1.85	15.3	20.7	27.0
	Lower Bahariya	0.83	2.18	8.81	-	-	-	-	-	-	-	-	-	-	-	-
	ARG	0.39	0.82	1.68	-	-	-	0.03	0.15	0.22	0.03	0.15	0.22	8.2	18.8	13.2
	Kharita(El Salmiya-2, 6&5ST)	8.00	8.90	9.80	1.72	9.31	3.58	0.10	0.40	2.22	3.68	3.98	5.80	45.9	44.7	59.2
ASA	A/R "C"	1.00	1.66	2.56	0.09	-	0.09	0.03	0.06	0.05	0.12	0.15	0.14	12.2	9.0	5.5
	A/R "E"	3.81	4.35	5.81	0.87	-	0.87	0.14	0.23	0.48	1.01	1.11	1.35	26.6	25.4	23.2
ASH	AEB	14.08	16.51	18.63	3.96	2.65	4.49	0.42	1.05	4.21	4.92	5.54	8.70	34.9	33.6	46.7
ASZ	A/R"C"	1.86	3.54	6.60	0.24	-	0.24	-	0.01	0.02	0.24	0.24	0.26	12.8	6.9	3.9
ASD	A/R"C"	5.26	6.97	8.94	0.14	-	0.14	0.26	0.62	1.47	0.40	0.77	1.61	7.6	11.0	18.0
	A/R "D"	0.18	0.31	0.55	-	-	-	0.02	0.05	0.11	0.02	0.05	0.11	12.9	17.5	20.7
	A/R "E"	7.27	10.40	13.60	0.33	-	0.33	0.60	1.25	2.67	0.92	1.58	3.00	12.7	15.2	22.0
	Lower Bahariya	1.66	2.20	2.86	-	-	-	0.19	0.33	0.49	0.19	0.33	0.49	11.4	14.8	17.1
	Kharita	0.07	0.10	0.14	-	-	-	0.01	0.01	0.03	0.01	0.01	0.03	11.5	15.0	17.7
ASX	A/R"C"	1.11	1.94	3.31	0.16	-	0.16	0.01	0.01	0.24	0.16	0.17	0.40	14.7	8.7	12.0
	A/R "E"	0.07	0.13	-	-	-	-	0.01	0.02	0.06	0.01	0.02	0.06	13.6	18.1	-
	Upper Bahariya	0.28	0.37	0.47	-	-	-	0.03	0.06	0.09	0.03	0.06	0.09	11.6	15.3	19.4
	Lower Bahariya	0.13	0.20	0.25	-	-	-	0.01	0.03	0.04	0.01	0.03	0.04	10.5	14.5	17.0
Total		89.05	122.07	169.26	14.39	17.61	17.92	4.86	11.99	26.34	17.25	29.79	23.21			

Notes to

1. Cumulative production is based on the historical data provided to end October 2022 and the Best Estimate production forecast to YE 2022

13. Appendix 4: Cash Flow Tables

Table 13.1: Abu Sennan 1P Developed Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	8.63	8.63
5%	8.15	8.15
7.5%	7.94	7.94
10%	7.74	7.74
12.5%	7.54	7.54
15%	7.36	7.36

Field:	Abu Sennan	
Case:	1P Dev	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.20	86.15	0.00	3.10	17.42	7.61	0.35	3.04	-	4.22	-	-	4.22
01/01/2024	0.16	86.15	-	3.10	14.09	6.16	0.16	2.96	-	3.04	-	-	3.04
01/01/2025	0.12	81.15	-	3.10	9.77	4.27	0.07	2.84	-	1.36	-	-	1.36
01/01/2026	-	82.79	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2027	-	84.47	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2028	-	86.17	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2029	-	87.91	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2030	-	89.69	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2031	-	91.50	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2032	-	93.35	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2033	-	95.23	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2034	-	97.15	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2035	-	99.11	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2036	-	101.11	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2037	-	103.15	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2038	-	105.23	-	3.10	-	-	-	-	-	-	-	-	-
Totals:	0.49	MMBbl	0.00	Bscf	41.28	18.05	0.58	8.85	-	8.63	-	-	8.63
Entitlements	0.21	MMBbl	0.00	Bscf									

Table 13.2: Abu Sennan 1P Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	8.63	8.63
5%	8.15	8.15
7.5%	7.94	7.94
10%	7.74	7.74
12.5%	7.54	7.54
15%	7.36	7.36

Field:	Abu Sennan	
Case:	1P	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.20	86.15	0.00	3.10	17.42	7.61	0.35	3.04	-	4.22	-	-	4.22
01/01/2024	0.16	86.15	-	3.10	14.09	6.16	0.16	2.96	-	3.04	-	-	3.04
01/01/2025	0.12	81.15	-	3.10	9.77	4.27	0.07	2.84	-	1.36	-	-	1.36
01/01/2026	-	82.79	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2027	-	84.47	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2028	-	86.17	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2029	-	87.91	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2030	-	89.69	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2031	-	91.50	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2032	-	93.35	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2033	-	95.23	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2034	-	97.15	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2035	-	99.11	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2036	-	101.11	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2037	-	103.15	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2038	-	105.23	-	3.10	-	-	-	-	-	-	-	-	-
Totals:	0.49	MMBbl	0.00	Bscf	41.28	18.05	0.58	8.85	-	8.63	-	-	8.63
Entitlements	0.21	MMBbl	0.00	Bscf									

Table 13.3: Abu Sennan 2P Developed Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	26.65	26.65
5%	22.94	22.94
7.5%	21.43	21.43
10%	20.09	20.09
12.5%	18.92	18.92
15%	17.87	17.87

Field:	Abu Sennan	
Case:	2P Dev	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.23	86.15	0.01	3.10	19.93	8.71	0.37	3.16	-	5.18	-	-	5.18
01/01/2024	0.22	86.15	0.08	3.10	19.40	8.48	-	3.20	-	5.28	-	-	5.28
01/01/2025	0.20	81.15	0.06	3.10	16.14	7.06	0.16	3.16	-	3.74	-	-	3.74
01/01/2026	0.19	82.79	0.03	3.10	15.50	6.78	0.07	3.18	-	3.53	-	-	3.53
01/01/2027	0.16	84.47	-	3.10	13.27	5.80	-	3.12	-	2.69	-	-	2.69
01/01/2028	0.14	86.17	-	3.10	12.41	5.43	-	3.12	-	2.31	-	-	2.31
01/01/2029	0.13	87.91	0.06	3.10	11.98	5.24	0.07	3.14	-	2.02	-	-	2.02
01/01/2030	0.11	89.69	0.04	3.10	9.59	4.19	-	3.07	-	1.12	-	-	1.12
01/01/2031	0.10	91.50	0.03	3.10	8.82	3.85	-	3.08	-	0.77	-	-	0.77
01/01/2032	-	93.35	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2033	-	95.23	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2034	-	97.15	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2035	-	99.11	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2036	-	101.11	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2037	-	103.15	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2038	-	105.23	-	3.10	-	-	-	-	-	-	-	-	-
Totals:	1.47	MMBbl	0.32	Bscf	127.03	55.54	0.68	28.22	-	26.65	-	-	26.65
Entitlements	0.64	MMBbl	0.14	Bscf									

Table 13.4: Abu Sennan 2P Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	29.85	29.85
5%	25.87	25.87
7.5%	24.23	24.23
10%	22.79	22.79
12.5%	21.51	21.51
15%	20.36	20.36

Field:	Abu Sennan	
Case:	2P	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.29	86.15	0.08	3.10	25.40	11.11	1.61	3.40	-	6.11	-	-	6.11
01/01/2024	0.30	86.15	0.15	3.10	25.95	11.35	1.87	3.50	-	5.98	-	-	5.98
01/01/2025	0.24	81.15	0.09	3.10	19.43	8.50	0.29	3.32	-	4.89	-	-	4.89
01/01/2026	0.20	82.79	0.04	3.10	16.88	7.38	0.23	3.24	-	3.90	-	-	3.90
01/01/2027	0.16	84.47	0.00	3.10	13.61	5.95	0.07	3.13	-	2.75	-	-	2.75
01/01/2028	0.14	86.17	0.00	3.10	12.42	5.43	-	3.12	-	2.31	-	-	2.31
01/01/2029	0.13	87.91	0.06	3.10	11.98	5.24	0.07	3.14	-	2.02	-	-	2.02
01/01/2030	0.11	89.69	0.04	3.10	9.59	4.19	-	3.07	-	1.12	-	-	1.12
01/01/2031	0.10	91.50	0.03	3.10	8.82	3.85	-	3.08	-	0.77	-	-	0.77
01/01/2032	-	93.35	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2033	-	95.23	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2034	-	97.15	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2035	-	99.11	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2036	-	101.11	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2037	-	103.15	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2038	-	105.23	-	3.10	-	-	-	-	-	-	-	-	-
Totals:	1.67	MMBbl	0.51	Bscf	144.08	63.00	4.15	29.00	-	29.85	-	-	29.85
Entitlements	0.73	MMBbl	0.22	Bscf									

Table 13.5: Abu Sennan 3P Developed Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	52.65	52.65
5%	40.44	40.44
7.5%	36.01	36.01
10%	32.36	32.36
12.5%	29.33	29.33
15%	26.79	26.79

Field:	Abu Sennan	
Case:	3P Dev	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.23	86.15	0.22	3.10	20.66	9.03	0.37	3.16	-	5.50	-	-	5.50
01/01/2024	0.22	86.15	0.19	3.10	19.53	8.54	-	3.19	-	5.35	-	-	5.35
01/01/2025	0.22	81.15	0.18	3.10	18.70	8.18	0.16	3.27	-	4.75	-	-	4.75
01/01/2026	0.23	82.79	0.16	3.10	19.25	8.42	-	3.35	-	5.07	-	-	5.07
01/01/2027	0.20	84.47	0.14	3.10	17.61	7.70	-	3.31	-	4.39	-	-	4.39
01/01/2028	0.19	86.17	0.13	3.10	16.53	7.23	-	3.31	-	3.92	-	-	3.92
01/01/2029	0.19	87.91	0.13	3.10	17.09	7.47	0.07	3.39	-	4.01	-	-	4.01
01/01/2030	0.18	89.69	0.13	3.10	16.60	7.26	-	3.41	-	3.84	-	-	3.84
01/01/2031	0.17	91.50	0.11	3.10	15.91	6.96	-	3.43	-	3.52	-	-	3.52
01/01/2032	0.16	93.35	0.10	3.10	15.31	6.70	0.08	3.46	-	3.16	-	-	3.16
01/01/2033	0.17	95.23	0.07	3.10	16.28	7.12	0.19	3.56	-	3.36	-	-	3.36
01/01/2034	0.15	97.15	-	3.10	14.62	6.39	-	3.55	-	2.85	-	-	2.85
01/01/2035	0.12	99.11	-	3.10	12.32	5.39	-	3.49	-	1.90	-	-	1.90
01/01/2036	0.10	101.11	-	3.10	10.22	4.47	-	3.44	-	1.03	-	-	1.03
01/01/2037	-	103.15	-	3.10	-	-	-	-	-	-	-	-	-
01/01/2038	-	105.23	-	3.10	-	-	-	-	-	-	-	-	-
Totals:	2.54	MMBbl	1.56	Bscf	230.61	100.84	0.88	47.31	-	52.65	-	-	52.65
Entitlements	1.11	MMBbl	0.68	Bscf									

Table 13.6: Abu Sennan 3P Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	75.77	75.77
5%	61.37	61.37
7.5%	56.00	56.00
10%	51.49	51.49
12.5%	47.66	47.66
15%	44.38	44.38

Field:	Abu Sennan	
Case:	3P	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.42	86.15	0.44	3.10	37.87	16.56	2.68	3.92	-	9.96	-	-	9.96
01/01/2024	0.53	86.15	0.50	3.10	46.97	20.54	5.77	4.43	-	10.33	-	-	10.33
01/01/2025	0.50	81.15	0.46	3.10	41.85	18.30	0.22	4.40	-	13.68	-	-	13.68
01/01/2026	0.42	82.79	0.35	3.10	35.47	14.12	0.16	4.14	-	9.82	-	-	9.82
01/01/2027	0.34	84.47	0.28	3.10	29.24	9.98	0.07	3.88	-	6.03	-	-	6.03
01/01/2028	0.28	86.17	0.23	3.10	25.21	8.49	0.22	3.74	-	4.53	-	-	4.53
01/01/2029	0.26	87.91	0.20	3.10	23.85	7.17	0.22	3.72	-	3.23	-	-	3.23
01/01/2030	0.23	89.69	0.18	3.10	21.60	6.76	-	3.66	-	3.10	-	-	3.10
01/01/2031	0.21	91.50	0.15	3.10	19.63	6.41	-	3.62	-	2.80	-	-	2.80
01/01/2032	0.19	93.35	0.12	3.10	18.24	6.21	0.08	3.60	-	2.53	-	-	2.53
01/01/2033	0.19	95.23	0.08	3.10	18.46	6.30	0.19	3.67	-	2.44	-	-	2.44
01/01/2034	0.17	97.15	0.01	3.10	16.99	6.05	-	3.66	-	2.39	-	-	2.39
01/01/2035	0.16	99.11	-	3.10	15.61	5.85	-	3.65	-	2.20	-	-	2.20
01/01/2036	0.12	101.11	-	3.10	12.41	5.30	-	3.55	-	1.76	-	-	1.76
01/01/2037	0.10	103.15	-	3.10	10.26	4.49	-	3.50	-	0.99	-	-	0.99
01/01/2038	-	105.23	-	3.10	-	-	-	-	-	-	-	-	-
Totals:	4.13	MMBbl	2.99	Bscf	373.67	142.54	9.62	57.14	-	75.77	-	-	75.77
Entitlements	1.58	MMBbl	1.16	Bscf									

Table 13.7: Abu Sennan Extension 1P Developed Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	2.19	2.19
5%	2.04	2.04
7.5%	1.97	1.97
10%	1.91	1.91
12.5%	1.85	1.85
15%	1.80	1.80

Field:	Abu Sennan	
Case:	1P Dev - Ext	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.05	86.15	-	-	4.15	1.77	0.13	0.59	-	1.05	-	-	1.05
01/01/2024	0.03	86.15	-	-	2.59	1.10	-	0.53	-	0.57	-	-	0.57
01/01/2025	0.02	81.15	-	-	1.97	0.84	0.07	0.51	-	0.26	-	-	0.26
01/01/2026	0.02	82.79	-	-	1.56	0.66	0.07	0.50	-	0.09	-	-	0.09
01/01/2027	0.02	84.47	-	-	1.75	0.74	-	0.52	-	0.22	-	-	0.22
01/01/2028	-	86.17	-	-	-	-	-	-	-	-	-	-	-
01/01/2029	-	87.91	-	-	-	-	-	-	-	-	-	-	-
01/01/2030	-	89.69	-	-	-	-	-	-	-	-	-	-	-
01/01/2031	-	91.50	-	-	-	-	-	-	-	-	-	-	-
01/01/2032	-	93.35	-	-	-	-	-	-	-	-	-	-	-
01/01/2033	-	95.23	-	-	-	-	-	-	-	-	-	-	-
01/01/2034	-	97.15	-	-	-	-	-	-	-	-	-	-	-
01/01/2035	-	99.11	-	-	-	-	-	-	-	-	-	-	-
01/01/2036	-	101.11	-	-	-	-	-	-	-	-	-	-	-
01/01/2037	-	103.15	-	-	-	-	-	-	-	-	-	-	-
01/01/2038	-	105.23	-	-	-	-	-	-	-	-	-	-	-
01/01/2039	-	107.35	-	-	-	-	-	-	-	-	-	-	-
01/01/2040	-	109.51	-	-	-	-	-	-	-	-	-	-	-
01/01/2041	-	111.72	-	-	-	-	-	-	-	-	-	-	-
01/01/2042	-	113.97	-	-	-	-	-	-	-	-	-	-	-
Totals:	0.14	MMBbl	-	Bscf	12.02	5.11	0.27	2.65	-	2.19	-	-	2.19
Entitlements	0.06	MMBbl	-	Bscf									

Table 13.8: Abu Sennan Extension 1P Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	2.19	2.19
5%	2.04	2.04
7.5%	1.97	1.97
10%	1.91	1.91
12.5%	1.85	1.85
15%	1.80	1.80

Field:	Abu Sennan	
Case:	1P - Ext	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.05	86.15	-	-	4.15	1.77	0.13	0.59	-	1.05	-	-	1.05
01/01/2024	0.03	86.15	-	-	2.59	1.10	-	0.53	-	0.57	-	-	0.57
01/01/2025	0.02	81.15	-	-	1.97	0.84	0.07	0.51	-	0.26	-	-	0.26
01/01/2026	0.02	82.79	-	-	1.56	0.66	0.07	0.50	-	0.09	-	-	0.09
01/01/2027	0.02	84.47	-	-	1.75	0.74	-	0.52	-	0.22	-	-	0.22
01/01/2028	-	86.17	-	-	-	-	-	-	-	-	-	-	-
01/01/2029	-	87.91	-	-	-	-	-	-	-	-	-	-	-
01/01/2030	-	89.69	-	-	-	-	-	-	-	-	-	-	-
01/01/2031	-	91.50	-	-	-	-	-	-	-	-	-	-	-
01/01/2032	-	93.35	-	-	-	-	-	-	-	-	-	-	-
01/01/2033	-	95.23	-	-	-	-	-	-	-	-	-	-	-
01/01/2034	-	97.15	-	-	-	-	-	-	-	-	-	-	-
01/01/2035	-	99.11	-	-	-	-	-	-	-	-	-	-	-
01/01/2036	-	101.11	-	-	-	-	-	-	-	-	-	-	-
01/01/2037	-	103.15	-	-	-	-	-	-	-	-	-	-	-
01/01/2038	-	105.23	-	-	-	-	-	-	-	-	-	-	-
01/01/2039	-	107.35	-	-	-	-	-	-	-	-	-	-	-
01/01/2040	-	109.51	-	-	-	-	-	-	-	-	-	-	-
01/01/2041	-	111.72	-	-	-	-	-	-	-	-	-	-	-
01/01/2042	-	113.97	-	-	-	-	-	-	-	-	-	-	-
Totals:	0.14	MMBbl	-	Bscf	12.02	5.11	0.27	2.65	-	2.19	-	-	2.19
Entitlements	0.06	MMBbl	-	Bscf									

Table 13.9: Abu Sennan Extension 2P Developed Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	5.04	5.04
5%	4.41	4.41
7.5%	4.15	4.15
10%	3.92	3.92
12.5%	3.72	3.72
15%	3.55	3.55

Field:	Abu Sennan	
Case:	2P Dev - Ext	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.06	86.15	-	-	5.25	2.23	0.13	0.64	-	1.46	-	-	1.46
01/01/2024	0.04	86.15	-	-	3.59	1.53	-	0.57	-	0.95	-	-	0.95
01/01/2025	0.04	81.15	-	-	3.09	1.31	-	0.57	-	0.74	-	-	0.74
01/01/2026	0.03	82.79	-	-	2.69	1.14	0.07	0.56	-	0.51	-	-	0.51
01/01/2027	0.02	84.47	-	-	1.81	0.77	-	0.52	-	0.25	-	-	0.25
01/01/2028	0.02	86.17	-	-	1.71	0.73	0.07	0.53	-	0.13	-	-	0.13
01/01/2029	0.03	87.91	-	-	2.93	1.24	-	0.60	-	0.65	-	-	0.65
01/01/2030	0.02	89.69	-	-	2.00	0.85	-	0.56	-	0.29	-	-	0.29
01/01/2031	0.01	91.50	-	-	1.37	0.58	-	0.54	-	0.05	-	-	0.05
01/01/2032	-	93.35	-	-	-	-	-	-	-	-	-	-	-
01/01/2033	-	95.23	-	-	-	-	-	-	-	-	-	-	-
01/01/2034	-	97.15	-	-	-	-	-	-	-	-	-	-	-
01/01/2035	-	99.11	-	-	-	-	-	-	-	-	-	-	-
01/01/2036	-	101.11	-	-	-	-	-	-	-	-	-	-	-
01/01/2037	-	103.15	-	-	-	-	-	-	-	-	-	-	-
01/01/2038	-	105.23	-	-	-	-	-	-	-	-	-	-	-
01/01/2039	-	107.35	-	-	-	-	-	-	-	-	-	-	-
01/01/2040	-	109.51	-	-	-	-	-	-	-	-	-	-	-
01/01/2041	-	111.72	-	-	-	-	-	-	-	-	-	-	-
01/01/2042	-	113.97	-	-	-	-	-	-	-	-	-	-	-
Totals:	0.29	MMBbl	-	Bscf	24.44	10.39	0.28	5.08	-	5.04	-	-	5.04
Entitlements	0.12	MMBbl	-	Bscf									

Table 13.10: Abu Sennan Extension 2P Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	8.93	8.93
5%	7.32	7.32
7.5%	6.70	6.70
10%	6.18	6.18
12.5%	5.73	5.73
15%	5.34	5.34

Field:	Abu Sennan	
Case:	2P - Ext	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.09	86.15	-	-	8.09	3.06	1.23	0.77	-	1.07	-	-	1.07
01/01/2024	0.07	86.15	-	-	6.22	2.55	0.00	0.70	-	1.84	-	-	1.84
01/01/2025	0.06	81.15	-	-	4.74	2.02	0.06	0.66	-	1.30	-	-	1.30
01/01/2026	0.05	82.79	-	-	3.82	1.63	0.06	0.62	-	0.95	-	-	0.95
01/01/2027	0.03	84.47	-	-	2.59	1.10	-	0.56	-	0.54	-	-	0.54
01/01/2028	0.03	86.17	-	-	2.24	0.95	0.06	0.55	-	0.34	-	-	0.34
01/01/2029	0.04	87.91	-	-	3.29	1.40	-	0.62	-	0.78	-	-	0.78
01/01/2030	0.03	89.69	-	-	2.45	1.04	-	0.58	-	0.46	-	-	0.46
01/01/2031	0.04	91.50	-	-	3.45	1.35	-	0.64	-	0.71	-	-	0.71
01/01/2032	0.03	93.35	-	-	2.58	0.98	0.07	0.61	-	0.31	-	-	0.31
01/01/2033	0.02	95.23	-	-	1.75	0.75	-	0.57	-	0.17	-	-	0.17
01/01/2034	0.03	97.15	-	-	2.47	1.01	-	0.62	-	0.39	-	-	0.39
01/01/2035	0.02	99.11	-	-	1.50	0.64	-	0.58	-	0.06	-	-	0.06
01/01/2036	-	101.11	-	-	-	-	-	-	-	-	-	-	-
01/01/2037	-	103.15	-	-	-	-	-	-	-	-	-	-	-
01/01/2038	-	105.23	-	-	-	-	-	-	-	-	-	-	-
01/01/2039	-	107.35	-	-	-	-	-	-	-	-	-	-	-
01/01/2040	-	109.51	-	-	-	-	-	-	-	-	-	-	-
01/01/2041	-	111.72	-	-	-	-	-	-	-	-	-	-	-
01/01/2042	-	113.97	-	-	-	-	-	-	-	-	-	-	-
Totals:	0.52	MMBbl	-	Bscf	45.21	18.48	1.48	8.07	-	8.93	-	-	8.93
Entitlements	0.21	MMBbl	-	Bscf									

Table 13.11: Abu Sennan Extension 3P Developed Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	10.97	10.97
5%	8.26	8.26
7.5%	7.37	7.37
10%	6.66	6.66
12.5%	6.10	6.10
15%	5.64	5.64

Field:	Abu Sennan	
Case:	3P Dev - Ext	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.08	86.15	-	-	7.02	2.64	0.07	0.72	-	1.86	-	-	1.86
01/01/2024	0.06	86.15	-	-	5.42	2.18	-	0.66	-	1.52	-	-	1.52
01/01/2025	0.05	81.15	-	-	3.94	1.68	-	0.61	-	1.06	-	-	1.06
01/01/2026	0.04	82.79	-	-	3.15	1.34	-	0.58	-	0.76	-	-	0.76
01/01/2027	0.03	84.47	-	-	2.54	1.08	-	0.56	-	0.52	-	-	0.52
01/01/2028	0.02	86.17	-	-	2.05	0.87	-	0.54	-	0.33	-	-	0.33
01/01/2029	0.02	87.91	-	-	1.65	0.70	-	0.53	-	0.17	-	-	0.17
01/01/2030	0.04	89.69	-	-	3.24	1.38	-	0.62	-	0.76	-	-	0.76
01/01/2031	0.04	91.50	-	-	3.79	1.25	0.08	0.66	-	0.52	-	-	0.52
01/01/2032	0.02	93.35	-	-	2.31	0.91	-	0.59	-	0.32	-	-	0.32
01/01/2033	0.02	95.23	-	-	1.60	0.68	-	0.57	-	0.11	-	-	0.11
01/01/2034	0.01	97.15	-	-	1.20	0.51	-	0.56	-	-0.04	-	-	-0.04
01/01/2035	0.05	99.11	-	-	5.40	1.90	0.17	0.78	-	0.96	-	-	0.96
01/01/2036	0.05	101.11	-	-	4.68	1.48	-	0.75	-	0.73	-	-	0.73
01/01/2037	0.04	103.15	-	-	3.76	1.29	-	0.72	-	0.57	-	-	0.57
01/01/2038	0.03	105.23	-	-	2.76	1.08	-	0.68	-	0.40	-	-	0.40
01/01/2039	0.02	107.35	-	-	2.25	0.96	-	0.66	-	0.30	-	-	0.30
01/01/2040	0.02	109.51	-	-	1.84	0.78	-	0.65	-	0.13	-	-	0.13
01/01/2041	-	111.72	-	-	-	-	-	-	-	-	-	-	-
01/01/2042	-	113.97	-	-	-	-	-	-	-	-	-	-	-
Totals:	0.64	MMBbl	-	Bscf	58.62	22.72	0.31	11.44	-	10.97	-	-	10.97
Entitlements	0.25	MMBbl	-	Bscf									

Table 13.12: Abu Sennan Extension 3P Reserves Cashflow

Nominal Net Present Values as at 01-Jan-22 (US$MM)		
Disc Rate	Pre-Tax	Post-Tax
0%	17.06	17.06
5%	12.52	12.52
7.5%	11.03	11.03
10%	9.86	9.86
12.5%	8.93	8.93
15%	8.18	8.18

Field:	Abu Sennan	
Case:	3P - Ext	
	Initial	Final
Cost Interest:	22%	22%
Revenue Interest:	22%	22%

Period Beginning	Oil		Gas		Field Revenue	Contractor Revenue	Capital Costs	Operating Costs	Bonus Payments	Pre Tax NCF	Other Taxes	Corporate Tax	Post Tax NCF
	Production MMBbl	Realised Price US$/Bbl	Production Bscf	Realised Price US$/Mscf	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM	US$MM
01/01/2023	0.13	86.15	-	-	10.96	3.67	1.17	0.90	-	1.60	-	-	1.60
01/01/2024	0.11	86.15	-	-	9.83	3.32	0.00	0.87	-	2.45	-	-	2.45
01/01/2025	0.09	81.15	-	-	7.16	2.73	-	0.78	-	1.95	-	-	1.95
01/01/2026	0.07	82.79	-	-	5.71	2.30	0.06	0.71	-	1.52	-	-	1.52
01/01/2027	0.05	84.47	-	-	4.57	1.71	-	0.66	-	1.04	-	-	1.04
01/01/2028	0.04	86.17	-	-	3.67	1.18	-	0.63	-	0.56	-	-	0.56
01/01/2029	0.03	87.91	-	-	2.93	1.02	-	0.60	-	0.43	-	-	0.43
01/01/2030	0.05	89.69	-	-	4.26	1.33	-	0.67	-	0.65	-	-	0.65
01/01/2031	0.05	91.50	-	-	4.60	1.41	0.06	0.70	-	0.64	-	-	0.64
01/01/2032	0.03	93.35	-	-	2.96	1.05	-	0.63	-	0.43	-	-	0.43
01/01/2033	0.04	95.23	-	-	4.23	1.34	-	0.70	-	0.64	-	-	0.64
01/01/2034	0.04	97.15	-	-	3.58	1.21	-	0.68	-	0.53	-	-	0.53
01/01/2035	0.07	99.11	-	-	7.38	2.08	0.14	0.88	-	1.06	-	-	1.06
01/01/2036	0.06	101.11	-	-	6.34	1.84	-	0.84	-	1.01	-	-	1.01
01/01/2037	0.05	103.15	-	-	5.14	1.59	-	0.79	-	0.80	-	-	0.80
01/01/2038	0.04	105.23	-	-	3.91	1.33	-	0.73	-	0.59	-	-	0.59
01/01/2039	0.03	107.35	-	-	3.22	1.18	-	0.71	-	0.47	-	-	0.47
01/01/2040	0.02	109.51	-	-	2.65	1.04	-	0.69	-	0.35	-	-	0.35
01/01/2041	0.02	111.72	-	-	2.18	0.93	-	0.68	-	0.25	-	-	0.25
01/01/2042	0.02	113.97	-	-	1.79	0.76	-	0.67	-	0.09	-	-	0.09
Totals:	1.05	MMBbl	-	Bscf	97.06	33.01	1.44	14.50	-	17.06	-	-	17.06
Entitlements	0.36	MMBbl	-	Bscf									