Year End 2020 Reserves and Resources Abu Sennan, Egypt

Prepared for

United Oil & Gas plc

April 2021

Gaffney Cline

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Introduction

At the request of United Oil & Gas plc (UOG), Gaffney, Cline & Associates Limited (GaffneyCline) has performed an independent technical and economic audit of the Reserves and Resources in the Abu Sennan concession in Egypt (Figure 1), in which UOG holds a 22% working interest (WI), as at an Effective Date of 31st December 2020.

The assessment has been conducted on the basis of a data set of technical information made available to GaffneyCline by the Operator of the licence, Kuwait Energy Egypt Ltd (KEE), which is a wholly-owned subsidiary of United Energy Group Ltd (UEGL). This data set included: details of concession interests and agreements, geological and geophysical data, interpretations and technical reports, historical production and engineering data, cost and commercial data, and approved development plans as at the Effective Date. Permission to use these data in the preparation of this report has been granted by UEGL.

In the preparation of this report, GaffneyCline has used definitions of Reserves and Resources contained within the Petroleum Resources Management System (PRMS) published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists and Engineers in June 2018 (see Appendix I).

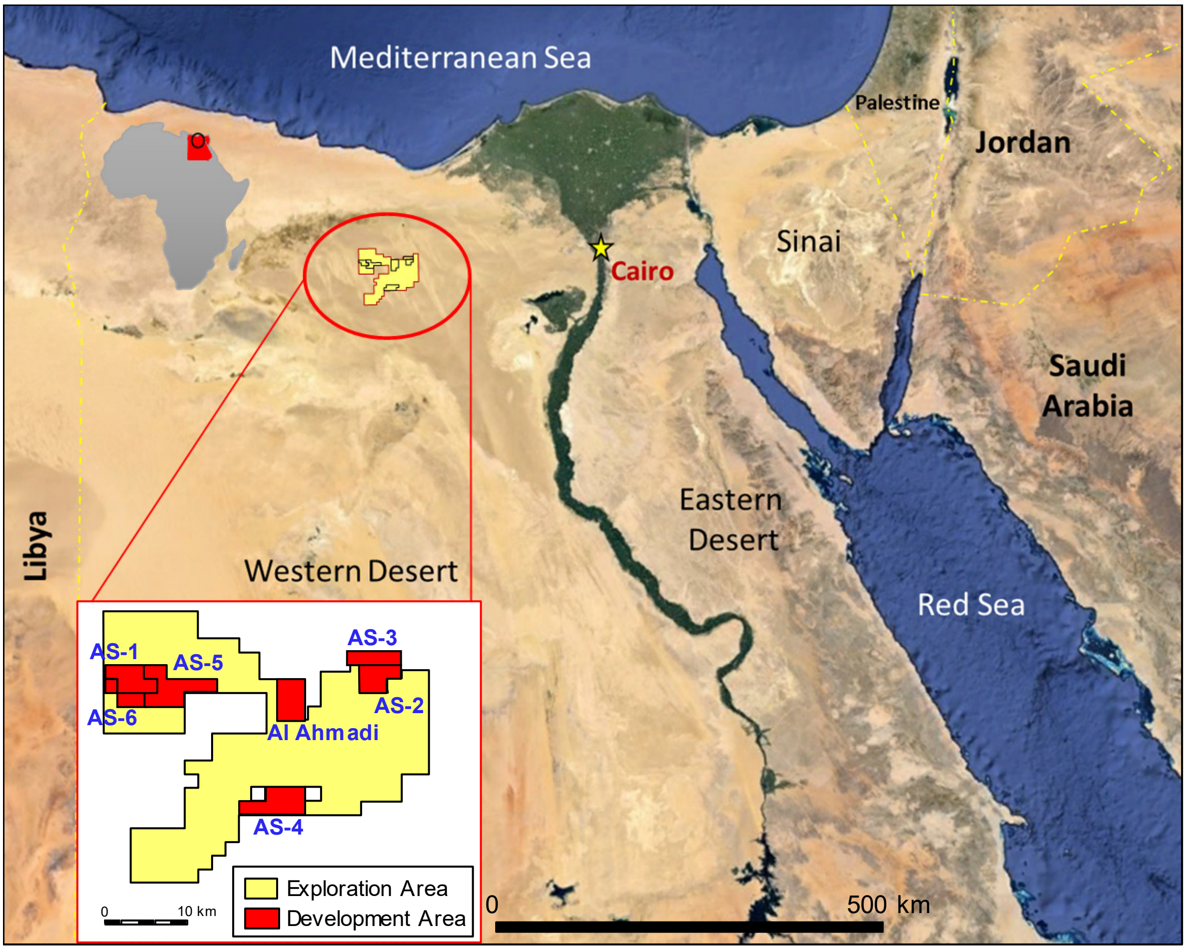
In accordance with UOG's instructions, GaffneyCline has also estimated a Net Present Value (NPV) for each Reserve volume as at an Effective Date of 31st December 2020.

This report is based on data available as at 31st December 2020, and takes no account of events since that date, such as the drilling and testing of the ASH-3 well in early 2021.

This report relates specifically and solely to the subject matter as defined in the scope of work and is conditional upon the assumptions described herein. The report must be considered in its entirety and must only be used for the purpose for which it was intended.

A glossary of abbreviations used in this report is contained in Appendix II.

Figure 1: Abu Sennan Location Map



Source: UEGL (adapted)

Basis of Opinion

This document reflects GaffneyCline's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by the Operator, the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GaffneyCline has not independently verified any information provided by the Operator, and has accepted the accuracy and completeness of these data. GaffneyCline has no reason to believe that any material facts have been withheld from it, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geoscience and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

This assessment has been conducted within the context of GaffneyCline's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GaffneyCline is not in a position to attest to property title or rights, conditions of these rights including environmental and abandonment obligations, and any necessary licences and consents including planning permission, financial interest relationships or encumbrances thereon for any part of the appraised properties.

In carrying out this study, GaffneyCline is not aware that any conflict of interest has existed. As an independent consultancy, GaffneyCline is providing impartial technical, commercial and strategic advice within the energy sector. GaffneyCline's remuneration was not in any way contingent on the contents of this report. In the preparation of this document, GaffneyCline has maintained, and continues to maintain, a strict independent consultant-client relationship with UOG. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or related with the analysis carried out as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

GaffneyCline has not undertaken any site visit and inspection as part of this work, although it previously undertook a site visit to Abu Sennan in January 2017. That visit was undertaken to examine the facilities and operations, and to assess their condition and state of operability. GaffneyCline does not warrant they are in compliance with any applicable regulations in terms of standards, rating, health, safety, and environment.

Reserves and Resources Definitions

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial and remaining (as of the evaluation's effective date) based on the development project(s) applied. All categories of Reserve volumes quoted herein have been determined within the context of an economic limit test (pre-tax and exclusive of accumulated depreciation amounts) prior to any NPV analysis.

Contingent Resources are 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 issues may exist. Contingent Resource volumes reported herein are un-risked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

Prospective Resources are those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery (the "Chance of Geologic Discovery" (P_g)) and a chance of development. There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas reserve engineering and resource assessment must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas reserves or resources prepared by other parties may differ, perhaps materially, from those contained within this report. The accuracy of any reserve estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

Oil and condensate reserves and resources volumes appearing in this report have been quoted at stock tank conditions. Natural gas reserves and resources volumes have been quoted in standard cubic feet and are volumes of sales gas, after an allocation has been made for fuel and process shrinkage losses. Standard conditions are defined as 14.7 psia and 60°F.

Use of Net Present Values

It should be clearly understood that the NPVs of future revenue potential of a petroleum property, such as those discussed in this report, do not represent GaffneyCline's opinion as to the market value of that property, nor any interest therein. In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves risk (i.e. that Reserves may not be realised within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and the competitive state of the market at the time. GaffneyCline has explicitly not taken such factors into account in deriving the reference NPVs presented herein.

Summary

The Abu Sennan concession is governed by a Production Sharing Contract (PSC). Seven development licences cover the eight fields that have already been discovered and put into production. An exploration licence covers the rest of the concession area. Oil and gas Reserves are attributed to six of the eight fields (two are no longer producing). Prospective Resources are attributed to a number of exploration Prospects that have been identified within the concession area. No Contingent Resources are currently identified.

Reserves Summary

The oil and gas Reserves attributable to UOG in Abu Sennan as at 31st December 2020 are shown in Table 1. The Reserves shown in Table 1 are expressed as a total in barrels of oil equivalent (boe) in Table 2. Gas volumes are converted to oil equivalent volumes using a conversion factor of 5.0 Mscf/boe (commensurate with the high calorific content of the gas).

Table 1: Summary of Reserves
as at 31st December 2020

(a) Oil

Status	Gross Field (MBbl)			WI (%)	Net Entitlement (MBbl)		
	Proved	Proved + Probable	Proved + Probable+ Possible		Proved	Proved + Probable	Proved + Probable+ Possible
Developed	5,825	10,657	16,173	22.0	545	997	1,512
Undeveloped	0	3,532	11,851		0	330	849
Total	**5,825**	**14,189**	**28,023**		**545**	**1,328**	**2,361**

(b) Gas

Status	Gross Field (Bscf)			WI (%)	Net Entitlement (Bscf)		
	Proved	Proved + Probable	Proved + Probable+ Possible		Proved	Proved + Probable	Proved + Probable+ Possible
Developed	4.15	9.35	19.47	22.0	0.39	0.87	1.82
Undeveloped	0.00	3.48	13.84		0.00	0.33	1.08
Total	**4.15**	**12.83**	**33.31**		**0.39**	**1.20**	**2.90**

Notes:

1. Gross Field Reserves are 100% of the volumes estimated to be commercially recoverable from the asset under the intended development plan.
2. Net Entitlement Reserves are UOG's net economic entitlement under the PSC that governs this asset.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

Table 2: Summary of Reserves as at 31st December 2020
Expressed in Oil Equivalent Volumes (Mboe)

Status	Gross Field (Mboe)			WI (%)	Net Entitlement (Mboe)		
	Proved	Proved + Probable	Proved + Probable + Possible		Proved	Proved + Probable	Proved + Probable + Possible
Developed	6,655	12,527	20,066	22.0	623	1,172	1,876
Undeveloped	0	4,227	14,618		0	396	1,065
Total	**6,655**	**16,754**	**34,685**		**623**	**1,568**	**2,941**

Note:

1. The Reserves shown in this Table are the sum of the oil and gas Reserves shown separately in Table 1, gas volumes being converted to oil equivalent volumes using a conversion factor of 5.0 Mscf/boe.
2. Totals may not exactly equal the sum of the individual entries due to rounding.

A summary of changes in Gross Field Reserves (in boe) since 31st December 2019 is shown in Table 3.

Table 3: Reconciliation of Reserves as at 31st December 2020
with Reserves as at 31st December 2019

Case	Gross Field Reserves (Mboe)				
	End 2019	Exploration Adds	2020 Production	Revisions	End 2020
Proved	4,179	0	-3,297	5,773	6,655
Proved + Probable	13,526	134	-3,297	6,391	16,754
Proved + Probable + Possible	28,589	269	-3,297	9,123	34,685

Notes:

1. Revisions are due to production performance in 2020, the results of wells drilled in late 2019 and 2020, notably ASH-2 and El Salmiya-5, and the maturation of the ASH gas development from Contingent Resources to Reserves.
2. The exploration add is the AR-G reservoir at El Salmiya; in the 1P case, all potentially recoverable volumes fall beyond the economic limits given the current development plan.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

A breakdown of the Gross Field Reserves to the individual field and reservoir level is shown in Table 4.

Table 4: Field and Reservoir Level Breakdown of Reserves as at 31st December 2020

Field	Reservoir	Gross Field Oil Reserves (MBbl)			Gross Field Gas Reserves (Bscf)		
		Proved	Proved + Probable	Proved + Probable+ Possible	Proved	Proved + Probable	Proved + Probable+ Possible
Al Jahraa[2]	AR-C	2,752	5,736	9,969	0.00	0.00	0.00
	AR-D	57	227	570	0.00	0.00	0.00
	AR-G	71	205	1,145	0.00	0.00	0.00
	L Bahariya	65	389	1,508	0.54	2.60	7.64
	AR-E (Jah-7)	13	21	35	0.00	0.00	0.00
	U Bahariya	18	61	203	0.00	0.00	0.00
	L Bahariya II	10	33	135	0.00	0.00	0.00
	Sub-Total	***2,985***	***6,673***	***13,564***	***0.54***	***2.60***	***7.64***
El Salmiya	AR-C	13	234	774	0.00	0.58	2.16
	AR-E	273	849	1,751	0.00	0.00	0.00
	AR-G	0	134	261	0.00	0.00	0.00
	Kharita	250	414	909	1.40	2.86	9.94
	Sub-Total	***536***	***1,632***	***3,695***	***1.40***	***3.44***	***12.10***
ASA	AR-C	32	0	0	0.00	0.00	0.00
	AR-E	144	348	750	0.00	0.00	0.00
	Sub-Total	***175***	***348***	***750***	***0.00***	***0.00***	***0.00***
ASH	AEB	1,830	5,116	9,162	2.20	6.78	13.56
ASZ	AR-C	298	421	852	0.00	0.00	0.00
Total		**5,825**	**14,189**	**28,023**	**4.15**	**12.83**	**33.31**

Notes:

1. The Reserves shown here equate to the Reserves shown in Table 1.
2. Al Jahraa volumes shown here include Al Jahraa SE.
3. No Reserves are attributed to the ZZ and Al Ahmadi fields, or to reservoirs not listed here.
4. Totals may not exactly equal the sum of the individual entries due to rounding.

Prospective Resources Summary

The Prospective Resources attributable to UOG in Abu Sennan as at 31st December 2020 are shown in Table 5. Only the potential volumes estimated to lie within the Abu Sennan licence area are reported here. GaffneyCline has not examined the economics of any of these Prospects, some of which are very small.

Prospective Resources are shown both as gross volumes and net to UOG on a Working Interest basis, i.e. UOG's Working Interest fraction of the gross volumes. These do not represent UOG's actual Net Entitlement under the terms of the PSC that governs the asset, which would be lower. Net Working Interest is quoted here since the Prospective Resources are not yet sufficiently mature to estimate the associated production profiles and costs that are needed to calculate the Net Entitlement.

Table 5: Summary of Oil Prospective Resources (Prospects) as at 31st December 2020

(a) Outside the Existing Development Areas

Prospect		Gross (MBbl)			WI (%)	Net (WI Basis) (MBbl)			P_g (%)
		1U	2U	3U		1U	2U	3U	
ASX[3]	AR-C	241	692	1,438	22	53	152	316	29
	AR-E	180	407	812		40	90	179	22
	AR-G	60	306	763		13	67	168	27
ASU	AR-G	3	25	64	22	1	5	14	43
	L Bahariya	40	114	233		9	25	51	39
ARQ	AR-C	87	217	439	22	19	48	97	45
	AR-E	57	202	454		12	44	100	34
	AR-G	109	316	666		24	69	146	28
	L Bahariya	55	195	455		12	43	100	34
ASG-I	AR-C	68	151	287	22	15	33	63	34
	AR-E	26	88	193		6	19	43	25
	AR-G	53	111	198		12	24	44	21
	L Bahariya	20	37	66		4	8	15	25
ASG-II	AR-C	44	93	172	22	10	20	38	34
	AR-E	51	102	184		11	22	41	25
	AR-G	41	83	141		9	18	31	21
	L Bahariya	14	30	56		3	7	12	25
ASF	AR-G	212	872	2,027	22	47	192	446	30
	Bahariya	124	561	1,334		27	123	294	26
	AEB	48	166	375		11	37	83	34
ASK	AR-G	148	346	681	22	32	76	150	20
	Bahariya	80	236	654		18	52	144	16
	AEB	86	205	417		19	45	92	20
Salmiya West	AR-C	156	384	896	22	34	84	197	35
	AR-E	102	246	481		22	54	106	35
	Bahariya	192	363	615		42	80	135	42
	Kharita	904	1,506	2,373		199	331	522	36
SW Al Ahmadi	AR-C	1,567	5,030	13,532	22	345	1,107	2,977	35
	Bahariya	1,349	3,543	7,193		297	779	1,583	24

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(a) Outside the Existing Development Areas (continued)

Prospect		Gross (MBbl)			WI (%)	Net (WI Basis) (MBbl)			P_g (%)
		1U	2U	3U		1U	2U	3U	
South Al Jahraa 1	ARC	55	163	442	22	12	36	97	54
	ARE	30	74	167		7	16	37	36
South Al Jahraa 2	ARC	83	175	335	22	18	38	74	54
	ARE	34	80	177		7	18	39	36
South Al Jahraa 5	ARC	98	295	828	22	22	65	182	54
	ARE	43	150	498		9	33	110	36
South Al Jahraa 6	ARC	48	91	153	22	11	20	34	54
	ARE	40	86	168		9	19	37	36
NE Al Jahraa 7	ARC	289	609	1,150	22	64	134	253	58
	ARE	211	471	961		46	104	211	38
	ARG I	164	284	463		36	63	102	36
	ARG II	122	270	528		27	59	116	36
NE Al Jahraa 8	ARC	328	651	1,170	22	72	143	257	54
	ARE	199	479	1,068		44	105	235	36
ASH West II[5]	AEB	211	456	994	22	46	100	219	30

(b) Within the Existing Development Areas

Prospect		Gross (MBbl)			WI (%)	Net (WI Basis) (MBbl)			P_g (%)
		1U	2U	3U		1U	2U	3U	
ASA	AR-C	84	220	765	22	18	48	168	40
	AR-E	100	337	1,541		22	74	339	40
	Bahariya	8	28	101		2	6	22	35
	Kharita	229	837	1,848		50	184	407	42
Al Jahraa[4]	U Bahariya	33	145	703	22	7	32	155	40
	L Bahariya	56	141	406		12	31	89	40
Al Ahmadi-3	AR-C	110	270	630	22	24	59	139	32
	AR-G	96	190	372		21	42	82	32
	Bahariya	153	291	496		34	64	109	22
	Kharita[4]	775	1,311	2,092		170	288	460	40
ASH East[4]	AEB	252	546	1,147	22	56	120	252	60
ASH West[4]	AEB	270	565	1,164	22	59	124	256	40

Continued on next page

Notes:

1. Gross Prospective Resources are 100% of the volumes estimated to be recoverable from the Prospect, in the event that a discovery is made and subsequently developed.
2. UOG Net Prospective Resources in this table are UOG's Working Interest fraction of the Gross Prospective Resources; they do not represent UOG's actual Net Entitlement under the terms of the PSC that governs the asset, which would be lower.
3. Prospect ASX extends outside the licence area; only the volumes estimated to lie within the licence area are reported here.
4. Volumes shown for Al Jahraa, Al Ahmadi-3 Kharita, and ASH East, West and West II are combined oil and gas volumes in Mboe.
5. The P_g reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery. This does not include any assessment of the risk that a discovery, if made, may not be developed.
6. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that no discovery will be made or that any discovery would not be developed.
7. Identification of Prospective Resources associated with a Prospect is not indicative of any certainty that the Prospect will be drilled, or will be drilled in a timely manner.
8. Prospective Resources should not be aggregated with each other, or with Reserves or Contingent Resources, because of the different levels of risk involved.
9. 1U = Low estimate, 2U = Best estimate, 3U = High estimate.
10. AR-C = Abu Roash C member, AR-E = Abu Roash E member, AR-G = Abu Roash G member, AEB = Alam El Bueib Formation.

NPV Summary

Reference Net Present Values (NPVs) have been attributed to the Proved, the Proved plus Probable, and the Proved plus Probable plus Possible Reserves. The reference post-tax NPVs for these cases at discount rates of 7.5%, 10.0% and 12.5% are summarised in Table 6.

GaffneyCline's own 1Q 2021 Brent Crude oil price scenario, adjusted for quality and location, has been used in preparing these NPVs. Sensitivities to other price scenarios are presented in Section 7 of this report. All NPVs quoted are those exclusively attributable to UOG's Net Entitlement Reserves in the properties under review.

Table 6: Summary of Post-Tax NPV (US$ MM) of Future Cash Flow from Reserves Net To UOG as at 31st December 2020

Discount Rate (%)	Proved	Proved + Probable	Proved + Probable + Possible
7.5	14.4	32.0	61.1
10.0	13.9	30.1	56.6
12.5	13.5	28.4	52.8

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the licence.
2. The NPVs shown here are for the Developed plus Undeveloped Reserves.
3. The reference NPVs reported here do not represent an opinion as to the market value of a property or any interest in it.

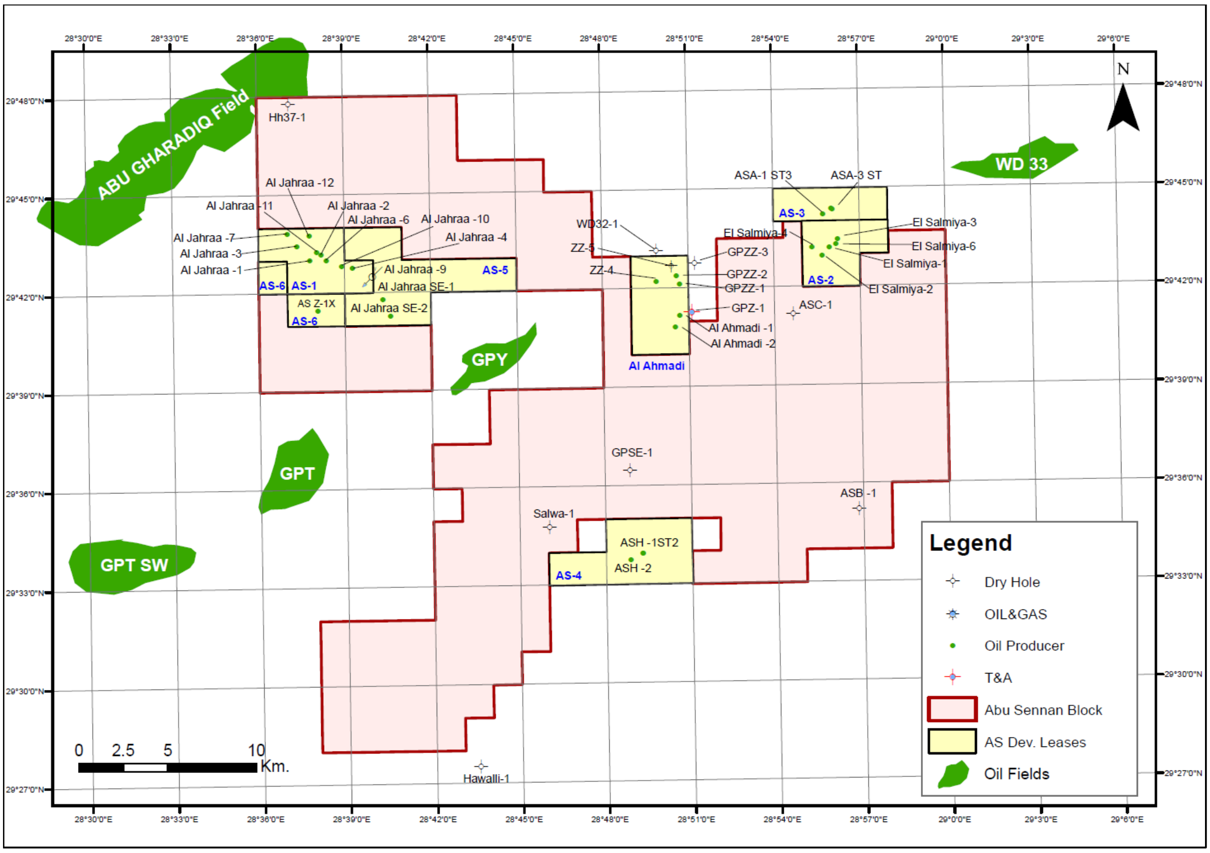
Discussion

1 Background

UOG holds a 22% WI in the Abu Sennan concession. UEGL holds 25% through its subsidiary company KEE and is the Operator. The other partners are GlobalConnect Ltd (25%) and Dover Investments Ltd (28%).

The concession lies in the Western Desert (Figure 1). Seven 20-year development licences have been granted covering the eight commercial discoveries that have been made (Figure 2 and Table 7). The development licences are operated by KEE through the East Abu Sennan Petroleum Company, which is a 50:50 joint venture (JV) between EGPC and the Contractor Group, with the Contractor Group represented by KEE. All decisions require approval from both the JV parties.

Figure 2: Map of Wells and Development Areas



Source: UEGL

The 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 (653.4 km^2 after relinquishments but including the subsequently granted AS-6 development licence) was approved in September 2018. Because of the delay in granting approval, EGPC agreed that the 5-year period should start on 10th September 2018. There is a commitment to spend a minimum of US$6 MM in the first 3-year period, to include two exploration wells, one of which has already been drilled. Each 1-year extension period carries a minimum expenditure of US$2 MM, to include one exploration well.

Table 7: Development Licences

Licence	Area (km^2)	Fields	Expiry	Options for Extension
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
Abu Sennan-06 (AS-6)	9	ASZ	Mar-39	5 years

1.1 Exploration and Production History

Five wells were drilled on the concession prior to 1985, resulting in the discovery of oil in the ZZ field (formerly known as GP ZZ), but this was not developed at the time.

In 2008, the Operator acquired, processed and interpreted 3D seismic data covering most of the concession area. Activity was suspended in 2009 and 2010 awaiting military approvals, but four wells were drilled in 2011, discovering the Al Ahmadi, Al Jahraa and El Salmiya fields.

In July 2012, an extended period of trial production began following installation of rented processing facilities, with produced oil being exported by truck and produced gas being flared. Results were mixed, however, with some wells declining rapidly and others being limited by restrictions on the amount of gas that could be flared. Two additional wells were drilled in 2013 and seven more in 2014, adding to production and discovering the ASA field as well as additional reservoirs in El Salmiya and Al Jahraa, notably the Al Jahraa AR-C which is the largest reservoir found to date at Abu Sennan.

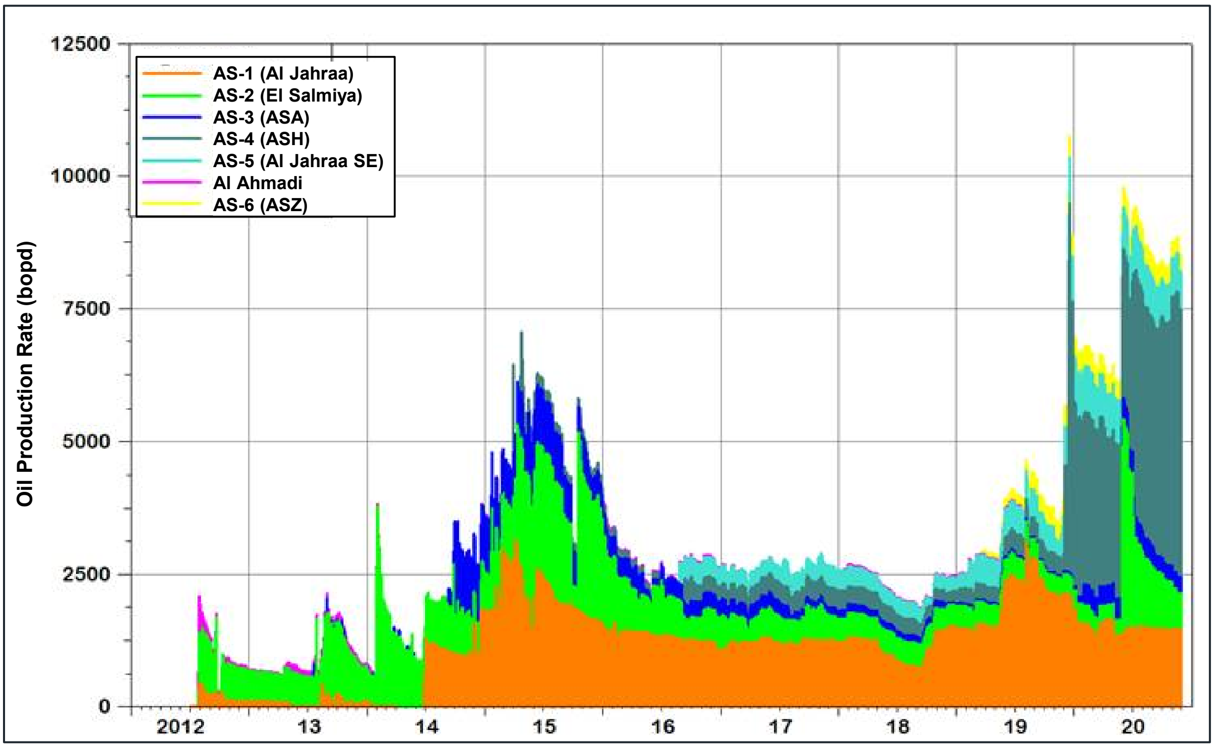
Three permanent production and processing stations were constructed in 2014, serving El Salmiya and ASA (the main station), Al Ahmadi and Al Jahraa respectively; these replaced the rented production facilities. The high GOR in some wells led the Operator to investigate the possibility of exporting the produced gas. A pipeline to a GPC gas facility located approximately 12 km from Al Ahmadi and 23 km from El Salmiya was constructed in 2014. Gas handling facilities have also been installed, and gas export began in April 2015. In 2020, the gas pipeline between Al Ahmadi (no longer producing) and El Salmiya was moved to connect Al Jahraa to a third party gas plant, allowing gas exports from Al Jahraa to begin. Produced oil continues to be transported by truck.

A sixth discovery was made at ASH in 2015 (with gas exports beginning on 26th December 2020 following installation of a gas pipeline to El Salmiya), a seventh at Al Jahraa SE in 2016 and an eighth at ASZ at the end of 2018. Additional reservoirs were discovered at Al Jahraa in 2018 and 2019, and at El Salmiya in 2020. In total, at least 23 separate accumulations have been discovered in the eight fields. The most significant is the AR-C reservoir at Al Jahraa/Al Jahraa SE, with a STOIIP estimated at between 16 and 34 MMBbl.

The 3D seismic data were reprocessed in 2015-16 and interpretation has been ongoing since then, focusing initially on the main reservoirs and more recently on exploration targets.

The oil production history is shown in Figure 3. The oil production rate initially peaked at 6,000 bopd in June 2015 before declining to approximately 2,500 bopd by June 2016. It subsequently remained fairly stable, apart from a dip in mid-2018, but rose significantly in 2019 as new wells were brought on stream in Al Jahraa, and again in 2020 with new wells in ASH (in December 2019) and El Salmiya, reaching 9,000 bopd in June and July 2020. Average rates in November 2020 and cumulative production to 30th November 2020 are shown in Table 8.

Figure 3: Oil Production History to November 2020



Source: UEGL

Table 8: Production Summary, November 2020

Field	Production Rate		Cumulative Production	
	Oil (bopd)	Sales Gas (MMscfd)	Oil (MBbl)	Gas (Bscf)
ZZ	0	0.00	37	1.86
Al Ahmadi	0	0.00	31	0.90
Al Jahraa	2,183	2.26	4,246	0.75
El Salmiya	712	3.77	2,464	11.73
ASA	309	0.00	771	0.00
ASH[4]	5,149	0.00	1,736	0.00
ASZ	314	0.00	190	0.00
Total	**8,666**	**6.03**	**9,475**	**15.23**

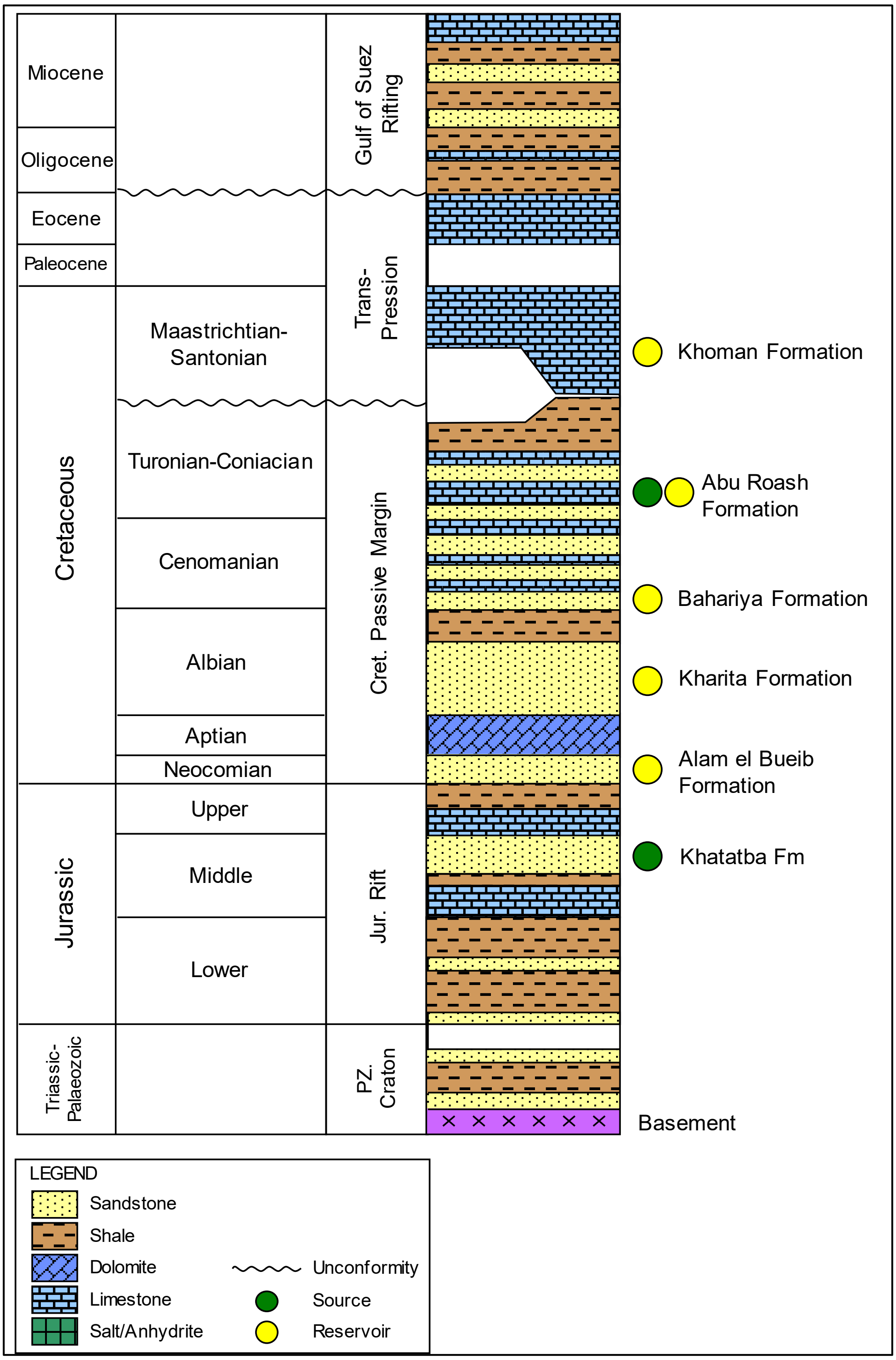
Notes:

1. Al Jahraa SE production is included with Al Jahraa.
2. Flared gas volumes for Al Jahraa, ASA, ASH and ASZ are not shown in this table.
3. Cumulative gas production for El Salmiya, Al Ahmadi and ZZ includes some gas flared before sales began in April 2015.
4. Gas exports from ASH began on 26th December 2020 at a rate of approximately 5 MMscfd.
5. Totals may not exactly equal the sum of the individual entries due to rounding.

2 Geology

Geologically, Abu Sennan lies in the Abu Gharadig Basin in the Western Desert. Overall stratigraphy is summarised in Figure 4.

Figure 4: Composite Stratigraphy, Western Desert



The proven reservoirs are Cretaceous in age and comprise a series of interbedded marine sandstones and carbonates. The Lower Bahariya Formation and Abu Roash Members C, D, E, and G (AR-C, AR-D, AR-E and AR-G) are of Cenomanian to Turonian age, the Kharita Formation is of Albian age and the Alam El Bueib (AEB) Formation is of Neocomian age. Seals are provided mainly by interbedded marine mudstone units. Traps are predominantly structural, occasionally with four-way dip closure but more commonly reliant on fault seal on one or more sides. The Middle Jurassic Khatatba Formation provides the principal source rock, although distribution and level of maturity varies between fault blocks.

2.1 Hydrocarbon Initially In Place

Hydrocarbon initially in place (HCIIP) estimates made by the Operator for each of the fields discovered to date are presented in Table 9.

Table 9: HCIIP Estimates

Field	Reservoir	Fluid	STOIIP/CIIP (MMBbl)			GIIP (Bscf)		
			Low	Best	High	Low	Best	High
ZZ	AR-G	Gas Condensate	0.2	0.2	0.2	2.1	2.7	3.2
	L Bahariya	Volatile Oil	0.1	0.2	0.2	0.2	0.3	0.4
Al Ahmadi	AR-G	Volatile Oil	0.1	0.1	0.1	0.2	0.3	0.4
	L Bahariya	Gas Condensate	0.3	0.4	0.4	4.0	5.0	6.0
Al Jahraa[1]	AR-E (Jah-1)	Oil	0.7	0.7	0.7	0.3	0.3	0.3
	AR-E (Jah-SE)	Oil	1.5	2.7	4.0	0.6	1.1	1.7
	AR-C	Oil	15.7	24.2	33.9	5.7	8.9	12.4
	AR-D	Oil	3.1	3.1	3.1	1.5	1.5	1.5
	AR-G	Oil	0.5	1.4	4.0	0.2	0.6	1.7
	L Bahariya	Volatile Oil	1.6	3.2	6.3	6.4	12.8	25.2
	AR-E (Jah-7)	Oil	0.3	0.6	1.3	0.1	0.3	0.6
	U Bahariya	Oil	0.2	0.4	0.8	0.3	0.6	1.1
	L Bahariya II	Volatile Oil	0.1	0.2	0.5	0.2	0.7	1.8
El Salmiya	AR-C	Oil	3.0	4.0	5.5	6.0	11.2	19.3
	AR-C (Sal-3)	Oil	0.7	0.7	0.7	1.4	1.4	1.4
	AR-E	Oil	3.5	4.9	6.4	1.2	1.7	2.2
	AR-G	Volatile Oil	0.4	0.6	1.1	1.5	3.9	15.8
	L Bahariya	Volatile Oil	0.5	1.4	5.7	0.2	0.9	2.8
	Kharita	Volatile Oil	5.0	5.5	6.0	15.0	17.0	19.0
ASA	AR-C	Oil	0.9	1.5	2.3	0.4	0.8	1.2
	AR-E	Oil	3.4	3.9	5.1	1.7	2.0	2.7
ASH	AEB	Volatile Oil	9.5	14.3	21.8	13.2	21.4	38.2
ASZ	AR-C	Oil	1.7	3.2	6.0	0.8	1.5	2.8
Total			**52.8**	**77.3**	**116.1**	**63.4**	**96.8**	**161.7**

Notes:

1. Al Jahraa SE is included with Al Jahraa.
2. Totals may not exactly equal the sum of the individual entries due to rounding.

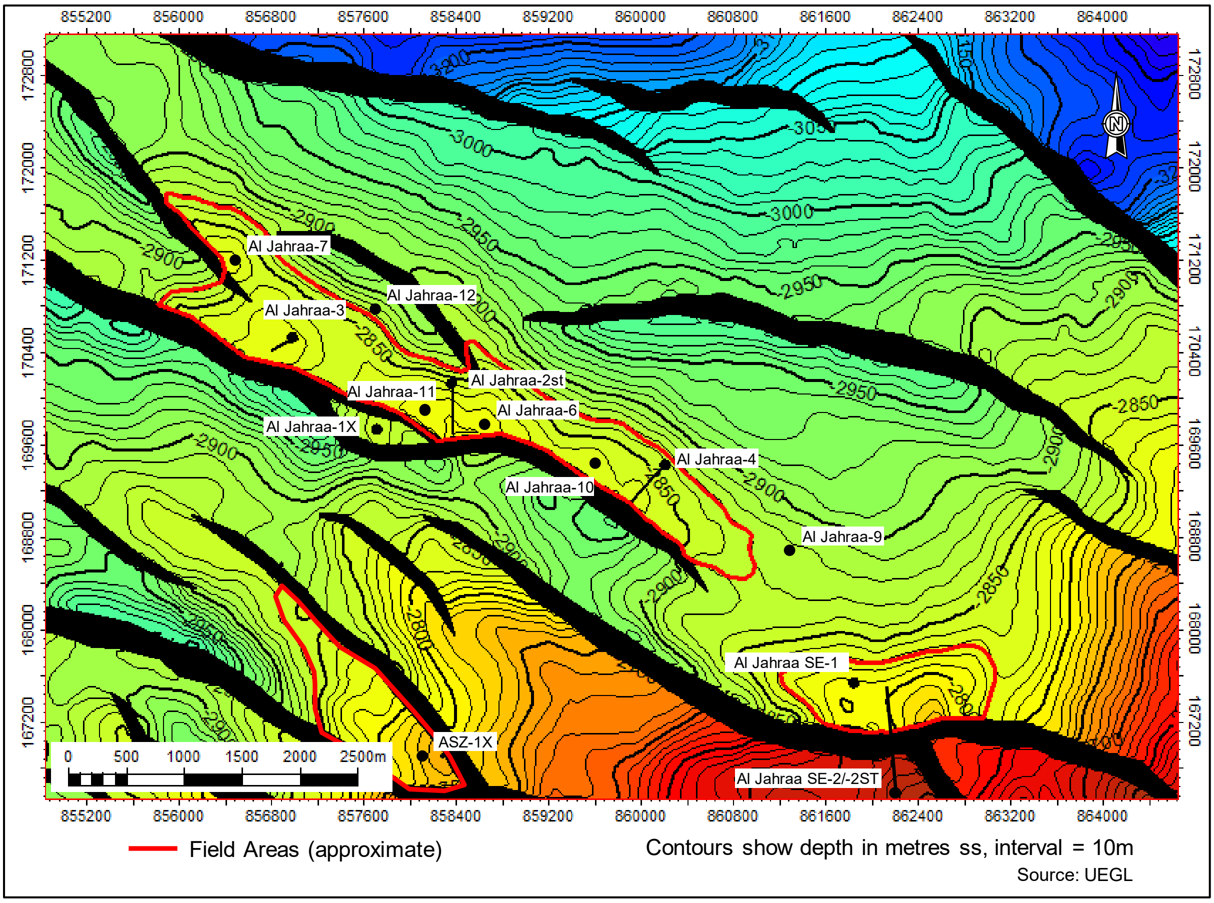
GaffneyCline accepts that these HCIIP estimates are reasonable in the aggregate. GOR was very high in some of the initial production tests and there has been debate as to whether the hydrocarbons exist in the reservoirs as volatile oil or gas condensate, based on PVT reports and the production data.

3 Al Jahraa and Al Jahraa SE

Al Jahraa is located in the AS-1 development area on the western side of the concession area (Figure 2). Twelve wells have been drilled to date (including Al Jahraa SE-1 and SE-2, which lie in the AS-5 development area). Oil is found in the AR-C, AR-D, AR-E, AR-G, Upper and Lower Bahariya reservoirs, of which the most significant is the AR-C (Figure 5), at depths of 2,750-3,050 m ss. The reservoirs contain light oil with a GOR of approximately 400 scf/stb in the AR-C, AR-D and AR-E, and higher GOR in the Upper and Lower Bahariya.

The field is an elongated anticline, partly controlled by a fault to the south. Al Jahraa-1X discovered the AR-E reservoir but produced only 74 MBbl between 2012 and 2016. The main AR-C reservoir (Figure 5) was discovered by Al Jahraa-2, and production therefrom began in 2014 with Al Jahraa-2ST, -3 and -4 each initially achieving approximately 1,000 bopd. Perforations in the AR-D were added to Al Jahraa-2ST in 2015.

Figure 5: Top AR-C Reservoir, Al Jahraa, Al Jahraa SE and ASZ Fields



The Al Jahraa SE-1 well was drilled in 2016. It found oil in the AR-C at lower than the expected initial pressure, suggesting communication with the existing Al Jahraa wells that were already in production. However, the two oil pools in the AR-C (Al Jahraa and Al Jahraa SE) are separate and correspond to the two mapped structural closures, as indicated in Figure 5, with pressure communication taking place via an aquifer. This was confirmed by the Al Jahraa-9 well, drilled in 2017, which produced water from the AR-C when tested. Al Jahraa SE-1 was put into production from the AR-E in 2016, with perforations in the AR-C added in 2017.

Al Jahraa-SE-2 was drilled in 2017, initially as an exploration well on the southern side of the main bounding fault (Figure 5). It was drilled to a total depth of 3,460 m, in the Kharita Formation, but found no hydrocarbon so was side-tracked to the north of the fault where it encountered oil in the AR-C and AR-E, testing at 275 bopd in the latter. After producing for 18 months from the AR-E, its rate had declined to less than 40 bopd; it was then also perforated in the AR-C, which has produced at approximately 250 bopd throughout 2019 and 2020.

Two wells were drilled in 2018. Al Jahraa-6 found oil in the Lower Bahariya reservoir, a new discovery, as well as in the AR-C and AR-D. It came on production from the Lower Bahariya in late September and after cleaning up reached 500 bopd by early November, but this well has a high GOR, so production was limited by flaring restrictions until a gas export solution was put in place in March 2020. Al Jahraa-10 was drilled as an AR-C producer and came on production in December 2018 at approximately 130 bopd, with approximately 100 bopd from the AR-D reservoir added in March 2019 following an acid treatment.

As the aquifer provides limited pressure support in the AR-C reservoir, a water injection project was started in July 2018, with water being injected in Al Jahraa-9 at a rate that was ramped up to 2,000 bpd.

Three further wells were drilled in 2019:

- Al Jahraa-11 found oil in the AR-C, AR-D, AR-G (a new discovery), Upper Bahariya (also a new discovery) and Lower Bahariya reservoirs and was fitted with a dual completion. It started producing in May at 420 bopd from the Lower Bahariya (long string) and 480 bopd from the AR-C (short string). However, this well also produces with a high GOR, approximately 12,000 scf/Bbl in mid-2020.

- Al Jahraa-7 found oil in the AR-C, AR-E, Upper Bahariya and two intervals in the Lower Bahariya. The AR-E and one of the Lower Bahariya sands appear to be separate pools from those penetrated by previous wells, so were new discoveries. It was tested at 160 bopd from the Lower Bahariya, 500 bopd from the Upper Bahariya, and more than 700 bopd from the AR-E before being put into production from the AR-E in early August, declining to approximately 300 bopd by October 2019.

- Al Jahraa-12 was drilled as a second water injector in the AR-C reservoir. It had been drilled by end September but injection did not begin until March 2020, at 1,000 bpd.

No new wells were drilled in 2020 but in addition to the start of gas exports and water injection in Al Jahraa-12, both in March, 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.

The oil production rate from the AR-C reservoir in November 2020 was 1,710 bopd. Cumulative oil production from the AR-C reservoir to end November 2020 was 3.12 MMBbl, from seven wells (including Al Jahraa SE-1 and SE-2).

4 Other Fields

4.1 El Salmiya

El Salmiya is located in the AS-2 development area on the eastern side of the concession area (Figure 1). Six wells have been drilled in the field to date. Oil has been found in the AR-C, AR-E, AR-G (discovered in 2020), Lower Bahariya and Kharita reservoirs at depths of 3,200 to 3,800 m ss. Apart from the AR-E, where 33°API oil with a GOR of 200-300 scf/stb was found, all the reservoirs contain volatile oil with high GOR in the order of 1,900-2,500 scf/stb.

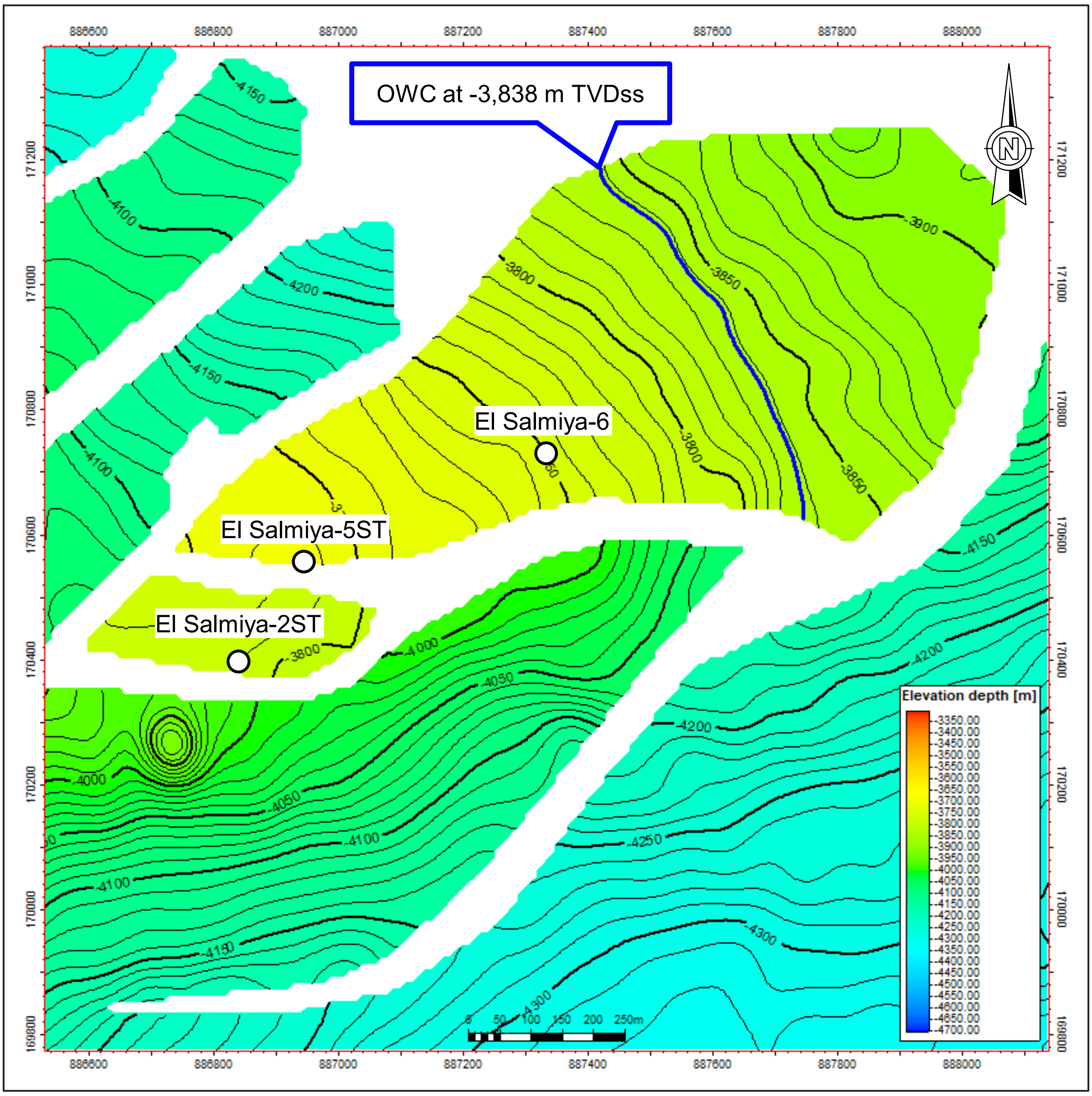
The field is a complex, heavily faulted, anticlinal structure, and there are at least two separate pools in each of the AR-C and Kharita reservoirs. Figure 6 shows the depth structure map for the Kharita reservoir, which is estimated to contain approximately 36% of the STOIIP in the field.

Although initial production rates of up to 3,500 bopd were achieved in several of the wells, production was initially constrained due to the high GOR. After gas export was put in place, rates increased but then declined quite steeply, confirming the compartmentalised nature of the reservoirs.

In 2020, the Operator drilled the El Salmiya-5ST well, which encountered hydrocarbons in the AR-C, AR-E, AR-G (a new discovery) and Kharita reservoirs. It was tested at up to 6,200 bopd and 23.6 MMscfd in the Kharita and 1,250 bopd in the AR-E before being put into production from the Kharita, initially achieving almost 4,000 bopd but being choked back after a month to approximately 1,500 bopd and 7.0 MMscfd gas. This has declined steadily to 602 bopd and 3.8 MMscfd gas by November.

In November 2020, El Salmiya-2 was producing 110 bopd from the AR-E, while El Salmiya-1 and El Salmiya-6 were shut in pending work-overs (planned for 2021), having been producing 35 bopd from the AR-C and 180 bopd and 5.2 MMscfd from the Kharita respectively. Sucker-rod pumps were installed in El Salmiya-1, El Salmiya-2 and El Salmiya-3 (AR-C) in 2017, but the latter produced for less than a month. El Salmiya-4 was recompleted in the AR-E in 2018 but there was no flow.

Figure 6: Top Kharita Reservoir, El Salmiya Field

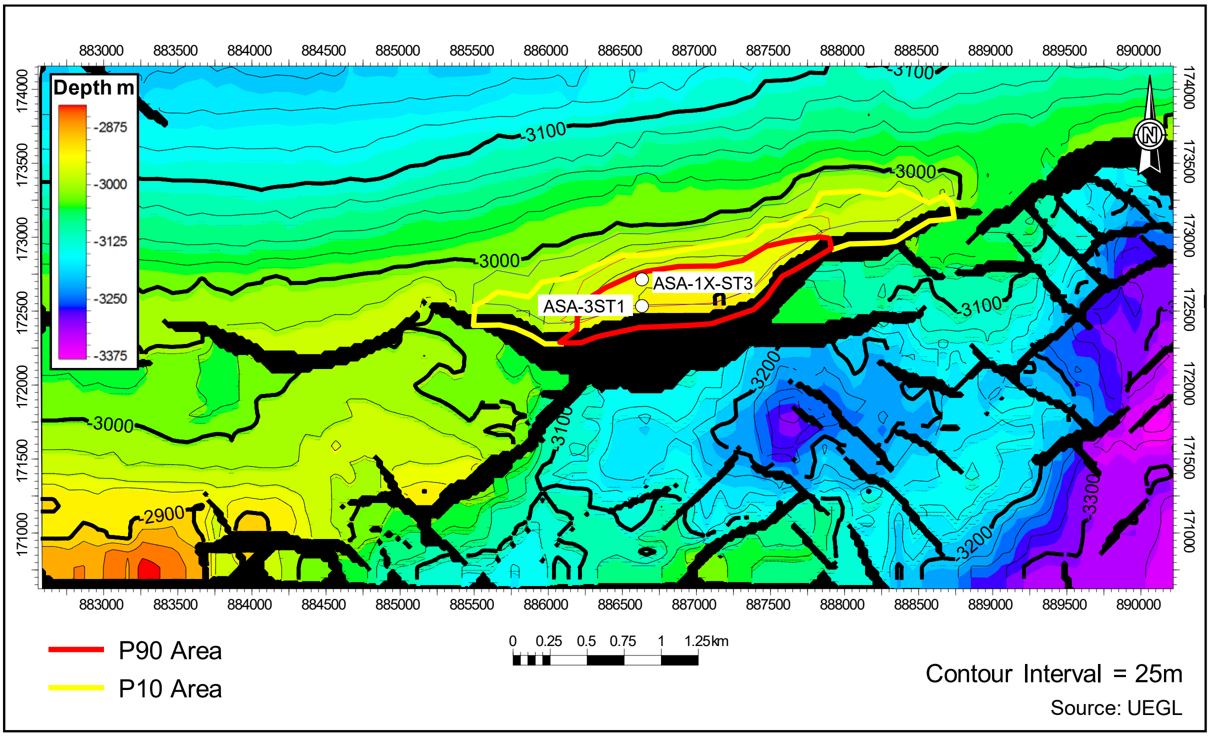


Source: UEGL Static Model (adapted)

4.2 ASA

ASA, located in the AS-3 development area (Figure 1), is a tilted fault structure to the north of El Salmiya (Figure 7). Two wells and two side-tracks have been drilled in the field to date. Light oil with a GOR of approximately 400 scf/stb has been found in the AR-C and AR-E reservoirs at a depth of approximately 3,000 m ss. Production in 2019 was from ASA-3 only (AR-E reservoir) but ASA-1ST3, which is completed in the AR-C and AR-E reservoirs, was worked-over for re-perforation and cleaning and re-started in February 2020 at 320 bopd (compared to approximately 60 bopd in 2018).

Figure 7: Top AR-E Reservoir, ASA Field



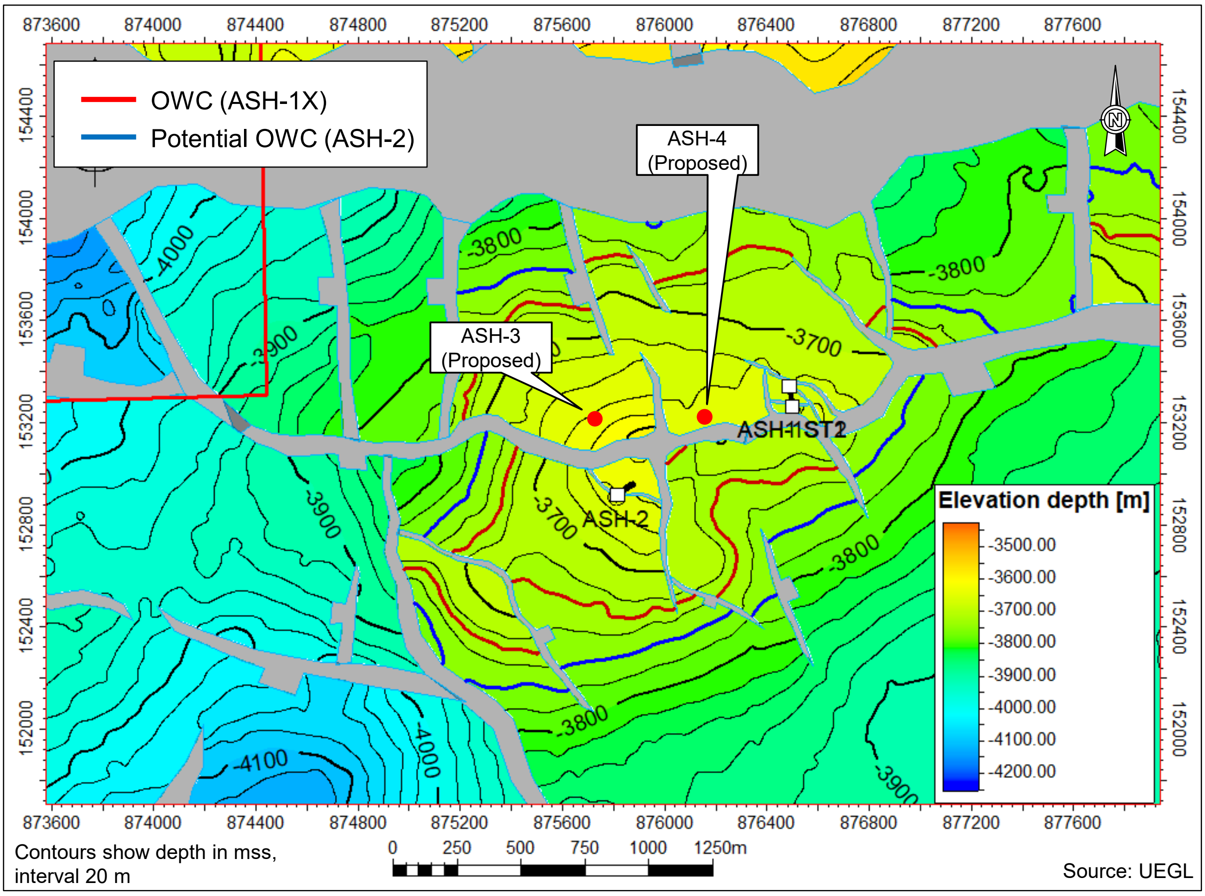
4.3 ASH

The ASH-1X exploration well drilled in 2015 in the southern part of the concession area (Figure 1). Previous wells in this area had been dry and there were doubts about the presence of source rock. However, the well discovered light oil with a GOR of approximately 1,750 scf/stb in the AEB Formation at a depth of 3,700 m TVDss. ASH-1X penetrated the OWC, and although an initial rate of more than 1,000 bopd was achieved, it declined rapidly as the water cut rose; it was side-tracked to a more up-dip location in 2016 and produced fairly steadily at 300-400 bopd from then until early 2020 when it developed a tubing leak. It was worked over in October 2020 to replace the tubing and install an SRP, and was producing at approximately 220 bopd in December 2020. A workover to perform a fracture stimulation is planned in 2021.

ASH-2 was drilled in late 2019 just less than 1 km southwest of ASH-1X. The well found 50 m of net pay in three sand intervals within the AEB Formation, at close to the initial pressure recorded in ASH-1X and potentially with a deeper OWC. Up to 7,000 bopd was achieved during production tests in December 2019, with a GOR of 1,100-1,300 scf/Bbl. It was put into production at a rate of approximately 3,000 bopd, limited by restrictions on the amount of gas that can be flared. A gas pipeline was installed in late 2020 and gas exports began on 26th December, at a rate of approximately 5 MMscfd.

The structure is difficult to resolve on seismic, being fairly small and faulted. The Operator's latest interpretation is shown in Figure 8, which also shows the locations of for the two wells planned for drilling in 2021-2022.

Figure 8: Top Upper Sand, AEB Reservoir, ASH Field



4.4 ASZ

In late 2018, the ASZ-1X exploration well was drilled in a fault block just to the south of the Al Jahraa field (Figure 2 and Figure 5). It encountered 6 m of net oil pay in the AR-C reservoir. It came on production in April 2019 via a flow-line to the Al Jahraa facilities and after cleaning up had reached a rate of 400 bopd at 30% water cut by the end of 2019, which has declined only slightly in 2020.

4.5 ZZ and Al Ahmadi

The ZZ (formerly GP ZZ) and Al Ahmadi fields have proven to be smaller than originally envisaged and to contain either gas condensate or very volatile oil with high GOR. Small volumes of oil and gas have been produced from one well in each field, There has been no production from ZZ since 2018, while the Al Ahmadi-1 well was producing gas at a rate of approximately 1.5 MMscfd with some 20 bopd of condensate until July 2019, when it ceased to flow. The gas pipeline from Al Ahmadi to El Salmiya has now been moved to provide an export line for Al Jahraa, so there are no plans for further production.

5 Reserves

5.1 Development Plans

In the 2P case, the Operator is planning to drill four new production wells and two new water injection wells in Abu Sennan over the period 2021-2023 as follows:

- Two AEB producers in ASH in 2021-2022;
- In Al Jahraa, an AR-D producer in 2022 and an AR-C water injector in 2022;
- A water injection well in the AR-E reservoir at ASA in 2023; and
- An AR-C producer in El Salmiya in 2023.

No Proved Reserves are attributed to the El Salmiya producer or to the water injectors. In the Proved case, the ASA water injector is assumed to find no AR-E reservoir and instead be completed as an AR-C producer. However, the new wells are uneconomic in the Proved case, so there are no Proved Undeveloped Reserves in any of the fields.

In the 3P case, the Operator includes four more producers (two in the Bahariya, later recompleted in the AR-G, and two in the AR-C) and two more AR-C water injectors in Al Jahraa, plus another production well in El Salmiya.

Table 10 shows the drilling schedule by year and by reserves category.

Table 10: Planned Drilling Schedule

Year	Production Wells			Water Injection Wells		
	1P	2P	3P	1P	2P	3P
2021	1	1	2	0	0	0
2022	2	2	3	0	1	2
2023	1	1	4	0	1	2
Total	**4**	**4**	**9**	**0**	**2**	**4**

Notes:

1. The above table shows development wells only, not exploration wells or water source wells.
2. Although four wells target Proved volumes, these wells are uneconomic in the Proved case, so no Proved Reserves are attributed to them.

5.2 Production Profiles

GaffneyCline has audited production profiles prepared by the Operator for all the fields and considers them to be reasonable in the aggregate. Future production from currently producing wells has been estimated by decline curve analysis, except for those in the AR-C reservoir in Al Jahraa, where the production profiles are taken from a material balance reservoir model. This model is also used to forecast production from the planned wells in that reservoir, while initial oil production rates and decline rates for the other new wells have been estimated using regional analogues and recoverable volume estimates.

A summary of HCIIP, remaining technically recoverable volumes, estimated ultimate recovery (EUR) and recovery factor (RF) is given in Appendix III.

5.3 Costs

Future CAPEX and OPEX profiles associated with the development plans have been provided by the Operator. GaffneyCline has reviewed these and considers them to be reasonable. Key elements include:

- US$3.5 MM per well, including flowline, for each new production well in Al Jahraa or ASA;
- US$3.1 MM per well for an injection well in Al Jahraa or ASA;
- US$4.3 MM per well in ASH;
- US$4.5 MM per well in El Salmiya;
- US$0.3 MM for a major work-over (e.g. El Salmiya-6);
- US$0.7 MM for the hydraulic fracturing of ASH-1X;
- US$6.6 MM facilities CAPEX over the period 2021-2025 (none in the Developed cases), mainly for facility upgrades at ASH and Al Jahraa in 2021 and improvements to the power supply;
- Fixed OPEX of US$7.0 MM p.a.; and
- Variable OPEX of US$3.54/Bbl for transportation (trucking), processing and handling.

GaffneyCline understands that the Contractor Group has no liability for abandonment costs.

5.4 Reserves Reconciliation

Changes in Gross Field Reserves between 31st December 2019 and 31st December 2020 are summarized in Table 3 and are shown on a field by field basis in Table 11.

The AR-G reservoir at El Salmiya discovered by El Salmiya-5 is an exploration add in 2020. However, the STOIIP is small and it is planned to produce it only by recompleting El Salmiya-5 and the planned El Salmiya-7 and El Salmiya-8 wells after these wells have completed production from other reservoirs. This leads to a small volume of 2P and 3P Reserves but in the 1P case, all potentially recoverable volumes fall beyond the economic limit, so no 1P Reserves are assigned to the AR-G reservoir.

There are large upward revisions to Reserves in El Salmiya and ASH; these are due to the results of the El Salmiya-5 and ASH-2 wells, the production performance of these wells, and the maturation of the ASH gas development from Contingent Resources to Reserves. ASA and ASZ also have upward revisions, which are large in percentage terms, due to the production performance of these fields in 2020. There is a slight downward revision in the 2P case at Al Jahraa, but a narrowing of the uncertainty in remaining volumes, again due to production performance in 2020.

Table 11: Reconciliation of Reserves as at 31st December 2020, with Reserves as at 31st December 2019

Field	Case	Gross Field Reserves (Mboe)				
		End 2019	Exploration Adds	2020 Production	Revisions	End 2020
Al Jahraa	1P	2,500	0	-953	1,546	3,094
	2P	8,753	0	-953	-607	7,193
	3P	17,666	0	-953	-1,621	15,092
El Salmiya	1P	558	0	-782	1,041	817
	2P	1,859	134	-782	1,109	2,319
	3P	4,477	269	-782	2,152	6,116
ASA	1P	46	0	-119	249	175
	2P	321	0	-119	146	348
	3P	568	0	-119	301	750
ASH	1P	1,026	0	-1,314	2,559	2,271
	2P	2,445	0	-1,314	5,342	6,473
	3P	5,576	0	-1,314	7,613	11,875
ASZ	1P	50	0	-129	376	298
	2P	148	0	-129	401	421
	3P	303	0	-129	679	852
Total	**1P**	**4,179**	**0**	**-3,297**	**5,771**	**6,654**
	2P	**13,526**	**134**	**-3,297**	**6,391**	**16,754**
	3P	**28,589**	**269**	**-3,297**	**9,124**	**34,685**

Notes:

1. Revisions are due to production performance in 2020, the results of wells drilled in late 2019 and 2020, notably ASH-2 and El Salmiya-5, and the maturation of the ASH gas development from Contingent Resources to Reserves.
2. The exploration add is the AR-G reservoir at El Salmiya; in the 1P case, all potentially recoverable volumes fall beyond the economic limit given the current development plan.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

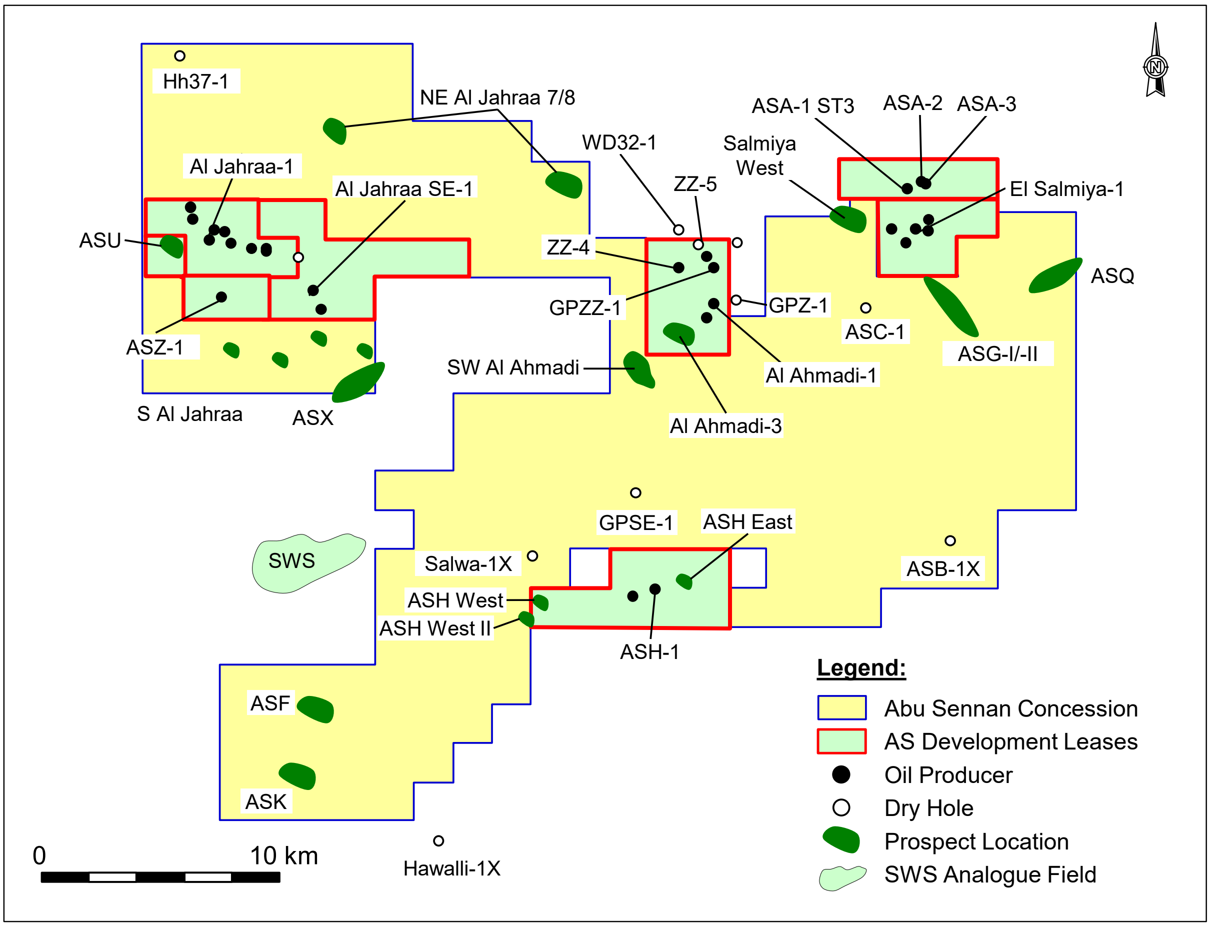
5.5 Site Visit

GaffneyCline, through its sub-contractor, undertook a site visit to Abu Sennan on 23rd January 2017. GaffneyCline's overall impression was that the facilities appeared generally to be in good condition and fit for purpose relating to the current operations. No risk to continued operation due to mechanical conditions was obviously apparent, although ongoing maintenance remains important to the longevity of the facilities. Some minor external corrosion was noted in places. No obvious safety hazards were noted and there were no complaints from the staff about lack of safety measures. The full site visit report is included in Appendix IV.

6 Prospective Resources

A significant amount of exploration potential remains in the Abu Sennan Concession and the Operator has presented several Prospects (Figure 9 and Table 5) to GaffneyCline for audit. Each Prospect has 2-4 reservoir targets that could be tested with a single exploration well. The targets are in the established Upper Cretaceous plays (Abu Roash and Bahariya Formations) and in some cases in deeper, higher risk Lower Cretaceous plays (AEB and Kharita Formations). The targets lie at depths between 2,000 m and 4,000 m, being shallower in the ASF and ASK Prospects in the southwest part of the concession.

Figure 9: Location of Prospects



While individual target volumes are mostly fairly modest, and there is some uncertainty on the nature of any fluids (oil or gas-condensate) that may be present in some of the targets, the chance of success in some of the Prospects close to the existing fields is relatively high.

Almost the entire licence area is covered by 3D seismic data. The seismic dataset and its interpretation are sufficiently robust to define the Prospects presented, with some uncertainty surrounding the definition of small structural closures and the linkage between shallow and deep faults.

Volumes have been estimated from the results of the mapping and estimates of rock and fluid parameters from wells within Abu Sennan or in nearby analogues (e.g. SWS – see Figure 9).

The discovery of the ASH oil field (AEB reservoir) lowered the migration risk in the southern part of the concession, which was previously thought to have been in a migration shadow (preventing hydrocarbon charge). Uncertainty remains within the individual Prospects, with the key geological risks being associated with trap integrity (fault seal) and reservoir presence/quality, plus hydrocarbon migration in the southwest extremes of the concession. There is a risk that hydrocarbon present in the Al Ahmadi-3 Prospect, if any, may be gas.

The first 3-year phase of the current exploration licence carries a commitment to drill two exploration wells, one of which has already been drilled (ASZ-1X).

A summary of the Prospective Resources is presented in Table 5 in the Summary section.

7 Economic Assessment

GaffneyCline has conducted an economic limit test for the Low, Best and High production and cost profiles to assess Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves respectively. The economic limit (or economic cut-off) is defined as the time when the maximum cumulative net cash flow occurs for a project. Additionally, GaffneyCline has conducted an economic entitlement calculation based on the PSC terms in order to derive UOG's Net Entitlement Reserves, which derive from the cost recovery and profit share.

Summary cash flows, net to UOG, for each Reserves case are presented in Appendix V. The NPV of each of these cash flows has been calculated, discounted on a mid-year basis to 31st December 2020.

These assessments have been based upon GaffneyCline's understanding of the fiscal and contractual terms governing these assets, and the various economic and commercial assumptions described herein.

7.1 Contract and Fiscal Terms

The relevant elements of the Egyptian fiscal regime for petroleum operations as they currently stand, together with the terms of the PSC that governs the asset, are summarised below and are assumed to remain constant going forward:

- Royalty: 10% of Gross Production. It is borne and paid by EGPC on behalf of the Contractor Group.
- Cost Recovery Limit: 30% of Gross Production with any unused cost recovery going fully to EGPC.
- Cost Recovery Depreciation: exploration and development costs to be recovered at a rate of 20% p.a. Operating cost to be recovered in the year incurred. Unrecovered costs can be carried forward until fully recovered.
- Production Sharing: 82.1% of all hydrocarbon (after cost recovery) to EGPC and 17.9% to the Contractor Group.
- Production Bonuses: when reaching certain rates of oil production, the following amounts (which are not cost recoverable) must be paid:

Production Rate (bopd)	Bonus (US$ MM)
3,000	0.5
5,000	1.0
10,000	1.5
25,000	2.0

- Training Fee: US$50,000 p.a. for the duration of the exploration phase.
- Corporate tax: borne and paid by EGPC on behalf of the Contractor Group.

For the purpose of these assessments, the following forward schedule of gross unrecovered historical costs provided by the Operator has been used:

Year	Unrecovered Costs (US$ MM)	
	Original	Extension
Balance at 31st December 2020	113.48	0.72
2021 Addition	11.73	0.62
2022 Addition	9.15	0.62
2023 Addition	7.46	0.62
2024 Addition	4.27	0.62
2025 Addition	0.84	0.18

7.2 Costs

Estimates of CAPEX and OPEX have been provided by the Operator as discussed in Section 5.3. For the cash flow calculations, costs have been escalated at 2.0% p.a. from 2022 onwards.

7.3 Oil and Gas Prices

GaffneyCline's 1Q 2021 Brent Crude oil price scenario, shown in Table 12, has been used as the reference oil price.

Table 12: Reference Oil Price Scenario

Year	Price (US$/Bbl)
2021	51.38
2022	54.00
2023	57.00
2024	60.00
2025+	+2% per annum

As advised by the Operator, the above price scenario has been adjusted by a quality discount against Brent of US$1.70/Bbl for Abu Sennan.

For gas, as advised by the Operator, a price of US$2.65/MMBTU will apply if the Brent price is US$22/Bbl or more. A calorific value of 1.240 MMBTU/Mscf has been used to arrive at a gas price of US$3.29/Mscf. However, GaffneyCline understands that gas is delivered off spec and an 8% price reduction is consequently applied. It has been assumed that EGPC will continue to accept off spec gas in the future, though they are not obliged to do so under the terms of the Gas Sales Agreement.

7.4 Results

The economic limit for production was found to occur at end 2026, 2032 and 2036 in the Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves cases respectively. Corresponding limits for the Developed Reserves cases were end 2026, 2031 and 2036 respectively.

The resulting Reserves, both gross (100%) and net to UOG, are shown in Table 1 in the Summary section. The corresponding NPVs at a discount rate of 7.5%, 10% and 12.5%, net to UOG, are shown in Table 6.

7.5 Economic Sensitivity

In view of the recent volatility in oil prices, GaffneyCline has estimated the break-even price for production from Abu Sennan in 2021 (i.e. the price at which revenue from production equals OPEX), assuming no further development and no reduction in costs. This is less than US$10/Bbl at the gross field level, and approximately US$15/Bbl for UOG.

GaffneyCline also reran the economic calculations varying the reference oil prices (Table 12) by ±US$10/Bbl. As in the base case oil price scenario, costs were escalated at 2.0% p.a. from 2022, with no adjustment for the higher or lower oil price. There was no material impact on Reserves, but the NPV at 10% discount rate (net to UOG) was found to vary by ±32% compared to the base case scenario in the Proved plus Probable case.

Appendix I
Abbreviated Form of SPE PRMS

Society of Petroleum Engineers, World Petroleum Council,
American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers,
Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts,
and European Association of Geoscientists & Engineers

Petroleum Resources Management System

Definitions and Guidelines ([1])

(Revised June 2018)

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	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.
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.

[1] These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised June 2018) document.

Class/Sub-Class	Definition	Guideline s
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.
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.

Class/Sub-Class	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.
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—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—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.

Category	Definition	**Guidelines**
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.

Figure 1.1—RESOURCES CLASSIFICATION FRAMEWORK

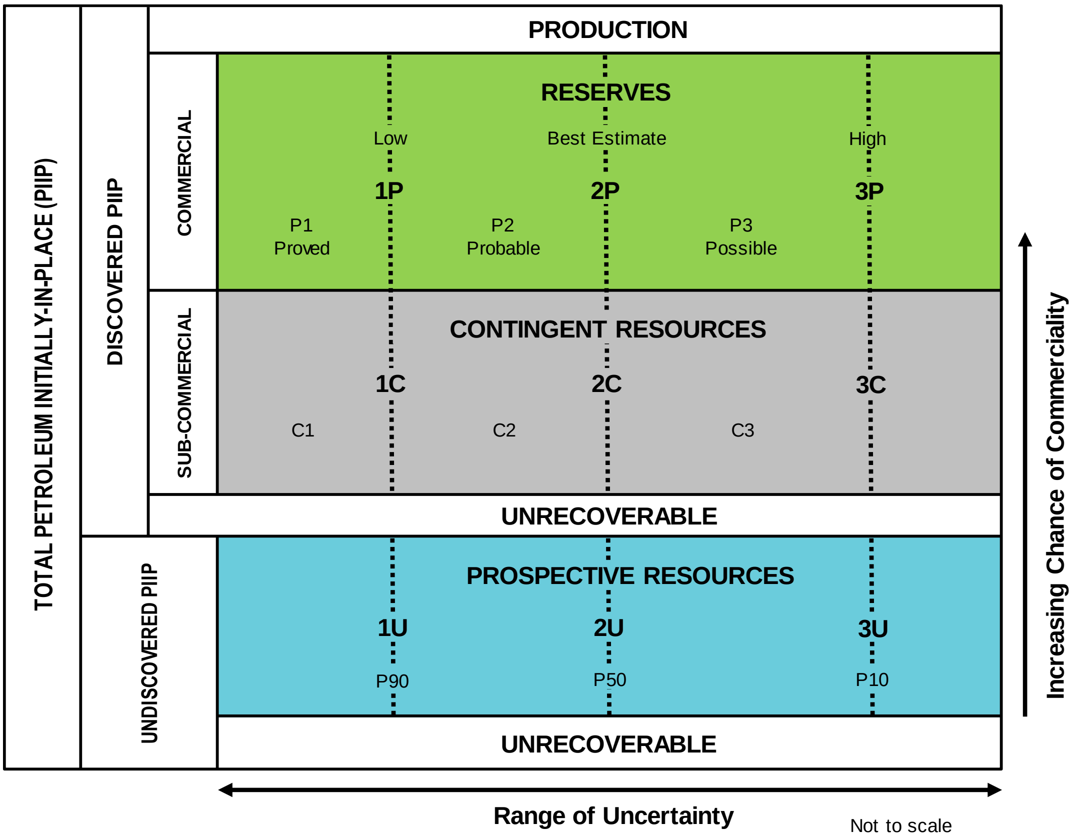
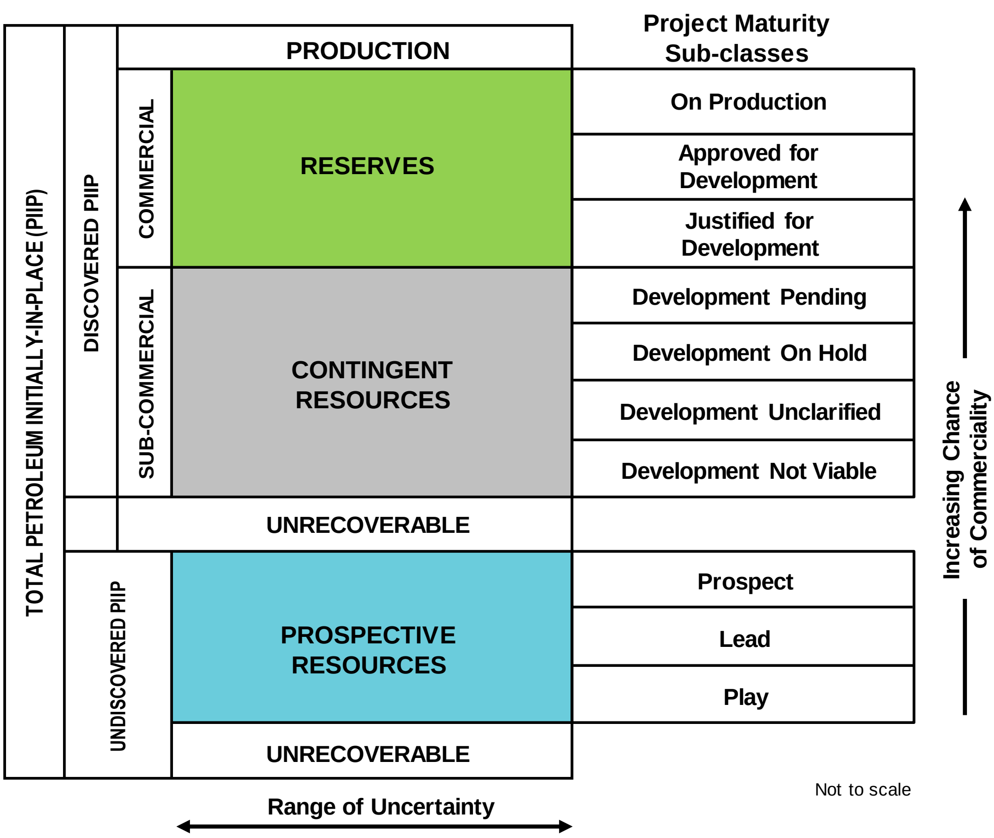


Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY



Appendix II
Glossary of Abbreviations

Gaffney Cline

Glossary

API	American Petroleum Institute
°API	Degrees API (a measure of oil gravity)
B	Billion
Bbl	Barrels
/Bbl	Per barrel
boe	Barrels of oil equivalent
bopd	Barrels of oil per day
bpd	Barrels per day
bwpd	Barrels of water per day
Bscf	Billion standard cubic feet
BTU	British thermal unit
CAPEX	Capital expenditure
CGR	Condensate gas ratio
CIIP	Condensate initially in place
DST	Drill Stem Test
EGPC	Egyptian General Petroleum Corporation
ELT	Economic Limit Test
ESP	Electrical submersible pump
EUR	Estimated ultimate recovery
°F	Degrees Fahrenheit
GIIP	Gas initially in place
GOR	Gas oil ratio
ft	Foot or feet
HCIIP	Hydrocarbon initially in place
HSE	Health, safety and environment
H_2S	Hydrogen sulphide
km	Kilometres
km^2	Square kilometres
m	Metres
M	Thousand
MBbl	Thousand barrels
Mbopd	Thousand barrels of oil per day
Mboe	Thousand barrels of oil equivalent
MM	Million
MMBbl	Million barrels
MMboe	Million barrels of oil equivalent
MMBTU	Million British thermal units
MDT	Modular Dynamic Tester
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
Mscf	Thousand standard cubic feet

NPV	Net Present Value
ODT	Oil down to
OPEX	Operating expenditure
OWC	Oil-water contact
p.a.	Per annum
P_g	Chance of Geologic Success
PSC	Production Sharing Contract
psia	Pounds per square inch absolute
PVT	Pressure, volume, temperature
RF	Recovery factor
scf	Standard cubic feet
SRP	Sucker-rod pump
ss	Sub sea
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
TVD	True vertical depth
US$	United States Dollar
WI	Working Interest
WUT	Water up to
%	Percentage
1C	Low estimate of Contingent Resources
2C	Best estimate of Contingent Resources
3C	High estimate of Contingent Resources
3D	Three-dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
1Q	First quarter (of year)

Appendix III
Summary of HCIIP, EUR and Recovery Factor

Gaffney Cline

Table AIII.1: Summary of HCIIP, EUR and Recovery Factor as at 31st December 2020

Field	Reservoir	HCIIP (MMboe)			Production (MMBbl)	Remaining (MMboe)			EUR (MMboe)			Ultimate RF (%)		
		Low	Best	High		Low	Best	High	Low	Best	High	Low	Best	High
ZZ	AR-G	0.6	0.7	0.9	0.29	0.00	0.00	0.00	0.29	0.29	0.29	50	39	33
	L Bahariya	0.2	0.2	0.3	0.01	0.00	0.00	0.00	0.01	0.01	0.01	6	5	4
Al Ahmadi	AR-G	0.1	0.2	0.2	0.01	0.00	0.00	0.00	0.01	0.01	0.01	10	7	6
	L Bahariya	1.1	1.4	1.6	0.18	0.00	0.00	0.00	0.18	0.18	0.18	16	13	11
Al Jahraa	AR-E (Jah-1)	0.7	0.7	0.7	0.07	0.00	0.00	0.00	0.07	0.07	0.07	10	10	10
	AR-E (Jah-SE)	1.6	2.9	4.3	0.30	0.00	0.00	0.00	0.30	0.30	0.30	19	10	7
	AR-C	16.8	26.0	36.4	3.18	3.50	6.48	10.01	6.68	9.66	13.19	40	37	36
	AR-D	3.3	3.3	3.3	0.36	0.19	0.23	0.57	0.55	0.59	0.93	16	18	28
	AR-G	0.5	1.5	4.3	0.00	0.07	0.27	1.15	0.07	0.27	1.15	14	18	27
	L Bahariya	2.9	5.8	11.3	0.48	0.17	0.91	3.04	0.65	1.39	3.52	23	24	31
	AR-E (Jah-7)	0.3	0.7	1.5	0.08	0.01	0.02	0.03	0.09	0.10	0.11	28	15	8
	U Bahariya	0.2	0.5	1.0	0.00	0.02	0.06	0.20	0.02	0.06	0.20	8	12	20
	L Bahariya II	0.1	0.3	0.8	0.00	0.01	0.03	0.13	0.01	0.03	0.13	9	11	17
El Salmiya	AR-C	4.2	6.2	9.4	0.91	0.16	0.35	1.21	1.07	1.26	2.11	25	20	23
	AR-C (Sal-3)	1.0	1.0	1.0	0.27	0.00	0.00	0.00	0.27	0.27	0.27	27	27	27
	AR-E	3.8	5.3	6.9	0.21	0.36	0.93	1.76	0.57	1.14	1.96	15	22	29
	AR-G	0.6	1.4	4.3	0.00	0.02	0.14	0.27	0.02	0.14	0.27	4	10	6
	L Bahariya	0.6	1.6	6.2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0
	Kharita	8.0	8.9	9.8	3.04	0.53	0.99	2.90	3.57	4.03	5.94	45	45	61
ASA	AR-C	1.0	1.7	2.6	0.08	0.07	0.00	0.00	0.15	0.08	0.08	15	5	3
	AR-E	3.7	4.2	5.6	0.69	0.14	0.43	0.75	0.84	1.12	1.44	22	26	26
ASH	AEB	12.1	18.6	29.5	1.87	2.96	6.49	11.88	4.83	8.35	13.74	40	45	47
ASZ	AR-C	1.9	3.5	6.6	0.20	0.37	0.52	0.91	0.57	0.72	1.10	30	20	17
Total		**65.5**	**96.6**	**148.5**	**12.21**	**8.59**	**17.85**	**34.81**	**20.81**	**30.06**	**47.02**	**32**	**31**	**32**

Notes:
1. Gas volumes are converted to oil equivalent volumes using a conversion factor of 5.0 Mscf/boe.
2. Remaining and EUR do not take account of economic cut-offs or licence expiry and do not equate to Reserves.
3. Totals may not exactly equal the sum of the individual entries due to rounding.

Table AIII.2: Reconciliation of Remaining Technically Recoverable Volumes as at 31st December 2020 with Remaining Technically Recoverable Volumes as at 31st December 2019

(a) Gross

Case	Remaining Technically Recoverable Volumes – Gross (MMboe)				
	End 2019	Exploration Adds	2020 Production	Revisions	End 2020
Low	6.31	0.02	-3.30	5.55	8.59
Best	14.43	0.14	-3.30	6.58	17.85
High	28.67	0.27	-3.30	9.16	34.81

(a) UOG's Working Interest Fraction

Case	Remaining Technically Recoverable Volumes – UOG's WI Fraction (MMboe)				
	End 2019	Exploration Adds	2020 Production	Revisions	End 2020
Low	1.39	0.01	-0.73	1.22	1.89
Best	3.18	0.03	-0.73	1.45	3.93
High	6.31	0.06	-0.73	2.02	7.66

Notes:

1. Remaining technically recoverable volumes are to the end of the licence period and do not take account of economic cut-offs; they do not equate to Reserves.
2. UOG's Working Interest Fraction of the volumes does not represent UOG's Net Economic Entitlement under the terms of the PSA that governs the asset, which would be lower.
3. Revisions are due to production performance in 2020, the results of wells drilled in late 2019 and 2020, notably ASH-2 and El Salmiya-5, and the maturation of the ASH gas development from Contingent Resources to Reserves.
4. Exploration adds are in the AR-G reservoir at El Salmiya discovered by El Salmiya-5.
5. Totals may not exactly equal the sum of the individual entries due to rounding.

Appendix IV
Site Visit Report

United Oil & Gas plc
April 2021

Summary

GaffneyCline, through its sub-contractor, undertook a site visit to Abu Sennan on 23rd January 2017.

GaffneyCline's visit was undertaken to examine the facilities and operations, and to assess their condition and state of operability. The site visit was limited in duration and no testing of any kind was carried out. The visit provided a snapshot of the overall facilities, pipelines and well sites, but it should be recognized that such a short visit can only provide an overview of the condition of the facilities and the state of operations. GaffneyCline does not warrant that they are in compliance with any applicable regulations in terms of standards, rating, health, safety and environment.

GaffneyCline's overall impression was that the facilities appeared generally to be in good condition and fit for purpose relating to the current operations. No risk to continued operation due to mechanical conditions was obviously apparent. Some minor external corrosion was noted in places. No obvious safety hazards were noted and there were no complaints from the staff about lack of safety measures.

Site Visit

Abu Sennan is located in the Western Desert. It is operated by a Joint Venture (JV) company owned equally by the Contractor Group and EGPC. There are several processing facility centres within the licence area, at Al Ahmadi, Al Jahraa, ASH and El Salmiya. There are production wells and flowlines that consolidate at each facility, with produced gas being exported via a gas facility and pipeline to a nearby General Petroleum Company (GPC) gas plant. The facilities are relatively new, having been constructed in 2013-14.

The one-day site visit commenced at about 12:30 pm with a 45-minute HSE and operational discussion, followed by a two-hour site inspection. Due to the limited time available, only the El Salmiya site was visited. This is where the main East Abu Sennan base is located; the base is reached via an approximately 60 km long unpaved road from the Qarun main road.

During the site visit, the gas facility and oil station at El Salmiya were observed, as well as one oil production well (El Salmiya-6).

The gas facility has dehydration and compression equipment along with metering and ancillary services. Gas is exported from the gas facility via an 8" underground pipeline, 25 km long, to the GPC facility and then to the national gas grid. Oil is exported from the site via truck to a number of destinations. Produced water is transported by truck to a safe disposal plant.

AIV.1 Tanks

In El Salmiya oil station there are 5 oil storage tanks each of 2,400 Bbl capacity. All appeared to be in good condition (Figure AIV.1). The tanks are also serviced by the firefighting system. The oil is trucked from the tanks to either the BADR location or the GPC facility. The tanks were surrounded by a 2 m concrete bund wall. There was no fencing around the facility, but according to operations personnel a security fence is planned.

During the visit, the loading of one truck was observed. The Operations Manager mentioned that they transport about 2,680 bopd via trucks.

Figure AIV.1: Production Tanks at El Salmiya Oil Station

AIV.2 Manifolds

Two manifolds gather production through the flowlines from the El Salmiya Area (Figure AIV.2). The manifolds themselves looked in very good condition but some of the pipelines seemed to be old with minor external surface corrosion. The pipelines entering the manifold were laid directly on the sand with no other support, as is common practice in the Western Desert.

Figure AIV.2: Production Manifold at El Salmiya Oil Station

AIV.3 El Salmiya Oil Station

Equipment at the El Salmiya oil station includes a rented, indirect heater that is used during the winter season to heat the oil to improve the water separation when required. The indirect heater looked in a good condition but it was not operating at the time of the visit.

A 3-phase separator separates gas, oil and water. The separator is reportedly capable of handling 30 MMscfd and 5,000 bopd. It has pneumatic control valves to control the fluid level inside the separator. The separator looked new and in an excellent condition (Figure AIV.3).

Figure AIV.3: 3-Phase Separator

Two air compressors support the separator, manufactured by Stanley; these also looked new and in an excellent condition.

There are two gas boots inside the oil station, which separate the remaining associated gas from the production after the separator and send it to the gas facility. The gas boots have a capacity of 1 MMscfd and can work in parallel or in independent service. The gas boots appeared in good condition.

There are two electrically-operated shipping pumps (Figure AIV.4), both manufactured by Goulds. Each pump has a capacity of 15,000 bpd and both appeared to be in excellent condition. Although fully connected to the tanks, the pumps were not operating during the field visit.

Finally, a firefighting system is located between the oil station and the gas facility. It seemed to be in excellent condition.

Figure AIV.4: Shipping Pumps at El Salmiya Oil Station

AIV.4 El Salmiya Gas Facility

The gas facility (Figure AIV.5) purifies the gas coming from the oil station prior to shipping it through the 8-inch gas export pipeline. A small part of this produced gas is used to feed the gas generators inside the gas facility. The gas facility was originally used by Qarun Petroleum Company before being transferred to El Salmiya.

Figure AIV.5: General View of Gas Facility

The gas facility control room is equipped with the following:

- SCADA Compressors Control Panel - used to automatically control the compressors and the Molecular Sieve units;
- Rectifier Control Panel;
- Fire and Gas Detectors Unit;
- Switch Gear Unit; and
- UPS System – its main purpose is to provide the gas facility control units with back-up power in case the generators inside the facility go down.

A Free Water Knock Out (FWKO) drum is used to separate the free water associated with the gas before being processed. The FWKO drum is equipped with level control valves working automatically by SCADA and can handle 3,000 bwpd and 30 MMscfd. The FWKO drum looked in a good condition but its valves looked old with some external corrosion evident (Figure AIV.6); the Operator has informed GaffneyCline that the valves were inspected, repaired and tested before installation and are under a new maintenance contract.

A closed drain vessel is used to collect the knocked out water and this looked in good condition with some minor external corrosion.

Figure AIV.6: FWKO Vessel and its Valves

A dehydration package is present and is used to remove the water associated with the gas. The dehydration unit has two molecular sieve towers, with a capacity of 28 MMscfd. At the time of the visit, one tower was operating and the other was under regeneration. Some valves of the molecular sieve unit and associated pipelines looked old and corroded, though KE has informed GaffneyCline that all welds have been inspected and the pipe network was hydro-tested to the maximum rated pressure with water and nitrogen. There is also an indirect gas heater used for the molecular sieve regeneration purpose, which looked in good condition.

A number of other equipment items were observed and appeared in good or reasonable condition including:

- Gas engines for the low and high pressure compressors;
- Rectifying tower after the dehydration unit for gas processing;
- Overhead drum; and
- Heat exchangers.

In addition, there were two generators at the gas facility (Figure AIV.7). One generator uses produced gas and is manufactured by Waukesha. It is used to supply the power demands of the gas facility, the oil station and the camp. Another rented standby generator is also available, this being a diesel generator manufactured by CAT.

Figure AIV.7: Power Generators

There are also two air compressors to support the units, manufactured by ATLAS COPCO. One is in operation and the other one on standby.

Finally, there is a metering unit to meter the transported gas. This is a dual flow meter unit with a capacity of 16 MMscfd per meter, linked to the Control Unit. During the visit, only one meter was operating.

The produced sales gas is transported some 25 km to the GPC plant via an 8-inch shipping line. The first section of the line is on supports (Figure AIV.8) and the remaining section is buried. The unburied part and the valves looked to be in very good condition.

AIV.6 Water Treatment

The produced water goes to a safe disposal plant. Production is about 600 bwpd and is sent to an open pond, from where the water is trucked (through a contract with UNICO) to UNICO`s facilities for treatment.

Figure AIV.8: Gas Shipping Line

AIV.7 Wells and Drilling

No rigs were observed during the visit but some time was made available to view the El Salmiya-6 well. It is a naturally flowing well producing about 200 bopd and about 1.6 MMscfd at the time of the visit. The X-mas tree and valves looked in an excellent condition (Figure AIV.9).

Figure AIV.9: El Salmiya-6 Well

AIV.8 Other Observations

- No leaks or signs of oil spills were seen during the visit.
- The operations personnel confirmed that there is no H_2S present in the production.
- Some maintenance records were present, specifically the hours of maintenance for the gas compressors, low pressure compressors and the air compressors.
- There was a reporting sheet for the routine activities on each compressor such as change-overs or greasing. The running hours of equipment are recorded manually in a sheet and on SCADA.

AIV.9 HSE

- A copy of the HSE policy was available on site as well as an Emergency Response Plan.
- Safety shoes, safety glasses, helmets and coveralls were provided to all personnel.
- The incident log was not inspected, but the HSE Manager mentioned that the last LTI was on 7th December 2015 (a vehicle accident) and there had been 408 perfect HSE days without any incident.
- The facilities are all secured by fencing except for the El Salmiya oil station; GaffneyCline understands that fencing for the oil station is planned.
- The HSE Manager mentioned that a fire detection and alarm system is being commissioned for the camp, a tender for sewage water treatment has been launched, and there are plans for a water disposal well, which is waiting for environmental approvals.

The condition of the road to the El Salmiya area is poor with sand dunes and potholes; GaffneyCline understands that it is intended to reconstruct this road.

Appendix V
UOG Net Interest Cash Flows

Net UOG Interest Cashflow Analysis
Proved Case
Escalated Prices and Costs

Nominal Net Present Values as at 01-Jan-21 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	15.88	15.88
5.0%	14.82	14.82
7.5%	14.35	14.35
10.0%	13.92	13.92
12.5%	13.52	13.52
15.0%	13.14	13.14

Field:	**Abu Sennan**		
Case:	1P		
		Initial	***Final***
Working Interest:		22.0%	22.0%
Revenue Interest:		22.0%	22.0%

Period Beginning	Oil Production MMBbl	Oil Price US$/Bbl	Gas Production Bscf	Gas Price US$/Mscf	Field Revenue US$ MM	Contractor Revenue US$ MM	Capital Costs US$ MM	Operating Costs US$ MM	Bonus Payments US$ MM	Pre Tax NCF US$ MM	Other Taxes US$ MM	Corporate Tax US$ MM	Post Tax NCF US$ MM
Jan-21	0.501	49.68	0.58	2.96	26.62	11.32	0.07	3.31	-	7.94	-	-	7.94
Jan-22	0.286	52.30	0.20	2.96	15.53	6.61	-	2.60	-	4.00	-	-	4.00
Jan-23	0.179	55.30	0.07	2.96	10.07	4.28	0.07	2.26	-	1.95	-	-	1.95
Jan-24	0.129	58.30	0.04	2.96	7.64	3.25	-	2.12	-	1.13	-	-	1.13
Jan-25	0.095	59.50	0.03	2.96	5.75	2.44	-	2.03	-	0.41	-	-	0.41
Jan-26	0.091	60.72	0.00	2.96	5.56	2.36	-	1.93	-	0.44	-	-	0.44
Totals:	**1.281**	**MMBbl**	**0.91**	**Bscf**	**71.17**	**30.27**	**0.13**	**14.26**	**-**	**15.88**	**-**	**-**	**15.88**
Entitlements:	**0.545**	**MMBbl**	**0.39**	**Bscf**									

Notes:

1. Cashflows are shown up to Economic Limit only.
2. Entitlements are UOG's Net Entitlement Reserves as per the PSC terms, i.e. UOG's share of the Cost Oil plus Profit Oil (up to the Economic Limit).
3. The Proved and Proved Developed cases are identical as there are no Proved Undeveloped Reserves.

Net UOG Interest Cashflow Analysis
Proved plus Probable Case
Escalated and Costs

Nominal Net Present Values as at 01-Jan-21 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	40.05	40.05
5.0%	34.29	34.29
7.5%	32.02	32.02
10.0%	30.07	30.07
12.5%	28.36	28.36
15.0%	26.87	26.87

Field:	**Abu Sennan**		
Case:	2P		
		Initial	***Final***
Working Interest:		22.0%	22.0%
Revenue Interest:		22.0%	22.0%

Period Beginning	Oil Production MMBbl	Oil Price US$/Bbl	Gas Production Bscf	Gas Price US$/Mscf	Field Revenue US$ MM	Contractor Revenue US$ MM	Capital Costs US$ MM	Operating Costs US$ MM	Bonus Payments US$ MM	Pre Tax NCF US$ MM	Other Taxes US$ MM	Corporate Tax US$ MM	Post Tax NCF US$ MM
Jan-21	0.754	49.68	1.04	2.96	40.55	17.25	2.23	4.21	-	10.81	-	-	10.81
Jan-22	0.575	52.30	0.74	2.96	32.29	13.73	2.60	3.65	-	7.49	-	-	7.49
Jan-23	0.358	55.30	0.40	2.96	20.99	8.93	1.83	2.92	-	4.18	-	-	4.18
Jan-24	0.263	58.30	0.24	2.96	16.07	6.83	0.09	2.62	-	4.12	-	-	4.12
Jan-25	0.205	59.50	0.15	2.96	12.64	5.38	0.16	2.45	-	2.76	-	-	2.76
Jan-26	0.178	60.72	0.11	2.96	11.14	4.74	-	2.40	-	2.34	-	-	2.34
Jan-27	0.154	61.97	0.09	2.96	9.83	4.18	-	2.35	-	1.83	-	-	1.83
Jan-28	0.161	63.25	0.04	2.96	10.32	4.39	-	2.29	-	2.10	-	-	2.10
Jan-29	0.160	64.54	-	2.96	10.35	4.40	-	2.33	-	2.07	-	-	2.07
Jan-30	0.127	65.87	-	2.96	8.33	3.54	-	2.23	-	1.31	-	-	1.31
Jan-31	0.102	67.22	-	2.96	6.84	2.91	-	2.17	-	0.74	-	-	0.74
Jan-32	0.083	68.60	-	2.96	5.71	2.43	-	2.13	-	0.29	-	-	0.29
Totals:	**3.122**	**MMBbl**	**2.82**	**Bscf**	**185.07**	**78.71**	**6.90**	**31.76**	**-**	**40.05**	**-**	**-**	**40.05**
Entitlements:	**1.328**	**MMBbl**	**1.20**	**Bscf**									

Notes:

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Gaffney Cline

Net UOG Interest Cashflow Analysis
Proved plus Probable plus Possible Case
Escalated Prices and Costs

Nominal Net Present Values as at 01-Jan-21 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	80.75	80.75
5.0%	66.50	66.50
7.5%	61.15	61.15
10.0%	56.63	56.63
12.5%	52.78	52.78
15.0%	49.46	49.46

Field:	Abu Sennan	
Case:	3P	
	Initial	*Final*
Working Interest:	22.0%	22.0%
Revenue Interest:	22.0%	22.0%

Period Beginning	Oil Production MMBbl	Oil Price US$/Bbl	Gas Production Bscf	Gas Price US$/Mscf	Field Revenue US$ MM	Contractor Revenue US$ MM	Capital Costs US$ MM	Operating Costs US$ MM	Bonus Payments US$ MM	Pre Tax NCF US$ MM	Other Taxes US$ MM	Corporate Tax US$ MM	Post Tax NCF US$ MM
Jan-21	1.030	49.68	1.66	2.96	56.10	23.86	3.17	5.19	0.33	15.17	-	-	15.17
Jan-22	0.876	52.30	1.42	2.96	50.02	21.27	3.90	4.73	-	12.64	-	-	12.64
Jan-23	0.663	55.30	1.07	2.96	39.83	16.94	5.17	4.04	-	7.73	-	-	7.73
Jan-24	0.598	58.30	0.82	2.96	37.29	15.86	0.09	3.88	-	11.89	-	-	11.89
Jan-25	0.478	59.50	0.60	2.96	30.24	12.55	0.09	3.50	-	8.97	-	-	8.97
Jan-26	0.392	60.72	0.47	2.96	25.16	8.31	-	3.23	-	5.08	-	-	5.08
Jan-27	0.343	61.97	0.39	2.96	22.43	7.03	-	3.10	-	3.93	-	-	3.93
Jan-28	0.297	63.25	0.28	2.96	19.61	5.47	-	2.98	-	2.49	-	-	2.49
Jan-29	0.255	64.54	0.22	2.96	17.10	5.02	-	2.86	-	2.16	-	-	2.16
Jan-30	0.249	65.87	0.17	2.96	16.88	5.02	0.08	2.89	-	2.05	-	-	2.05
Jan-31	0.226	67.22	0.14	2.96	15.62	4.82	-	2.85	-	1.97	-	-	1.97
Jan-32	0.198	68.60	0.07	2.96	13.79	4.51	-	2.79	-	1.72	-	-	1.72
Jan-33	0.166	70.01	0.02	2.96	11.70	4.15	-	2.70	-	1.45	-	-	1.45
Jan-34	0.159	71.44	-	2.96	11.37	4.12	-	2.72	-	1.40	-	-	1.40
Jan-35	0.128	72.90	-	2.96	9.31	3.64	-	2.47	-	1.17	-	-	1.17
Jan-36	0.106	74.39	-	2.96	7.91	3.36	-	2.42	-	0.94	-	-	0.94
Totals:	**6.165**	**MMBbl**	**7.33**	**Bscf**	**384.37**	**145.94**	**12.49**	**52.36**	**0.33**	**80.75**	**-**	**-**	**80.75**
Entitlements:	**2.361**	**MMBbl**	**2.90**	**Bscf**									

Notes:

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United Oil & Gas plc
April 2021

Gaffney Cline

Net UOG Interest Cashflow Analysis
Proved Developed Case
Escalated Prices and Costs

Nominal Net Present Values as at 01-Jan-21 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	15.88	15.88
5.0%	14.82	14.82
7.5%	14.35	14.35
10.0%	13.92	13.92
12.5%	13.52	13.52
15.0%	13.14	13.14

Field:	Abu Sennan	
Case:	1P Developed	
	Initial	***Final***
Working Interest:	22.0%	22.0%
Revenue Interest:	22.0%	22.0%

Period Beginning	Oil Production MMBbl	Oil Price US$/Bbl	Gas Production Bscf	Gas Price US$/Mscf	Field Revenue US$ MM	Contractor Revenue US$ MM	Capital Costs US$ MM	Operating Costs US$ MM	Bonus Payments US$ MM	Pre Tax NCF US$ MM	Other Taxes US$ MM	Corporate Tax US$ MM	Post Tax NCF US$ MM
Jan-21	0.501	49.68	0.58	2.96	26.62	11.32	0.07	3.31	-	7.94	-	-	7.94
Jan-22	0.286	52.30	0.20	2.96	15.53	6.61	-	2.60	-	4.00	-	-	4.00
Jan-23	0.179	55.30	0.07	2.96	10.07	4.28	0.07	2.26	-	1.95	-	-	1.95
Jan-24	0.129	58.30	0.04	2.96	7.64	3.25	-	2.12	-	1.13	-	-	1.13
Jan-25	0.095	59.50	0.03	2.96	5.75	2.44	-	2.03	-	0.41	-	-	0.41
Jan-26	0.091	60.72	0.00	2.96	5.56	2.36	-	1.93	-	0.44	-	-	0.44
Totals:	**1.281**	**MMBbl**	**0.91**	**Bscf**	**71.17**	**30.27**	**0.13**	**14.26**	**-**	**15.88**	**-**	**-**	**15.88**
Entitlements:	**0.545**	**MMBbl**	**0.39**	**Bscf**									

Notes:

1. Cashflows are shown up to Economic Limit only.
2. Entitlements are UOG's Net Entitlement Reserves as per the PSC terms, i.e. UOG's share of the Cost Oil plus Profit Oil (up to the Economic Limit).
3. The Proved and Proved Developed cases are identical as there are no Proved Undeveloped Reserves.

Gaffney Cline

Net UOG Interest Cashflow Analysis
Proved plus Probable Developed Case
Escalated Prices and Costs

Nominal Net Present Values as at 01-Jan-21 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	31.48	31.48
5.0%	27.65	27.65
7.5%	26.10	26.10
10.0%	24.74	24.74
12.5%	23.54	23.54
15.0%	22.47	22.47

Field:	**Abu Sennan**	
Case:	2P Developed	
	Initial	***Final***
Working Interest:	22.0%	22.0%
Revenue Interest:	22.0%	22.0%

Period Beginning	Oil Production MMBbl	Oil Price US$/Bbl	Gas Production Bscf	Gas Price US$/Mscf	Field Revenue US$ MM	Contractor Revenue US$ MM	Capital Costs US$ MM	Operating Costs US$ MM	Bonus Payments US$ MM	Pre Tax NCF US$ MM	Other Taxes US$ MM	Corporate Tax US$ MM	Post Tax NCF US$ MM
Jan-21	0.593	49.68	0.80	2.96	31.82	13.53	0.22	3.64	-	9.68	-	-	9.68
Jan-22	0.410	52.30	0.51	2.96	22.96	9.77	-	3.05	-	6.71	-	-	6.71
Jan-23	0.276	55.30	0.30	2.96	16.13	6.86	-	2.62	-	4.24	-	-	4.24
Jan-24	0.207	58.30	0.16	2.96	12.52	5.32	-	2.41	-	2.91	-	-	2.91
Jan-25	0.168	59.50	0.11	2.96	10.32	4.39	0.07	2.31	-	2.01	-	-	2.01
Jan-26	0.141	60.72	0.08	2.96	8.79	3.74	-	2.25	-	1.49	-	-	1.49
Jan-27	0.120	61.97	0.07	2.96	7.66	3.26	-	2.21	-	1.04	-	-	1.04
Jan-28	0.124	63.25	0.03	2.96	7.95	3.38	-	2.14	-	1.24	-	-	1.24
Jan-29	0.126	64.54	-	2.96	8.13	3.46	-	2.19	-	1.27	-	-	1.27
Jan-30	0.099	65.87	-	2.96	6.53	2.78	-	2.12	-	0.66	-	-	0.66
Jan-31	0.081	67.22	-	2.96	5.42	2.31	-	2.08	-	0.22	-	-	0.22
Totals:	**2.345**	**MMBbl**	**2.06**	**Bscf**	**138.23**	**58.79**	**0.29**	**27.02**	**-**	**31.48**	**-**	**-**	**31.48**
Entitlements:	**0.997**	**MMBbl**	**0.87**	**Bscf**									

Notes:

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Gaffney Cline

Net UOG Interest Cashflow Analysis
Proved plus Probable plus Possible Developed Case
Escalated Prices and Costs

Nominal Net Present Values as at 01-Jan-21 (US$ MM)		
Disc Rate	Pre-Tax	Post-Tax
0.0%	51.53	51.53
5.0%	43.26	43.26
7.5%	40.10	40.10
10.0%	37.41	37.41
12.5%	35.11	35.11
15.0%	33.10	33.10

Field:	**Abu Sennan**	
Case:	3P Developed	
	Initial	***Final***
Working Interest:	22.0%	22.0%
Revenue Interest:	22.0%	22.0%

Period Beginning	Oil Production MMBbl	Oil Price US$/Bbl	Gas Production Bscf	Gas Price US$/Mscf	Field Revenue US$ MM	Contractor Revenue US$ MM	Capital Costs US$ MM	Operating Costs US$ MM	Bonus Payments US$ MM	Pre Tax NCF US$ MM	Other Taxes US$ MM	Corporate Tax US$ MM	Post Tax NCF US$ MM
Jan-21	0.679	49.68	1.05	2.96	36.82	15.66	0.22	3.94	-	11.50	-	-	11.50
Jan-22	0.545	52.30	0.81	2.96	30.87	13.13	-	3.54	-	9.59	-	-	9.59
Jan-23	0.385	55.30	0.55	2.96	22.94	9.76	-	3.02	-	6.74	-	-	6.74
Jan-24	0.285	58.30	0.41	2.96	17.84	7.59	-	2.71	-	4.88	-	-	4.88
Jan-25	0.229	59.50	0.33	2.96	14.58	6.20	-	2.54	-	3.66	-	-	3.66
Jan-26	0.191	60.72	0.27	2.96	12.37	5.26	-	2.44	-	2.82	-	-	2.82
Jan-27	0.182	61.97	0.25	2.96	12.00	5.09	-	2.46	-	2.64	-	-	2.64
Jan-28	0.167	63.25	0.18	2.96	11.07	4.67	-	2.45	-	2.22	-	-	2.22
Jan-29	0.152	64.54	0.14	2.96	10.24	4.33	-	2.44	-	1.90	-	-	1.90
Jan-30	0.139	65.87	0.13	2.96	9.52	4.04	0.08	2.43	-	1.53	-	-	1.53
Jan-31	0.126	67.22	0.11	2.96	8.80	3.74	-	2.42	-	1.32	-	-	1.32
Jan-32	0.120	68.60	0.05	2.96	8.39	3.57	-	2.44	-	1.12	-	-	1.12
Jan-33	0.106	70.01	0.01	2.96	7.42	3.16	-	2.43	-	0.73	-	-	0.73
Jan-34	0.095	71.44	-	2.96	6.81	2.90	-	2.43	-	0.47	-	-	0.47
Jan-35	0.082	72.90	-	2.96	5.98	2.55	-	2.26	-	0.29	-	-	0.29
Jan-36	0.076	74.39	-	2.96	5.67	2.41	-	2.28	-	0.14	-	-	0.14
Totals:	**3.558**	**MMBbl**	**4.28**	**Bscf**	**221.33**	**94.05**	**0.30**	**42.22**	**-**	**51.53**	**-**	**-**	**51.53**
Entitlements:	**1.512**	**MMBbl**	**1.82**	**Bscf**									

Notes:

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2. Entitlements are UOG's Net Entitlement Reserves as per the PSC terms, i.e. UOG's share of the Cost Oil plus Profit Oil (up to the Economic Limit).

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