22 March 2019

Mr Paul Welch
Chief Executive Officer
SDX Energy Inc
38 Welbeck Street,
London,
W1G 8DP,
United Kingdom

Dear Mr Welch,

RE: P4579 December 31, 2018 Reserves and Resources Audit, SDX Energy Inc.

ERC Equipoise Limited (ERCE) has completed an independent Reserves audit and evaluation of certain oil and gas properties of SDX Energy Inc. (the "Company" or "SDX"). The effective date of the evaluation is December 31, 2018. ERCE also assessed certain Contingent and Prospective Resources within the SDX portfolio.

As per the requirements of Canadian regulations NI 51-101 and the June 2009 AIM Note for Mining, Oil and Gas Companies, this report has been prepared for the Company for the purpose of disclosure in accordance with Reserves and resources definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook, published by the Society of Petroleum Evaluation Engineers Calgary Chapter (formerly published by the Canadian Institute of Mining, Metallury and Petroleum).

It was ERCE's mandate in this evaluation to provide independent economic evaluation of the oil and gas properties at the aggregated level of the production/mining license. Accordingly, it may not be appropriate to extract individual property or entity estimates for other purposes.

We trust that this evaluation meets your current requirements. Should you have any questions regarding this analysis, please contact the undersigned.

Sincerely,

Paul Chernik
Director, ERC Equipoise Limited

SDX Energy, Year End 2018 Reserves and Resources Report

Effective 31 December 2018

Prepared For: SDX Energy

By: ERCE, Rev 1

Date: 21 March 2019

ERCE
Independent Energy Experts

Approved By: Paul Chernik

Date Released to Client: 22 March 2019

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1. Independent Petroleum Consultant's Consent

ERC Equipoise Limited ("ERCE"), an Independent Petroleum Consultancy based in Croydon, London, United Kingdom has prepared an audit of the Reserves and Resources belonging to SDX Energy Inc. ("SDX") in certain of their Egypt and Morocco oil and gas properties and hereby gives consent to the use of its name to the said estimates. The effective date of the evaluation is December 31, 2018.

As advised by SDX Energy, as at the publication date of the 22 March 2019 of this Competent Persons Report ("CPR"), no material change has occurred since the Effective Date, other than production in the ordinary course. This includes, inter alia, no material change to the Reserve and Resource statements or the technical information as reported in this CPR.

ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this CPR and ERCE will receive no other benefit for the preparation of this CPR. ERCE does not have any pecuniary or other interests that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the Reserves and Resources, opined upon by ERCE and reported herein.

Neither ERCE nor the Competent Persons who are responsible for authoring this CPR, nor any directors of ERCE have at the date of this report, nor have had within the previous two years, any shareholding in the Company, the oil and gas properties reported on in this report or any other economic or beneficial interest (present or contingent) in any of the assets being reported on. None of ERCE's partners or officers are officers or employees or proposed officers of any group, holding or associated company of the Company.

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

In the course of the audit, SDX provided ERCE personnel with information as detailed in Section 2.6. Other engineering, geological or economic data required to conduct the evaluation and upon which this report is based, were obtained from public records and from ERCE non-confidential files. SDX has provided a representation letter confirming that all information provided to ERCE is correct and complete to the best of its knowledge. Procedures recommended in the Canadian Oil and Gas Evaluation Handbook ("COGEH") to verify certain interests and financial information were applied in this audit. A full text of COGEH is available at https://speecanada.org/.

In applying these procedures and tests, nothing came to the attention of ERCE that would suggest that information provided by SDX was not complete and accurate. ERCE Reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this report.

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

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

In the Case of Contingent Resources presented in this report, there is no certainty that it will be commercially viable to produce any portion of the resources.

In the case of undiscovered Resources (Prospective Resources) presented in this report, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the Resources.

No site visit was undertaken in the generation of this report.

2. Summary

2.1. Introduction

SDX Energy Inc. ("SDX") requested ERCE to carry out an audit (the "Audit") of SDX's estimates of crude oil, natural gas and natural gas liquid ("NGL") Reserves and Resource estimates and associated future net revenue of the Reserves with an effective date of December 31, 2018.

The Audit involved certain of SDX's assets in Egypt and Morocco. In Egypt this included SDX's interests in the West Gharib Block H, South Disouq and North West Gemsa concessions. In Morocco this included the Sebou, Gharb Centre and Lalla Mimouna Nord concessions. A summary of the concessions is presented in Table 2.1. This document summarises the Reserves, Contingent Resource and Prospective Resource estimates audited by ERCE for these assets. The Audit was prepared during the period from January to March 2019 and was based on technical and financial data to the end of December 2018.

Reserves and Resources have been prepared in accordance with standards set out in the AIM 2009 listing Guidelines applying the standards of the Canadian Oil and Gas Evaluation Handbook ("COGEH").

Table 2.1: Summary of SDX's audited assets

Country	Operator	Asset (Concession)	Field(s)	Status	SDX Working Interest	Expiry Date	Contract Area (km2)	Comments & Outstanding Commitments
Egypt	North Petroleum International Corporation	North West Gemsa	Al Amir SE, Al Ola, Geyad	Development	50%	(i) Al Amir 17-Nov-28 (ii) Geyad 11-Aug-29 (iii) Al Ola 4-Jan-31	83	n/a
Egypt	Dublin Petroleum Limited	West Gharib Block H	Meseda, Rabul	Development	50%	(i) Meseda 9-Nov-21[1] (ii) South H 23-Dec-23	22	n/a
Egypt	SDX	South Disouq	South Disouq	Exploration/ Development	55%	(i) Exploration 18-Mar-20 (ii) Development 2-Jan-39	828	n/a
Morocco	SDX	Sebou	-	Exploration	75%	08/09/2021[2]	210	n/a
Morocco	SDX	Lalla Mimouna Nord	-	Exploration	75%	22/07/2020[2]	1,371	n/a
Morocco	SDX	Gharb Centre	-	Exploration	75%	08/09/2021[2]	1,343	1 Expl. Well
Morocco	SDX	Ksiri Centre	Ksiri	Production	75%	09-Jan-25	7.20	n/a
Morocco	SDX	Sid Al Harati SW	Sidi Al Harati SW	Production	75%	06-Oct-23	0.75	n/a
Morocco	SDX	Sidi Al Harati West	-	Production	75%	11-Oct-24	0.24	n/a
Morocco	SDX	Gaddari S	Gaddari S	Production	75%	09-Jan-20	1.80	n/a

1. *ERCE has assumed a 10 year license extension will be granted in the evaluation of Reserves*
2. *End of Current Contract for the Morocco exploration concessions includes the extension periods which are then also reflected in the outstanding commitments.*

Reserves are reported as Gross Field Reserves and both as SDX Working Interest Reserves and Net Entitlement Reserves. Gross Field Reserves are 100% of the volumes estimated to be economically recoverable from the fields as of December 31, 2018. SDX Working Interest Reserves are SDX's

Working Interest portion of the Gross Field Reserves. In Morocco, where licence blocks are governed by tax/royalty terms, SDX's Net Entitlement Reserves are equal to SDX Working Interest portion of Gross Field Reserves minus royalties. In Egypt, the West Gharib Block H is governed by a production service agreement and SDX's Net Entitlement Reserves are based on their share of the service fees payable. The remaining Egyptian assets are covered by production sharing arrangements and SDX's Net Entitlement Reserves are based on their share of the cost petroleum and the profit petroleum; in addition, as income tax is paid on behalf of SDX by the Government, ERCE has included the volumetric equivalent as Net Entitlement Reserves.

For those fields in production, historical production data were available to ERCE up to the end of December 2018. Volumes of oil and gas shown in this report are quoted at stock tank, or standard conditions of pressure (14.65 psia) and temperature (60 deg F).

In the estimates of Net Present Value presented in this document ERCE has used the pricing and foreign exchanges assumptions presented in Table 2.2 and Table 2.3.

Table 2.2: ERCE Nominal Hydrocarbon Price Assumptions

Year	Brent Crude Oil Price $US/bbl	W Gharib Oil Price $US/bbl	NW Gemsa Oil & NGL Price $US/bbl	NW Gemsa Cost Gas Price $US/Mscf	NW Gemsa Profit Gas Price $US/Mscf	S Disouq Cond. Price $US/bbl	S Disouq Gas Price $US/Mscf	Sebou Gas Price $US/Mscf	Inflation Forecast %
2019	67	49	62	1.60	1.00	67	2.85	10.00	2.0
2020	70	52	65	1.60	1.00	70	2.85	10.09	2.0
2021	71	53	66	1.60	1.00	71	2.85	10.13	2.0
2022	74	55	69	1.60	1.00	74	2.85	10.43	2.0
2023	75	56	70	1.60	1.00	75	2.85	10.69	2.0
2024	78	58	73	1.60	1.00	78	2.85	11.44	2.0
2025	80	59	74	1.60	1.00	80	2.85	11.44	2.0
2026	81	60	76	1.60	1.00	81	2.85	11.44	2.0
2027	83	61	77	1.60	1.00	83	2.85	11.44	2.0
2028	84	63	79	1.60	1.00	84	2.85	11.44	2.0
2029	86	64	80	1.60	1.00	86	2.85	11.44	2.0
2030	88	65	82	1.60	1.00	88	2.85	11.44	2.0
2031	90	66	83	1.60	1.00	90	2.85	11.44	2.0
2032	91	68	85	1.60	1.00	91	2.85	11.44	2.0
2033	93	69	87	1.60	1.00	93	2.85	11.44	2.0
2034	95	70	88	1.60	1.00	95	2.85	11.44	2.0
2035	97	72	90	1.60	1.00	97	2.85	11.44	2.0
2036	99	73	92	1.60	1.00	99	2.85	11.44	2.0
2037	101	75	94	1.60	1.00	101	2.85	11.44	2.0
2038	103	76	96	1.60	1.00	103	2.85	11.44	2.0

1. *Brent price forecast based on the ERCE 1 January 2019 price forecast*
2. *South Disouq gas price is subject to negotiation as part of a gas sales agreement but the forecast price is considered by SDX to be a minimum achievable price.*
3. *Sebou gas price is a volume weighted average gas price based on signed gas sales agreements*
4. *W Gharib and NW Gemsa crude oil prices are based on historical sales differentials*

Table 2.3: ERCE Foreign Exchange Assumptions

Exchange Rate Assumptions	Rate
US$/MAD	0.105

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

The Reserves estimates reported for West Gharib Block H relate to continued production and various development activities in the Meseda and Rabul fields. The crude oil product type, as defined by the COGE Handbook, is heavy oil.

The Reserves estimates reported for the North West Gemsa concession relate to continued production and various development activities in the Al Amir South East, Al Ola and Geyad fields. The product type for all the fields is light crude oil.

The Reserves estimates reported for the South Disouq concession relate to the field development of an Abu Madi gas-condensate discovery made by Well SD-1X during 2017 and the development of two Kafr El Sheikh (KES) discoveries made by Well SD-3X and Well Ibn Yunus-1X in 2018.

The Reserves estimates reported for the assets in Morocco are associated with existing production wells in the Sebou area concessions (Ksiri, Sidi Al Harati South West and Gaddari South).

In addition to the discoveries, this report details Contingent and Prospective resources in Morocco and Egypt. In Morocco, drilling in the Lalla Mimouna Nord has encountered gas in the Upper Dlalha and H9 Miocene sands. Following on these discoveries, SDX has identified a number of new prospects, in addition to the prospects in plays previously reported in the Sebou, Lalla Mimouna Nord and Gharb Centre areas.

In Egypt, within the South Disouq concession a number of prospects have been identified at the Abu Madi and KES intervals. In addition, there are Contingent Resources associated with the producing Meseda and Rabul fields.

2.2. Reserves Summary

There is no assurance that the forecast production and cost profiles contained in this report will be attained and variances could be material. The recovery and estimates of the company's oil and natural gas Reserves are estimates only and there is no guarantee that the estimated Reserves will be recovered. Actual volumes recovered may be greater than or less than the estimates stated in this report. ERCE has adopted the standard measure of six thousand standard cubic feet (6 Mscf) to one stock tank barrel (1 stb) when converting natural gas to barrels of oil equivalent or boe.

The tables below summarise the oil and gas Reserves by country at the 1P, 2P and 3P levels of uncertainty.

A summary of Reserves by asset is shown below in Table 2.4 and Table 2.5.

Table 2.4: Oil & Liquids Reserves Per Asset

Country	Concession	Gross			Gross WI (Net Attributable)			Net Entitlement			Operator
		Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
		Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	
Egypt	North West Gemsa	1,885	2,737	4,008	943	1,369	2,004	485	704	1,032	North Petroleum
Egypt	West Gharib Block H	5,427	9,113	12,197	2,713	4,556	6,099	1,038	1,743	2,329	Dublin Petroleum
Egypt	South Disouq	279	414	564	154	228	310	90	134	183	SDX
	Total for Oil + Liquids	**7,591**	**12,264**	**16,770**	**3,810**	**6,153**	**8,413**	**1,614**	**2,581**	**3,544**	

Table 2.5: Gas Reserves Per Asset

Country	Concession	Gross			Gross WI (Net Attributable)			Net Entitlement			Operator
		Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
		MMscf	MMscf	MMscf	Mbbl	Mbbl	Mbbl	MMscf	MMscf	MMscf	
Egypt	North West Gemsa	2,275	3,302	4,836	1,137	1,651	2,418	617	896	1,312	North Petroleum
Egypt	South Disouq	46,302	63,150	81,905	25,466	34,732	45,048	14,376	19,607	25,430	SDX
Morocco	Ksiri Centre, Gaddari South Sidi al Harati South West, Sidi Al Harati West and Oulad N'Zala Central	2,838	5,096	8,604	2,129	3,822	6,453	2,029	3,641	6,144	SDX
	Total for Gas	**51,414**	**71,548**	**95,345**	**28,732**	**40,206**	**53,918**	**17,022**	**24,144**	**32,886**	

A summary of SDX's crude oil, natural gas and NGL Reserves are presented in Table 2.6, Table 2.7 and Table 2.8 respectively on a country and total basis.

Table 2.6: SDX Energy - Crude Oil Reserves Summary as of December 31, 2018

Crude Oil Reserves as of 31 December 2018 Country/Reserve Category	SDX Gross WI Mbbl	SDX Net Entitlement Mbbl
Egypt		
Proved Producing Reserves	3,138	1,317
Proved Developed Reserves	3,624	1,511
Proved Undeveloped Reserves	14	4
Total Proved Reserves	3,639	1,514
Proved + Probable Reserves	5,900	2,434
Proved + Probable + Possible Reserves	8,066	3,342
Morocco		
Proved Producing Reserves	-	-
Proved Developed Reserves	-	-
Proved Undeveloped Reserves	-	-
Total Proved Reserves	-	-
Proved + Probable Reserves	-	-
Proved + Probable + Possible Reserves	-	-
Total		
Proved Producing Reserves	3,138	1,317
Proved Developed Reserves	3,624	1,511
Proved Undeveloped Reserves	14	4
Total Proved Reserves	**3,639**	**1,514**
Proved + Probable Reserves	**5,900**	**2,434**
Proved + Probable + Possible Reserves	**8,066**	**3,342**

Table 2.7: SDX Energy - Natural Gas Reserves Summary as of December 31, 2018

Natural Gas Reserves as of 31 December 2018 Country/Reserve Category	SDX Gross WI MMscf	SDX Net Entitlement MMscf
Egypt		
Proved Producing Reserves	1,094	593
Proved Developed Reserves	1,137	617
Proved Undeveloped Reserves	25,466	14,376
Total Proved Reserves	26,603	14,993
Proved + Probable Reserves	36,384	20,503
Proved + Probable + Possible Reserves	47,466	26,742
Morocco		
Proved Producing Reserves	1,662	1,588
Proved Developed Reserves	2,129	2,029
Proved Undeveloped Reserves	-	-
Total Proved Reserves	2,129	2,029
Proved + Probable Reserves	3,822	3,641
Proved + Probable + Possible Reserves	6,453	6,144
Total		
Proved Producing Reserves	2,756	2,181
Proved Developed Reserves	3,266	2,646
Proved Undeveloped Reserves	25,466	14,376
Total Proved Reserves	**28,732**	**17,022**
Proved + Probable Reserves	**40,206**	**24,144**
Proved + Probable + Possible Reserves	**53,918**	**32,886**

Table 2.8: SDX Energy - NGL Reserves Summary as of December 31, 2018

Natural Gas Liquid Reserves as of 31 December 2018 Country/Reserve Category	SDX Gross WI Mbbl	SDX Net Entitlement Mbbl
Egypt		
Proved Producing Reserves	16	8
Proved Developed Reserves	18	9
Proved Undeveloped Reserves	154	90
Total Proved Reserves	171	99
Proved + Probable Reserves	253	147
Proved + Probable + Possible Reserves	348	202
Morocco		
Proved Producing Reserves	-	-
Proved Developed Reserves	-	-
Proved Undeveloped Reserves	-	-
Total Proved Reserves	-	-
Proved + Probable Reserves	-	-
Proved + Probable + Possible Reserves	-	-
Total		
Proved Producing Reserves	16	8
Proved Developed Reserves	18	9
Proved Undeveloped Reserves	154	90
Total Proved Reserves	**171**	**99**
Proved + Probable Reserves	**253**	**147**
Proved + Probable + Possible Reserves	**348**	**202**

2.3. Net Present Value Summary

A summary of SDX's net present values in millions of US dollars are presented in Table 2.9 as of December 31, 2018 on a before and an after-tax basis.

Table 2.9: SDX Energy – Summary of Net Present Values as of December 31, 2018

	NPVs Before Income Taxes $MM US Dollars					NPVs After Income Taxes $MM US Dollars				
Country/Reserve Category	0.0%	5.0%	10.0%	15.0%	20.0%	0.0%	5.0%	10.0%	15.0%	20.0%
Egypt										
Proved Producing Reserves	34	33	32	32	31	31	29	27	25	24
Proved Developed Reserves	38	37	36	35	34	34	31	28	26	25
Proved Undeveloped Reserves	11	10	8	7	6	11	10	9	8	7
Total Proved Reserves	49	47	44	42	41	45	41	37	34	32
Proved + Probable Reserves	97	91	87	82	79	87	76	67	60	55
Proved + Probable + Possible Reserves	151	141	133	126	119	134	115	100	89	80
Morocco										
Proved Producing Reserves	10	10	10	10	9	10	10	10	10	9
Proved Developed Reserves	15	14	14	14	13	15	14	14	14	13
Proved Undeveloped Reserves	-	-	-	-	-	-	-	-	-	-
Total Proved Reserves	15	14	14	14	13	15	14	14	14	13
Proved + Probable Reserves	30	29	27	26	25	30	29	27	26	25
Proved + Probable + Possible Reserves	52	48	45	42	40	52	48	45	42	40
Total										
Proved Producing Reserves	45	44	42	41	40	41	39	37	35	33
Proved Developed Reserves	53	52	50	49	47	49	45	42	40	38
Proved Undeveloped Reserves	11	10	8	7	6	11	10	9	8	7
Total Proved Reserves	**64**	**61**	**58**	**56**	**54**	**59**	**55**	**51**	**48**	**45**
Proved + Probable Reserves	**127**	**120**	**114**	**109**	**104**	**116**	**104**	**95**	**87**	**80**
Proved + Probable + Possible Reserves	**202**	**189**	**178**	**168**	**159**	**186**	**163**	**145**	**131**	**120**

1. *Based on forecast prices and costs as of 1 January 2019 (see Table 2.2).*
2. *Interest expenses, corporate overheads etc were not included.*
3. *The net present values may not represent the fair market value of the Reserves.*

2.4. Contingent Resources Summary

Contingent Resources for Morocco and Egypt are presented in Table 2.10 and Table 2.11.

Table 2.10: SDX Energy – Morocco Gas Contingent Resources as of December 31, 2018

Permit	Discovery	Gross Contingent Gas Resources (Bscf)			SDX Working Interest	Net Attributable Contingent Gas Resources (Bscf)			Risk Factor (COD)	Net Risked Attributable Contingent Gas Resources (Bscf)			Sub-Classification	Operator
		1C	2C	3C		1C	2C	3C		1C	2C	3C		
LAM	LMS-1	2.24	3.43	5.24	75%	1.68	2.57	3.93	100%	1.68	2.57	3.93	On-Hold	SDX
	LNB-1_Upper	0.07	0.15	0.31	75%	0.05	0.11	0.24	22%	0.01	0.02	0.05	On-Hold	SDX
	Total for Gas	**2.31**	**3.57**	**5.55**		**1.73**	**2.68**	**4.17**		**1.69**	**2.59**	**3.98**		

1. *Net Attributable unrisked Contingent Resources are based on the working interest share of the field gross resources and do not represent the net entitlement resources.*
2. *In the case of Contingent Resources, the Chance of Development (" COD") is the chance of commerciality.*
3. *Quantifying the COD requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are out with the expertise of ERCE they must be used with caution.*
4. *Net risked Contingent Resources are the product of the unrisked resources and the chance of commerciality.*

Table 2.11: SDX Energy – Egypt Oil Contingent Resources as of December 31, 2018

Concession	Field	Gross Contingent Oil Resources (Mbbl)			SDX Working Interest	Net Attributable Contingent Oil Resources (Mbbl)			Risk Factor (COD)	Net Risked Attributable Contingent Oil Resources (Mbbl)			Sub-Classification	Operator
		1C	2C	3C		1C	2C	3C		1C	2C	3C		
West Gharib Block H	Meseda	151	473	750	50%	76	236	375	90%	68	213	337	On-Hold	Dublin
West Gharib Block H	Rabul	128	287	634	50%	64	144	317	90%	58	129	286	On-Hold	Dublin
	Total for Oil	**279**	**760**	**1,384**		**140**	**380**	**692**		**126**	**342**	**623**		

1. *Net Attributable unrisked Contingent Resources are based on the working interest share of the field gross resources and do not represent the net entitlement resources.*
2. *In the case of Contingent Resources, the Chance of Development (" COD") is the chance of commerciality.*
3. *Quantifying the COD requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are out with the expertise of ERCE they must be used with caution.*
4. *Net risked Contingent Resources are the product of the unrisked resources and the chance of commerciality.*

2.5. Prospective Resources Summary

Crude oil, natural gas and natural gas liquids (condensate) Prospective Resources are presented in Table 2.12 through Table 2.14.

Table 2.12: SDX Energy – Egypt Crude Oil Prospective Resources Summary as of December 31, 2018

Prospect	Gross Unrisked Oil Prospective Resources (MMbbl)			SDX Working Interest	Net Unrisked Attributable Oil Resources (MMbbl)			gCOS	COD	Net Risked Attributable Oil Resources (MMbbl)			Operator
	1U	2U	3U		1U	2U	3U			1U	2U	3U	
Young	2.3	13.5	54.4	55%	1.3	7.4	29.9	32%	85%	0.35	2.04	8.23	SDX

1. *Gross unrisked Prospective Resources are the probabilistic aggregation of individual reservoirs incorporating dependencies (see* Table 4.21*)*
2. *Net unrisked Prospective Resources are based on the working interest share of the field gross resources and do not represent the net entitlement resources.*
3. *gCOS is the chance of geological success and COD is the chance of development. The product of gCOS x COD is the chance of commerciality.*
4. *Quantifying the COD requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are out with the expertise of ERCE they must be used with caution.*
5. *Net risked Prospective Resources are the product of the unrisked resources and the chance of commerciality.*
6. *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.*

Table 2.13: SDX Energy – Egypt Natural Gas Prospective Resources Summary as of December 31, 2018

Prospect	Gross Unrisked Gas Prospective Resources (Bscf)			SDX Working Interest	Net Unrisked Attributable Gas Resources (Bscf)			gCOS	COD	Net Risked Attributable Gas Resources (Bscf)			Operator
	1U	2U	3U		1U	2U	3U			1U	2U	3U	
Salah	30.2	75.4	184.6	55%	16.6	41.5	101.5	29%	100%	4.78	11.94	29.23	SDX
Shikabala	6.4	16.4	41.7		3.5	9.0	22.9	52%	100%	1.84	4.68	11.88	SDX
Hadary	1.7	3.3	5.8		1.0	1.8	3.2	52%	80%	0.39	0.75	1.32	SDX
Sobhi	5.7	17.1	50.4		3.1	9.4	27.7	35%	100%	1.10	3.31	9.79	SDX
Mohsen	21.3	40.7	78.6		11.7	22.4	43.2	30%	100%	3.54	6.77	13.08	SDX
Samir	3.9	10.3	26.5		2.1	5.7	14.6	25%	100%	0.54	1.43	3.67	SDX
Kahraba	6.0	15.7	40.7		3.3	8.6	22.4	25%	100%	0.84	2.18	5.64	SDX
Elneny	3.2	7.9	19.6		1.8	4.3	10.8	14%	100%	0.25	0.62	1.55	SDX
Newton	2.5	6.7	11.9		1.4	3.7	6.6	36%	100%	0.49	1.32	2.35	SDX
Determinstic Total	**80.9**	**193.4**	**459.8**		**44.5**	**106.4**	**252.9**			**13.8**	**33.0**	**78.5**	

1. *Net unrisked Attributable Prospective Resources are based on the working interest share of the field gross resources and do not represent the net entitlement resources.*
2. *COS is the chance of geological success and COD is the chance of development. The product of COS x COD is the chance of commerciality.*
3. *Quantifying the COD requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are out with the expertise of ERCE they must be used with caution.*
4. *Net risked Attributable Prospective Resources are the product of the unrisked resources and the chance of commerciality.*
5. *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.*

Table 2.14: SDX Energy – Egypt NGL Prospective Resources Summary as of December 31, 2018

Prospect	Unrisked Prospective Condensate Resources (MMbbl)			SDX Working Interest	Net Unrisked Attributable Condensate Resources (MMbbl)			gCOS	COD	Net Risked Attributable Condensate Resources (MMbbl)			Operator
	1U	2U	3U		1U	2U	3U			1U	2U	3U	
Salah	0.39	1.03	2.68	55%	0.21	0.57	1.47	29%	100%	0.06	0.16	0.42	SDX
Shikabala	0.08	0.22	0.59		0.04	0.12	0.33	52%	100%	0.02	0.06	0.17	SDX
Hadary	0.02	0.04	0.09		0.01	0.02	0.05	52%	80%	0.00	0.01	0.02	SDX
Sobhi	0.07	0.23	0.72		0.04	0.13	0.40	35%	100%	0.01	0.05	0.14	SDX
Mohsen	0.26	0.56	1.15		0.14	0.31	0.64	30%	100%	0.04	0.09	0.19	SDX
Samir	0.05	0.14	0.38		0.03	0.08	0.21	25%	100%	0.01	0.02	0.05	SDX
Kahraba	0.08	0.21	0.57		0.04	0.12	0.32	25%	100%	0.01	0.03	0.08	SDX
Elneny	0.04	0.11	0.28		0.02	0.06	0.15	14%	100%	0.00	0.01	0.02	SDX
Newton	0.01	0.03	0.06		0.01	0.02	0.03	36%	100%	0.00	0.01	0.01	SDX
Determinstic Total	**1.01**	**2.59**	**6.53**		**0.55**	**1.42**	**3.59**			**0.17**	**0.44**	**1.11**	

1. *Net unrisked Attributable Prospective Resources are based on the working interest share of the field gross resources and do not represent the net entitlement resources.*
2. *COS is the chance of geological success and COD is the chance of development. The product of COS x COD is the chance of commerciality.*
3. *Quantifying the COD requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are out with the expertise of ERCE they must be used with caution.*
4. *Net risked Attributable Prospective Resources are the product of the unrisked resources and the chance of commerciality.*
5. *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.*

Table 2.15 SDX Energy – Morocco Natural Gas Prospective Resources Summary as of 31 December 2018

Prospect	Gross Unrisked Gas Prospective Resources (Bscf)			SDX Working Interest	Net Unrisked Attributable Gas Resources (Bscf)			gCOS	COD	Net Risked Attributable Gas Resources (Bscf)			Operator
	1U	2U	3U		1U	2U	3U			1U	2U	3U	
LTO_2_AAA	0.23	0.62	1.66	75%	0.17	0.47	1.25	34%	100%	0.06	0.16	0.42	SDX
LTU_AAA	0.27	1.14	4.76	75%	0.20	0.85	3.57	34%	100%	0.07	0.29	1.20	SDX
LTU_AAB	0.45	1.41	4.39	75%	0.34	1.06	3.29	28%	100%	0.09	0.30	0.92	SDX
LTU_AAC	0.28	0.98	3.46	75%	0.21	0.73	2.60	28%	100%	0.06	0.21	0.73	SDX
LTU_AAD_Upper	0.09	0.26	0.78	75%	0.07	0.20	0.59	56%	85%	0.03	0.09	0.28	SDX
LTU_AAD_Lower	0.11	0.27	0.65	75%	0.09	0.20	0.49	44%	85%	0.03	0.08	0.18	SDX
DOB_AAC_Upper	0.10	0.31	1.00	75%	0.07	0.23	0.75	28%	100%	0.02	0.07	0.21	SDX
DOB_AAC_Lower	0.21	0.62	1.85	75%	0.16	0.47	1.38	34%		0.05	0.16	0.47	SDX
DOB_AAD_Upper	0.16	0.39	0.97	75%	0.12	0.29	0.73	34%	90%	0.04	0.09	0.22	SDX
DOB_AAD_Lower	0.07	0.21	0.64	75%	0.05	0.16	0.48	56%		0.03	0.08	0.24	SDX
DOB_AAG	0.16	0.61	2.38	75%	0.12	0.46	1.78	56%	80%	0.05	0.21	0.80	SDX
DOB_AAH	0.15	0.66	2.97	75%	0.11	0.50	2.22	56%	80%	0.05	0.22	1.00	SDX
DOB_AAI	0.34	0.82	1.93	75%	0.26	0.61	1.45	34%	100%	0.09	0.21	0.49	SDX
DOB_AAS_Upper	0.24	0.71	2.15	75%	0.18	0.54	1.61	44%	100%	0.08	0.24	0.71	SDX
DOB_AAS_Lower	0.26	0.83	2.69	75%	0.19	0.62	2.02	44%		0.08	0.27	0.89	SDX
DRC_AAB	0.82	2.23	6.05	75%	0.62	1.67	4.54	34%	100%	0.21	0.56	1.52	SDX
DOB_AAB	0.59	2.18	8.13	75%	0.44	1.64	6.10	44%	100%	0.19	0.72	2.69	SDX
BFD-RE	0.29	0.83	2.37	75%	0.22	0.62	1.78	63%	100%	0.14	0.39	1.12	SDX
DOB_AAF_Upper	0.37	1.26	4.31	75%	0.28	0.94	3.23	28%	100%	0.08	0.26	0.91	SDX
DOB_AAF_Lower	0.62	2.18	7.63	75%	0.47	1.64	5.72	44%		0.21	0.72	2.52	SDX
LTO_AAE	0.47	1.26	3.38	75%	0.35	0.94	2.54	49%	100%	0.17	0.46	1.24	SDX
CGD-14	0.12	0.23	0.45	75%	0.09	0.17	0.34	72%	50%	0.03	0.06	0.12	SDX
sm1005	0.44	1.99	8.92	75%	0.33	1.49	6.69	40%	100%	0.13	0.60	2.68	SDX
sm81	0.68	2.46	8.86	75%	0.51	1.84	6.65	25%	100%	0.13	0.46	1.66	SDX
p121	0.41	0.83	1.68	75%	0.31	0.62	1.26	26%	100%	0.08	0.16	0.33	SDX
sm77	0.19	0.65	2.25	75%	0.14	0.49	1.69	35%	85%	0.04	0.15	0.50	SDX
p122	0.46	1.67	6.09	75%	0.34	1.25	4.56	26%	100%	0.09	0.32	1.18	SDX
p142	0.42	1.43	4.86	75%	0.31	1.07	3.65	40%	100%	0.13	0.43	1.46	SDX
P141	0.51	1.43	3.97	75%	0.39	1.07	2.98	30%	100%	0.12	0.32	0.89	SDX
sm47	0.13	0.43	1.43	75%	0.10	0.32	1.07	35%	75%	0.03	0.08	0.28	SDX
KSR-E	0.38	0.66	1.16	75%	0.28	0.50	0.87	80%	100%	0.23	0.40	0.69	SDX
KSR-G	0.32	0.61	1.17	75%	0.24	0.46	0.88	80%	100%	0.19	0.37	0.70	SDX
KSR-H	0.45	0.82	1.50	75%	0.33	0.61	1.12	80%	100%	0.27	0.49	0.90	SDX
KSR-I	0.29	0.49	0.83	75%	0.22	0.37	0.63	80%	100%	0.17	0.30	0.50	SDX
KSR-F	0.33	0.67	1.35	75%	0.25	0.50	1.01	80%	100%	0.20	0.40	0.81	SDX
SW_KSR_29	0.19	0.51	1.36	75%	0.14	0.38	1.02	80%	85%	0.10	0.26	0.69	SDX
CGD-6_Upper	0.04	0.13	0.44	75%	0.03	0.10	0.33	80%	80%	0.02	0.06	0.21	SDX
CGD-6_Lower	0.12	0.23	0.44	75%	0.09	0.17	0.33	80%		0.06	0.11	0.21	SDX
CGD-8_NE_Upper	0.10	0.27	0.72	75%	0.07	0.20	0.54	80%	65%	0.04	0.10	0.28	SDX
CGD-8_NE_Lower	0.01	0.05	0.16	75%	0.01	0.04	0.12	80%		0.01	0.02	0.06	SDX
SAH-3_Gaddari	0.02	0.05	0.16	75%	0.01	0.04	0.12	40%	100%	0.01	0.02	0.05	SDX
SAH-3_Guebbas	0.14	0.26	0.50	75%	0.11	0.20	0.37	60%		0.06	0.12	0.22	SDX
SAH-3_U_Hoot	0.09	0.18	0.36	75%	0.07	0.14	0.27	80%		0.06	0.11	0.22	SDX
LAM-1_A	0.09	0.36	1.42	75%	0.07	0.27	1.06	35%	65%	0.02	0.06	0.24	SDX
LNB-C	0.45	1.81	7.24	75%	0.34	1.36	5.43	35%	100%	0.12	0.47	1.88	SDX
LNB-D	1.00	3.39	11.51	75%	0.75	2.55	8.63	23%	100%	0.17	0.59	1.99	SDX
LNB-E	0.44	1.32	3.96	75%	0.33	0.99	2.97	18%	100%	0.06	0.18	0.53	SDX
LNB-F	0.63	1.77	4.95	75%	0.47	1.32	3.71	35%	100%	0.16	0.46	1.28	SDX
LNB-G	0.33	0.91	2.55	75%	0.25	0.69	1.92	35%	100%	0.08	0.24	0.66	SDX
LNB-H	0.26	0.83	2.63	75%	0.20	0.62	1.97	18%	100%	0.04	0.11	0.36	SDX
NFA_WEST_A	1.32	4.12	12.81	75%	0.99	3.09	9.61	35%	100%	0.34	1.07	3.32	SDX
NFA_WEST_B	0.35	0.92	2.43	75%	0.26	0.69	1.83	29%	100%	0.08	0.20	0.53	SDX
LNB-2_Upper	0.58	1.71	5.01	75%	0.44	1.28	3.76	35%	100%	0.15	0.44	1.30	SDX
LNB-2_Lower	0.60	1.60	4.31	75%	0.45	1.20	3.23	35%		0.15	0.42	1.12	SDX
LCG-1	0.76	2.06	5.55	75%	0.57	1.54	4.17	29%	100%	0.16	0.44	1.20	SDX
LNB-1_Lower	2.26	5.38	12.80	75%	1.69	4.03	9.60	80%	100%	1.36	3.23	7.68	SDX
OYF Upper	0.26	0.54	1.13	75%	0.19	0.40	0.85	72%	100%	0.14	0.29	0.61	SDX
OYF Lower	0.19	0.40	0.88	75%	0.14	0.30	0.66	72%		0.10	0.22	0.48	SDX
BMK Upper	0.05	0.17	0.61	75%	0.03	0.13	0.46	50%	85%	0.01	0.05	0.20	SDX
BMK Lower	0.14	0.40	1.12	75%	0.10	0.30	0.84	50%		0.04	0.13	0.36	SDX
SAH-W	0.15	0.41	1.09	75%	0.11	0.31	0.82	72%	75%	0.06	0.17	0.44	SDX
ERM-A	0.04	0.12	0.34	75%	0.03	0.09	0.26	58%	20%	0.00	0.01	0.03	SDX
SAK-A	1.25	3.78	11.46	75%	0.93	2.83	8.59	43%	100%	0.40	1.22	3.71	SDX
Determinstic Total	**23.3**	**67.8**	**206.6**		**17.4**	**50.9**	**155.0**			**7.7**	**21.1**	**61.3**	

1. *Net unrisked Attributable Prospective Resources are based on the working interest share of the field gross resources and do not represent the net entitlement resources.*
2. *COS is the chance of geological success and COD is the chance of development. The product of COS x COD is the chance of commerciality.*
3. *Quantifying the COD requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are out with the expertise of ERCE they must be used with caution.*
4. *Net risked Attributable Prospective Resources are the product of the unrisked resources and the chance of commerciality.*
5. *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.*

2.6. Data Provision and Material Changes

ERCE was provided with a technical and financial dataset which varied for each of the assets. SDX presentation material provided an overview of the producing assets and the exploration potential. Seismic data (and interpretations) and most well data was provided in the form of Petrel models. Well petrophysical data and interpretations were included in IP projects. Daily production data was provided in a mix of formats including OFM databases and spreadsheets. For the gas properties in Morocco “well books” were provided in spreadsheet format summarizing key information for the well including the p/z plot. Certain assets had simulation models and for those, key input and output files were provided. ERCE used the dynamic reservoir simulation study report for the Meseda field provided at YE 2017, supplemented with new well data. FDPs for the South Disouq field and the Ibn Yunus field were provided together with well test analysis reports and cost estimations. Some PVT data was provided. TCM and OCM presentation materials and minutes were available and were a good source of general information on the fields.

Financial related data comprised of the various concession agreements, some joint operating agreements, budget information, historical costs, gas sales agreements and sales information. SDX provided a corporate economic model incorporating the fiscal terms and their best estimate case production and cost forecasts.

In preparing this report, ERCE has relied upon certain factual information including ownership, technical well data, production data, prices, revenues, operating costs, capital costs, contracts including hydrocarbon sales contracts, and other relevant data supplied by SDX. The extent and character of all factual information supplied were relied upon by ERCE in preparing this report and have been accepted as represented without independent verification. ERCE has relied upon representations made by SDX as to the completeness and accuracy of the data provided and that no material changes in the performance of the fields has occurred nor is expected to occur, from that forecasted in this report, between the date that the data was obtained for this audit and the date of this report, and that no new data has come to light that may result in a material change to the evaluation of the Reserves and Prospective Resources presented in this report.

3. West Gharib Block H Development Lease

The West Gharib Block H is located on the SW edge of the Gulf of Suez in the West Gharib Basin, onshore Egypt. The block is operated by Dublin Petroleum Ltd. who hold a 50% working interest. Madison Egypt Limited, a wholly owned subsidiary of SDX Energy, hold the remaining 50% working interest. SDX acquired their interest in the block in 2015 after they acquired Madison PetroGas Ltd. and in turn Madison Egypt Limited. The block contains the Meseda and Rabul fields both of which were on production as at 31st December 2018. The fields are produced and operated under a Production Service Agreement ("PSA") for the General Petroleum Company of Egypt ("GPC"). The PSA has an initial 10-year term plus a 10-year optional extension. The first 10-year term expires in November, 2021. The 10-year optional extension is detailed in the PSA and although it requires the approval of EGPC this cannot be unreasonably withheld; as such ERCE has assumed that Reserves at all levels of confidence may be booked beyond the current PSA expiry up to 11 November 2031.

3.1. Meseda Field

3.1.1. Introduction

The Meseda field was discovered in June 2011 as an extension of the neighbouring EPM field to the SE. The EPM field wells are operated by TransGlobe Energy. The fields are operated separately with no unitization agreement in place. As such, when evaluating Meseda competitive drainage must be taken into account. The Meseda field is producing 16 – 17 deg API oil from two Asl sands within the Rudeis formation. The producing structure is a three-way closure against a NW-SE striking fault. The structure is bisected by a lease boundary. Wells drilled north and west of the lease line belong to the Meseda field while those drilled to the south and east belong to the EPM field.

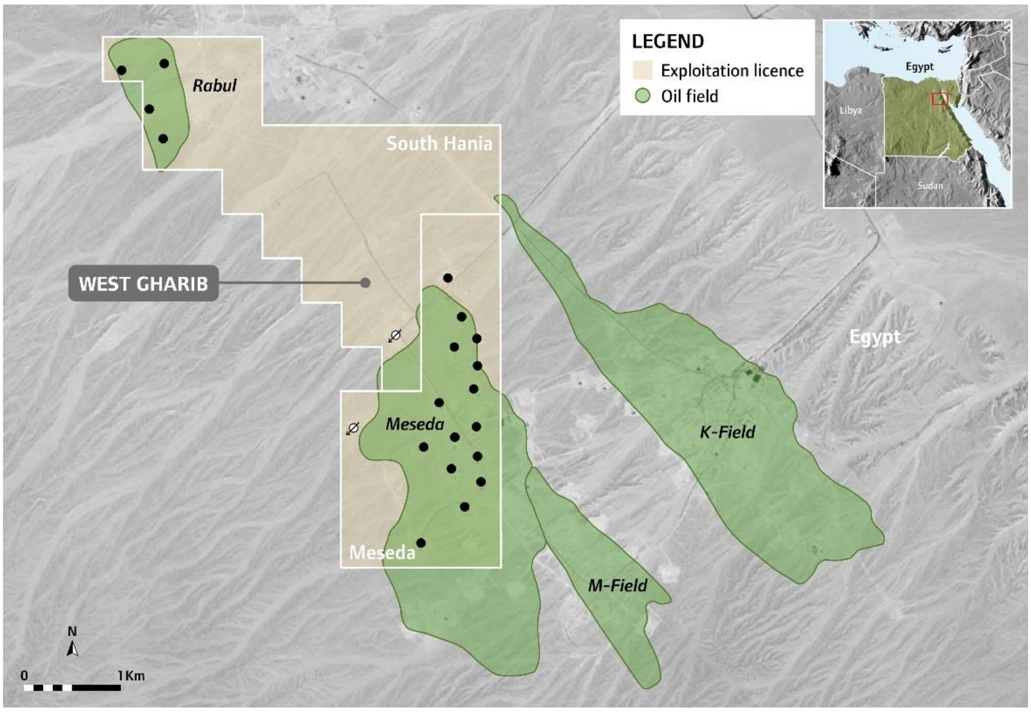

Figure 3.1: Licence map for the West Gharib area with SDX blocks in beige

3.1.2. Development History

The Meseda field was discovered in June 2011 and came on production in November 2011 with the MSD-01 well. Prior to this production from the EPM field wells had commenced in 1991 and by the time Meseda began production, the field had produced an estimated 10 MMbbl of oil and 22 MMbbl of water from 8 production wells. The water production is a result of some natural aquifer support which is interpreted to be from the south. (It should be noted that SDX does not have the complete production history for the EPM wells and the data for the period from 2004 to 2012 had to be estimated by SDX from decline trends.) A plot of the estimated oil production history for the two areas through to mid-2017 is presented in Figure 3.2.

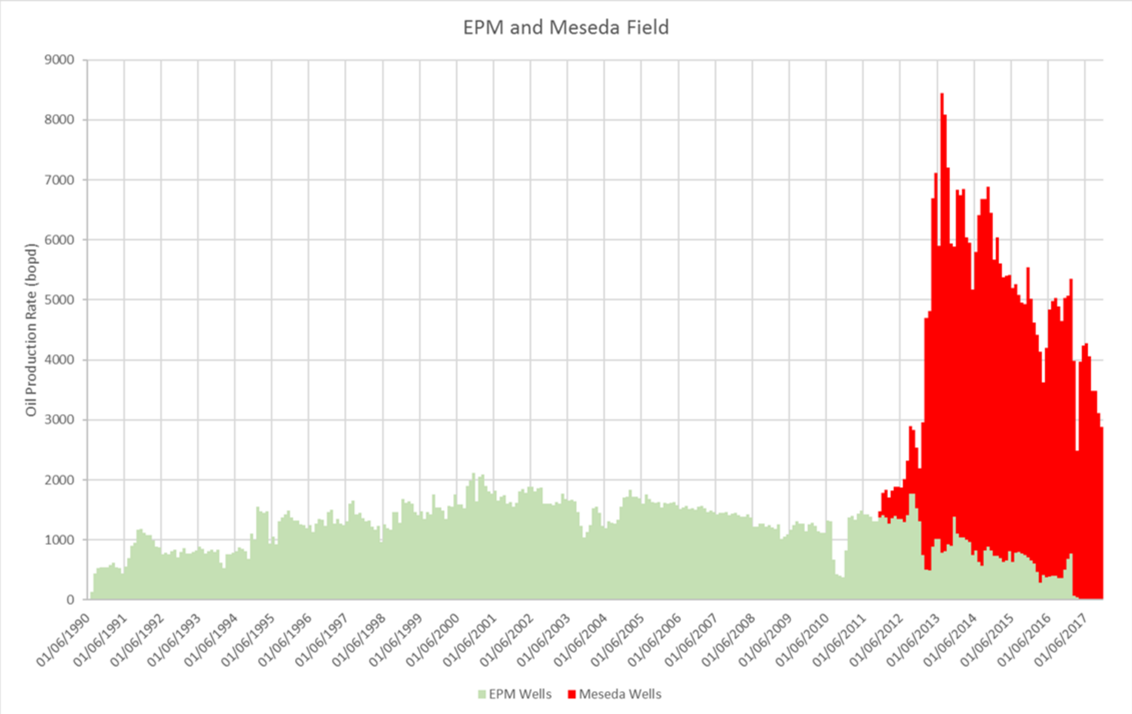

Figure 3.2: Estimated Oil Production History for the EPM and Meseda Wells

The oil is undersaturated with low GOR (115 scf/bbl) and a density of 956 kg/m3 (16.5°API). The reservoir quality is good with porosity averaging approximately 24% and permeability 500 – 1,500 mD.

A total of 19 wells (16 producers) have been drilled within the Meseda development area with 12 wells producing in December 2018. Two new wells were drilled in 2018 close to the lease line with the EPM part of the field: MSD-16 which was bought online in July 2018 and MSD-15 in September 2018. In August 2018 TransGlobe also drilled two new updip producers across the lease line in EPM, M-North and M-South.

MSD-4 is a long term shut-in downdip well that is now planned to be converted to a water injector in Q2 2019. MSDW-01/FDLN-01 have not produced since February 2018 and are now assumed to be long term shut-in. MSD-13 has been shut in since September 2018 due to a mechanical issue but it is assumed this will be fixed and the well will come back online by Q2 2019. Wells EPJ-1 and MSD-WI1 are completed as peripheral, downdip water injectors. Since December 2014, EPJ-1 had been injecting at rates of ca. 3,500 bbl/d but in December 2018 injection was increased to 6,000 bbl/d. MSD-WI1 was bought into service in March 2018 with injection in this well also being ramped up to 6,000 bbl/d by the end of 2018 . Any remaining produced water is injected into a shallow water disposal well (NWK-1). During December 2018 the field produced an average 4,083 bbl/d of oil and 8,984 bbl/d of water (water cut of 69%). Of the 12 producing wells, 8 were producing with electric submersible pumps (ESPs) and the rest with sucker rod pumps (SRPs). As of 31 December 2018, the cumulative oil production from the Meseda wells was 10.32 MMbbl.

As of the end of 2018 water injection had been significantly increased in the Meseda field, towards the 15,000 bbl/d target. A conversion of MSD-04 to injection in 2019 will give an additional injection capacity. In line with this, five workovers are budgeted in 2019 to replace the remaining SRPs in the field with ESPs to allow additional liquid production.

The Operator has proposed the drilling of a third infill well, MSD-17 (previously MSD-18), at the very crest of the structure which has been approved and is expected to be drilling in mid 2019. A fourth infill well, MSD-18, is proposed further downdip close to MSD-01 and MSD-02. This well is considered to be a contingent resource in the production forecast as it has not yet been approved but would be expected to be drilled in 2020.

3.1.3. **Geological Description**

The Meseda field lies within the West Gharib basin which contains a series of similar fault bounded dip closures on a NW-SE trend. The majority of faults dip to the SW with closures on the hanging wall side. The bounding Meseda Fault is interpreted to dip to the NE.

The Asl sands are part of the Lower Miocene, Rudies formation as shown in the stratigraphic column presented in Figure 3.3. Oil is contained in two intervals, the Upper Asl and Asl B sands. The Asl is interpreted to be late syn-rift with medium to coarse grained sandstones passing upwards into shales. Sediment influx is believed to be fault controlled with shales deposited in periods of tectonic quiescence. The depositional environment is hard to characterise as there is no core data from the Meseda wells. The interpretation is that the Asl formation comprises high quality fluvio-deltaic sands intercollated with minor shales however they may have been alternatively been deposited as part of a shallow water turbidite system. Correlation between wells is also problematic as sands and shales vary in thickness. The reservoir is sealed by the Rudeis shale which is several hundred metres thick.

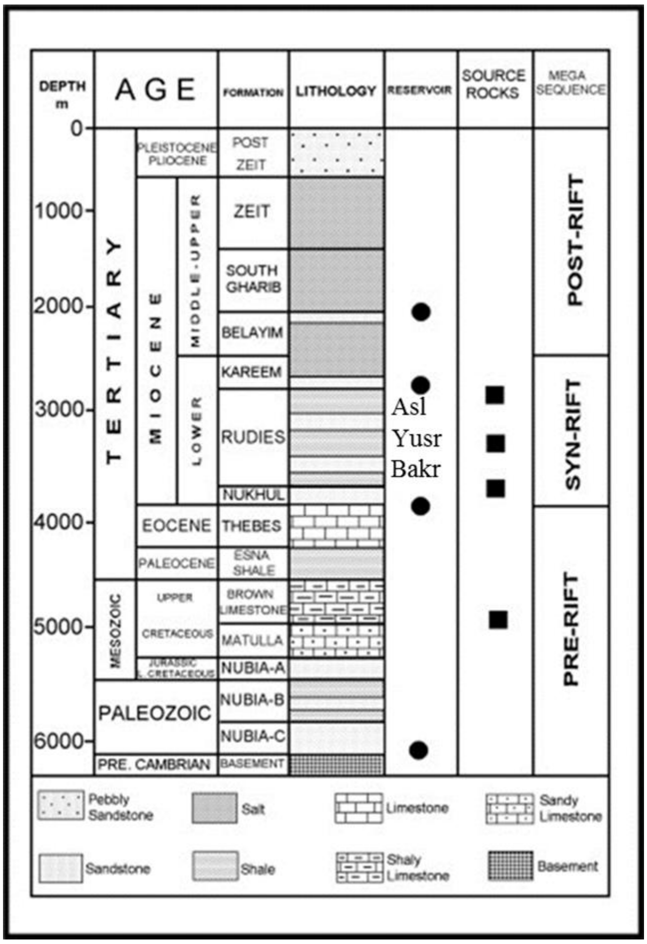

Figure 3.3: Gulf of Suez Stratigraphic Column

The field is wholly covered by one 3D seismic volume, however, the seismic data quality is relatively poor due to the presence of anyhdrites in the overburden which impacts horizon and fault interpretation. Only 2 wells (FADL N-1 and MSD-13) out of the 94 wells in the region have check-shot data and time-depth calibration. Fault interpretation is largely based on regional knowledge combined with well picks and dipmeter data in wells. Some seismic package wedging can be seen into the south-western most fault that bounds the field to the SW. For reservoir modelling purposes a near Top Asl interpretation has been made which has then been isopached down to the Upper Asl sand, the Mid Asl shale and the Asl B sand. A top structure map for the Top Asl sand is presented in Figure 3.3.

ERCE has reviewed the seismic interpretation. The near Top Asl interpretation has been depth converted with what appears to be a simple linear function which is likely too simplistic given the complexities in the overburden. The resulting surface has subsequently been adjusted to the wells however in some cases the tie was still quite poor. The difference between the tied and untied maps is significant requiring a shift up of more than 180 feet to match the wells. This suggests there is likely significant structural uncertainty on the flanks of the structure away from well control. In addition, given the uncertainty in the fault interpretations, the precise location of the field bounding fault is also uncertain.

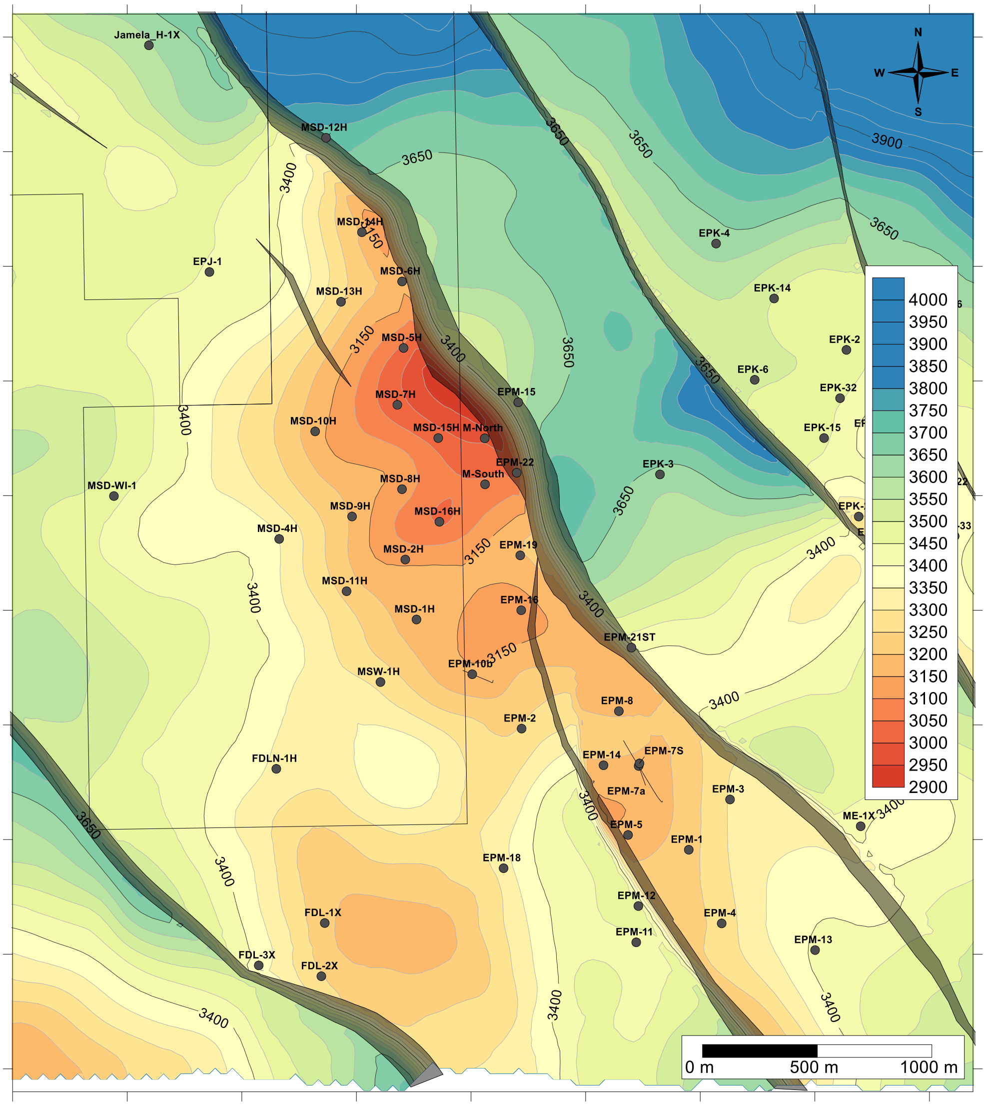

Figure 3.4: Top Asl sand depth structure map for the Meseda field, Block H (Black outline)

3.1.4. Petrophysics

Three wells were reviewed for the evaluation of Meseda (MSD-4H, MSD-7H and MSD-9H) and the intervals of interest were the Asl and Hawara Formations. The petrophysical evaluation of the Meseda field is difficult and has a high uncertainty because there is no core for calibration of the input parameters or output interpretations. The neighbouring EPM field does have core and is a useful analogue, showing porosities <35% and permeabilities <1D.

Vsh was calculated from gamma ray using 5 & 95th percentiles, and from neutron/density cross plot; then the minimum of the two methods was used as the final Vsh. Vsh is typically overestimated so using the minimum of two methods helps to reduce this.

Porosity was estimated using the density log, assuming a clean sandstone matrix of 2.65g/cm3 and a fluid density of 0.9g/cm3 which takes into account mud-based filtrate invasion into the formation. No hydrocarbon corrections were completed for this reason. Effective porosity was calculated from total porosity by assuming 30% shale porosity. This removes ineffective porosity in shaley intervals, but does not affect porosity in clean sands.

The neutron and density logs (Figure 3.5 and Figure 3.6) show a clean sand crossover in the Asl and Hawara intervals, suggesting that the sands are good porosity, quartz rich and suggesting a hydrocarbon fill.

Water saturation (*Sw*) was determined from the Archie equation with the Archie parameters of *a*, *m* and *n* assumed to be 1, 2 and 2 respectively. As there is no core data, there is also no SCAL data for calibration of electrical parameters.

No formation water data were available hence *Rw* was selected from Pickett plots. The Hawara and Asl appear to have different salinities, and this is seen most clearly in MSD-4H where both intervals are water bearing. The Hawara appears to have a salinity of ~58kppm, but the Asl is much fresherat ~15kppm. There is a thick shale (the Asl shale) separating the two intervals so it is entirely feasible that the two waters are not in communication.

Net reservoir interval was based on an effective porosity cut-off of >5%, a Vsh cut off of <50% and net pay also included a Sw cut off of 70%. These cut offs were selected interactively in order to identify those intervals that were considered to be reservoir based on the log character. These cut offs are different to SDX's, but this is partly due to SDX's use of Vclay rather than Vshale.

Having completed an independent view of the petrophysics, ERCE accepts SDX's petrophysical interpretation.

A comparison of the two petrophysical interpretations in well MSD-9H is shown in Figure 3.5 and in MSD-4H in Figure 3.6. SDX interpreted curves are shown in black; ERCE interpreted curves are shown in red. Well MSD-4H contains water in the Asl and Hawara so is key to understanding the difference in salinity. There is a difference in interpretation of Phie in the shalier intervals, but otherwise SDX's interpretation is very similar to ERCE's.

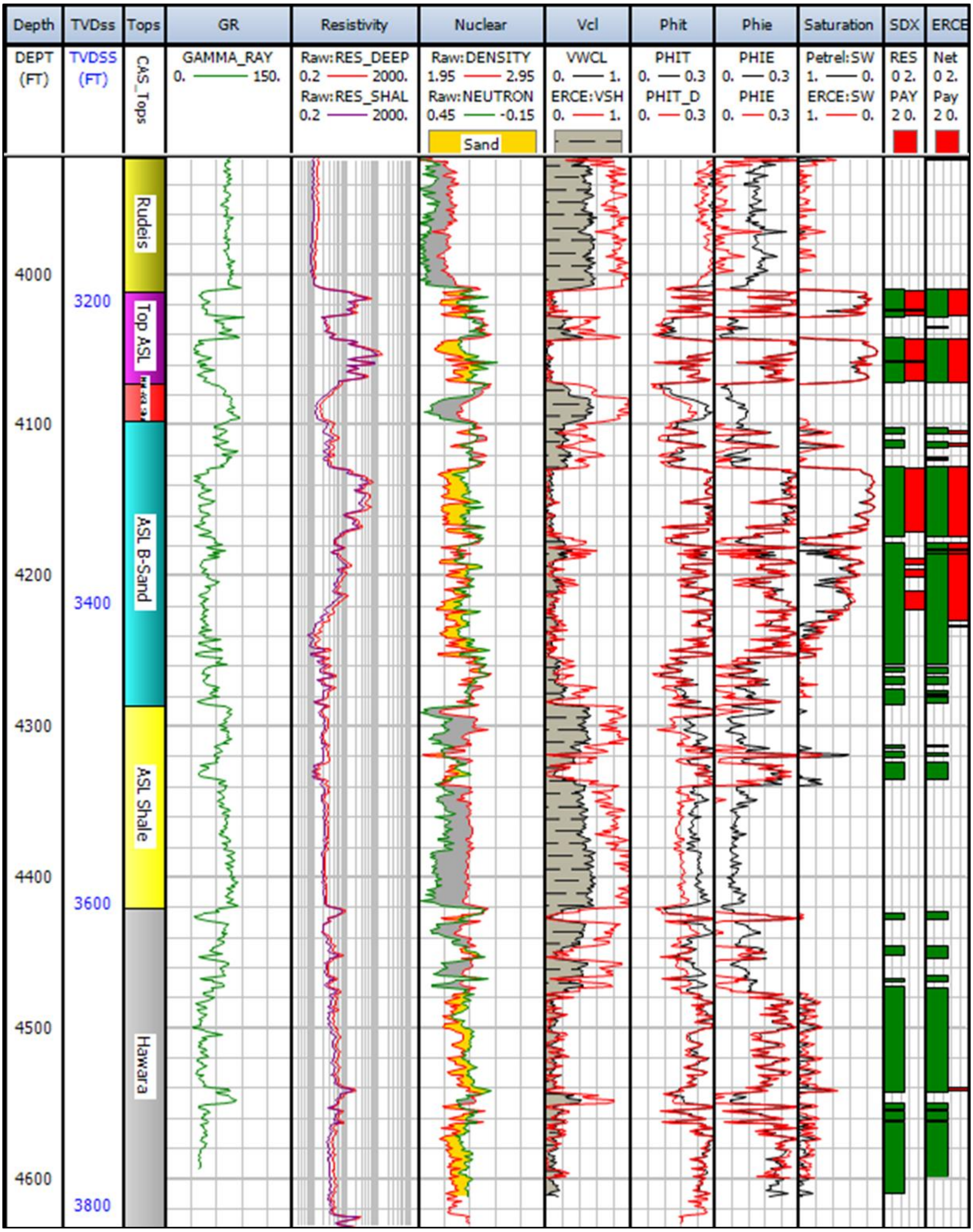

Figure 3.5: Petrophysical interpretation for the Asl and Hawara intervals, well MSD-9H

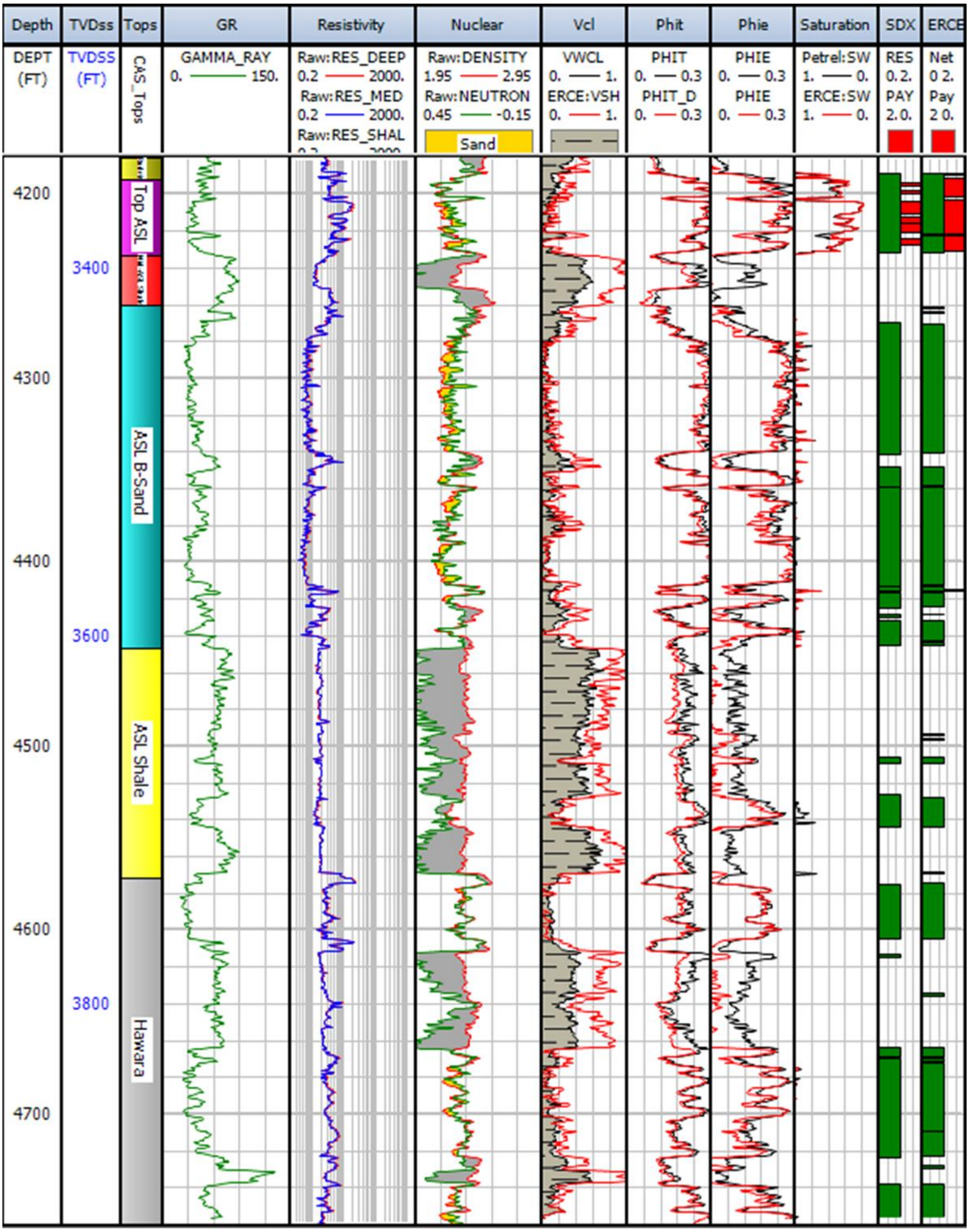

Figure 3.6: Petrophysical interpretation for Asl and Hawara intervals, well MSD-4H

3.1.5. Reservoir Engineering

Several oil samples have been analysed for Meseda and the resulting properties can be seen in Table 3.1. The most representative sample is considered to be the MSD-10 MDT sample which indicates a bubble point pressure of 820 psia, a solution GOR of 115 scf/bbl and a viscosity of 18.5 cP. The properties estimated from other samples vary significantly from this but are considered unlikely to be representative given the reservoir behaviour to date, with little gas production seen and Meseda mobility data and analogues suggesting lower viscosity oil than seen in the MSD-10 and MSD-14 surface samples. ERCE has not reviewed the PVT data in detail as part of this report but believe there remains some uncertainty in the properties of the Meseda fluid.

Table 3.1: Meseda PVT Samples (Source: SDX)

Well	Type	Sample	API	Pb	Bob	GOR	Viscosity
		Bottle no.		psia		SCF/STB	cp
MSD-6	Surface	7 & 508a	16.15	1266	1.081	171	13.7
MSD-10	Surface	26 & 512	15.0	329	1.055	73	53.1
MSD-10	MDT		16.5	820	1.077	115	18.5
MSD-14	Surface	13 & 14197	12.6	1200	1.073	88	57.3

Viscosity at Pb and Reservoir Temperature 143°F

The initial reservoir pressure in Meseda/EPM is estimated at 1,550 psia (at a datum depth of 3,350 ft TVDSS). Production at EPM resulted in ca. 240psia pressure depletion in Meseda by the time it came on production in 2011. By the time MSD-06 was drilled in 2015 the reservoir pressure had reduced to 950 psia, where it appears to have stabilised with some water injection and aquifer support. This was verified when MSD-16 was logged in July 2018 and very little further depletion was seen. An MDT pressure plot for the various wells drilled in the field is presented in Figure 3.7.

As previously mentioned, producing sub-hydrostatically requires the use of SRPs and ESPs in the wells.

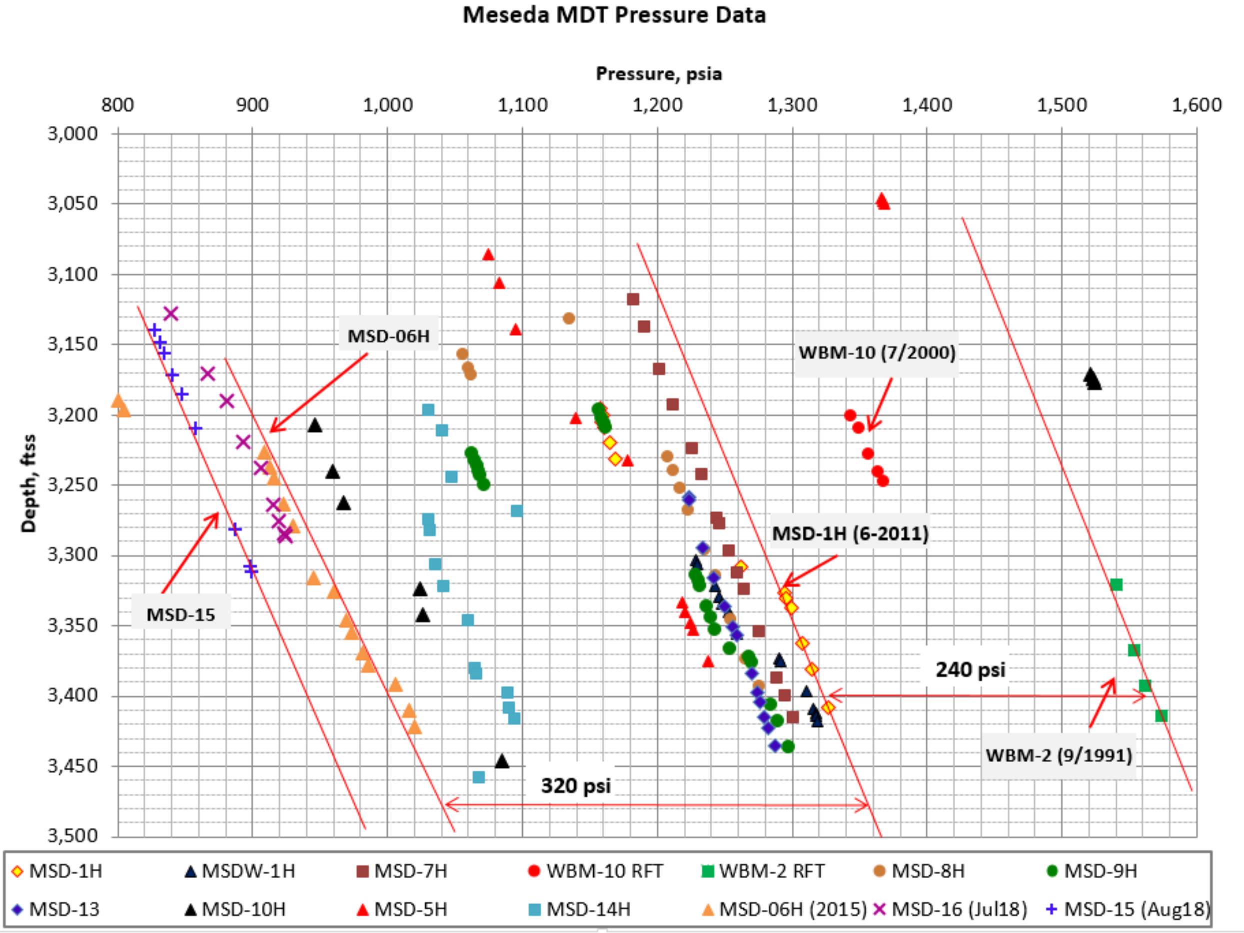

Figure 3.7: Meseda MDT Pressure Data

3.1.6. Hydrocarbons Initially In Place

SDX presented ERCE with a mid case STOIIP value of 73.8 MMbbl which we have audited with respect to GRV and reservoir parameters and found to be reasonable.

3.1.7. Production Performance

As discussed in Section 3.1.1 the Meseda field wells commenced production in November 2011. Production rates increased to just over 8,000 bopd in 2013 as more wells were drilled and as artificial lift has been changed from SRP to ESP. The field water cut has steadily increased over this period to around 69%. All of the wells are producing some water and individual water cuts vary between 50% and 90%. The higher water cuts are often associated with some of the structurally lower wells however the two crestal wells MSD-5 and MSD-7 also currently have water cuts over 80%.

To date the recovery mechanism appears to be edge/bottom water drive through water injection and aquifer support. Reservoir pressure declined up to 2015 but since then the water injection appears to have helped stabilize pressures with some wells showing stable FBHPs and liquid rates. A plot of the total field oil and gross fluid rates is presented in Figure 3.9. Oil production had been in a relatively steady decline, with some fluctuations in liquid throughput rate, until MSD-15 and MSD-16 came online with initial rates of 1300 bopd and 1800 bopd.

The in-situ oil viscosity at Meseda is 18.5 cP resulting in an unfavourable oil water mobility ratio which in turn means that significant volumes of oil will need to be recovered at high water cut. Since 2016 SDX has been lobbying Dublin to install bigger, more reliable ESPs across the Meseda wells to help recovery. Dublin has already installed large ESPs in the two new wells, MSD-15 and MSD-16 and the workovers to replace the remaining SRPs in the field with ESPs have now been included in the 2019 budget.

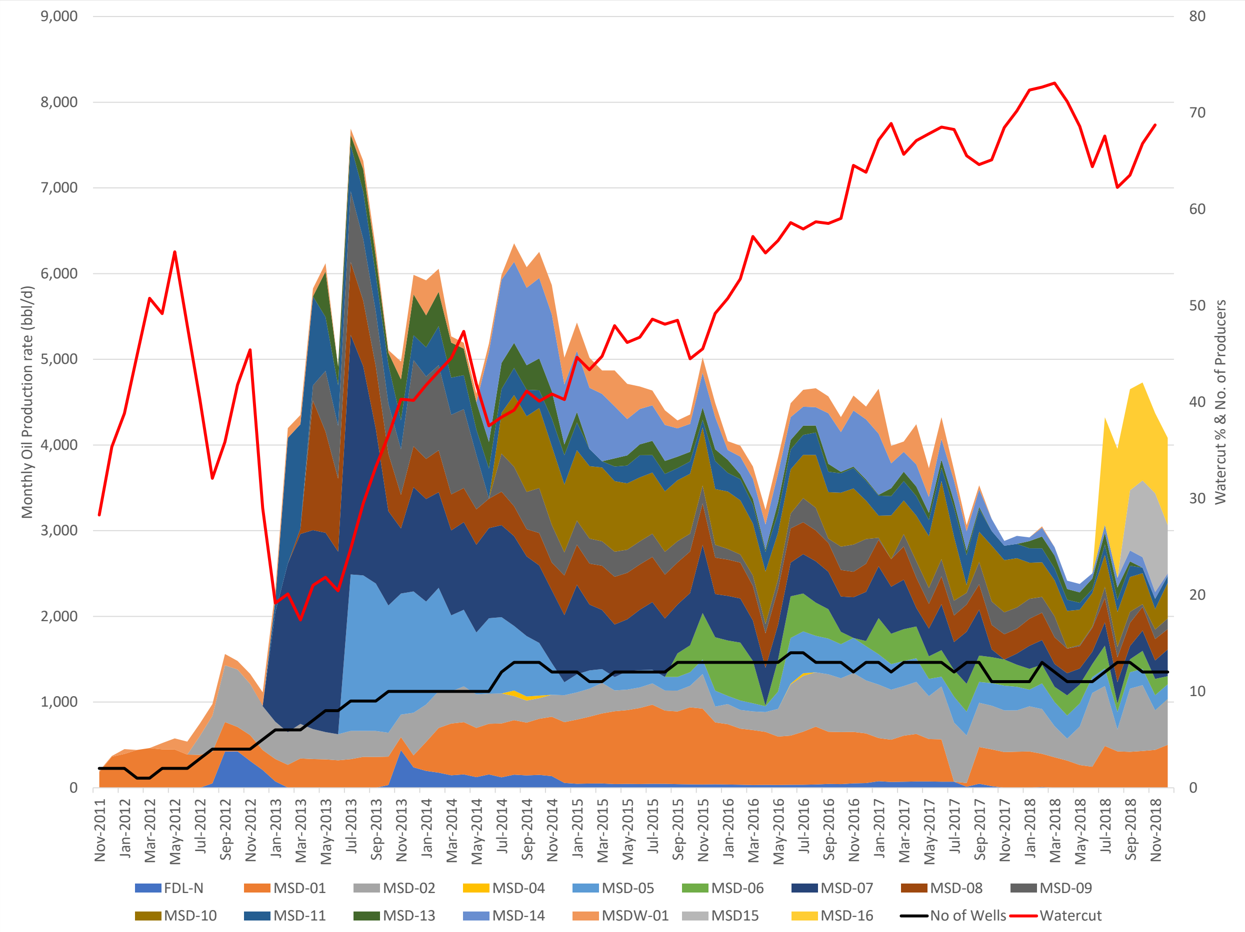

Figure 3.8: Meseda oil production history by well

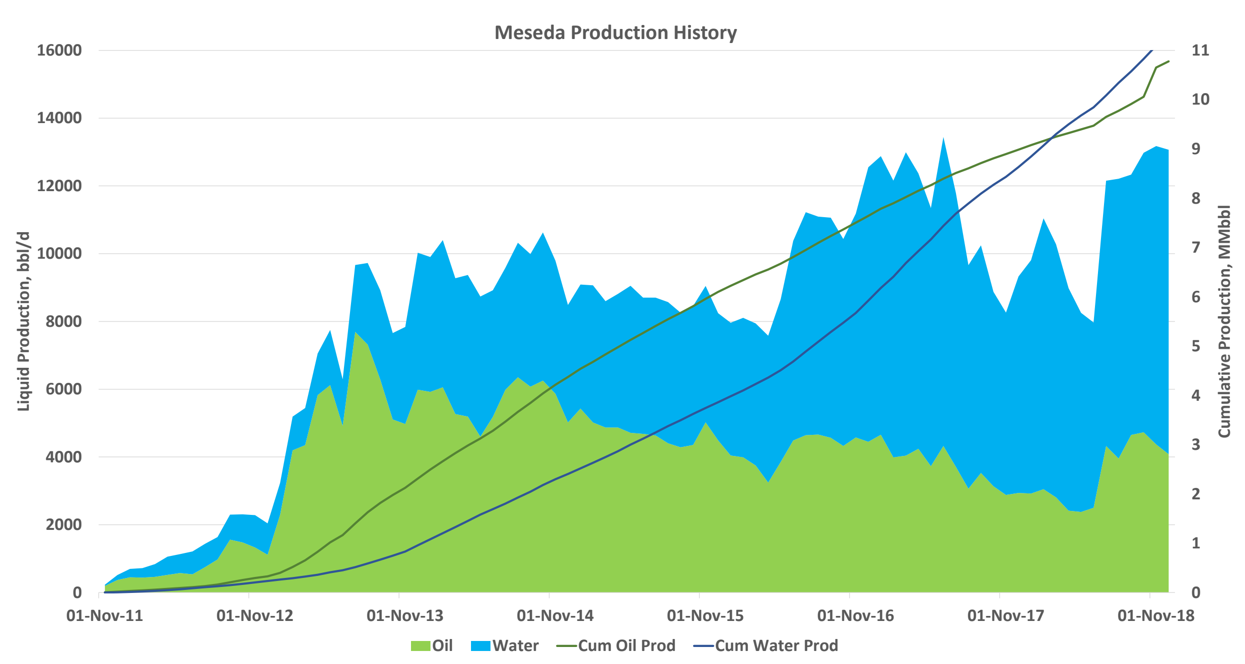

Figure 3.9: Meseda oil and water production history

3.1.8. Recoverable Resources

Recoverable resources were mainly estimated using performance based methods, with some use of numerical and volumetric methods. Recoverable resources are an intermediate step in determining Reserves and represent the recoverable volumes prior to economic cut-off (or economic limit test ("ELT")).

SDX were in the process of updating the static and simulation models with the results of the wells drilled in 2018 but these were not complete at YE 2018. As the 2017 SDX simulation model we had previously been supplied with had not been updated for the MSD-15/16 well results or operational changes (delays in ESP change outs, water injection rate and liquid rate increases), it was therefore not used as the basis for the developed forecast in this update. Individual well EURs were all estimated using decline curve analysis, including MSD-15 and MSD-16.

SDX had considered two forecast cases in their 2017 simulation model: a no further activity ("NFA") case with an average liquid throughput of 12,000 bbl/d and a development case with 2 infill wells, 5 ESP workovers, increased water injection to 15,000 bbl/d and increased liquid rates to 20,000 bbl/d. The development case mainly accelerated recovery rather than adding incremental recovery. This model output has still been used to estimate the expected acceleration and incremental recovery from new ESP installations and increased water injection.

Proved developed producing recoverable resources were based on aggregating the results of individual well declines using a hyperbolic decline exponent of 0.5. This is assumed a reasonable low case for a viscous oil field with established aquifer/water injection support and water cut trends. The Reserves predicted by a hyperbolic decline also appeared to match a water oil ratio analysis for wells with established water cut trends. MSD-13 was categorised as developed non-producing given its current S/I status.

Proved undeveloped recoverable resources associated with the ESP change out/water injection increases, including MSD-04 conversion to an injector, were estimated using the 2017 simulation incremental recovery associated with these activities, with the ESP change outs deferred to 2019. The proposed updip MSD-17 well was also included in the proved undeveloped reserves forecast as this well has now been approved. The 1P reserves for MSD-17 assume its production is mainly acceleration to account for the uncertainty in the main fault position at the crest of the field and the potential impact of competitive production from M-North and M-South wells across the lease line.

The estimated 1P ultimate recovery (“EUR”) including undeveloped resources was 15.5 MMbbl, giving a 20% recovery factor based on the latest ERCE best case STOIIP.

The new proposed MSD-18 downdip infill well is assumed in a 1C scenario to have limited incremental resources associated with it (0.15 MMbbl) due to the risk it may already have been drained by MSD-01/02 (ca. 250m away).

Probable developed producing recoverable resources were based on the aggregating the results of individual well declines, including MSD-15 & MSD-16, using harmonic decline. Previously harmonic decline had aligned closely with the SDX simulation model results.

Probable undeveloped recoverable resources associated with ESP change out/water injection increases were again estimated using the 2017 simulation incremental recovery associated with these activities. 2P resources assigned to MSD-17 assumes the well develops ca. 50% of the 5.2MMbbl STOIIP estimated in the SDX Petrel model updip of existing well control.

The estimated 2P ultimate recovery (“EUR”) included undeveloped resources was 18.1 MMbbl, giving a 24% recovery factor based on the latest ERCE best case STOIIP.

The new proposed MSD-18 downdip infill well is assumed in a 2C scenario to start at 50% watercut (MSD-01/MSD-02 currently at 53/77% watercut) and then perform as per MSD-16 hyperbolic decline (0.47 MMbbl).

The 3P+3C recoverable resources were estimated by applying a higher recovery factor of 27% to the ERCE best estimate (P50) STOIIP, which is in line with the recovery factor seen in the previous Meseda simulation model (which carried a lower STOIIP). This includes the assumption that MSD-17 is successful at developing all of the STOIIP updip of existing well control and contributes 3P resources of 1.4 MMbbl and MSD-18 contributes 0.75 MMbbl 3C resources.

Note that the Contingent Resources are assessed to have a 90% Chance of Development, but are considered Development on Hold, pending government approval to proceed.

Table 3.2: Meseda field recoverable resources estimates as of December 31, 2018, before economic limits are applied

Category	EUR Mbbl	Cumulative Production Mbbl	Recoverable Resources (1) Mbbl	Working Interest %	WI Recov. Resources (2) Mbbl
PDP	15,102	10,323	4,779	50%	2,390
PD	15,102	10,323	4,779	50%	2,390
1P	15,530	10,323	5,207	50%	2,603
2P	18,119	10,323	7,796	50%	3,898
3P	20,140	10,323	9,818	50%	4,909
1C	151	-	151	50%	76
2C	473	-	473	50%	236
3C	750	-	750	50%	375

1. *Recoverable Resources are prior to applying an ELT*
2. *Working interest recoverable resources are the Company share of the field gross resources*

3.1.9. Production Forecasts

The proved developed producing ("PDP") forecast was based on the hyperbolic decline curve forecasts for the individual wells aggregated to the field level. The 1P production forecast was based on the PDP forecast plus an incremental benefit associated with MSD-17 and ESP changes. The 2P production forecast was based on harmonic curve forecasts for the individual wells aggregated to field level plus an incremental benefit associated with MSD-17 and 2019 ESP changes. The 3P production forecast was based on the 2P scenario scaled to account for slightly higher recovery factor and STOIIP. The Meseda field production forecast is presented in Figure 3.10.

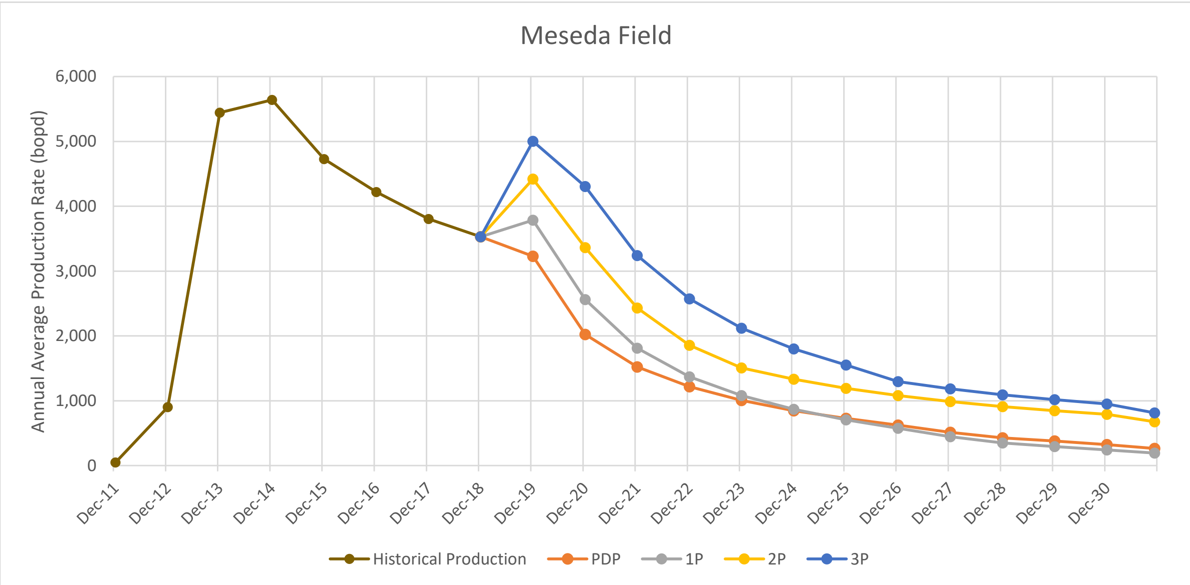

Figure 3.10: Meseda field production forecasts

3.2. Rabul Field

3.2.1. Introduction

The Rabul field was discovered in July 2017 by well Rabul-1X. The field lies approximately 4 km to the NW of the Meseda field and is also covered by the West Gharib Block H Development Lease. The field has been producing since September 2017 trucking oil to the Meseda production facilities. A second well, Rabul-2X was drilled in September 2017, followed by Rabul-5 in March 2018, Rabul-4 in April 2018 and Rabul-2R in October 2018. A location map showing the relative position of Rabul to Meseda is presented in Figure 3.11. The Rabul field contains 16 deg API oil in the Yusr and Bakr sand formations in the overall Rudeis formation. The Yusr and Bakr sands are slightly older than Asl sands present in the Meseda field but are still part of the Rudeis.

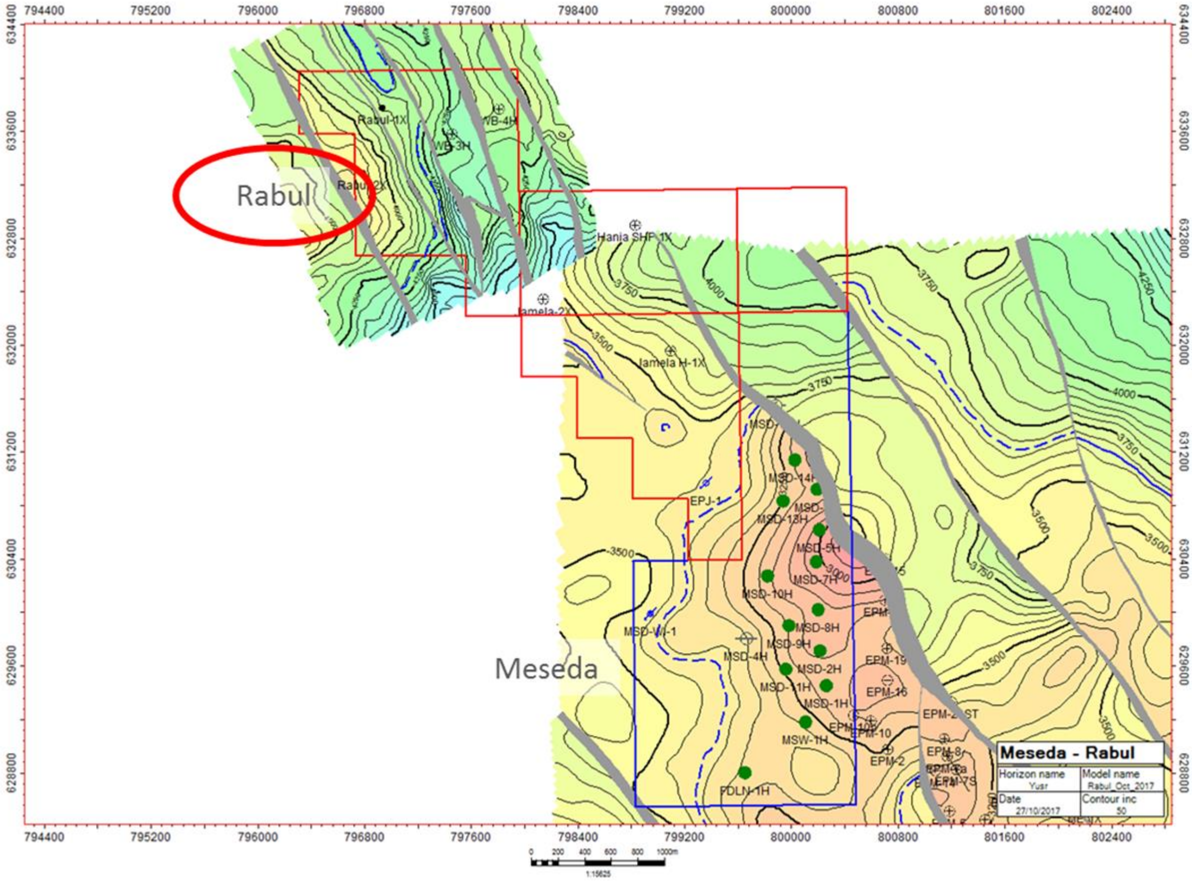

Figure 3.11: Location map for the Meseda and Rabul fields

3.2.2. Development History

The first two Rabul wells were drilled by Dublin during 2017 as commitment wells in order to retain the northern part of the development lease. Well Rabul-1X found oil in an upper sand within the Yusr interval and an oil sample was taken using a MDT tool. A well test with the drilling rig was not undertaken as productivity was not considered an issue. Well Rabul-2X was drilled to the south of the discovery well in an up dip location confirming the presence of oil in the Yusr but also establishing the presence of oil in the deeper Bakr sand. An OWC at 4,208 ft TVDSS was initially interpreted in the Bakr but this was recently adjusted to 4,177ft TVDSS following a corrected depth survey. Wireline pressure measurements in the Yusr formation in Rabul-2X well were depleted relative to Rabul-1X and this is most likely due to the Rabul-1X production.

It should be noted that a third well, WB-4H, had already come on production on the east side of the H block in a separate fault block, close to the EPH field, in February 2017 and this is included in the total field production and forecasts. In December 2018 this well was producing 65 bopd at 85% watercut. This well is completed in the Bakr, whereas the majority of EPH wells are completed in the Yusr.

As planned, in 2018 three new wells were drilled at Rabul. Rabul-5 was drilled updip further north in the Rabul-2X fault block and found both Yusr and Bakr with higher net pay than Rabul-2X. This well is currently completed in the Bakr and will be recompleted to the Yusr at a later date. Rabul-4 was drilled south of Rabul-2X and again encountered both Yusr and Bakr. However, Rabul-4 is assumed to be in a separate fault block to Rabul-2X as it encountered a deeper Bakr OWC at 4230ft TVSS. Rabul 2R penetrated top Yusr 60 m to the NW of Rabul-2X and was drilled due to the completion in Rabul-2X preventing production from the Yusr.

Single well facilities comprising a storage/settling tank and heater have been installed at each well. Demulsifiers are injected to help separation. The separated oil is then trucked to the Meseda facilities. Separated water is pumped to evaporation pits and ultimately injected into disposal wells at Meseda. Previous plans had included a flowline from Rabul to Meseda, but it is not believed this is yet in place.

It should be noted that part of the Rabul field as mapped lies outside of the Block H lease, including the updip portion of the Rabul-2X block, as well as likely STOIIP to the north. In April 2018 GPC drilled well HNW-1X in this updip location and started producing from it. A further four lease line wells have since been drilled on the field outside of the lease by GPC to the North and West. We have not specifically accounted for offset production in our reserve estimates, other than where it has already affected the production declines in the Rabul wells. Recovery factors associated with the ERCE production forecasts however have been checked against on lease STOIIPs only.

Dublin/SDX now have approval to drill an additional infill producer well in 2019, RB-7Y in the NW corner of the lease and also a Yusr water injector in the Rabul-2X block to add additional pressure support and improve the sweep of the different Yusr sands.

The proposed WB-5H well, updip of WB-4H in the East of the lease, has not yet been approved and it is assumed this will slip into 2020.

During December 2018 the field produced an average 1,514 bbl/d of oil and 3,168 bbl/d of water (water cut of 60%). As of 31 December 2018, the cumulative oil production from the Rabul wells was 0.82 MMbbl.

3.2.3. Geological Description

The Rabul field lies within the West Gharib basin which contains a series of similar fault bounded dip closures on a NW-SE trend. The majority of faults dip to the SW with closures on the hanging wall side. The Rabul field is interpreted as a 2-way dip closure against one such fault with stratigraphic closure to the NW.

The Yusr and Bakr sands are part of the Lower Miocene, Rudeis formation as shown in the stratigraphic column presented in Figure 3.3. The reservoirs are thought to have been deposited as turbidite fans, sourced from the SW and interbedded with shales and possible carbonate debris flows. The depositional environment is hard to characterise as there is no core data from the Rabul wells. Characterisation is largely based on using the nearby H-field as an analogue which does have core data, however this data was not available. Sands within both the Yusr and Bakr are of good quality with moderate to high porosities and high permeabilities. Sealing is provided by thick intraformational shales.

Two seismic volumes cover the Rabul field, a regional (FADL) survey that also covers the Meseda field and a smaller reprocessed (structurally smoothed) version that covers the Rabul field only. As is common in the Gulf of Suez, seismic data quality is very poor due to the presence of anhydrites in the overburden. This leads to considerable uncertainty in both fault and horizon interpretation. Dipmeter data, well tops and regional trends have been used by the Operator to guide fault interpretation. The uncertainty in interpretation is compounded by the fact that only two wells in the region have checkshot surveys or synthetic seismograms leading to uncertainty in the well to seismic tie.

ERCE has briefly reviewed the seismic interpretation and well tie and view SDX's surfaces as robust considering the poor quality of the seismic data.

The Top-Yusr depth map (Figure 3.12) does not close to the NW when using the OWC of 4177 ft TVDSS observed in the wells. Stratigraphic pinch out/shale out of the reservoir is inferred by SDX based on the nearby H-field which shows significant thinning of the Yusr sands to the North and anecdotal production evidence suggests a north-south split to the field of two separate turbidite lobes. This model has also been proposed for the Yusr field ~40km to the SE where positioning of lobes are thought to be controlled by relay ramp areas between faults. The location of the proposed pinch out is uncertain.

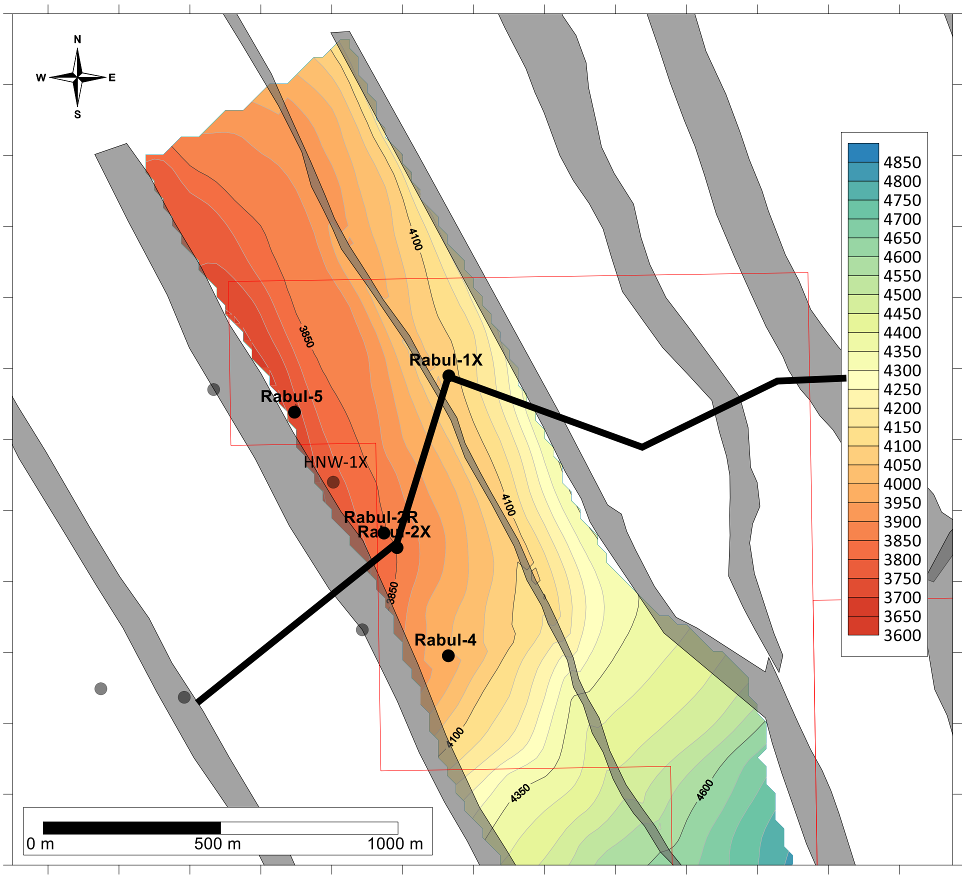

Figure 3.12: Top Yusr depth structure map for the Rabul field, Block H (Red outline)

A top structure map for the Bakr sand is presented in Figure 3.13, the black line on the map shows the location of the composite seismic line presented in Figure 3.14.

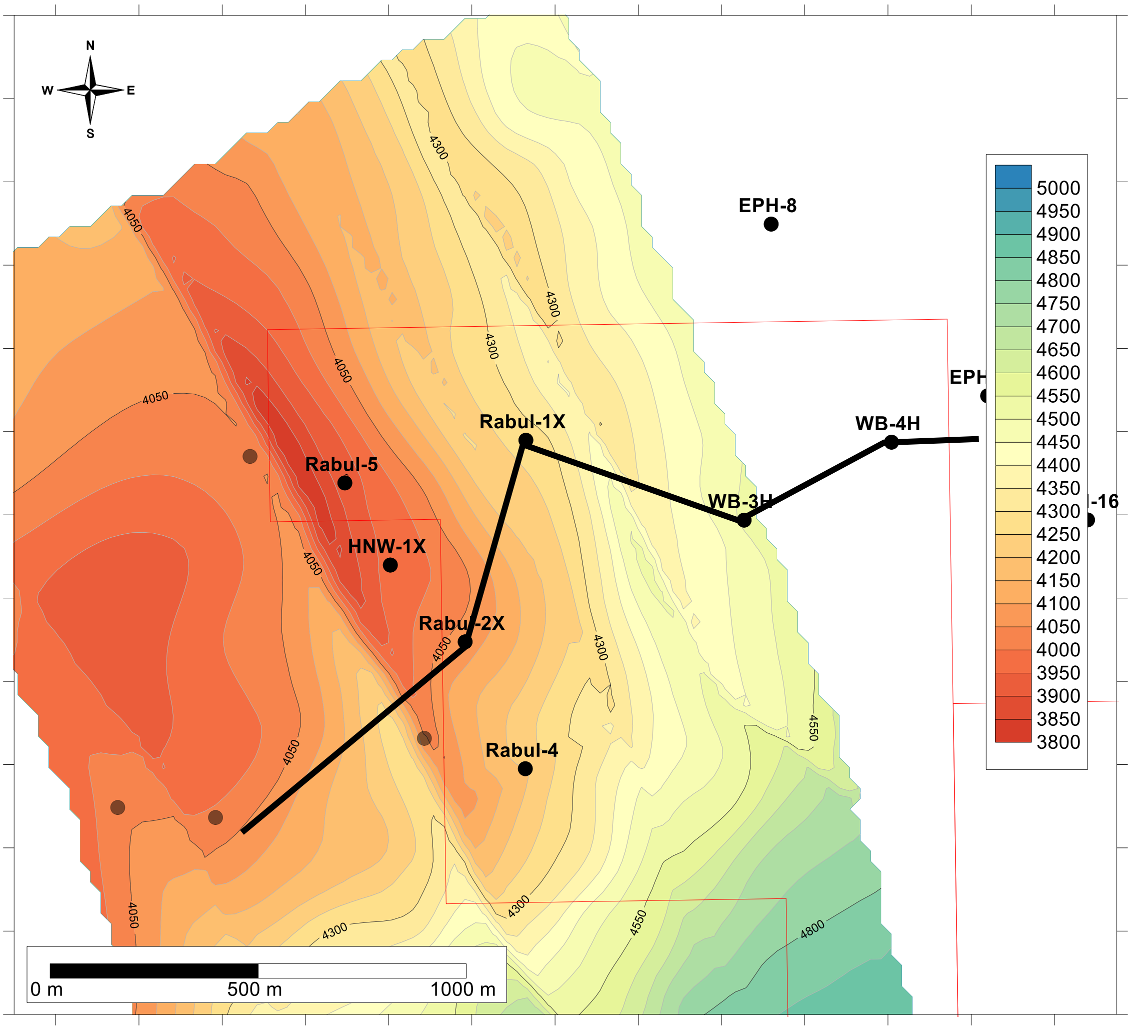

Figure 3.13: Top Bakr depth structure map for the Rabul field, Block H (Red outline)

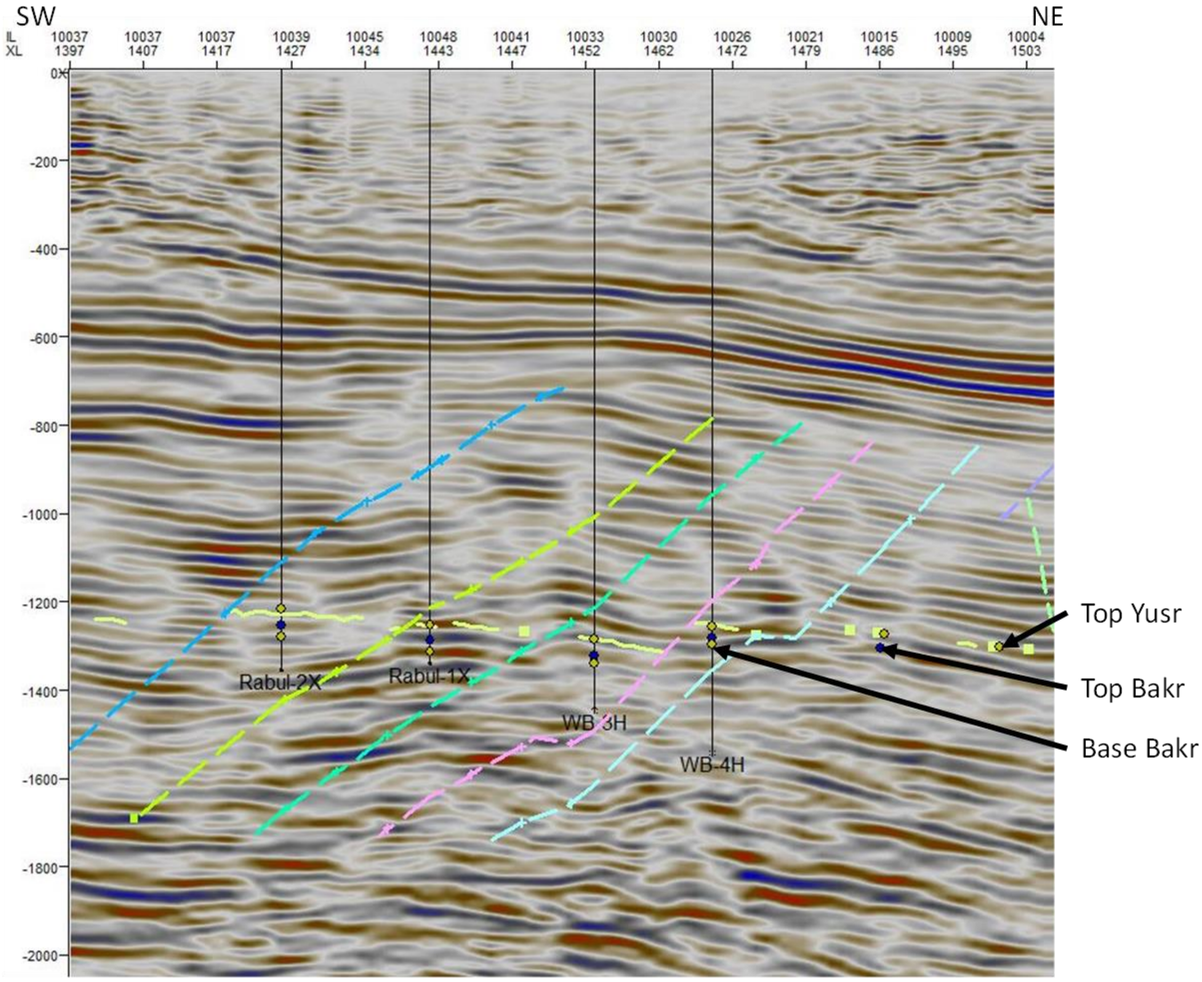

Figure 3.14: Composite seismic section through the Rabul field, Block H

3.2.4. Petrophysics

The Rabul-4 well was recently drilled and was reviewed by ERCE. The Rabul field does not have any core so input parameters are uncertain and there is no data for calibration of porosity, Sw or permeability. A neighbouring field, EPH, does have core and is analogous, however the data was not available.

Vsh was calculated from gamma ray using 5th & 95th percentiles, and from neutron/density cross plot; then the minimum of the two methods was used as the final Vsh. Vsh is typically overestimated so using the minimum of two methods helps to correct for this.

Porosity was estimated using the density log, assuming a clean sandstone matrix of 2.65 g/cm3 and apparent fluid densities were used that take into account mud based filtrate invasion into the formation. No hydrocarbon corrections were completed for this reason. Effective porosity was calculated from total porosity by assuming 15% shale porosity. This removes ineffective porosity in shaley intervals, but does not affect porosity in clean sands.

The sands are easy to pick from gamma ray response, and from neutron-density response, although they do not show a strong gas effect.

Water saturation (*Sw*) was determined from the Archie equation with the Archie parameters of *a*, *m* and *n* assumed to be 1, 1.8 and 2 respectively. As there is no core data, there is also no SCAL data for calibration of electrical parameters. The m value was picked from the slope of the Pickett plot.

No formation water data were available and hence *Rw* was selected from Pickett plots, assuming the lower Bakr is water bearing. Water salinity appears to be ~24 kppm, but is a key unknown.

Net reservoir interval was based on an effective porosity cut-off of >7 %, a Vsh cut off of <50 % and net pay also included an Sw cut off of <50 %. These cut offs were selected interactively in order to identify those intervals that were considered to be reservoir based on the log character. These cut offs are the same as SDX's.

ERCE and SDX have very similar interpretations for Vsh, Phit, Phie and net. However, there are some differences in the Sw, impacting the net thickness, which may be due to Archie parameters or Rw values used. There is also a noticeable difference when comparing resistivity based Sw to the saturation height function in Petrel. The height function is very pessimistic in the Yusr. ERCE believe the Sw-ht function will be reviewed by SDX at a later stage and so accepts SDX's petrophysical interpretation.

A comparison of the two petrophysical interpretations in well Rabul-4 is shown in Figure 3.15.

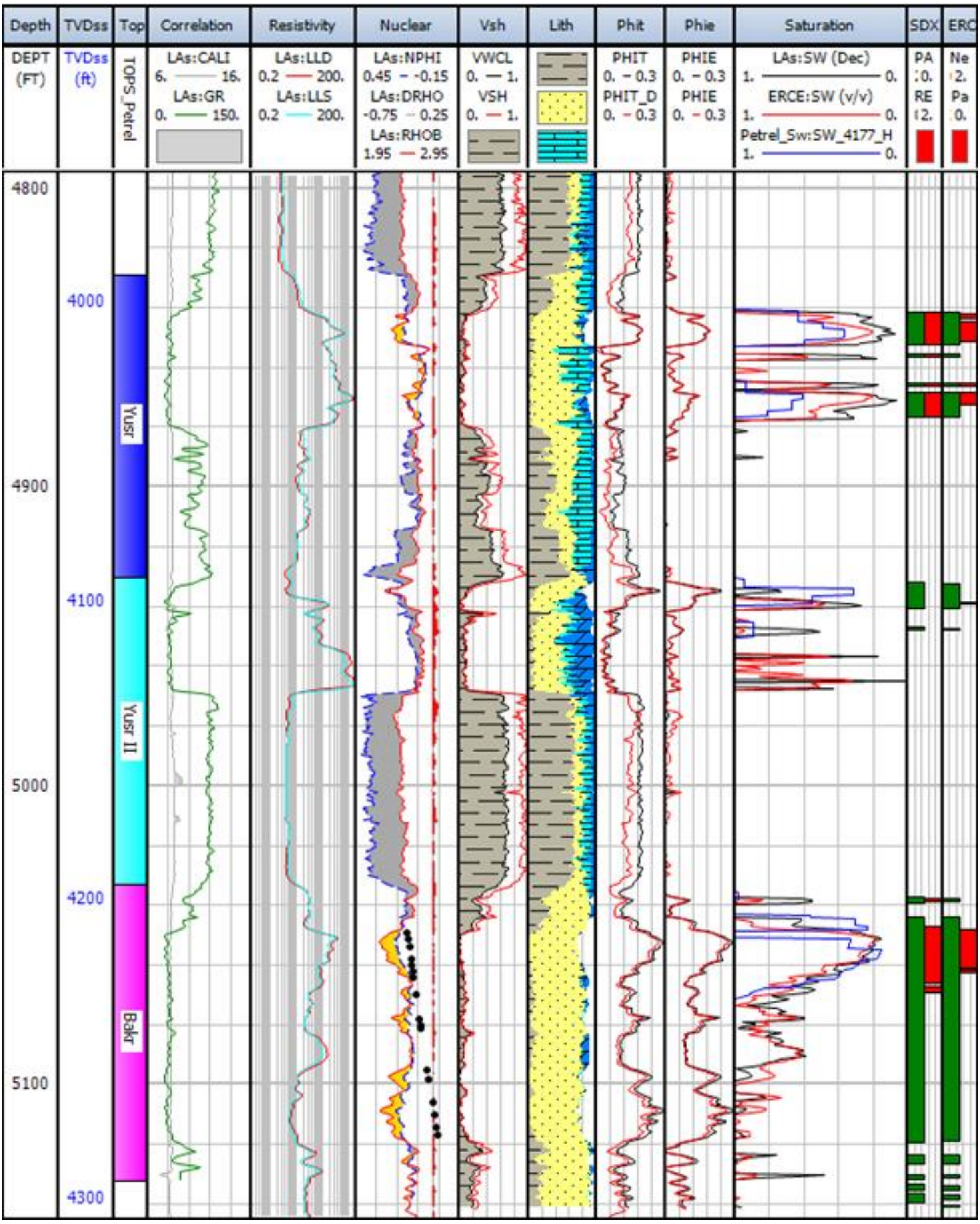

Figure 3.15: Petrophysical interpretation for Well Rabul-4

SDX interpreted curves are shown in black; ERCE interpreted curves are shown in red, with the Petrel Sw-ht function in blue. This well shows hydrocarbon bearing Yusr and Bakr intervals. The SDX and ERCE interpretations are similar.

3.2.5. Reservoir Engineering

The crude oil sample obtained using a MDT tool in Well Rabul-1X from the Yusr sand had a density of 927 kg/m3 (15.6°API) and a GOR of 50 scf/stb; similar to the undersaturated oil in the Meseda field. A PVT study on the MDT sample was used to define fluid properties. The oil formation volume factor is 1.042 at a reservoir pressure of 1,813 psia. In situ oil viscosity was measured at 78 cP (at a reservoir temperature of 157 deg F) which is slightly higher than the samples from Meseda which are in the range 14 – 57 cP.

The oil gradient from the MDT measurements in the Bakr sand in Rabul-2X (0.40 psi/ft vs 0.42 psi/ft in Yusr) suggests Bakr oil may be slightly lighter and a oil characrterisation report from December 2017 would seem to indicate Bakr oil from this well is ca. 17 deg API.

A plot of the MDT wireline pressures taken in the five Rabul wells is shown below (Figure 3.16). Pressures indicate aquifer support in both the Yusr and the Bakr, with stronger support in the Bakr. The Yusr shows some differential depletion in the different sands mapped from the logs. The Bakr barely showed any depletion up to April 2018 but after continued high production from the Rabul-5 Bakr well, Rabul-2R MDTs did indicate a limited depletion in the Bakr (ca. 100psi). These pressures, along with available production and PVT data were input into a simple material balance model which confirmed that an active aquifer must be present to match the pressures seen in Rabul-4 and Rabul 5 MDTs. Stabilised ESP inlet pressures recorded in Rabul-2X and Rabul-5 suggest a similar story. This means a higher recovery factor may be achievable from the Rabul field due to this pressure support.

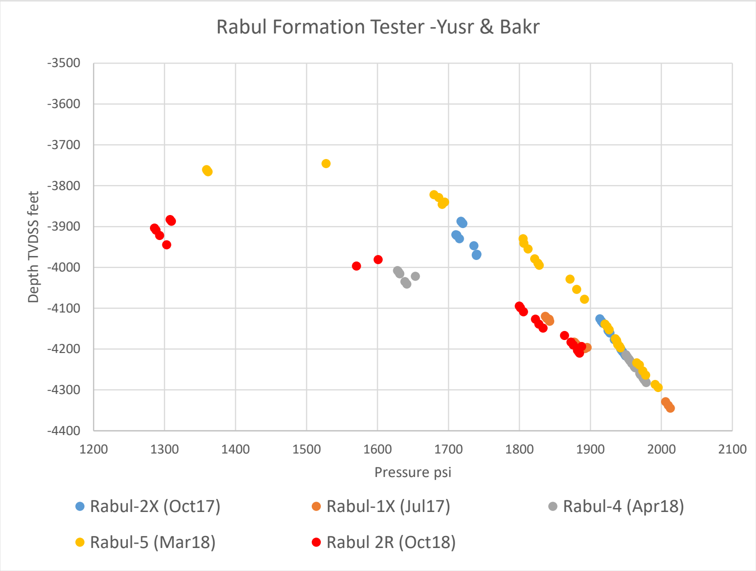

Figure 3.16: Rabul field MDT pressure plot

It should be noted that both Rabul-1X and 2X Yusr were depleted relative to the Bakr aquifer gradient when drilled which is likely caused by offtake from the EPH field to the East which mainly produces from the Yusr sands. The pressure plot does not help resolve the OWC in either sand.

3.2.6. Hydrocarbons Initially In Place

SDX presented ERCE with an updated static model complete with the new on lease wells. We have audited the mid case STOIIP value of 10.9 MMbbl with respect to GRV and reservoir parameters and found it to be reasonable.

3.2.7. Production Performance

Rabul-1X started production in September 2017 from the Yusr, initially producing at 500 bopd and has seen a steady decline; end December 2018 Rabul-1X was producing 215 bopd at 40% watercut. Rabul-2X was completed in the Bakr and commenced production in November 2017 at 475 bopd. This rate was increased to 1300 bopd in February 2018 when the SRP was replaced by an ESP, however watercut rose rapidly in the well. This was assumed by SDX to be due to a poor cement job which was channelling water into the well. Rabul-2X was sidetracked to a near-by location in October 2018 but Rabul-2R unfortunately experienced a similar issue with bad cement and the Bakr completion in this well watered out quickly as well. It is now planned to recomplete to the Yusr in this well in 3Q2019.

Rabul-5 started production from the Bakr in March 2018 at the significant rate of 2,200 bopd, and at the end of December 2018 it was producing 750 bopd at 79% watercut. Rabul-4 started production from the Bakr in May 2018 at 400 bopd but the watercut rose very rapidly in this well and the Bakr was shut in at the end of June 2018 at 97% watercut. The well was recompleted to the Yusr in mid-July, and the well was producing steadily in December 2018 at 290 bopd at <10% watercut. Field production plots are presented below in Figure 3.17 and Figure 3.18

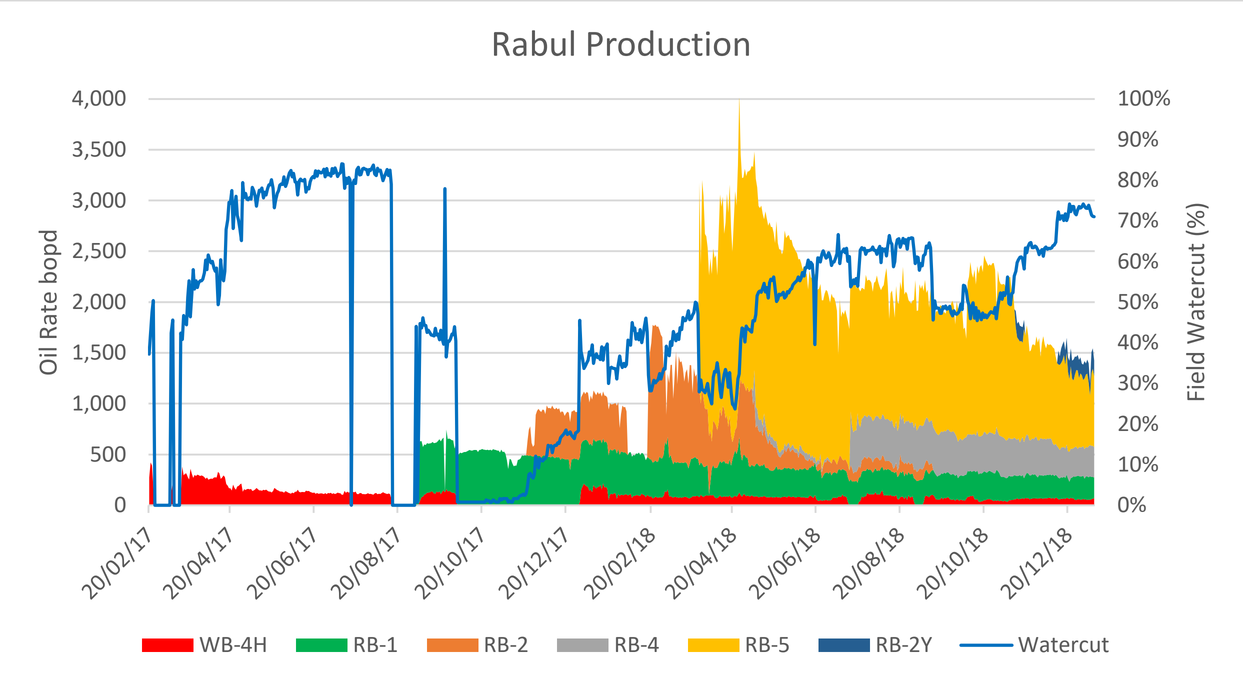

Figure 3.17: Oil production History by Well

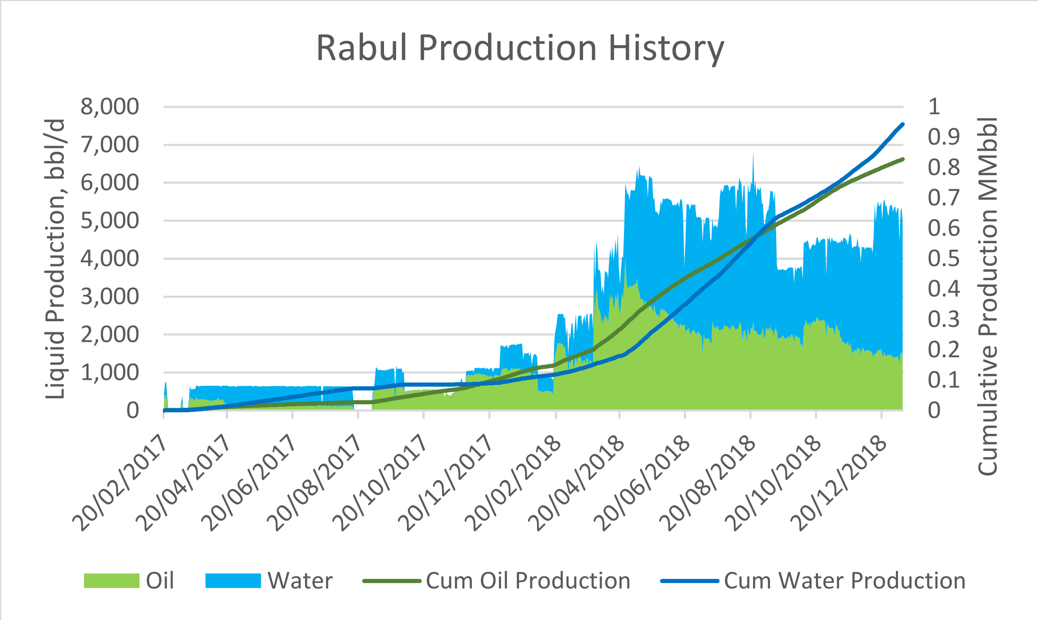

Figure 3.18: Total Oil and Water Production History at Rabul

It should be noted that HNW-1, the GPC well across the lease line, was producing at 960 bopd at 34% watercut in July 2018 but no further production information was available for this well or the additional wells drilled by GPC across the lease line.

3.2.8. Recoverable Resources

Recoverable resources were estimated for this update using performance based methods. SDX were in the process of updating the simulation model at YE 2018 but it was not complete in time for this audit. Undeveloped resources are based on the range of performance seen to date across the Rabul wells, taking into account the comparative net sand in different wells and on lease STOIIP estimates in each fault block.

Proved developed producing recoverable resources were based on aggregating the results of individual well declines, using exponential decline because it is still relatively early in field life for assessing long term reservoir behaviour across all areas of the feld. Proved undeveloped recoverable resources associated with Rabul-5/Rabul-2R recompletions to the Yusr are in line with the Rabul-4 Yusr 1P forecast. The proposed Rabul-7Y well is also targeting the Yusr sand, North of Rabul-5. In the ERCE profiles we have accounted for the fact that the the Yusr I sand is thin in Rabul-5. In the 1P scenario it is assumed no additional recovery is seen in the Yusr due to water injection (as improved sweep is unproven).

The proposed WB-5H well and a notional Northern Bakr well are included in the forecast as Contingent Resources, pending approval. It is assumed WB-5H performs like WB-4H in the 1C scenario and the Northern Bakr also carried limited 1C resources due to the uncertainty in extent of sands to the North.

Probable developed producing recoverable resources were based on aggregating the results of individual well declines, using hyperbolic decline, b=0.5. Material Balance suggest there must be strong aquifer support in both Yusr and Bakr and watercut appears to be stabilising in some wells suggesting some tail production could be expected. Probable undeveloped recoverable resources associated with Rabul-5/Rabul 2R Yusr recompletions are in line with Rabul-4 base performance. Rabul-7Y forecasting has captured greater uncertainty compared to Rabul 4 performance and Yusr water injection is assumed to increase Yusr recovery factor by ~4% by improving sweep.

2C resources assume WB-5H performs slightly better than WB-4H due to higher net pay and the Northern Bakr well performs as per SDX's original prediction for a Northenr Bakr well (0.17 MMbbl)

Possible developed producing recoverable resources were based on aggregating the results of individual well declines, using harmonic decline, assuming the field produces like Meseda. Rabul-5/Rabul 2R Yusr recompletions are in line with Rabul-4 high case performance as is Rabul-7Y and Yusr water injection is assumed to increase Yusr recovery factor by ~7% by improving sweep.

3C resources assumes the Northern Bakr well produces in line with Rabul-5 Bakr and assumes WB-5H performs twice as well as WB-4H, more in line with main Rabul wells and Yusr water injection improves Yusr recovery factor by ~7%.

ERCE has accepted the SDX on lease STOIIP of 10.9 MMbbl in the main Rabul area, and independently calculated a 3 MMbbl on lease STOIIP in WB-4H block to the East. Applying the ERCE forecasts a 2P+2C recovery factor of 17% is forecast on the total on-block STOIIP. However it should be noted that with the shift in focus to development of the Yusr, recovery factors approach 35% - 40% using on block STOIIP values in that reservoir interval.

Note that the Contingent resources are assessed to have a 90% Chance of Development, but are considered Development on Hold, pending government approval to proceed.

Table 3.3: Rabul field recoverable resources estimates as of December 31, 2018, before Economic Limits Applied

Category	EUR Mbbl	Production Mbbl	Resources (1) Mbbl	Interest %	Resources (2) Mbbl
PDP	1,072	815	257	50%	128
PD	1,072	815	257	50%	128
1P	1,422	815	607	50%	303
2P	2,118	815	1,303	50%	652
3P	3,166	815	2,351	50%	1,175
1C	128	-	128	50%	64
2C	287	-	287	50%	144
3C	634	-	634	50%	317

1. *Recoverable Resources are prior to applying an ELT*
2. *Working interest recoverable resources are the Company share of the field gross resources*

3.2.9. Production Forecasts

Decline based production forecasts were generated for the existing wells and profiles were generated for the proposed new wells based on existing wells as outlined under Section 3.2.8. Various Reserves categories are presented in Figure 3.19.

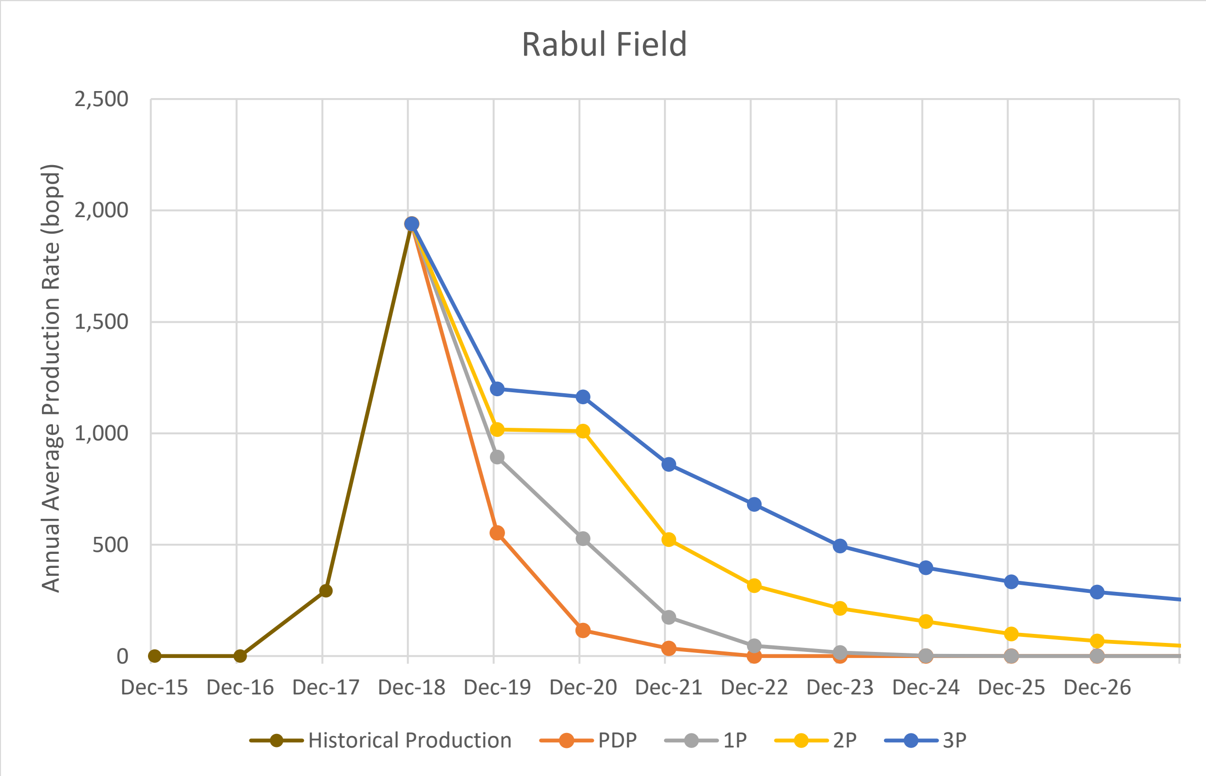

Figure 3.19: PDP, 1P, 2P and 3P production forecast for the Rabul field

3.3. Reserves and Net Present Values

The Reserves estimates were based on the Meseda and Rabul combined production forecasts cut off at the economic limit (or licence expiry) as determined by production and revenue analysis.

Crude oil revenue was derived from the production forecasts and the forecast Meseda crude oil price presented in Table 2.2. A 26% discount to Brent was based on the average discount estimated during 2017-2018.

Operating cost forecasts were based on budget information provided by SDX and actual costs for the Meseda field.

The working interest partners in Meseda and Rabul also have a 50-50 joint interest in the Brentford Oil Tool Company ("Brentford"), which operates the oil export infrastructure for the Meseda-Rabul concession. Both SDX and Dublin receive a dividend payment from Brentford, dependent on the profitability of the entity. This profitability is directly related the the export volumes of liquid hydrocarbons from Meseda and Rabul. As such, ERCE has included this dividend as "other income" attribuatable to the field, as the income from this dividend impacts the estimate of ELT of the field. SDX has provided ERCE historic dividend payments and a methodology for the forward estimate of dividend payments as a function of oil production. This income as treated as taxed and therefore equally contributes to SDX's pre and post tax value. ERCE has relied upon SDX for the accuracy of this calculation.

Forecasts of production and costs and Other Income can be found in Appendix 3.

Fiscal terms were based on production service agreement which expires on 10 November 2031. The service agreement involves an element of risk and as such Reserves can be assigned to SDX. The contractor revenue is based on a service fee which is 38.5% of the production revenue for the first 1,000 bopd and then 38% for rates above this. The contractor is charged a tariff fee based on incremental tiers that vary with the production rate and typically work out at around $0.5/bbl. Corporation tax of 22.5% is paid on behalf of the contractor by EGPC and this has been included when determining the net entitlement volumes. Costs were inflated at 2%.

A summary of the Reserves and net present value estimates are presented in Table 3.4, Table 3.5 and Table 3.6 respectively for each Reserves category.

Table 3.4: West Gharib Block H Reserves estimates as of December 31, 2018

Category	Field Gross Mbbl	Company Gross WI Mbbl	Company Net Entitlement Mbbl
PDP	4,535	2,268	869
PD	5,398	2,699	1,034
PUD	29	14	4
1P	5,427	2,713	1,038
2P	9,113	4,556	1,743
3P	12,197	6,099	2,329

1. *Company gross working interest Reserves are based on 50% of the field gross Reserves*
2. *Company net entitlement Reserves are based on Company share of the service fee*

Table 3.5: West Gharib Block H Before Tax Net Present Values as of December 31, 2018

Category	Company Share of Net Present Values at various discount rates (US$ MM)				
	0%	0%	5%	10%	15%
PDP	22	21	21	20	20
PD	25	25	24	24	23
PUD	2	2	2	2	2
1P	27	27	26	25	25
2P	55	53	52	51	50
3P	84	82	80	78	76

1. *Based on forecast prices and costs as of 1 January 2019 (see Table 2.2)*
2. *Interest expenses, corporate overheads etc were not included.*
3. *The net present values may not represent the fair market value of the Reserves.*

Table 3.6: West Gharib Block H After Tax Net Present Values as of December 31, 2018

Category	Company Share of Net Present Values at various discount rates (US$ MM)				
	0%	5%	10%	15%	20%
PDP	18	16	15	14	13
PD	21	18	16	15	13
PUD	2	2	2	2	2
1P	22	20	19	17	16
2P	44	38	33	29	26
3P	67	56	47	41	37

1. *Based on forecast prices and costs as of 1 January 2019 (see Table 2.2)*
2. *Interest expenses, corporate overheads etc were not included.*
3. *The net present values may not represent the fair market value of the Reserves.*

Cash flow tables for each Reserves category are presented in Appendix 3.

4. South Disouq Concession

4.1. Introduction

The South Disouq block covering 828 km^2 is located in the Nile Delta region of northern Egypt 150 km north of Cairo. SDX was awarded the exploration concession in April 2013 as part of an Egyptian Natural Gas Holding Company ("EGAS") sponsored bid round. In August 2014 SDX farmed out a 45% working interest to IPR Energy Resources Ltd. ("IPR") leaving SDX with 55% and operatorship.

In 2015-2016 SDX acquired a 300 km^2 3D seismic survey over part of the concession area as a precursor to exploration drilling. The minimum work programme required the drilling of one exploration well which SDX drilled during 2017 resulting in the South Disouq gas discovery. The well (SD-1X) found gas in the Abu Madi sands and tested at gas rates up to 25 MMscf/d with 5 bbl/MMscf of condensate.

Following development studies work SDX submitted a field development plan to the government in September 2017 based on a fast track development with a modular (early) production facility ("EPF") and a 12" pipeline tied into the national grid 10 km away.

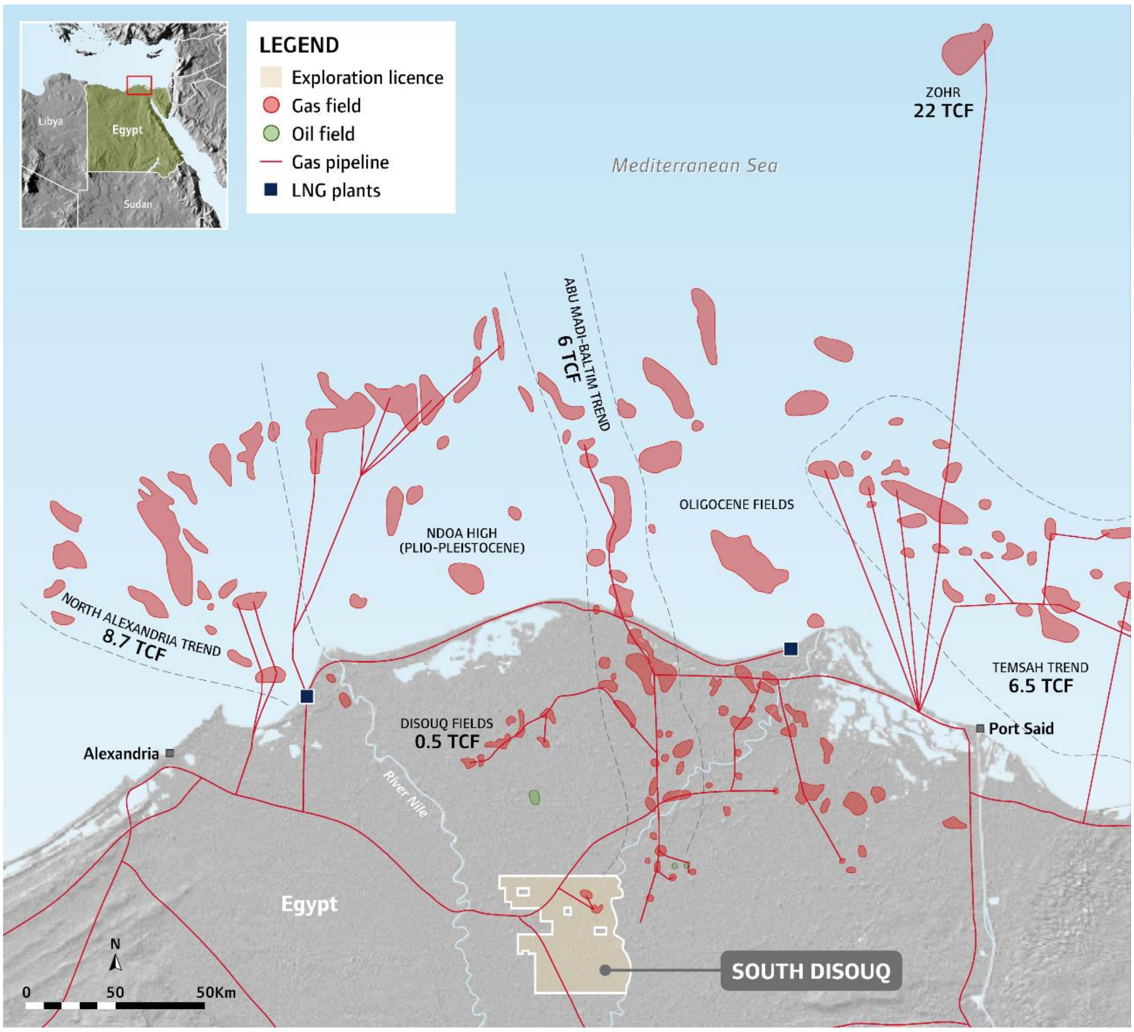

Figure 4.1: Location map for the South Disouq concession (source SDX)

As part of the concession development in 2018 SDX drilled three more wells that encountered hydrocarbons; SD-3X, SD-4X and Ibn Yunus-1X. SD-3X and SD-4X appraised the Abu Madi discovery made by SD-1X (this Abu Madi discovery is termed the South Disouq field). SD-3X also made a new discovery in the Kafr El Sheik (KES) reservoir. Ibn Yunus-1X made a new discovery in the KES reservoir. These KES discoveries have now been incorporated into the concession development plan.

4.2. Development History

There has been no development to date within the South Disouq area although that is now changing following the recent discoveries. SDX is pressing ahead with the development of the South Disouq field and has been putting in place permits and tendering and purchasing supplies and services for the construction a 12” pipeline, intra-field pipelines and a central processing facility (CPF).

4.3. Geological Description

The South Disouq concession lies on the flexure zone between the Northern Nile Delta Basin and South Delta Block. The SD-1X discovery proved a continuation of the Miocene Abu Madi gas play which is common in fields to the north and east of the concession. In addition, the Ibn Yunus-1X and SD-3X discovery wells proved gas in turbidite fans located at the base of the Kafr El Sheik formation. The licence also contains the potential for Western Desert carbonate plays which are discussed in Section 4.10.

The Abu Madi reservoir was deposited as fluvio-deltaic infill of a base Messinian incision event (Figure 4.2) which formed large canyons systems throughout the paleo-Nile delta area. One such canyon system can be clearly seen on seismic within the South Disouq area. During the Messinian, sea level rise led to filling of these canyon systems, initially with the Qawasim formation and after another smaller incision event, the Abu Madi formation. Within the South Disouq area braided channel sandstones and point bars with minor shales are expected to be the main depositional elements present. There is no core data available, so this is based largely on analogue information and setting within the canyon system from seismic data and image logs. Extensive, thick deep water shales of the Kafr El Sheik formation provide a good regional seal, though there is the possibility of deep water channels lying directly on top of the Abu Madi acting as thief sands. As is common for the Abu Madi play, structures are formed by compactional drape over deeper incised valley paleotopography. Analog information, such as from the Abu Madi field show that there can be a stratigraphic component to structures and/or sealing against the walls of the incised valley.

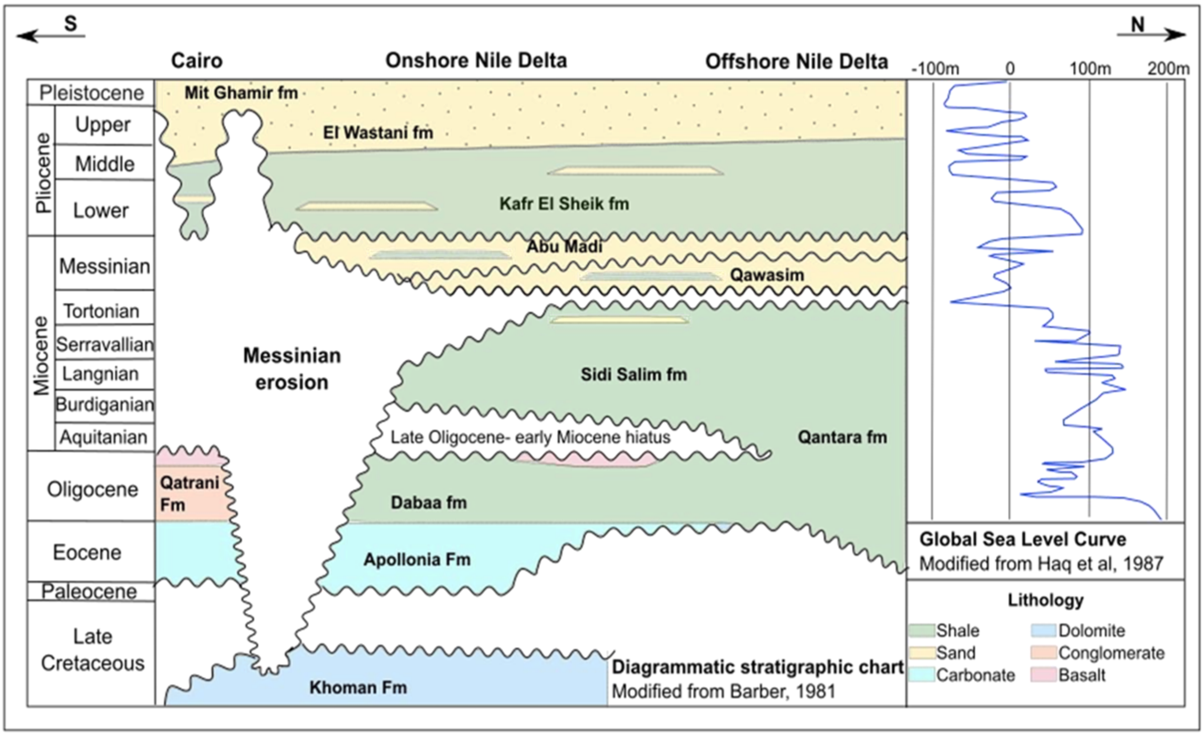

Figure 4.2: Chrono-stratigraphy of the Nile Delta region (modified from Barber, 1981 and Haq et al, 1987)

4.4. South Disouq Abu Madi Discovery

The South Disouq discovery is defined as a 4-way dip closure formed by compactional drape of the Abu Madi formation over incised channel paleotopography. Wells SD-1X, SD-3X and SD-4X have all encountered Abu Madi sands of good quality where present with high porosities and high permeabilities, but a relatively low NTG. The Abu Madi has been split into three sandstones (AM-I, AM-II and AM-III) separated by intraformational shales. Only wells SD-1X and SD-3X encountered AM-I, and there is an observed decrease in the thickness and quality of the AM-III to the east. Differing GWCs are observed (discussed in Section 4.4.1.2).

A top structure map for the Abu Madi I sand is presented in Figure 4.3.

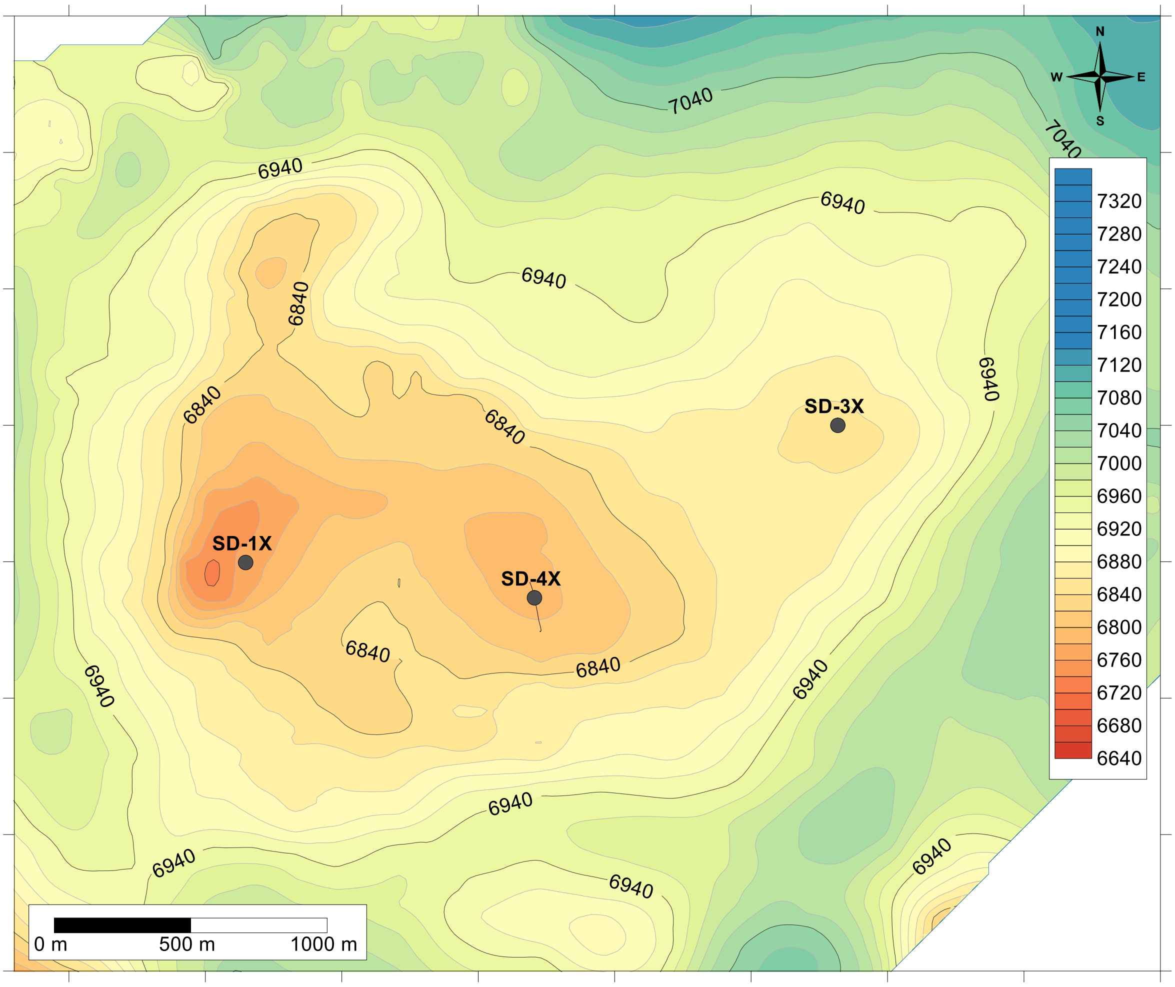

Figure 4.3: Top Abu Madi I depth structure map for the South Disouq discovery

One 3D seismic pre-stack depth migrated volume covers the South Disouq area. A regional 2D line has been used to tie the volume to the nearby Tanta-1 well, other nearby wells have also been tied. ERCE has briefly reviewed the seismic interpretation which was found to be reasonable. Top Abu Madi is clear on seismic as is the Base Messinian Unconformity, however the separation of Messinian incised valley fill into the individual Abu Madi sand units is challenging (Figure 4.4). The three wells provide control on the top location of the intra Abu Madi sands at the location of the wells, but significant uncertainty remains between well control. A relationship between amplitude and reservoir presence or quality has not been established for the Abu Madi interval, but it does give a guide to fault location and channel architecture.

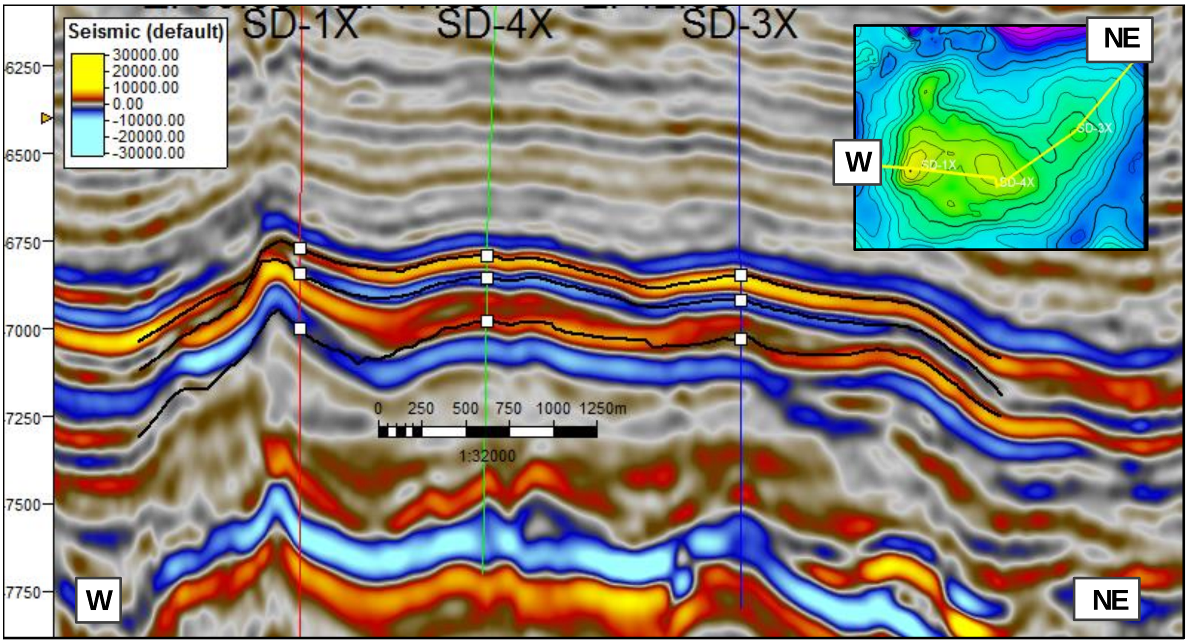

Figure 4.4: Seismic section through the South Disouq discovery

4.4.1.1. Petrophysics

The recently drilled SD-3X and SD-4X wells were evaluated by ERCE, focussing on the Abu Madi interval, including the AM-II, AM-II and AM-III sands; as well as the KESd and KESb intervals in SD-3X. No cores have been taken in these wells, or on the field at all, and as such the petrophysical interpretations are uncalibrated and have a high degree of uncertainty.

The AM III interval is thinly bedded with beds thinner than 1m. High resolution wireline logging tools were run to acquire the best data, however even this data may not resolve the beds fully.

Vsh was calculated from gamma ray using 5th & 95th percentiles, and from neutron/density cross plot; then the minimum of the two methods was used as the final Vsh. Vsh is typically overestimated so using the minimum of two methods helps to reduce this.

Porosity was estimated using the density log, assuming a clean sandstone matrix of 2.65g/cm3, and apparent fluid densities were used that take into account mud based filtrate invasion into the formation. No hydrocarbon corrections were completed for this reason. Effective porosity was calculated from total porosity by assuming 12% shale porosity. This removes ineffective porosity in shaley intervals, but does not affect porosity in clean sands.

Water saturation (*Sw*) was determined from the Archie equation with the Archie parameters of *a*, *m* and *n* assumed to be 1, 1.8 and 2 respectively. As there is no core data, there is also no SCAL data for calibration of electrical parameters. The m value is determined from the slope of the Pickett plot and 1.8 matches well to the data.

An MDT water sample was acquired in well SD-1X, indicating a water salinity of approximately 50kppm NaCl equivalent. A produced water sample form the same well had a measured salinity of ~62kppm NaCl equivalent, which ERCE considers to be within the range of uncertainty.

Net reservoir interval was based on an effective porosity cut-off of >10%, a Vsh cut off of <50% and net pay also included an Sw cut off of 70%. These cut offs were selected interactively in order to identify those intervals that were considered to be reservoir based on the log character. These cut offs are the same as were used in the SD-1X well, and similar to cut offs used by SDX.

Having completed an independent view of the petrophysics, ERCE accepts SDX's petrophysical interpretation.

A comparison of the two petrophysical interpretations in Well SD-3X and SD-4X are shown in Figure 4.5 and Figure 4.6 respectively.

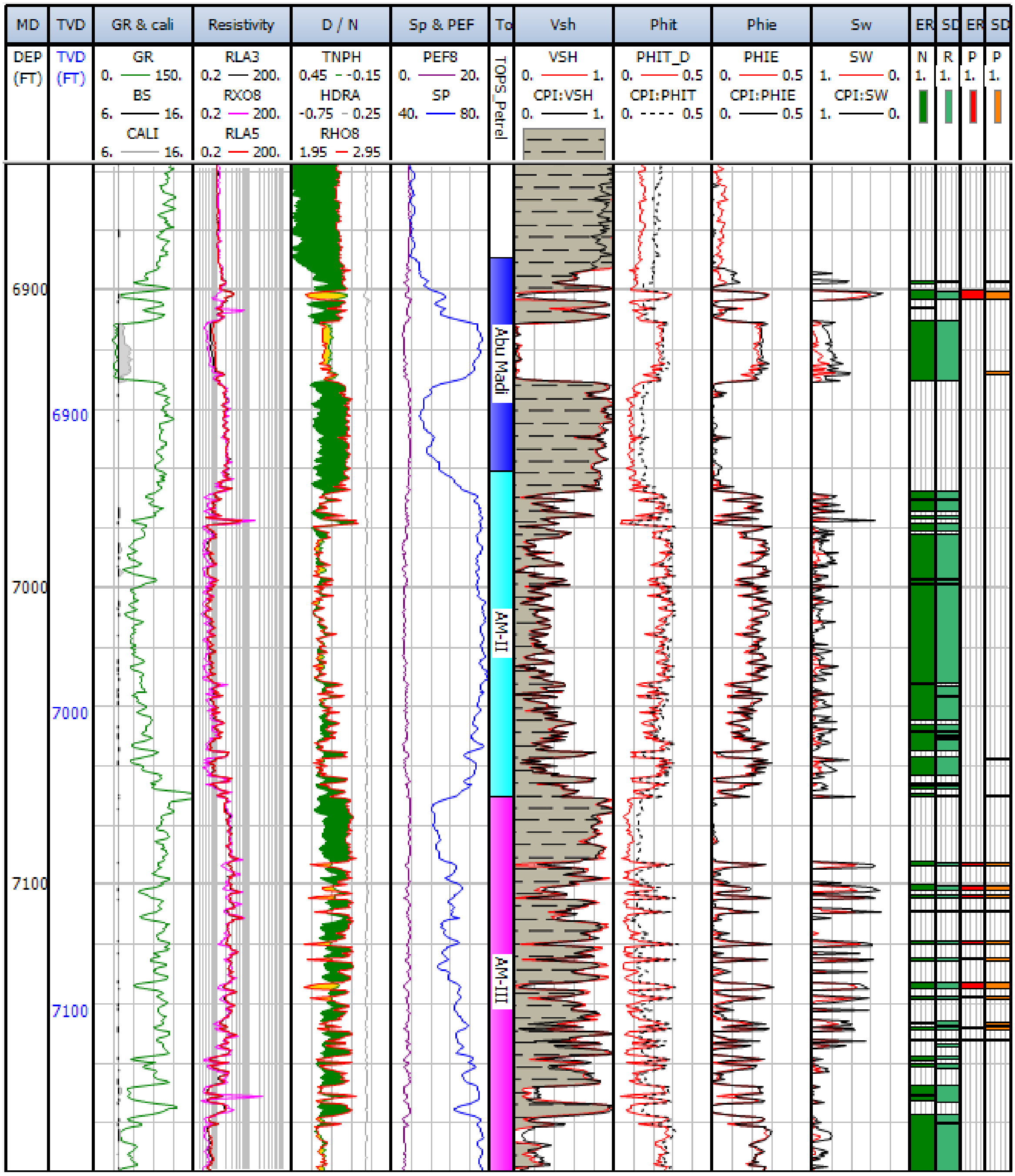

Figure 4.5: Petrophysical interpretation for Well SD-3X

SDX interpreted curves are shown in black; ERCE interpreted curves are shown in red. This well shows a thin gas bearing upper AM I sand above a water bearing thicker AM I sand. The AM II sand is water bearing. The AM II is comprised of thinly bedded sands with a gas down to ~7097ft TVDss. The two interpretations are considered to be within acceptable ranges of uncertainty and so SDX's interpretation is accepted.

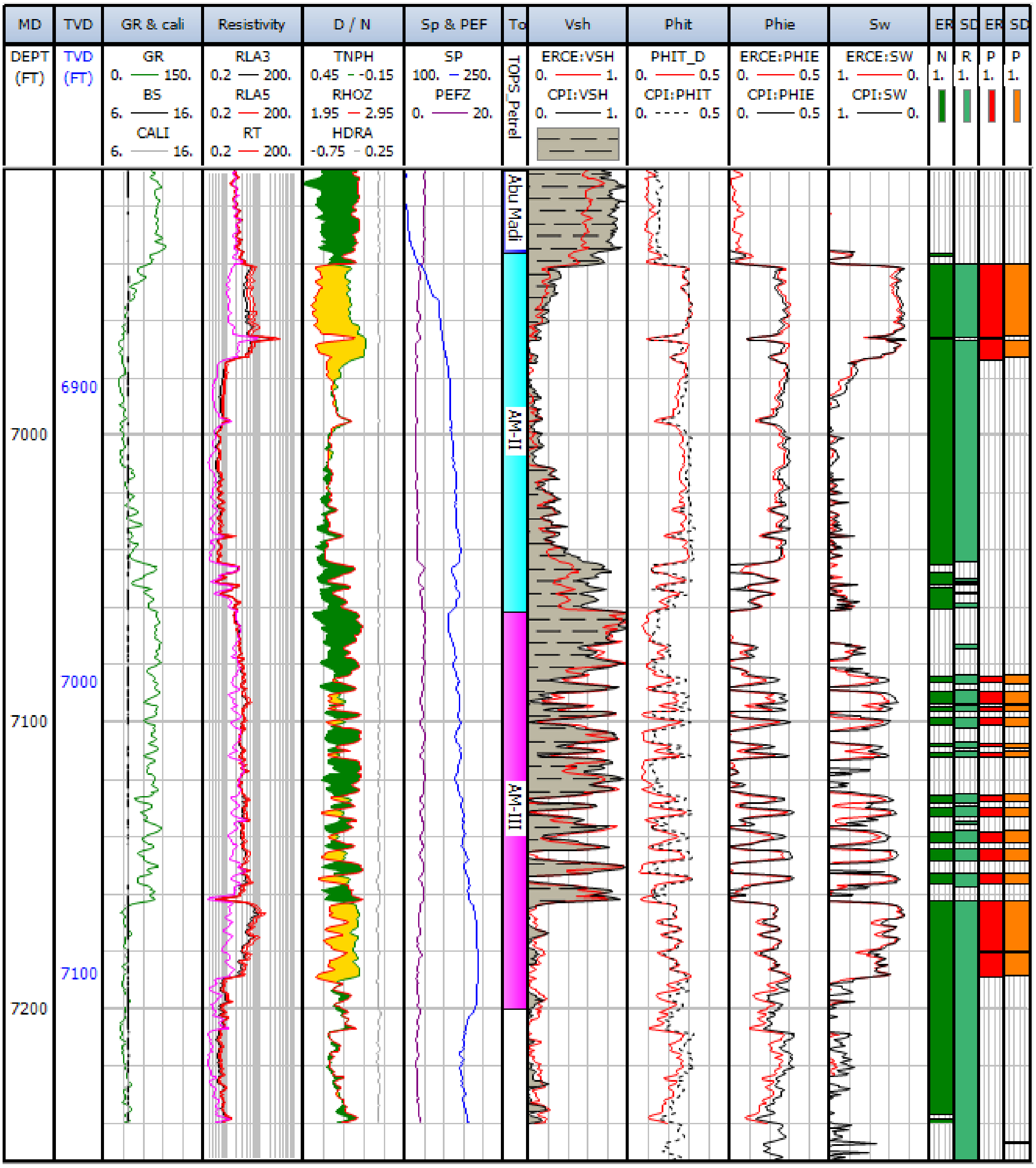

Figure 4.6: Petrophysical interpretation for Well SD-4X

SDX interpreted curves are shown in black; ERCE interpreted curves are shown in red. This well shows a thick gas bearing AM II sand with a gas water contact ~ 6891ft TVDss. The AM III is comprised of thinly bedded sands, then a thicker sand with a gas water contact ~7101ft TVDss. The two interpretations are considered to be within acceptable ranges of uncertainty and so SDX's interpretation is accepted.

4.4.1.2. **Reservoir Engineering**

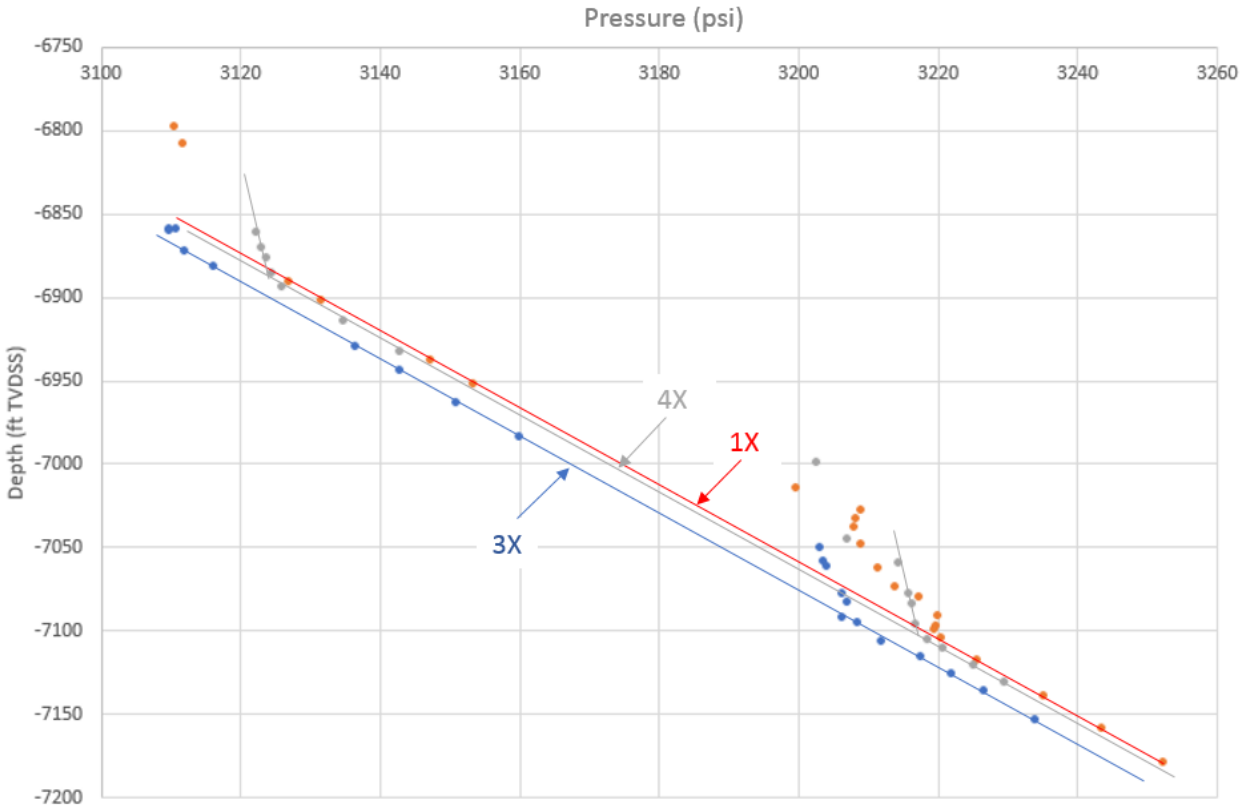

Figure 4.7: MDT pressures recorded in Wells SD-1X, -3X and -4X

Generally, the aquifer pressures in each well lie on a single straight line. However, the aquifer pressure lines in the different wells are offset relative to each other. In Well SD-4X, the pressures measured in the gas legs lie on lines consistent with gas gradients (~0.06 psi/ft). In the other wells, the pressures measured in the gas legs are very scattered.

Against this background, we consider that the MDT pressures measured in Well SD-4X may give a guide to the depths of the gas water contacts in the well in the AM-I, -II and AM-III sands, especially as the inferred contact depths are consistent with petrophysically derived values. However, we do not consider that they can give guidance on the contact depths in the other wells and the existence of stacked gas sands remains a possibility.

Well Test Interpretations

Well SD-1X

Well SDX-1X tested a perforated interval of 7,064 to 7,132 ft DF within the AM-III sand. The base of the perforations was 18 feet above the interpreted GWC to avoid early water production. The interval tested at rates of up to 26 MMscf/d through 3.5” tubing with an average CGR at separator conditions (220 psi and 91 °F) of five bbl/MMscf. A summary of the sequence of events is provided in Table 4.1.

Table 4.1: Well SD-1X well test - Sequence of events

Period	Duration (hrs)	Gas rate (MMscf/d)	Condensate rate (bbl/d)	Water rate (bbl/d)	Bottomhole pressure (psia)	Condensate gas ratio (bbl/MMscf)
Clean-up	7.0	Up to 26				
Initial b/u	12.0				3189	
Main flow 1	11.8	4.8	21.8	0	3178	5
Main flow 2	11.0	7.8	22.6	0	3167	3
Main flow 3	28.3	9.8	46.0	4	3162	5
Final b/u	100.0				3187	

The well test was analysed by SDX with the final build up providing estimates of permeability thickness and skin. SDX has matched the response using a radial composite model. A log-log plot is presented in Figure 4.8 and shows evidence of late time boundaries. ERCE interpreted the test independently and matched the response assuming 2 parallel faults (no flow boundaries most likely related to the GWC) at approximately 1,100 ft from the well. Although the models are different, ERCE concurs with SDX that the boundaries are likely the result of edge water. The interpreted permeability thickness is 15,200 mD.ft which equates to a permeability of 240 mD. A total skin of 5 was interpreted with the test unable to resolve any non-Darcy component. The reservoir pressure is interpreted to be 3,215 psia at top perfs and reservoir temperature is 189 deg F.

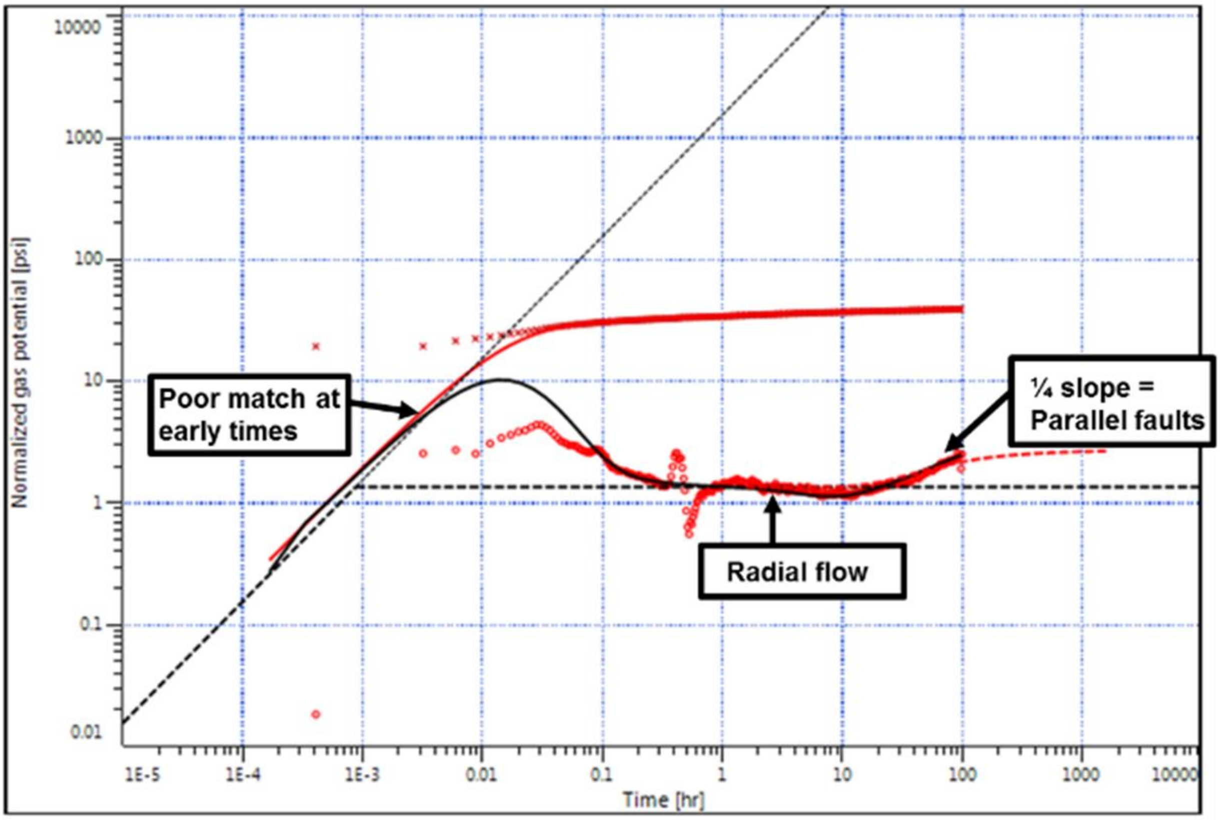

Figure 4.8: Well SD-1X log-log plot for final build up

Well SD-4X

Well SDX-4X tested a perforated interval of 7,084 to 7,170 ft MD RKB within the AM-III sand. The base of the perforations was about 20 feet above the interpreted GWC to avoid early water production. The interval tested at rates of up to 30 MMscf/d through 3.5" tubing with an average CGR at separator conditions (220 psi and 91 °F) of three to four bbl/MMscf. A summary of the sequence of events is provided in Table 4.2.

Table 4.2: Well SD-4X well test - Sequence of events

Period	Duration (hrs)	Gas rate (MMscf/d)	Condensate rate (bbl/d)	Water rate (bbl/d)	Bottomhole pressure (psia)	Condensate gas ratio (bbl/MMscf)
Clean-up	12.0	Up to 30				
Initial b/u	14.0				3180	
Main flow 1	12.0	5.4	18.0	3	3171	3
Main flow 2	12.0	8.6	38.0	8	3162	4
Main flow 3	24.0	10.5	45.0	7	3157	4
Final b/u	144.0				3180	

The well test was analysed by SDX with the final build up providing estimates of permeability thickness and skin. SDX has matched the response using a model incorporating two intersecting faults, both at a distance of approximately 1400 feet from the wellbore. The log-log plot for the main build-up is shown in Figure 4.10 and shows the upturn in the derivative associated with the presence of boundaries.

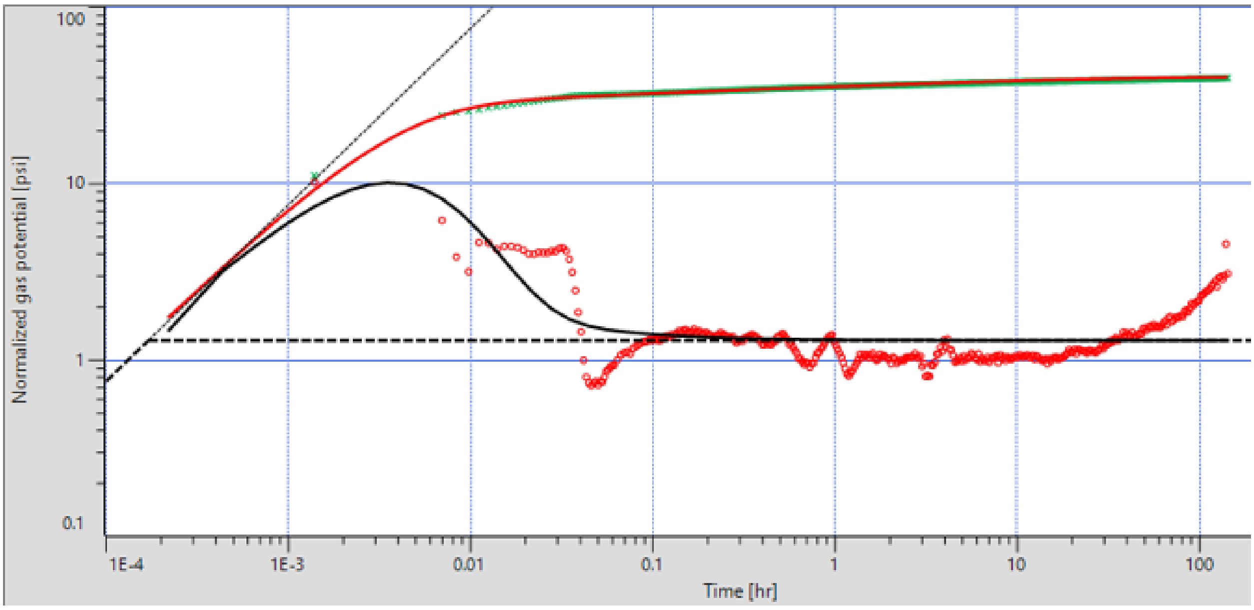

Figure 4.9: Log log plot for Well SD-4X main flow period

ERCE interpreted the test independently and agrees with the values of permeability-thickness and skin factor determined by SDX. ERCE also agrees with the possible existence of one or more no flow boundaries at a distance of approximately 1400 ft from the well. ERCE considers that these are likely be related to the location of the gas water contact rather than faulting.

ERCE estimated the minimum connected gas volume indicated by the test to be approximately 60 Bscf which is consistent with the volume inferred from volumetric analysis.

Well SD-3X

Well SDX-3X tested a perforated interval of 7,093 to 7,140 ft MD RKB within the AM-III sand. The interval tested at rates of up to 16 MMscf/d through 3.5" tubing with an average CGR at separator conditions of between four and five bbl/MMscf. A summary of the sequence of events is provided in Table 4.3.

Period	Duration (hrs)	Gas rate (MMscf/d)	Condensate rate (bbl/d)	Water rate (bbl/d)	Bottomhole pressure (psia)	Condensate gas ratio (bbl/MMscf)
Clean-up	7.0	Up to 16			3021	
Initial b/u	12.0				3137	
Main flow 1	6.0	5.3	24.0	0	3093	4
Main flow 2	6.0	8.4	41.0	3	3050	5
Main flow 3	12.0	10.5	43.0	8	3022	4
Final b/u	96.0				3139	

A log-log plot of the pressure data recorded during the test is presented in Figure 4.10.

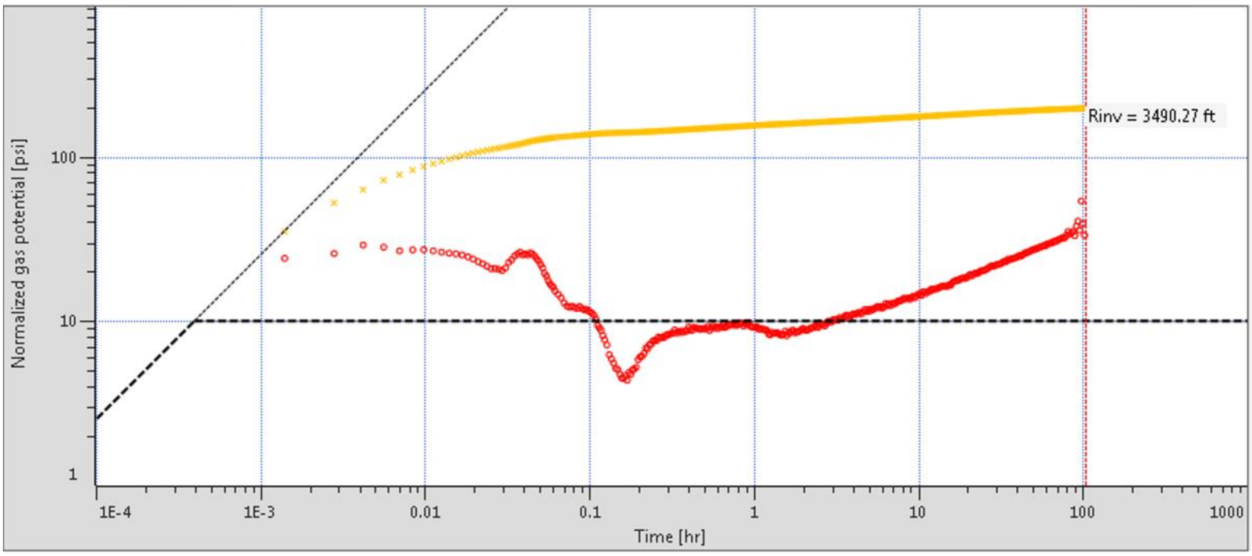

Figure 4.10: Well SD-3X log-log plot for final build up

ERCE interpreted the test independently. ERCE calculates a value of permeability-thickness from the test of 1700 md-ft. This is somewhat lower than value of 2300 md-ft determined by SDX but ERCE does not consider the difference to be material. ERCE calculates a value of skin factor close to zero, in line with that calculated by SDX.

The SDX interpretation of the test inferred the existence of two parallel faults approximately 465 ft from the well or two parallel faults approximately 512 ft from the well. ERCE recognises the upturn in the derivative but considers it is more likely to be due to the presence of the gas water contact or deteriorating reservoir quality away from the well. This would be consistent with the observation that the quality of the AM-III encountered in Well SD-3X is much poorer than that seen in the wells to the west and may indicate decreasing quality towards the east

The upward curvature of the pressure plot for the final build-up precludes the possibility of estimating the degree of depletion associated with the main flow period. However, the pressures do indicate that the well is in communication with a significant volume of gas.

Fluid Properties

Separator recombination samples were taken during the third flow period and a PVT recombination study undertaken by the Egyptian Petroleum Research Institute. The recombined fluid composition contains 93.2 mol% CH_4, 0.26% CO_2 and 0.5% N_2. The maximum cumulative liquid drop out measured during a constant mass depletion study was 0.26% suggesting condensate drop out in the reservoir will not be an issue. Based on this the PVT parameters a gas expansion factor of 187 scf/rcf (+/-7) and a CGR of 5 bbl/MMscf (+/-3) were used as input parameters for estimating the in-place volumes.

4.4.1.3. **Hydrocarbons Initially In Place**

ERCE has derived probabilistic estimates of GIIP for the South Disouq discovery using input distributions for GRV plus petrophysical and fluid parameters for each of the reservoir intervals.

ERCE was provided with top surfaces for the AM-I, AM-II and AM-III intervals which we have reviewed and adopted for GRV purposes. ERCE created one alternative surface for the top AM-III by isopaching down from the AM-I pick and tying to the well tops. This was used in our high case for this interval.

For the AM-I interval, ERCE adopted the top and base surface as provided by SDX. The surfaces were not varied as the largest uncertainty is related to the pinch out of the AM-I sands between SD-1X and SD-4X. In the area over SD-1X ERCE varied this termination limit based on low and high case assessments of the lateral reservoir deposition. ERCE then varied the contact using a GWC from MDT of 6870 ft in the low case and a Lowest Closing Contour (LCC) of 6946 ft, accounting for possibility of MDT error, in the high case (Figure 4.11).

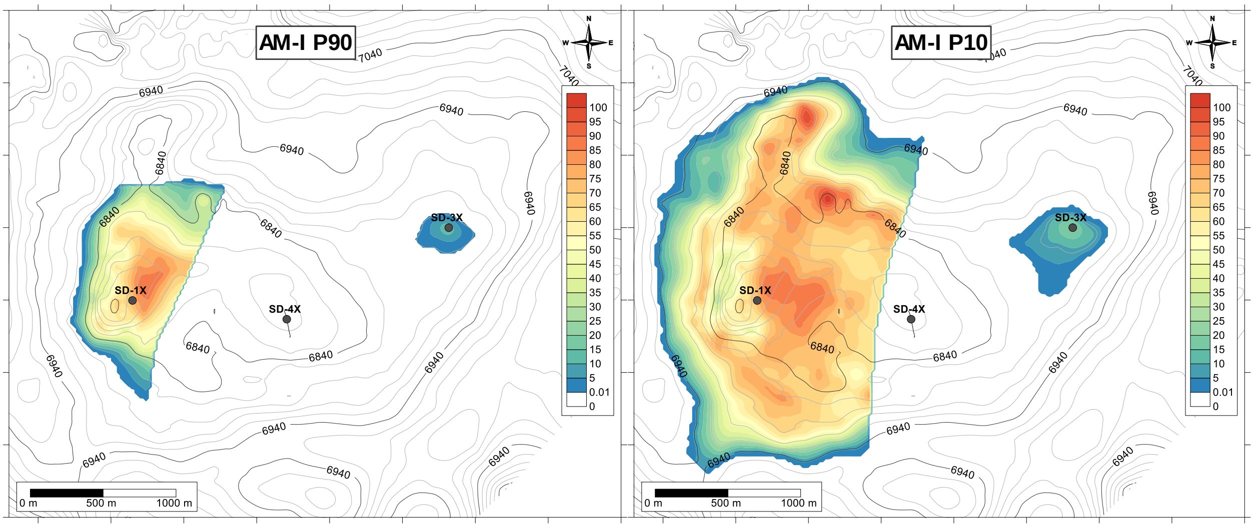

Figure 4.11 Gas column height for the AM-I interval (ft)

For the AM-II interval, ERCE adopted the top and base surface as provided by SDX. ERCE note this is a small GRV volume relative to the other intervals and as it is constrained by a contact observed in the well logs at 6889 ft TVDSS, there is less uncertainty in GRV than in the AM-I and AM-III reservoirs. The contact observed in the wells has been adopted to determine a best case GRV.. This was then varied appropriately to determine a low and high case to account for uncertainty at the flanks (Figure 4.12).

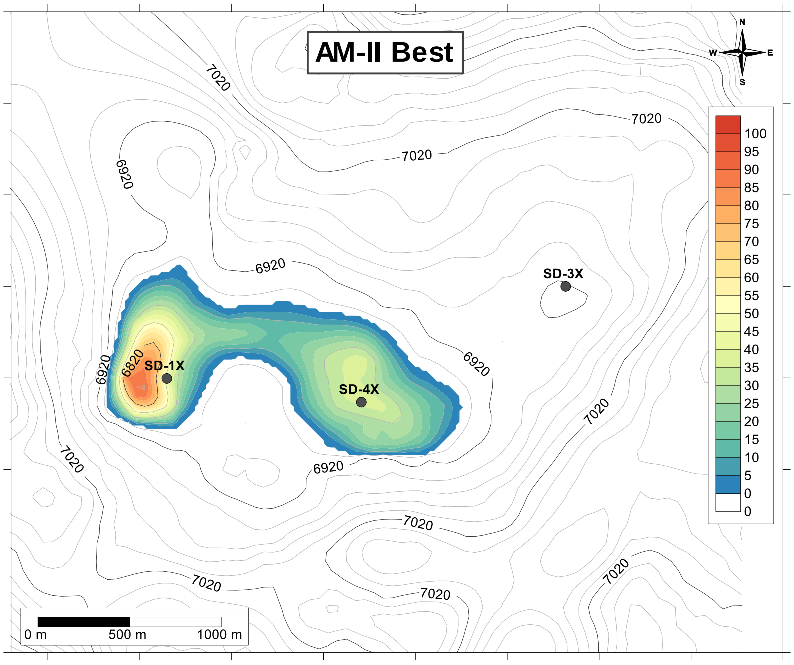

Figure 4.12 Gas column height for the AM-II interval (ft)

For the AM-III interval, ERCE adopted the top and base surface as provided by SDX for the low case, and for the high case created a top surface through isopaching from AM-I. The contact is observed at 7102 ft TVDSS in the logs and was applied to these low and high case maps to result in P90 and P10 GRV volumes (Figure 4.13). Although from a geological perspective there is the possibility of the GRV being lower than our P90, this possible downside is dismissed due to the positive well test in the AM-III from SD-4X.

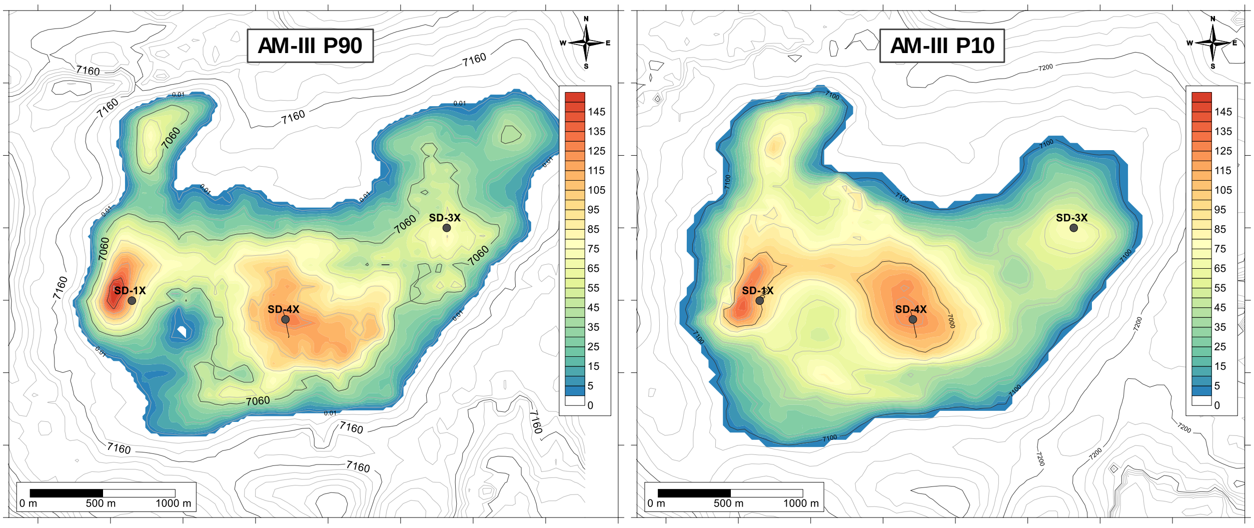

Figure 4.13 Gas column height for the AM-III interval (ft)

Petrophysical parameters are based on the sums and averages for the three wells, accounting for spatial distribution relative to the GRV. There is uncertainty in the log responses due to the thinly bedded nature of the Abu Madi sands, hence some adjustment has been made for this in the mid case based on comparing porosity distribution in the water zones versus the gas zones and analysing thin bed effects on hydrocarbon saturation.

Table 4.3: Input parameters to volumetric calculation for the South Disouq discovery

Interval	GRV (MMm3)			NTG (frac)			Porosity (frac)			Sh (frac)			GEF (scf/rcf)			GCR (bbl/MMscf)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
AM-I	12.0	26.4	58.1	0.15	0.20	0.25	0.20	0.22	0.24	0.40	0.48	0.55	180	187	194	2	5	8
AM-II	6.0	7.5	9.4	0.70	0.78	0.85	0.21	0.24	0.27	0.45	0.58	0.70	180	187	194	2	5	8
AM-III	67.5	79.2	93.0	0.45	0.50	0.55	0.19	0.21	0.22	0.65	0.70	0.75	180	187	194	2	5	8

Table 4.4: Probabilistic GIIP and CIIP for the SD-1X discovery

Interval	GIIP (Bscf)				CIIP (MMbbl)			
	Low	Mid	High	Mean	Low	Mid	High	Mean
AM-I	1.5	3.6	8.4	4.5	0.01	0.02	0.05	0.02
AM-II	3.6	5.2	7.4	5.4	0.01	0.01	0.05	0.03
AM-III	30.0	37.3	46.4	37.8	0.08	0.19	0.31	0.19
Total *(prob)*	**38.7**	**47.1**	**57.3**	**47.6**	**0.13**	**0.24**	**0.37**	**0.24**

4.4.1.4. **Recoverable Resources**

Recoverable resources were estimated probabilistically combining the GIIP and CIIP estimates with an estimated RF distribution. The recovery is likely to depend on the degree of aquifer support. Recovery under depletion drive could be up to 90% but if there is early water breakthrough it might be as low as 60%. This RF range (P10 to P90) was input as a triangular distribution and the recoverable volumes calculated probabilistically. The resulting recoverable resources are presented in Table 4.5.

Table 4.5: South Disouq field recoverable resources as of December 31, 2018, before Economic Limits Applied

Interval	Field Gross Raw Recoverable Natural Gas (Bscf)				Field Gross Condensate Recoverable Resources (MMbbl)				Working Interest
	1P	2P	3P	Mean	1P	2P	3P	Mean	%
AM-I	1.1	2.7	6.4	3.3	0.00	0.01	0.04	0.02	55%
AM-II	2.6	3.9	5.7	4.0	0.01	0.02	0.04	0.02	
AM-III	20.8	27.8	36.7	28.4	0.06	0.14	0.24	0.14	
Total *(prob)*	**26.7**	**35.1**	**78.4**	**35.8**	**0.09**	**0.18**	**0.28**	**0.18**	

1. *Natural Gas recoverable resources are prior to shrinkage and as such do not represent potential sales volumes*
2. *Working interest recoverable resources are not presented (but would be equal to the working interest share of the field gross resources)*

4.5. SD-3X Kafr El Sheik Discovery

Well SD-3X was drilled in 2018 to target the Abu Madi reservoir as discussed in Section 4.4, however it also encountered a seismically transparent gas bearing sand in a shallower interval within the Kafr El Sheik shales (Figure 4.14). The reservoir is a thin interval with relatively low NTG and gas saturation.

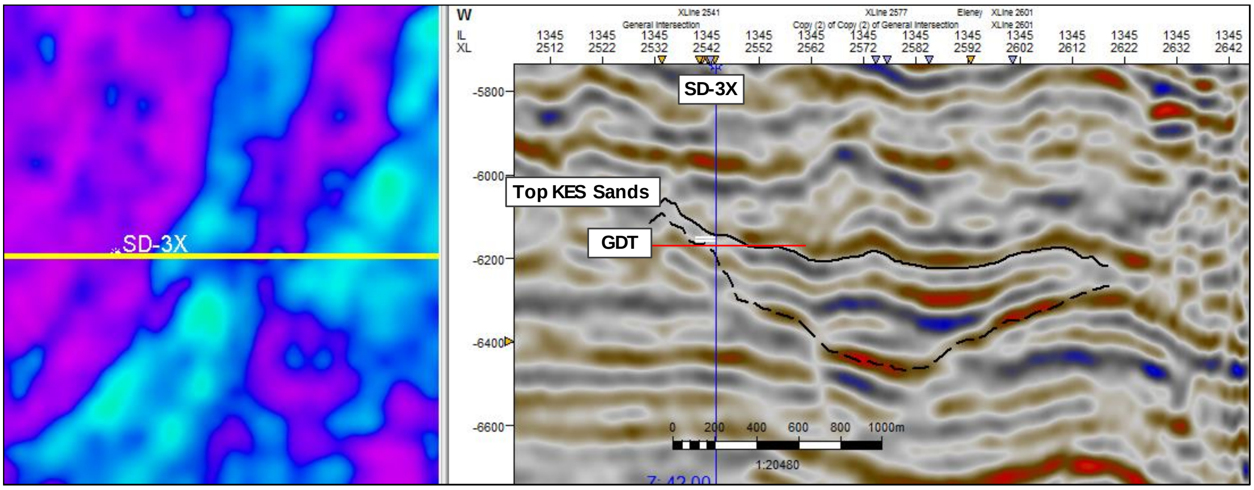

Figure 4.14 E-W seismic section through the SD-3X KES

The interval encountered by the well is likely below tuning thickness on seismic so is not identifiable. SDX have defined a channel feature on seismic which could encapsulate the full extent of the reservoir sands, however without further modelling is unclear whether these sands are expected to show up as bright amplitudes on seismic as they thicken away from well control.

4.5.1.1. Petrophysics

ERCE have completed a petrophysical interpretation for SD-3X KES (Figure 4.15) with resultant porosity, Vsh and net pay estimations similar to SDX's. However, there is a difference in Sw due to the Archie parameters used. ERCE have used conservative estimates of m and n to be in line with the deeper sands and have assumed the same salinity in the KESb as in the Abu Madi sands, which matches well to the Pickett plot. It appears that SDX have used a higher salinity.

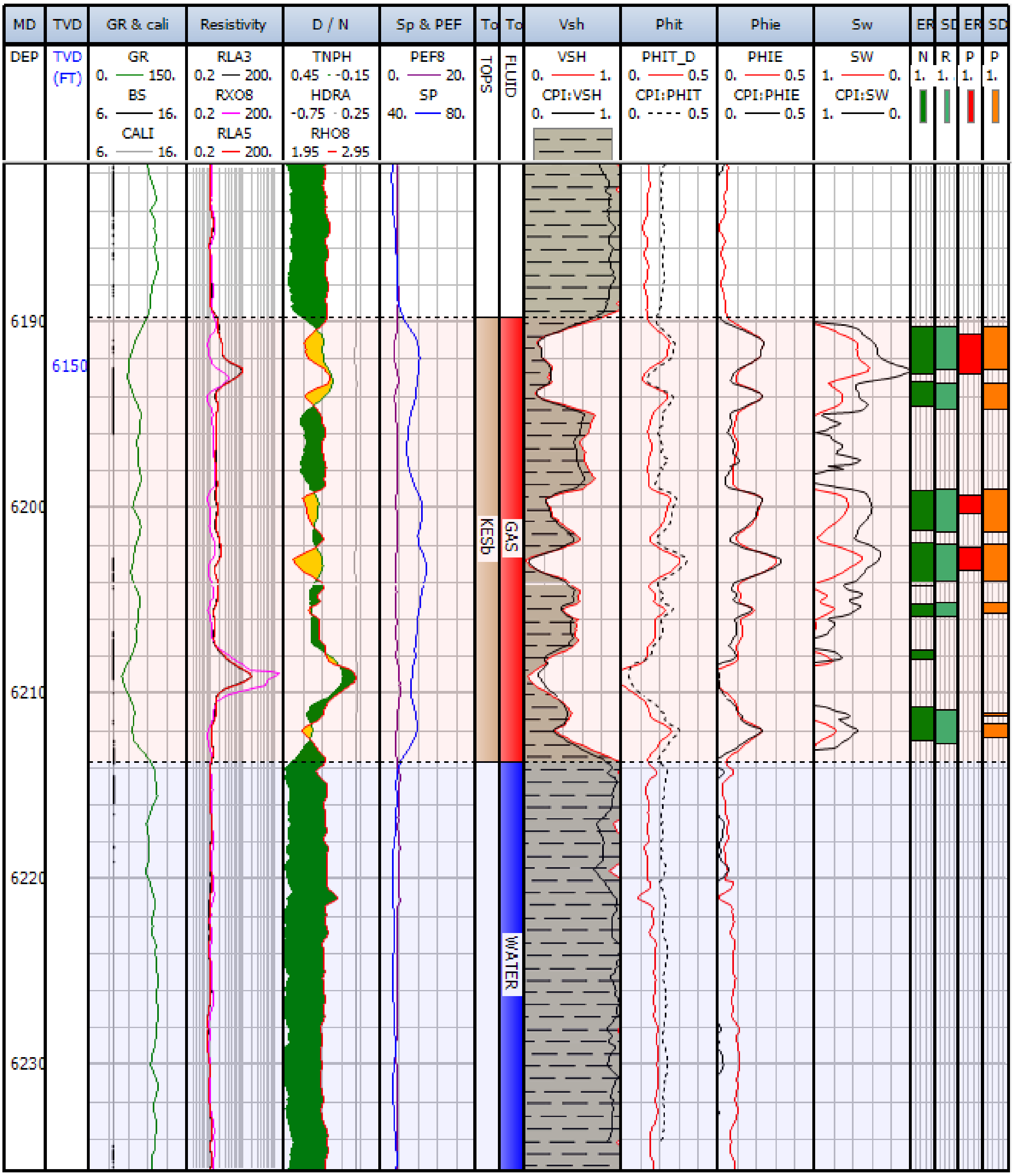

Figure 4.15 Petrophysical interpretation for Well SD-3X KES Sand interval

4.5.1.2. Reservoir Engineering

An MDT was run through the KES sand and recorded four points, all considered valid and lying on a gas gradient of 0.05 psi/ft, confirming the results of the petrophysical evaluation.

The interval was not flow tested, but the reservoir is analogous to the Ibn Yunus discovery (Section 4.6).

4.5.1.3. Hydrocarbons Initially In Place

ERCE has derived probabilistic estimates of STOIIP for the SD-3X KES discovery using input distributions for GRV plus petrophysical and fluid parameters for the reservoir interval.

As the sands at the well are transparent on seismic, the full extent of the discovery remains a large uncertainty. However, having reviewed the top structure provided by SDX we observe that the GDT in the sands form a 3-way dip closure with stratigraphic or fault seal required only to the NW. As the gas sands have not been encountered in Well SD-4X, this provides some constraint on the western limit of the accumulation. ERCE have thus adopted SDX's top surface and their interpretation of western pinch-out in the high case GRV. In the low case ERCE have constrained the accumulation to the core amplitude as identified by SDX and further truncated it to the SW to remain within 1 km of the well (Figure 4.16).

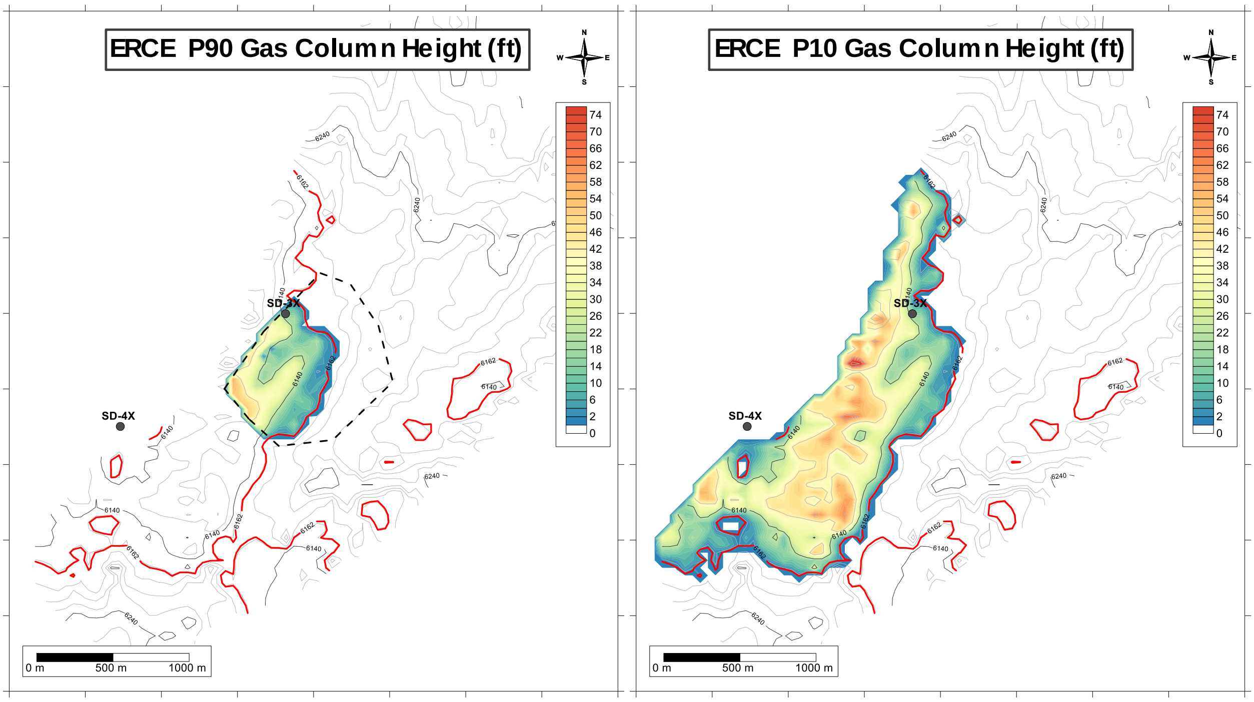

Figure 4.16 ERCE P90 and P10 gas column heights for the SD-3X KES discovery

Petrophysical parameters were adopted from the sums and average calculated over the KES interval in SD-3X.

Table 4.6: Input parameters to volumetric calculation for the SD-3X KES discovery

Discovery	GRV (MMm3)			NTG			Porosity			Sg			GEF		
	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
SD3X_KES	2.5	6.2	15.3	0.50	0.65	0.80	0.15	0.17	0.19	0.30	0.43	0.55	182	187	192

Table 4.7: Probabilistic GIIP for the SD-3X KES discovery

Discovery	GIIP (Bscf)			
	Low	Best	High	Mean
SD3X_KES	0.7	1.8	4.8	2.4

4.5.1.4. Recoverable Resources

Recoverable resources were estimated probabilistically combining the GIIP estimates with an estimated RF distribution. The recovery is likely to depend on the degree of aquifer support. Recovery under depletion drive could be up to 90% but if there is early water breakthrough it might be as low as 60%. This RF range (P10 to P90) was input as a triangular distribution and the recoverable volumes were calculated probabilistically. The resulting recoverable resources are presented in Table 4.5.

Table 4.8: SD-3X KES field recoverable resources as of December 31, 2018, Before Economic Limits Applied

Discovery	Field Gross Raw Recoverable Natural Gas (Bscf)				Field Gross Raw Recoverable Condensate (MMbbl)				WI
	1P	2P	3P	Mean	1P	2P	3P	Mean	
SD3X_KES	0.5	1.3	3.7	1.8	0.01	0.02	0.05	0.03	55%

1. *Natural Gas recoverable resources are prior to shrinkage and as such do not represent potential sales volumes*
2. *Working interest recoverable resources are not presented (but would be equal to the working interest share of the field gross resources)*

4.6. Ibn Yunus Discovery

The Ibn Yunus-1X well was drilled in 2018, 5 km to the north of the South Disouq discovery and is a gas discovery in the at the base of the Kafr El Sheik (KES). Sands within the discovery well are of very good quality with high porosities and permeabilities. The sands were likely deposited as a submarine fan, having sourced from a high to the NW. The structure is a 4-way dip closure with the potential for a stratigraphic upside and sealing is provided by the thick interval of KES deep water shales lying on top of the sands. A Gas Down To (GDT) of 6644 ft TVDSS is observed in the well at the base of the sand.

ERCE has reviewed the seismic interpretation which was found to be reasonable. A top structure map for the basal KES is presented in Figure 4.17 with the GDT displayed in red.

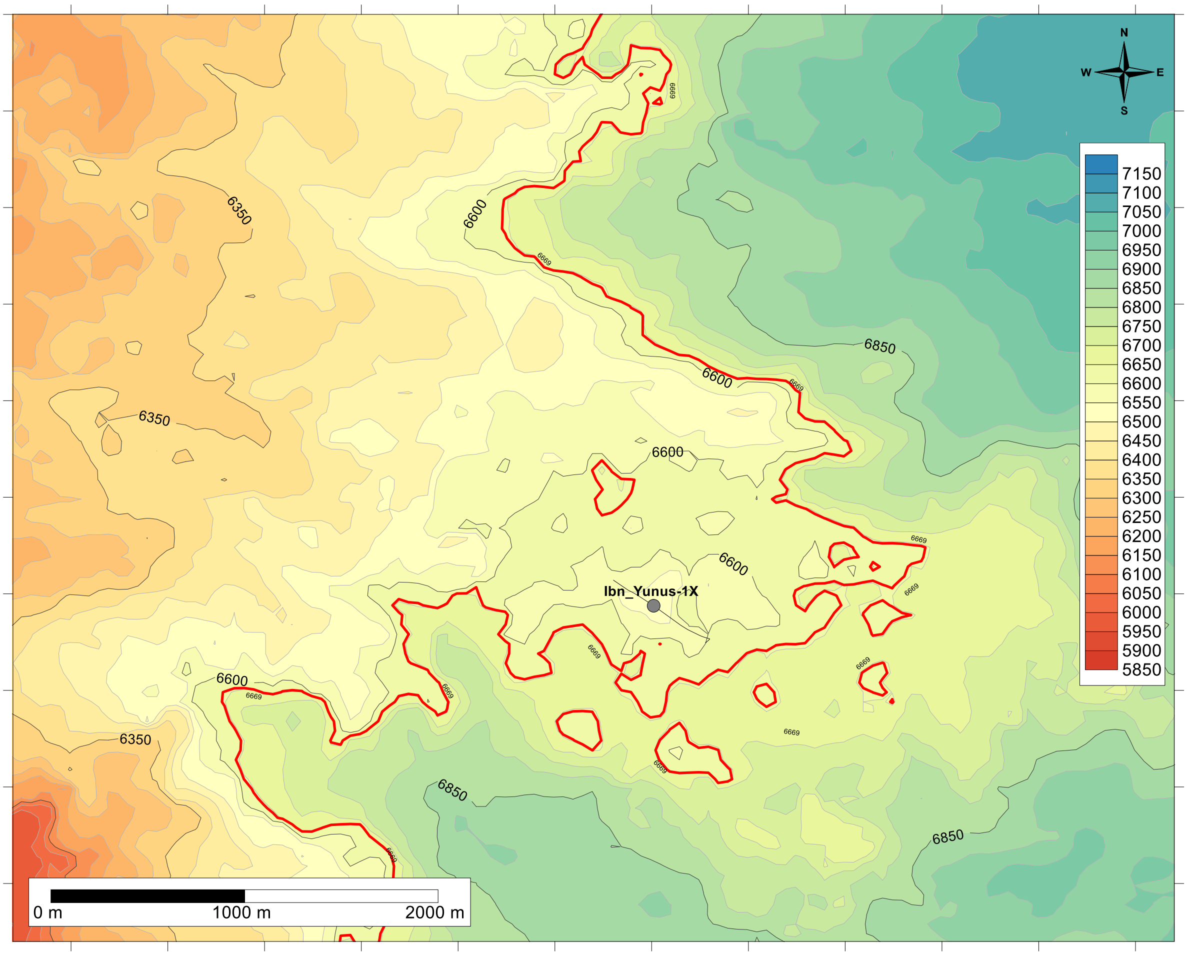

Figure 4.17: Base Kafr El Sheik structure map for the Ibn Yunus discovery

The interpretation to the NW lies close to the GDT, and with slight alteration of the pick would close to form a 4-way dip closure (Figure 4.18). The rock physics was reviewed to understand whether the gradient volume can be used to delineate sand bodies. The Poisson's ratio drop at the top of the sand in the well logs corroborates the strong negative response observed on the gradient volume at the Ibn Yunus discovery, and so can be used to determine the extent of the gas filled accumulation.

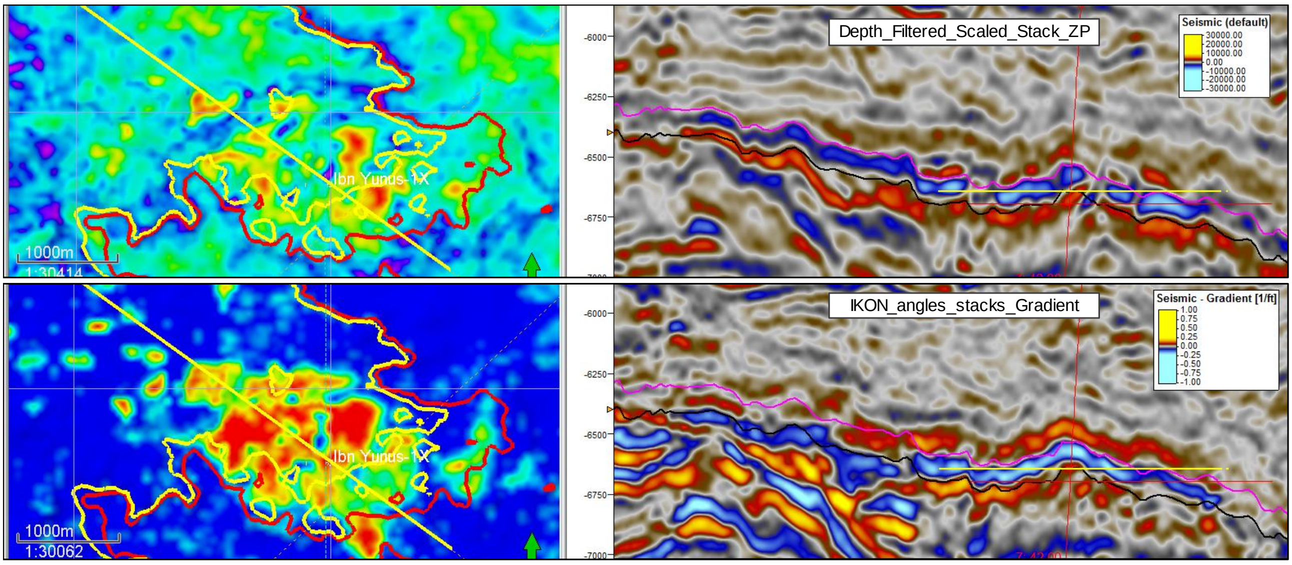

Figure 4.18: Seismic section through the Ibn Yunus-1X discovery

4.6.1.1. **Petrophysics**

The Ibn Yunus-1X was recently drilled and was reviewed by ERCE. The well was not cored so input parameters are uncertain and there is no data for calibration of porosity, Sw or permeability. Regional knowledge from nearby wells is therefore used as a basis.

Vsh was calculated from gamma ray using 5th & 95th percentiles, and from neutron/density cross plot; then the minimum of the two methods was used as the final Vsh. Vsh is typically overestimated so using the minimum of two methods helps to correct for this.

Porosity was estimated using the density log, assuming a clean sandstone matrix of 2.65g/cm3 and apparent fluid densities were used that take into account mud based filtrate invasion into the formation. No hydrocarbon corrections were completed for this reason. Effective porosity was calculated from total porosity by assuming 12% shale porosity. This removes ineffective porosity in shaley intervals, but does not affect porosity in clean sands.

The sands are easy to pick from GR response, and from N/D response.

Water saturation (*Sw*) was determined from the Archie equation with the Archie parameters of *a*, *m* and *n* assumed to be 1, 1.8 and 2 respectively. As there is no core data, there is also no SCAL data for calibration of electrical parameters. The m value was picked from the slope of the Pickett plot.

No formation water data were available and hence *Rw* was selected from Pickett plots. Water salinity appears to be ~50kppm, but is a key unknown. It appears that it may vary slightly between the sands, increasing with depth.

Net reservoir interval was based on an effective porosity cut-off of >10%, a Vsh cut off of <50% and net pay also included an Sw cut off of <70%. These cut offs were selected interactively in order to identify those intervals that were considered to be reservoir based on the log character, and are in line with the other Abu Madi wells. The cut offs are slightly different to SDX, who use harsher cut offs at >12% phie, <50% Vsh and <50% Sw. However, the gas sands are relatively insensitive to the cut offs.

Having completed an independent view of the petrophysics, ERCE accepts SDX's petrophysical interpretation.

A comparison of the two petrophysical interpretations in Well Ibn Yunus-1X is shown in Figure 4.19.

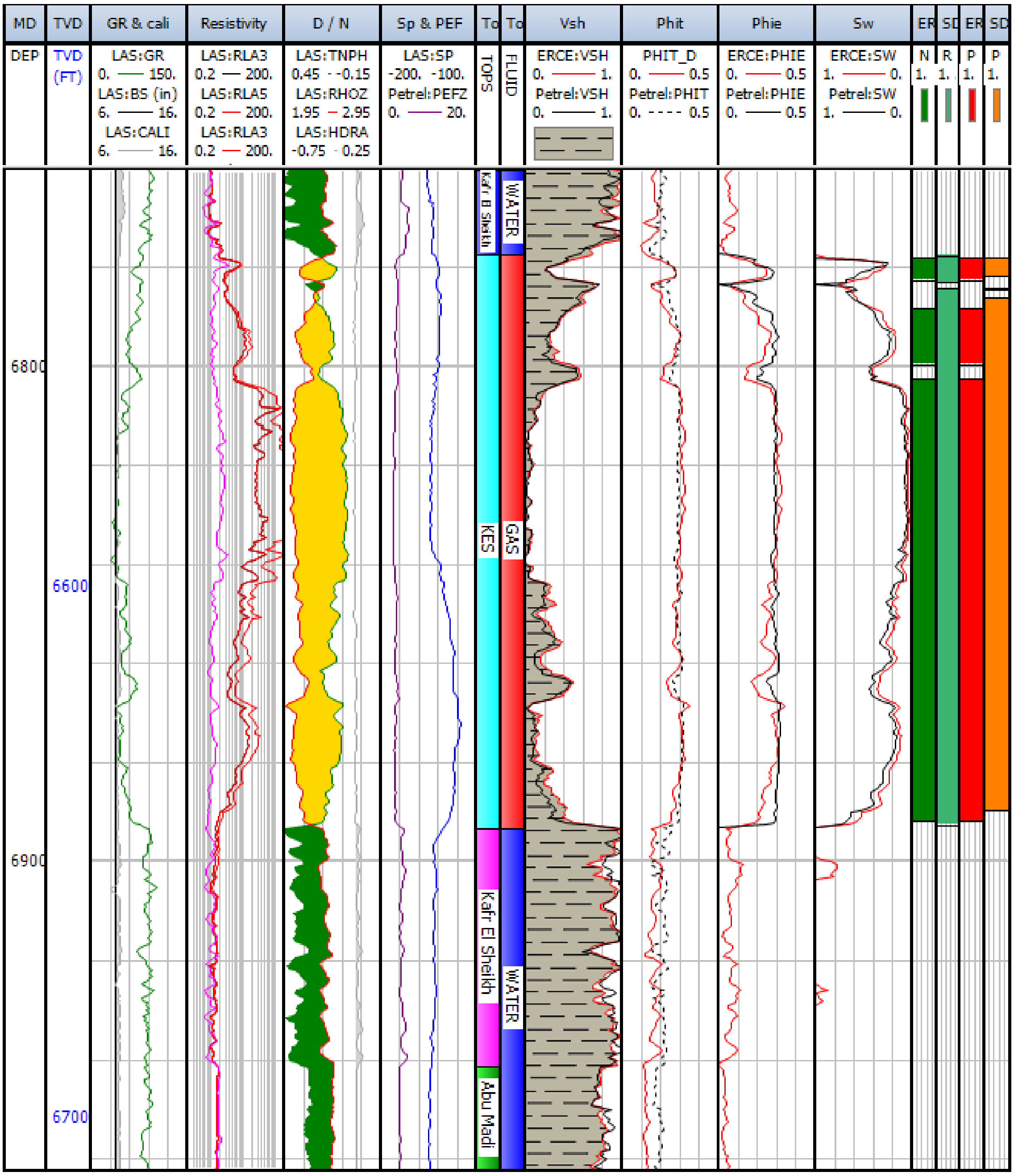

Figure 4.19: Petrophysical interpretation for Well Ibn Yunus-1X

SDX interpreted curves are shown in black; ERCE interpreted curves are shown in red. Ibn Yunus-1X shows a 100ft thick gas bearing KES sand. The Abu Madi sands below appear to be water bearing. The two interpretations are considered to be within acceptable ranges of uncertainty and so SDX's interpretation is accepted.

4.6.1.2. Reservoir Engineering

MDT

An MDT log was run in the well and recorded a clear gas gradient throughout the sand.

Well Test

Well Ibn Yunus 1 (IY-1) tested a perforated interval of 6,778 to 6,860 ft MD RKB within the KES formation. The interval tested at rates of up to 33 MMscf/d through 3.5" tubing with an average CGR at separator conditions of between 10 and 16 bbl/MMscf. A summary of the sequence of events is provided in Table 4.9.

Table 4.9: Ibn Yunus 1 Sequence of Drilling Events

Period	Duration (hrs)	Gas rate (MMscf/d)	Condensate rate (bbl/d)	Water rate (bbl/d)	Bottomhole pressure (psia)	Condensate gas ratio (bbl/MMscf)
Clean-up	8.0	Up to 33				
Initial b/u	12.0					
Main flow 1	13.0	7.9	98.0	0		11 - 15
Main flow 2	12.0	10.3	136.0	2		11 - 16
Main flow 3	34.0	11.9	128.0	4		10 - 13
Final b/u	120.0					

A log-log plot of the pressure data recorded during the main build-up is presented in Figure 4.20

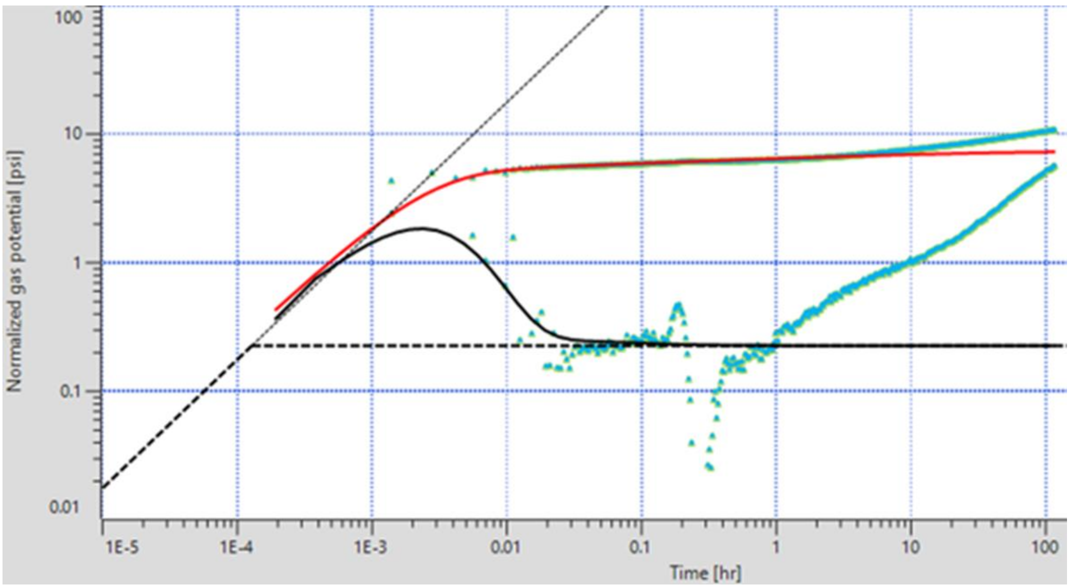

Figure 4.20: Ibn Yunus log-log Plot

The plots of the data show some unusual characteristics making them hard to interpret. ERCE has therefore:

- Analysed the data acquired during the main flow period, as if the well is producing in semi-steady state. This approach suggests a connected volume of approximately 12 Bscf.
- Generated Horner plots of the data and used them to infer built-up pressures. This approach suggests a gas initially in place volume of between 16 and 36 Bscf.

We have therefore concluded that the GIIP indicated from analysis of the well test lies between 12 and 36 Bscf.

ERCE has also used the initial build-up to determine the permeability-thickness of the tested sand. This is calculated to be approximately 45,000 md-ft. On the basis of a net thickness of 105 feet in the well, this implies a permeability of approximately 430 md which is consistent with the very high productivity of the well and shows that deliverability will be high.

4.6.1.3. **Hydrocarbons Initially In Place**

ERCE has derived probabilistic estimates of STOIIP for the Ibn Yunis-1X discovery using input distributions for GRV plus petrophysical and fluid parameters for the reservoir interval.

ERCE was provided with a top reservoir by SDX which we adopted for all our GRV calculations. Our low case GRV used this surface with the GDT in the well at 6644 ft and a polygon that was constrained to the bright amplitudes observed on the gradient seismic volume (Figure 4.21). In our high case, we expanded this polygon to incorporate additional amplitude areas to the NW of the main structure that may be connected to the main body when accounting for tuning thickness. A base reservoir was used that tracked the zero crossing at the base of the reflector in the full stack inversion and this was then combined with a GDT to give a P10 GRV (Figure 4.22).

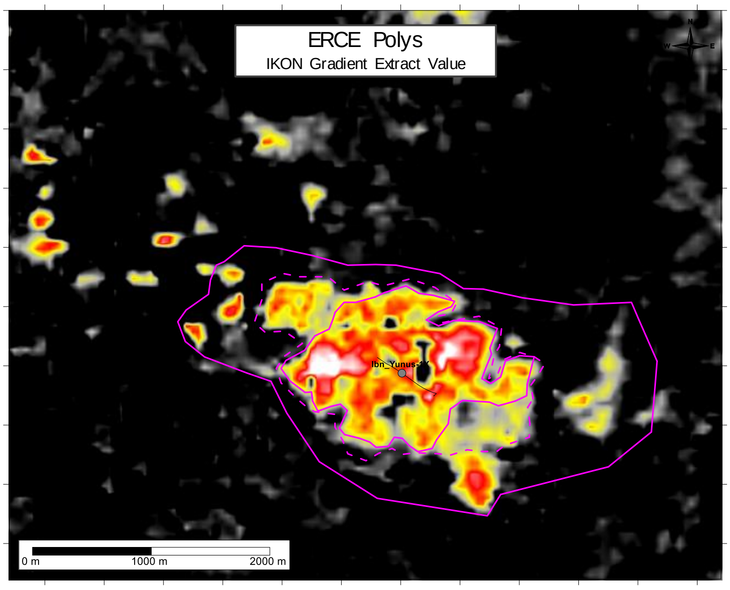

Figure 4.21 ERCE P90 and P10 polygons

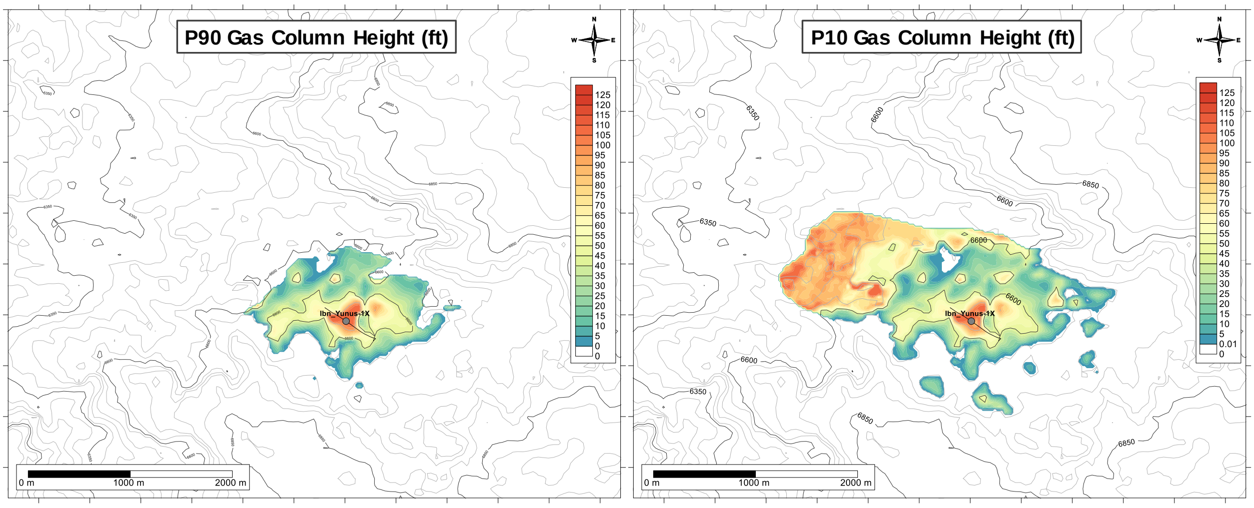

Figure 4.22 ERCE P90 and P10 gas column height maps (ft)

Petrophysical parameters were based on the sums and averages for the Ibn Yunus-1X well.

Table 4.10: Input parameters to volumetric calculation for the Ibn Yunus-1X discovery

Discovery	GRV (MMm3)			NTG *(tri min max)*			Porosity			Sg			GEF		
	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
Ibn_Yunus	14	26	48	0.90	0.95	1.00	0.24	0.27	0.29	0.75	0.80	0.85	190	197	204

Table 4.11: Probabilistic GIIP for the Ibn Yunus-1X discovery

Discovery	GIIP (Bscf)			
	P90	P50	P10	Mean
Ibn_Yunus	19.2	36.0	67.6	40.6

4.6.1.4. **Recoverable Resources**

Recoverable resources were estimated probabilistically combining the GIIP estimates with an estimated RF distribution. The recovery is likely to depend on the degree of aquifer support. Recovery under depletion drive could be up to 88% but if there is early water breakthrough it might be as low as 60%. This RF range (P10 to P90) was input as a normal distribution and the recoverable volumes calculated probabilistically. The resulting recoverable resources are presented in Table 4.12.

Table 4.12: Ibn Yunus field recoverable resources as of December 31, 2018, Before Economic Limits Applied

Discovery	Field Gross Raw Recoverable Natural Gas (Bscf)				Field Gross Raw Recoverable Condensate (MMbbl)				Working Interest
	1P	2P	3P	Mean	1P	2P	3P	Mean	
Ibn_Yunus	14.0	26.8	51.4	30.5	0.17	0.36	0.77	0.43	55%

1. *Natural Gas recoverable resources are prior to shrinkage and as such do not represent potential sales volumes*
2. *Working interest recoverable resources are not presented (but would be equal to the working interest share of the field gross resources)*

4.6.1.5. **Production Forecasts**

On the basis of the current Field Development Plans (FDPs), SDX will develop the South Disouq Abu Madi gas, the South Disouq KES gas and the Ibn Yunus KES gas together.

South Disouq will be developed using the three existing wells, SD-1X, -3X and -4X. Well SD-3X will initially be completed in the Abu Madi. Once the Abu Madi gas has been produced, the well will be recompleted in the KES. Ibn Yunus will be developed using two wells, the existing well and a second well to be drilled in 2020.

ERCE recognises that the uncertainties associated with the resources attributed to the Abu Madi sands, the SD-3X KES sand and the Ibn Yunus KES sand are independent. ERCE has therefore calculated the resources associated with the overall South Disouq-Ibn Yunus (SD-IY) development by probabilistically combining the resources attributed to each of the accumulations.

The SD-IY development will be tied into the National Grid. The tie-in point is approximately 10 km from the South Disouq field. Pressure at the tie-in point is reported to be 1030 psi. ERCE has assumed that compression will be installed, capable of reducing the flowing wellhead pressure to 30 bar, in order to maximise recovery.

In order to calculate production profiles for the SD-IY development, ERCE has used the reservoir and fluid properties for South Disouq and Ibn Yunus shown in Table 4.13 below. Fluid properties are not available for the KES sand in Well SD-3X.

Table 4.13: Reservoir and fluid properties - South Disouq and Ibn Yunus

	South Disouq	Ibn Yunus
Initial reservoir pressure (psi)	3215	3030
Reservoir temperature (°F)	189	179
Zi	0.92	0.91
Dew point pressure (psi)	1951	1965
CGR (bbl/MMscf)	5	15

ERCE has used an MBAL model to generate gas and condensate production profiles for the development corresponding to the three levels of confidence. An overall uptime for the production facility of 95% has been assumed. The resulting estimates of gas and condensate resources are shown in Table 4.14 and the production profiles prior to economic cut-off are shown in Figure 4.23 and Figure 4.24.

Table 4.14: Resources attributed to the South Disouq development

	Low	Best	High
Wellhead gas (Bcf)	47.5	64.2	89.2
Condensate (Mbbl)	334.5	449	627

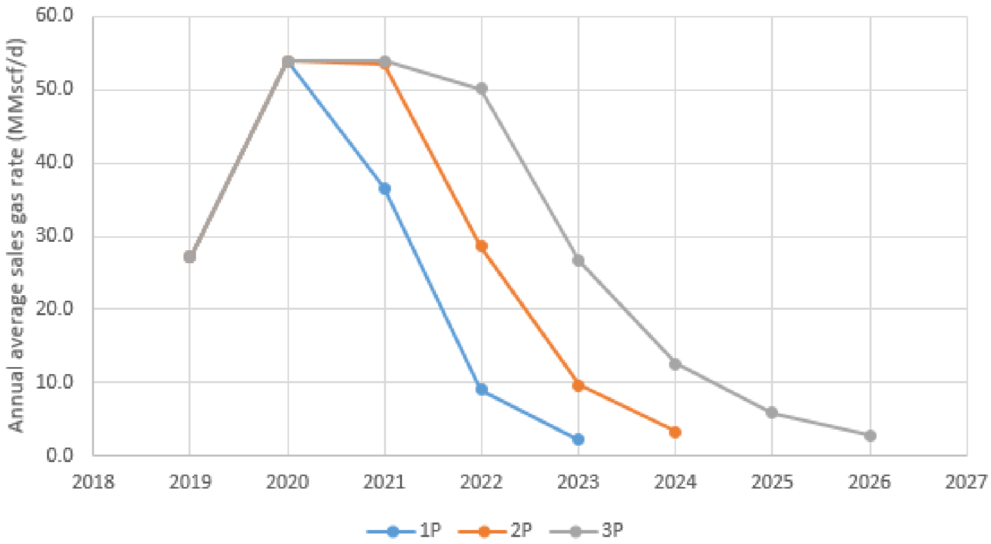

Figure 4.23: Wellhead gas profiles - South Disouq development

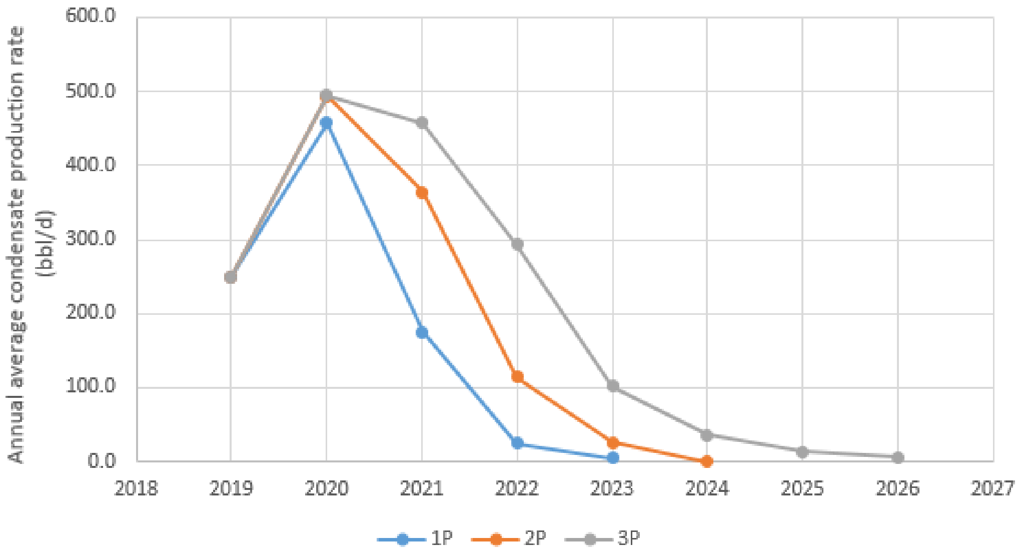

Figure 4.24: Condensate profiles - South Disouq development

4.7. Reserves and Net Present Values

The development of the Abu Madi sands via SD-1X and SD-4X and the development of the KES sands via SD-3X and IY-1X has been classified as Reserves (development justified), based on the data available as at December 31, 2018. All Reserves are treated as Undeveloped, based on the large capital expenditures remaining for facilities and pipelines.

SDX plans to produce the field through a temporary production facility initially, transitioning to a permanent facility later in the year. SDX has advised ERCE that the schedule will be as follows:

- May 2019 – Initial production through the temporary facility at a rate of 10MMscf/d
- June 2019 – Increase in temporary facility throughput to 40 MMscf/d.
- September 2019 – Transition to permanent production facility with throughput capacity of 60 MMscf/d.

The production profiles generated by ERCE are consistent with this schedule.

The Reserves estimates were based on the gas forecasts at a concession level, as shown in Figure 4.23, cut off at the economic limit as determined by production and revenue analysis.

A gas sales agreement has been signed with an agreed price of $2.65/Mbtu which is ca. $2.85/Mscf. Condensate revenue was based on a condensate price in line with the forecast Brent oil price (Table 2.2).

Forecast production and costs can be found in Appendix 3.

Fiscal terms were based on the exploration and exploitation concession agreement. The government approved the field development during 2018 at which point the field was granted a 20-year exploitation term. The contractor revenue is based on a production sharing arrangement. A cost gas/oil recovery limit of 25% of revenue is applicable. Operating costs can be recovered immediately (subject to the recovery limit) but capital costs are amortized at 20% per year over 5 years. The contractor share of profit gas is 32.5% (for production rates <100 MMscf/d) and the share of profit oil (i.e. condensate) is based on production rate and oil price; over the life of the field the typical share is 35%. A production bonus of $1 million is also payable as the barrels of oil equivalent rate is forecast to go over 5,000 boe/d. Corporation tax of 22.5% is paid on behalf of the contractor by EGAS and this has been included when determining the net entitlement volumes. Costs were inflated at 2%.

A summary of the natural gas and NGL (condensate) Reserves are presented in Table 4.15 and Table 4.16 respectively for each Reserves category. A summary of the Company share of the net present values is presented in Table 4.17.

Table 4.15: South Disouq natural gas Reserves estimates as of December 31, 2018

Category	Field Gross MMscf	Company Gross WI MMscf	Company Net Entitlement MMscf
PDP	-	-	-
PD	-	-	-
PUD	46,302	25,466	14,376
1P	46,302	25,466	14,376
2P	63,150	34,732	19,607
3P	81,905	45,048	25,430

1. *Company gross working interest Reserves are based on 55% of the field gross Reserves*
2. *Company net entitlement Reserves are based on Company share of the cost and profit hydrocarbons and the corporation tax paid on behalf of the Company by EGAS*

Table 4.16: South Disouq NGL Reserves estimates as of December 31, 2018

Category	Field Gross Mbbl	Company Gross WI Mbbl	Company Net Entitlement Mbbl
PDP	-	-	-
PD	-	-	-
PUD	279	154	90
1P	279	154	90
2P	414	228	134
3P	564	310	183

1. *Company gross working interest Reserves are based on 55% of the field gross Reserves*
2. *Company net entitlement Reserves are based on Company share of the cost and profit hydrocarbons and the corporation tax paid on behalf of the Company by EGAS*

Table 4.17: South Disouq Net Present Values as of December 31, 2018

Category	Company Share of Net Present Values at various discount rates (US$ MM)				
	0%	5%	10%	15%	20%
PDP	-	-	-	-	-
PD	-	-	-	-	-
PUD	9	8	7	6	5
1P	9	8	7	6	5
2P	22	19	16	14	12
3P	37	31	27	23	20

1. *Based on forecast prices and costs as of 1 January 2019 (seeTable 2.2).*
2. *Interest expenses, corporate overheads etc were not included.*
3. *The net present values may not represent the fair market value of the Reserves.*

4.8. Exploration Potential

4.8.1. Unrisked Prospective Resources

A number of prospects and leads exist within the South Disouq concession and are covered by the same high quality 3D pre-stack depth migrated seismic data as the South Disouq and Ibn Yunus discoveries. SDX provided ERCE with 10 prospects targeting different reservoirs over the South Disouq concession (Figure 4.25). Of these, the Newton prospect targets the Abu Madi as discovered by SD-1X, while the Young prospect targets reservoirs below this interval. The remaining prospects target the basal KES sand analogous to the Ibn Yunus discovery.

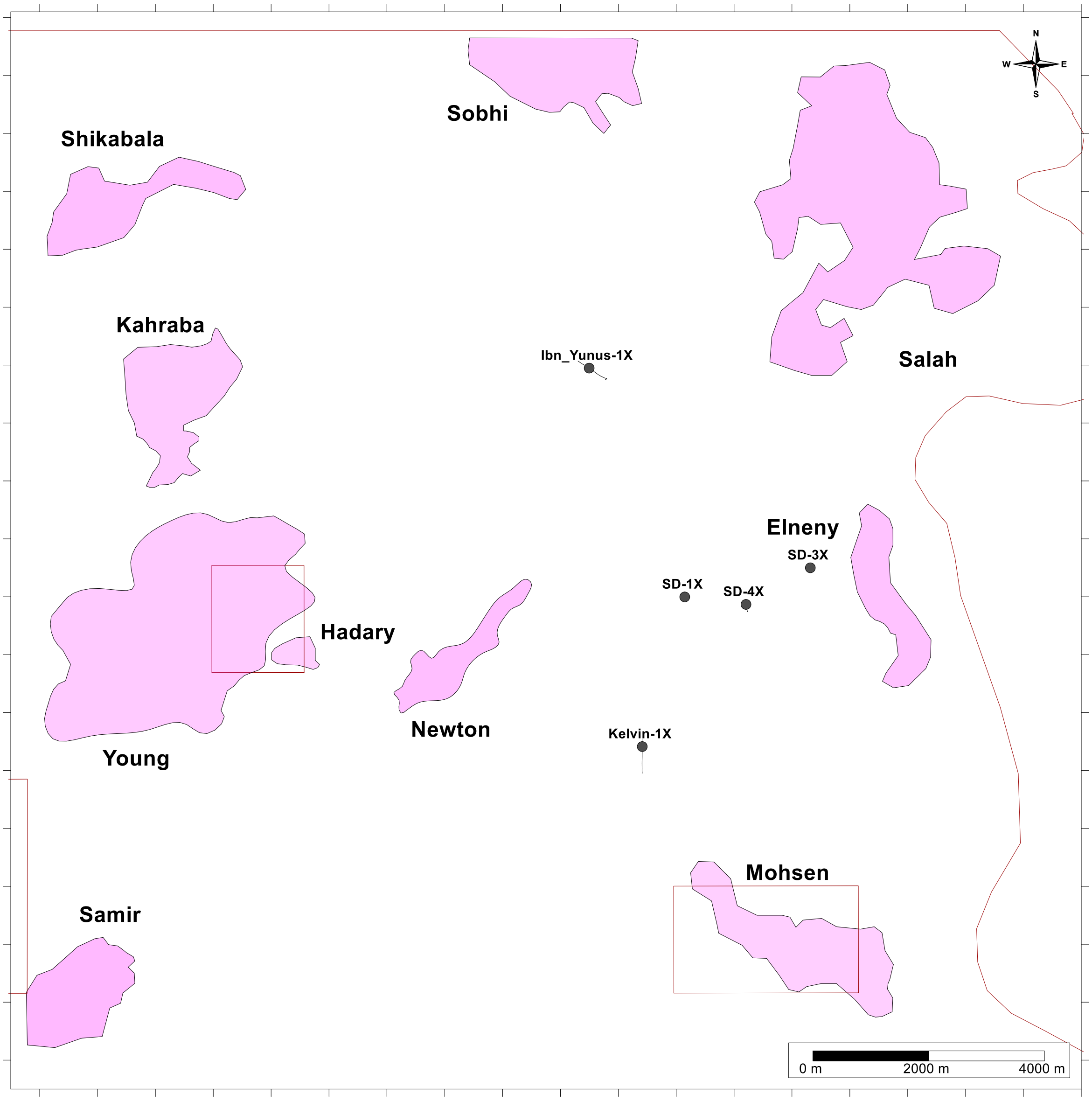

Figure 4.25 Map of prospect locations within the South Disouq concession

4.8.1.1. Newton Prospect

Newton is an Abu Madi prospect located 5 km to the west of the South Disouq discovery. Potential reservoirs have been identified within the AM-I/II and AM-III, which are expected to be of a similar depositional setting and reservoir quality to the South Disouq discovery. Newton is a small, 4-way dip closure at the AM-I and a more extensive 4-way closure at the AM-III interval. The structure is fault bound to the NW and SE at both levels. ERCE has reviewed SDX's seismic interpretation of the prospective intervals and found them to be reasonable. A top structure map for the AM-I sand is presented in Figure 4.26 and for the AM-III sand in Figure 4.27.

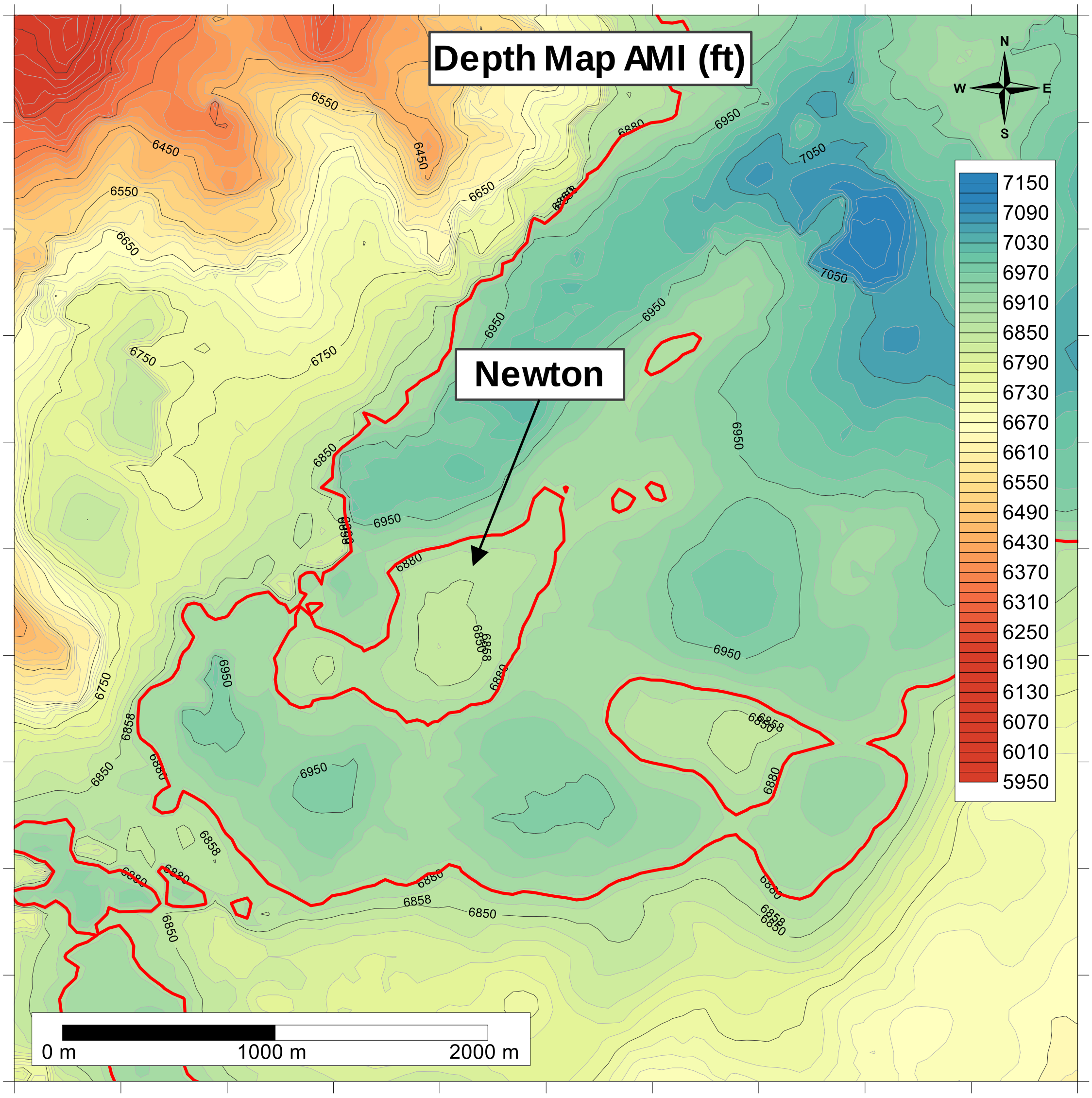

Figure 4.26: Top AM-I depth structure map for the Newton Prospect (ft)

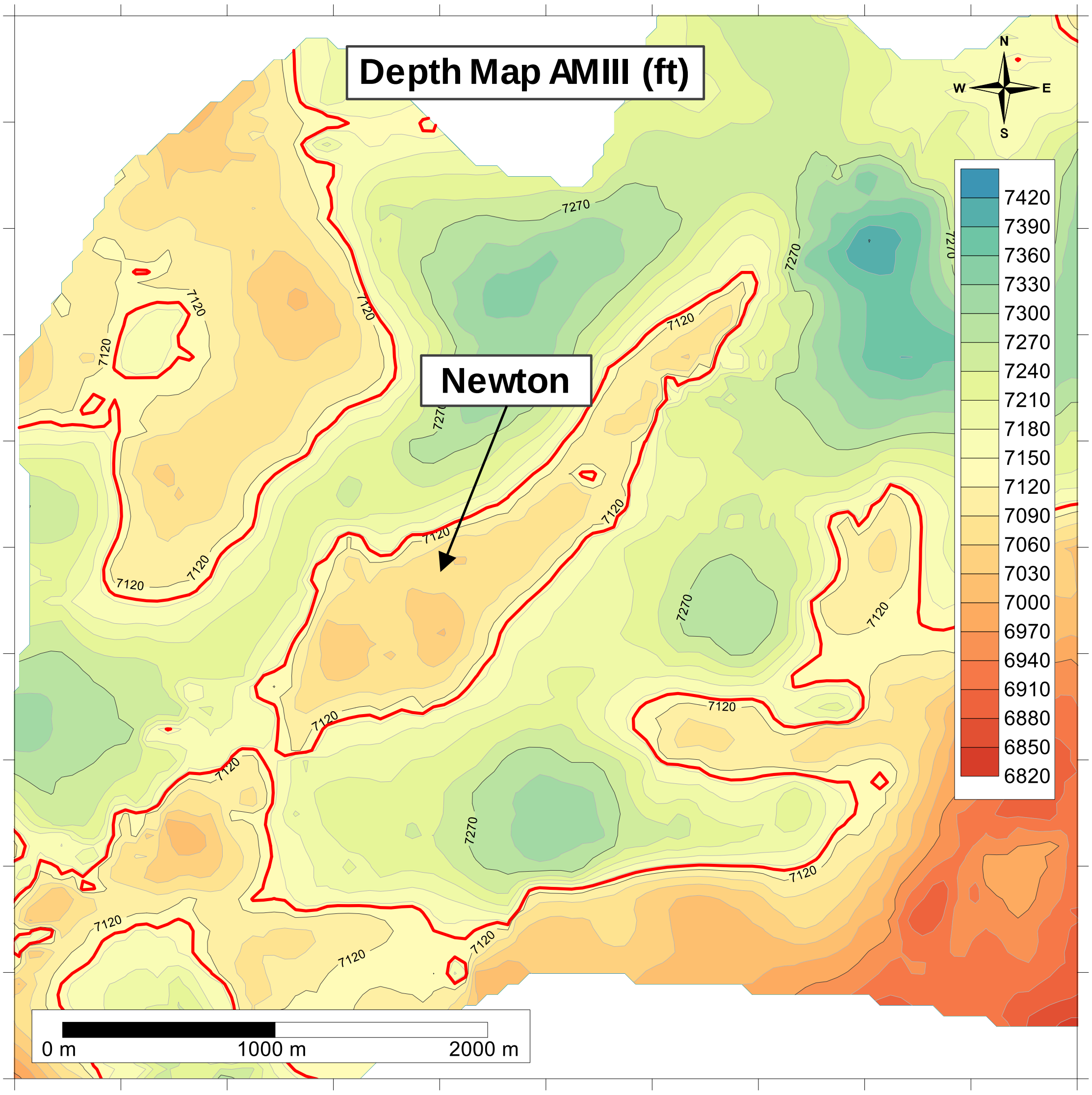

Figure 4.27 Top AM-III depth structure map for the Newton Prospect (ft)

ERCE has volumetrically assessed the AM-I/II and AM-III intervals. While there is a strong reflector present at the AM-III level, the seismic is dimmer at the AM-I and AM-II levels relative to the South Disouq discovery (Figure 4.28). Although there is not an identifiable relationship between sand deposition and amplitudes over the South Disouq wells, the lack of interim reflector over Newton suggests less heterogeneity and thus greater presence of shale in the section.

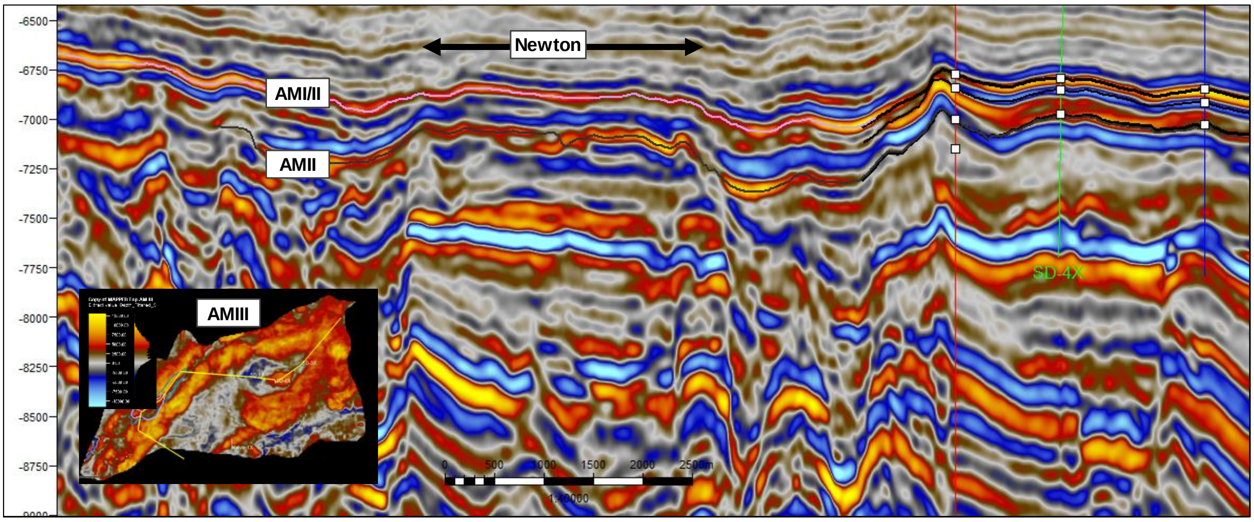

Figure 4.28: Seismic line through the Newton prospect

For the AM-I sands, ERCE calculated a low and high case GRV based on two possible lower closing contours (Figure 4.29). The low case uses a LCC of 6880 ft TVDSS and restricts the accumulation to a single 4-way dip closure with spill to the west. The high case uses a LCC of 6890 ft TVDSS and incorporates a second closure to the west with spill to the north of this smaller structure.

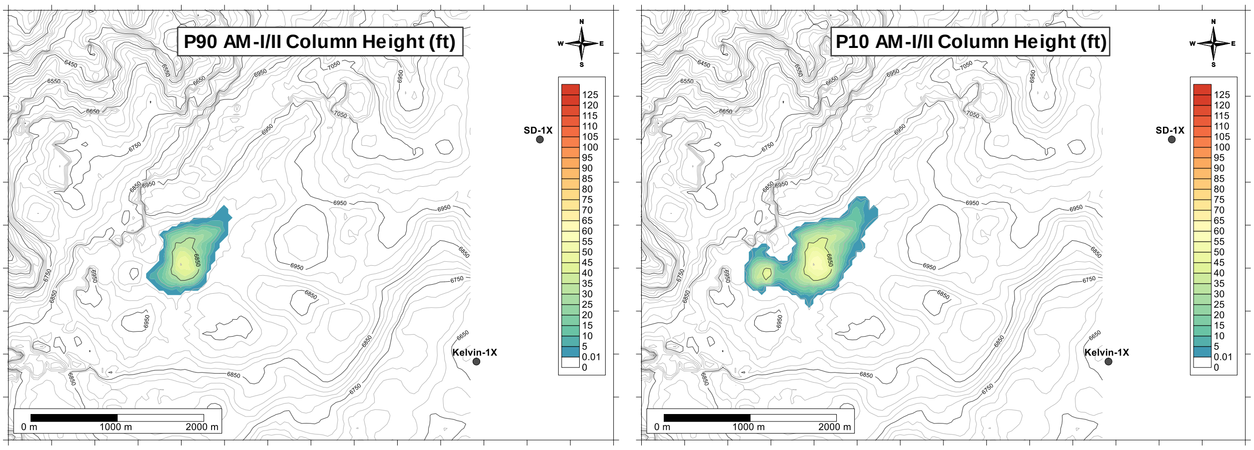

Figure 4.29 Gas column height for the Newton Prospect AM-I/II Interval

For the AM-III sands, ERCE varied the LCC between 7140 and 7150 ft TVDSS in the low and high case to account for relatively small uncertainty in pick and depth conversion. The low case was restricted based on uncertainty in the SE fault location, while the high case embraces the whole closure as fill to spill (Figure 4.30).

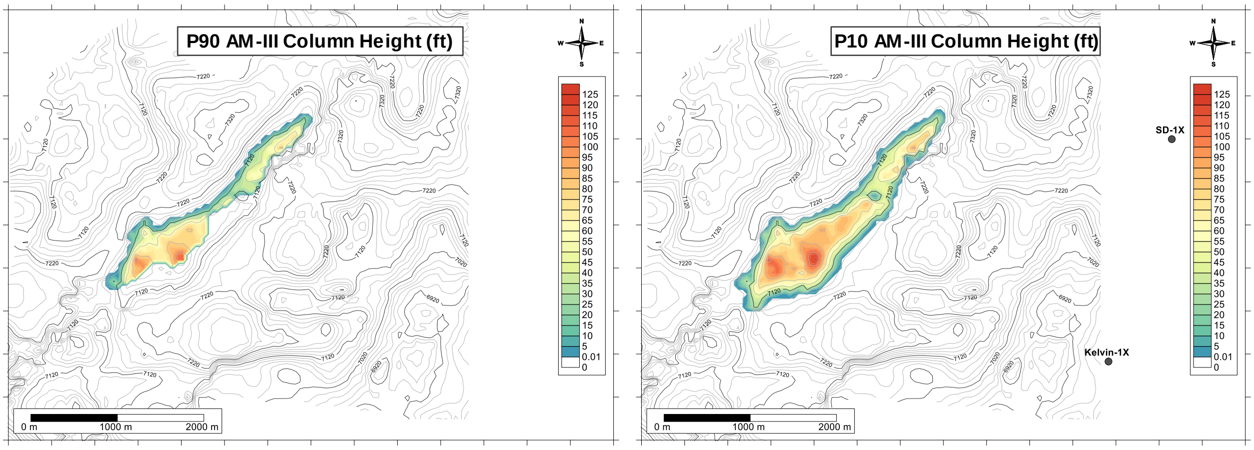

Figure 4.30 Gas column height for the Newton Prospect AM-III Interval

Petrophysical and fluid parameters applied to the AM-III interval are the same as the inputs used for the AM-III reservoir in the South Disouq discovery, while the AM-I is based on the AM-I properties but embraces the possibility of better quality sands similar to AM-II entering the GRV interval. RF was distributed normally with a low (P90) of 60% and a high (P10) of 90% in line with the South Disouq discovery. The in place and prospective resource volumes are displayed in Table 4.18.

Table 4.18 Probabilistic unrisked in place and Prospective Resources for the Newton prospect

Interval	Unrisked GIIP (Bscf)				Unrisked Gas Prospective Resources (Bscf)				Unrisked CIIP (MMbbl)				Unrisked Condensate Prospective Resources (MMbbl)			
	P90	P50	P10	Mean	P90	P50	P10	Mean	P90	P50	P10	Mean	P90	P50	P10	Mean
Newton_AMI	0.4	0.8	1.3	0.8	0.3	0.6	1.0	0.6	0.001	0.004	0.008	0.004	0.001	0.003	0.006	0.003
Newton_AMIII	5.4	7.9	11.8	8.3	3.8	5.9	9.1	6.3	0.016	0.039	0.073	0.043	0.012	0.029	0.056	0.032
Total *(prob)*	**6.1**	**8.8**	**12.6**	**9.2**	**2.5**	**6.7**	**11.9**	**7.0**	**0.02**	**0.04**	**0.08**	**0.05**	**0.01**	**0.03**	**0.06**	**0.04**

4.8.1.2. **Young**

Young is a faulted 4-way dip closure within the Cretaceous section located approximately 10 km to the west of the South Disouq discovery. Potential sandstone reservoirs are defined at four levels within the Cretaceous section: Top Abu Roash - G ("AR-G"), Top Bahariya, Top Kharita and Top Alamein (see stratigraphic column in Figure 4.31). SDX provided certain information on relevant analogue fields as well as petrophysical analysis of Cretaceous reservoirs encountered in SD-1X and Tanta-1X. This information, and regional knowledge within ERCE, supports the property ranges used by SDX as being reasonable. All the reservoir intervals are known to be productive for oil in the Western Desert south of the flexure zone.

There is a phase risk for the Young prospect. The SD-1X discovery well discovered gas which is believed to be sourced from thermal cracking to gas of Oligocene and older more oil prone source rocks. It is also possible that the Abu Madi is sourced by Type-III kerogen within the Miocene formations. However, bottom hole temperatures in the Tanta-1 well suggest that oil prone Cretaceous source rocks of the Abu Roash, Alamein and Safa formations are within the early peak-oil generation window in the South Disouq area. No detailed basin modelling work has been provided by SDX. It is inferred that the South Disouq area is early peak mature for oil and that the gas found by the SD-1X well is the result of long distance gas migration from the NE.

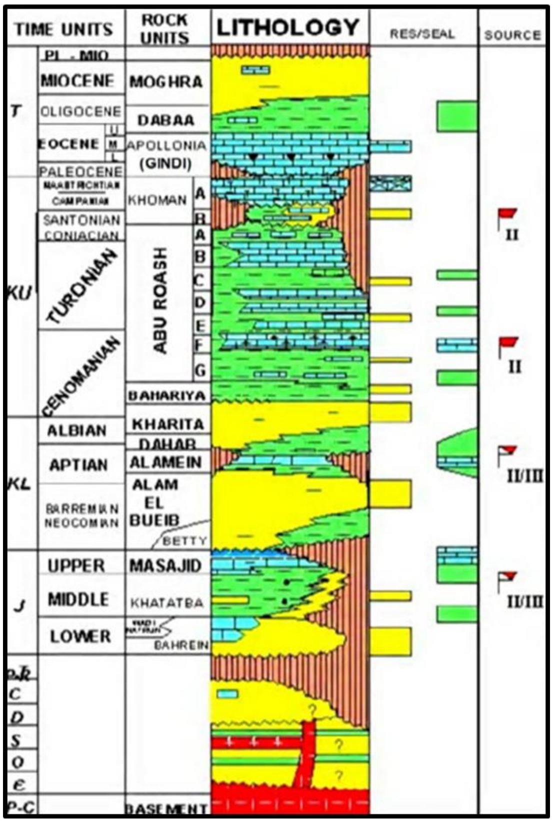

Figure 4.31: Stratigraphic column for the Cretaceous in the Egyptian Western Desert area

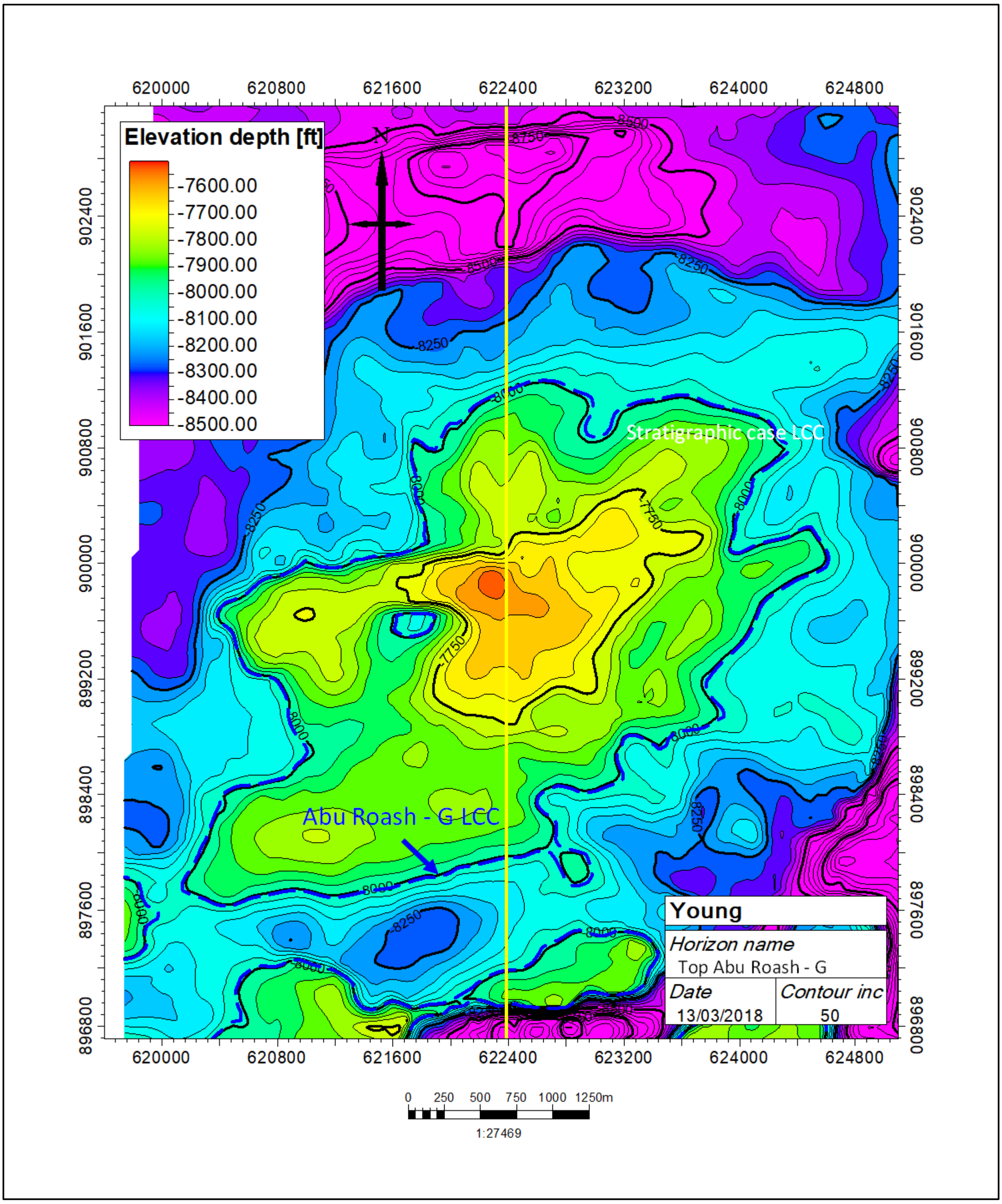

Figure 4.32: Top AR-G depth structure map for the Young Prospect

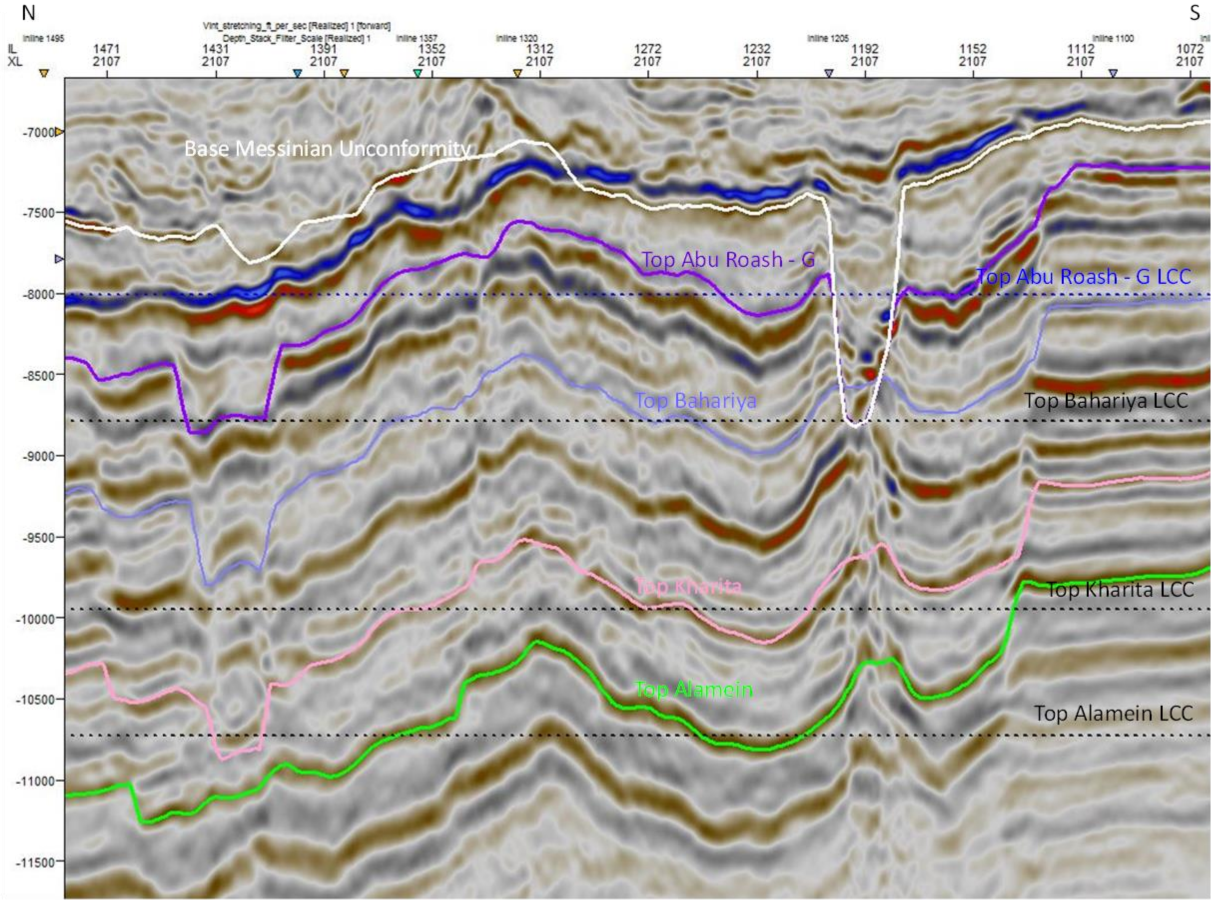

Figure 4.33: East-west seismic line through the Young prospect

High case net rock volumes (NRVs) were calculated for all reservoirs based on the mapped surfaces provided by SDX, the expected net thickness and using the lowest closing contours. Low case NRVs were then calculated using percentage fill and by varying pay thickness based on analogue information. These low and high case NRVs were then set as lognormal and the resulting mid case displayed. Table 4.19 summarises the NRV cases.

Petrophysical parameters used were taken from SDX after comparison with analogue information and regional knowledge, mid case hydrocarbon saturation was adjusted to represent a normal distribution given the paucity of data to suggest otherwise. Input parameters used in STOIIP calculation are provided in Table 4.20.

Table 4.19: Summary of Young prospect NRV cases

Reservoir	Case	Case Description
AR-G	LOW	OWC 7765 ft (50% full), 25 ft pay thickness
	HIGH	NRV above 8010 ft (LCC), 125 ft pay thickness
Bahariya	LOW	OWC 8545 ft (50% full), 25 ft pay thickness
	HIGH	NRV above 8790 ft (LCC), 125 ft pay thickness
Kharita	LOW	OWC 9685 ft (50% full), 25 ft pay thickness
	HIGH	NRV above 9950 ft (LCC), 125 ft pay thickness
Alamein	LOW	OWC 10424 ft (50% full), 25 ft pay thickness
	HIGH	NRV above 10728 ft (LCC), 125 ft pay thickness

Table 4.20: Input parameters for the Young prospect

Interval	NRV (MMm3)			Porosity			Sh			Bo			RF		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
AR-G	12.5	59.6	283.3	0.14	0.18	0.24	0.50	0.63	0.75	1.20	1.40	1.60	0.10	0.20	0.30
Bahariya	4.5	26.4	153.3	0.14	0.18	0.24	0.50	0.63	0.75	1.20	1.40	1.60	0.10	0.20	0.30
Kharita	9.2	43.9	209.4	0.14	0.18	0.24	0.50	0.63	0.75	1.20	1.40	1.60	0.10	0.20	0.30
Alamein/AEB	13.7	58.5	250.0	0.13	0.17	0.20	0.50	0.63	0.75	1.20	1.40	1.60	0.10	0.20	0.30

1. *RF treated as dependent between intervals*

Table 4.21: Probabilistic unrisked in place and Prospective Resources for the Young prospect

Interval	Unrisked STOIIP (MMbbl)				Unrisked Oil Prospective Resources (MMbbl)			
	P90	P50	P10	Pmean	P90	P50	P10	Pmean
AR-G	6.1	30.4	151.1	66.3	1.0	5.7	30.5	13.3
Bahariya	2.2	13.4	80.9	35.8	0.4	2.5	16.2	7.2
Kharita	4.5	22.4	111.3	53.3	0.7	4.2	22.5	9.9
Alamein/AEB	6.1	27.2	120.6	49.0	0.7	4.2	22.5	9.9
Probabilistic aggregation incorporating dependencies	**14.6**	**73.1**	**261.6**	**118.9**	**2.3**	**13.5**	**54.4**	**23.9**

1. *Prospect total based on probabilistic addition assuming oil encountered*

4.8.1.3. **Basal Kafr El Sheik Prospects**

ERCE has volumetrically assessed the Prospective Resources associated with eight prospects identified at the basal Kafr El Sheik (KES) as provided by SDX. These are analogous to the Ibn Yunus discovery, with the exception that all require stratigraphic trapping.

ERCE has reviewed SDX's depth seismic interpretations of the top basal KES and found it to be reasonable. As discussed in Section 4.5, the gradient volume was found to be a good match to the gas filled reservoir observed in Ibn Yunus-1X. This volume has thus been used as the basis for the definition of the basal KES prospects. It should be noted however that ERCE did not conduct fluid replacement modelling, so the effect of gas relative to reservoir quality on the amplitude is less known. In addition, the tuning thickness of the seismic and its associated amplitude response at this level has not been investigated. We have taken account of these unknown aspects when evaluating the volumetric extent and chance of success of the prospects.

ERCE has used an area-net pay method to define the net rock volume. This involved amplitude analysis of the gradient volume, with consideration of the full stack, to define a low and high case area for each prospect. The low case area was confined to the brightest amplitudes while the high case incorporated the full extent of the amplitude anomaly to allow for tuning effects.

The net pay ranges for each prospect were based on the KES interval in Ibn Yunus-1X. It was noted that the average amplitude excursion over the Ibn Yunus discovery is brighter on the gradient volume than the majority of the prospects. To account for this, the net pay of each prospect was scaled relative to the discovery well, considering the average amplitude over both the low and high case areas. We acknowledge that the amplitude response may not be directly related to the net pay as it could also reflect differing porosity and/or gas saturation, however we have chosen to account for the variability in reservoir quality indicated by the seismic in the net pay parameter.

The shape factors applied to the structures were based on a likely degree of fill taking account of the dip of the overall structure. There is a relatively high degree of uncertainty related to these aspects, so a wide range was applied to the shape factor distribution.

An example of this methodology is now discussed for the Salah prospect. It is located 6 km to the NE of the Ibn Yunus discovery and is likely a turbidite fan with sands sourced off the high to the south. On the full stack inversion, the amplitudes appear continuous over the prospect, however on the gradient volume a clear definition is observed that creates an anomaly resembling that of a deep-water fan (Figure 4.34). The seismic line highlights a change in the gradient volume across a fault, with strong negative amplitudes observed over the prospect and positive amplitudes occurring to the east. This can be attributed to either a change in reservoir quality or gas fill. The northern extent of the prospect is observed to dim slightly before the termination of the seismic volume, however it is possible the volumes may continue further north.

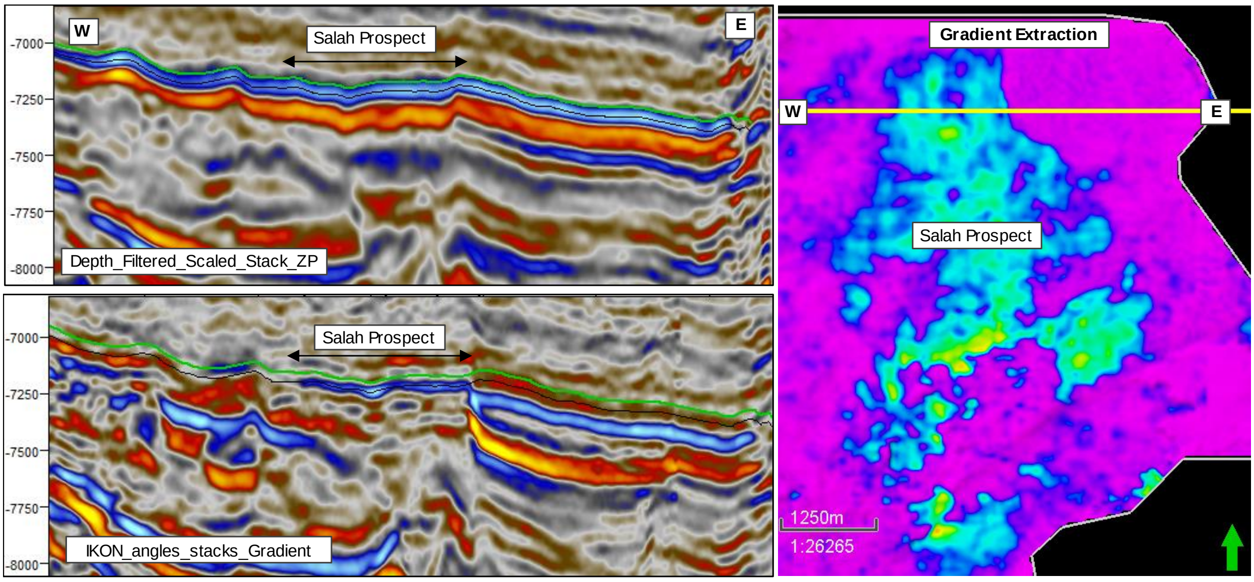

Figure 4.34: E-W seismic line through the Salah prospect

The low case area is confined to the core area of brightest amplitudes, while the high case incorporates the whole area of elevated amplitudes accounting for tuning effects (Figure 4.35).

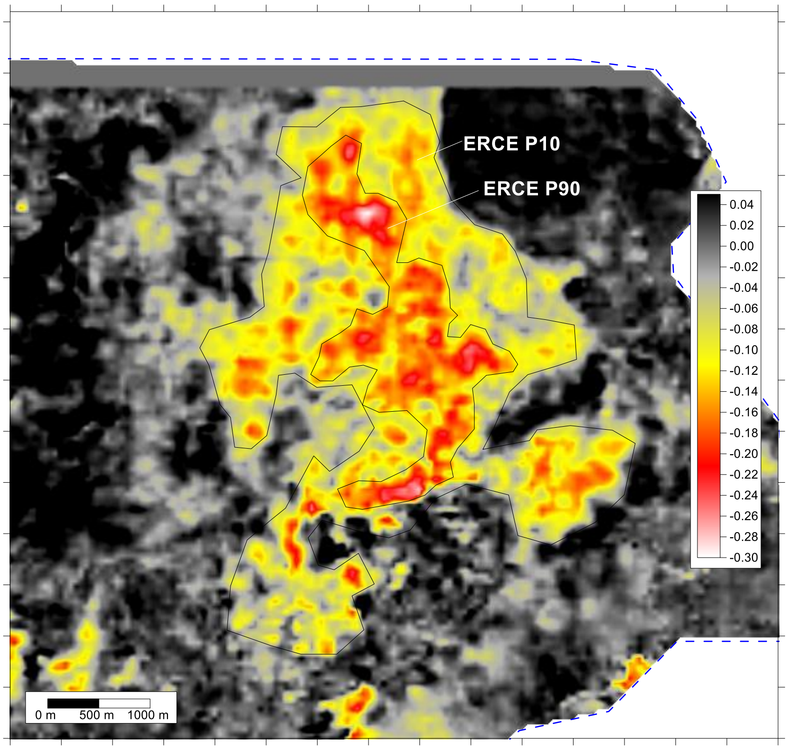

Figure 4.35 ERCE P90 and P10 areal definitions for the Salah Prospect

The net reservoir range was assigned as 20 – 32 m in the low and high case, while the porosity and Sw parameters were directly adopted from those observed in the Ibn Yunus well. The net sand distribution embraces the possibility of the average over the area resembling that of Ibn Yunus, but has a low case that takes account of the lower amplitudes over the Salah prospect relative to Ibn Yunus. As discussed, the lower amplitudes in this prospect may also reflect poorer porosities and/or gas saturation but we have chosen to reflect this in a lower net reservoir thickness.

Recovery factors were based on the analogous Ibn Yunus discovery at a low and high case range of 60% – 90%.

The estimates of GIIP and gross unrisked Prospective Resources for the South Disouq basal KES prospects are presented in Table 4.22.

Table 4.22: Probabilistic unrisked in place and Prospective Resources for the KES prospects

Interval	Unrisked GIIP (Bscf)				Unrisked Gas Prospective Resources (Bscf)				Unrisked CIIP (MMbbl)				Unrisked Condensate Prospective Resources (MMbbl)			
	P90	P50	P10	Mean	P90	P50	P10	Mean	P90	P50	P10	Mean	P90	P50	P10	Mean
Salah	41.5	101.1	244.9	128.3	30.2	75.4	184.6	96.2	0.53	1.39	3.52	1.81	0.39	1.03	2.68	1.36
Shikabala	8.9	22.1	55.8	28.6	6.4	16.4	41.7	21.5	0.11	0.30	0.78	0.40	0.08	0.22	0.59	0.30
Hadary	2.4	4.4	7.7	4.8	1.7	3.3	5.8	3.6	0.03	0.06	0.11	0.07	0.02	0.04	0.09	0.05
Sobhi	7.8	22.9	66.5	32.5	5.7	17.1	50.4	24.3	0.10	0.32	0.95	0.46	0.07	0.23	0.72	0.34
Mohsen	29.3	54.7	104.1	62.1	21.3	40.7	78.6	46.4	0.36	0.75	1.51	0.87	0.26	0.56	1.15	0.65
Samir	5.4	14.0	35.0	18.2	3.9	10.3	26.5	13.6	0.07	0.19	0.51	0.26	0.05	0.14	0.38	0.19
Kahraba	8.2	21.2	53.6	27.6	6.0	15.7	40.7	20.7	0.11	0.29	0.76	0.38	0.08	0.21	0.57	0.29
Elneny	4.4	10.6	26.0	13.5	3.2	7.9	19.6	10.1	0.06	0.15	0.38	0.19	0.04	0.11	0.28	0.14
Total *(det)*	**107.9**	**251.0**	**593.6**	**315.6**	**78.4**	**186.7**	**447.9**	**236.5**	**2.68**	**4.09**	**6.54**	**4.43**	**1.91**	**3.03**	**4.99**	**3.32**

4.8.2. Risking

ERCE has estimated the geological Chance of Success (COS) associated with each of the prospects.

ERCE uses a four-component prospect risking system in our estimation of prospect COS (Table 4.23). Trap risk is defined as both definition and efficacy. Seal refers to the presence and efficacy of an identified seal: top, bottom and side (where relevant). Source risk reflects the presence and maturity of a suitable source rock, and the risk to migration of hydrocarbons from the source rock into the prospect. Reservoir risk reflects the presence and efficacy (i.e. porosity and permeability), of any identified reservoir interval.

Table 4.23: Prospect risk matrix

Prospect Risk			
Source (Migration)	**Reservoir** (Efficacy)	**Trap** (Definition & Efficacy)	**Seal** (Presence & Efficacy)

In addition, a phase risk may be applied to an individual prospect where there is a risk of gas rather than oil, or vice versa.

The tables below present our risks associated with each of the prospects assessed.

Table 4.24: Geological chance of success for the Newton prospect

Prospect	Source (Migration)	Reservoir (Efficacy)	Trap (Definition & Efficacy)	Seal (Presence & Efficacy)	COS
Newton	80%	80%	80%	70%	36%

Table 4.25: Geological Chance of Success for the basal Kafr El Sheik prospects

Prospect	Source (Migration)	Reservoir (Efficacy)	Trap (Definition & Efficacy)	Seal (Presence & Efficacy)	COS
Salah	80%	80%	50%	90%	29%
Shikabala	80%	80%	90%	90%	52%
Hadary	80%	80%	90%	90%	52%
Sobhi	80%	70%	70%	90%	35%
Mohsen	80%	70%	60%	90%	30%
Samir	80%	70%	50%	90%	25%
Kahraba	80%	70%	50%	90%	25%
Elneny	80%	50%	40%	90%	14%

As the Young Prospect has multiple possible reservoir levels the volumes and risks have been probabilistically combined in Crystal Ball. Source, phase and trap risk have been set as dependent i.e. they apply for all reservoirs. The main trap risk is breach by Late Eocene movement on faults which can be observed on seismic to cut through all reservoir horizons.

Table 4.26: Geological chance of success for the Young prospect

Risk element	Risk	
Trap	0.6*	4-way dip closure on good quality seismic. Late (Eocene) fault movement may have breached trap
Seal	0.8	Abundant shales and marls to seal. Small risk of sand on sand across faults.
Reservoir (presence & quality)	0.7	Productive reservoirs within the Western Desert to the South. Reservoir sands present in Tanta-1X and MGNE-1
Migration	0.7*	SD-1X proves working petroleum system to Abu Madi but possibly local source. Weak show recorded in SD-1X Kharita but not logged. Oil shows reported in SEK-1 and MG NE-1 offset wells. Unproven oil source in South Disouq area.
Phase	0.8*	Success dependent on finding oil. Only gas proven in South Disouq area. Oil charge inferred but not proven.
Individual reservoir COS	0.19	
Combined whole prospect COS	0.31	*dependent risks

As per COGEH requirements prospects must be risked for chance of development ("COD") as well as geological chance of success. The product of the COS and the COD being the chance of commerciality. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are out with the expertise of the evaluator they must be used with caution.

For the prospects assessed there is a very high chance of development. ERCE has estimated the COD based on the probability of the GIIP exceeding 3 Bscf which SDX believe is the minimum required to justify completing the well and hooking it up.

4.8.3. Risked Prospective Resources

A summary of the South Disouq concession, unrisked and risked Prospective Resources on a gross and working interest share basis are presented in Table 4.27.

Table 4.27: Summary of the South Disouq concession unrisked and risked Prospective Resources

Gas Prospective Resources

Prospect	Gross Unrisked Gas Prospective Resources (Bscf)				SDX Working Interest	Net Unrisked Prospective Gas Resources (Bscf)				gCOS	COD	Net Risked Prospective Gas Resources (Bscf)			
	1U	2U	3U	Mean		1U	2U	3U	Mean			1U	2U	3U	Mean
Salah	30.2	75.4	184.6	96.2		16.6	41.5	101.5	52.9	29%	100%	4.78	11.94	29.23	15.24
Shikabala	6.4	16.4	41.7	21.5		3.5	9.0	22.9	11.8	52%	100%	1.84	4.68	11.88	6.12
Hadary	1.7	3.3	5.8	3.6		1.0	1.8	3.2	2.0	52%	80%	0.39	0.75	1.32	0.82
Sobhi	5.7	17.1	50.4	24.3		3.1	9.4	27.7	13.4	35%	100%	1.10	3.31	9.79	4.72
Mohsen	21.3	40.7	78.6	46.4	55%	11.7	22.4	43.2	25.5	30%	100%	3.54	6.77	13.08	7.72
Samir	3.9	10.3	26.5	13.6		2.1	5.7	14.6	7.5	25%	100%	0.54	1.43	3.67	1.89
Kahraba	6.0	15.7	40.7	20.7		3.3	8.6	22.4	11.4	25%	100%	0.84	2.18	5.64	2.87
Elneny	3.2	7.9	19.6	10.1		1.8	4.3	10.8	5.6	14%	100%	0.25	0.62	1.55	0.80
Newton	2.5	6.7	11.9	7.0		1.4	3.7	6.6	3.9	36%	100%	0.49	1.32	2.35	1.39
Determinstic Tot	**80.9**	**193.4**	**459.8**	**243.5**		**44.5**	**106.4**	**252.9**	**133.9**			**13.8**	**33.0**	**78.5**	**41.6**

Oil Prospective Resources

Prospect	Gross Unrisked Oil Prospective Resources (MMbbl)				SDX Working Interest	Net Unrisked Prospective Oil Resources (MMbbl)				oCOS	COD	Net Risked Prospective Oil Resources (MMbbl)			
	1U	2U	3U	Mean		1U	2U	3U	Mean			1U	2U	3U	Mean
Young	2.3	13.5	54.4	23.9	55%	1.3	7.4	29.9	13.2	32%	85%	0.35	2.04	8.23	3.62

Condensate Prospective Resources

Prospect	Unrisked Prospective Condensate Resources (MMbbl)				SDX Working Interest	Net Unrisked Prospective Condensate Resources (MMbbl)				gCOS	COD	Net Risked Prospective Condensate Resources (MMbbl)			
	1U	2U	3U	Mean		1U	2U	3U	Mean			1U	2U	3U	Mean
Salah	0.39	1.03	2.68	1.36		0.21	0.57	1.47	0.75	29%	100%	0.06	0.16	0.42	0.22
Shikabala	0.08	0.22	0.59	0.30		0.04	0.12	0.33	0.16	52%	100%	0.02	0.06	0.17	0.08
Hadary	0.02	0.04	0.09	0.05		0.01	0.02	0.05	0.03	52%	80%	0.00	0.01	0.02	0.01
Sobhi	0.07	0.23	0.72	0.34		0.04	0.13	0.40	0.19	35%	100%	0.01	0.05	0.14	0.07
Mohsen	0.26	0.56	1.15	0.65	55%	0.14	0.31	0.64	0.36	30%	100%	0.04	0.09	0.19	0.11
Samir	0.05	0.14	0.38	0.19		0.03	0.08	0.21	0.11	25%	100%	0.01	0.02	0.05	0.03
Kahraba	0.08	0.21	0.57	0.29		0.04	0.12	0.32	0.16	25%	100%	0.01	0.03	0.08	0.04
Elneny	0.04	0.11	0.28	0.14		0.02	0.06	0.15	0.08	14%	100%	0.00	0.01	0.02	0.01
Newton	0.01	0.03	0.06	0.04		0.01	0.02	0.03	0.02	36%	100%	0.00	0.01	0.01	0.01
Determinstic Tot	**1.01**	**2.59**	**6.53**	**3.35**		**0.55**	**1.42**	**3.59**	**1.84**			**0.17**	**0.44**	**1.11**	**0.57**

1. *Net unrisked Prospective Resources are based on the working interest share of the field gross resources and do not represent the net entitlement resources.*
2. *COS is the chance of geological success and COD is the chance of development. The product of COS x COD is the chance of commerciality.*
3. *Quantifying the COD requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are out with the expertise of ERCE they must be used with caution.*
4. *Net risked Prospective Resources are the product of the unrisked resources and the chance of commerciality*
5. *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*
6. *For the Young prospect, Gross unrisked Prospective Resources are the probabilistic aggregation of individual reservoirs incorporating dependencies (see* Table 4.21*)*

5. North West Gemsa Concession

5.1. Introduction

The NW Gemsa concession is an 83 km^2 onshore concession located approximately 300 km SE of Cairo in the Eastern Desert adjacent to the Gulf of Suez. The concession consists of three main oilfields, the Al Amir SE, Al Ola and Geyad fields. The Al Amir and Al Ola fields are essentially part of the same accumulation. The three fields produce a light 42 °API oil from two separate intervals in the Kareem formation, the Shagar sandstone and the Rahmi sandstone members.

In December 2009, SDX acquired a 10% participating interest in the concession which was increased to 50% in January 2017. The Operator is North Petroleum International Company, which also has a 50% participating interest.

The Al Amir SE (AASE) field and Geyad field both extend into the neighbouring concession to the east which is operated by Dana. Three wells penetrate the AASE field and one well penetrates the Geyad field in the neighbouring concession. The wells in the AASE field in the neighbouring concession produce oil from the field. The well in the Geyad field penetrated a gas cap. There is no unitisation agreement in place.

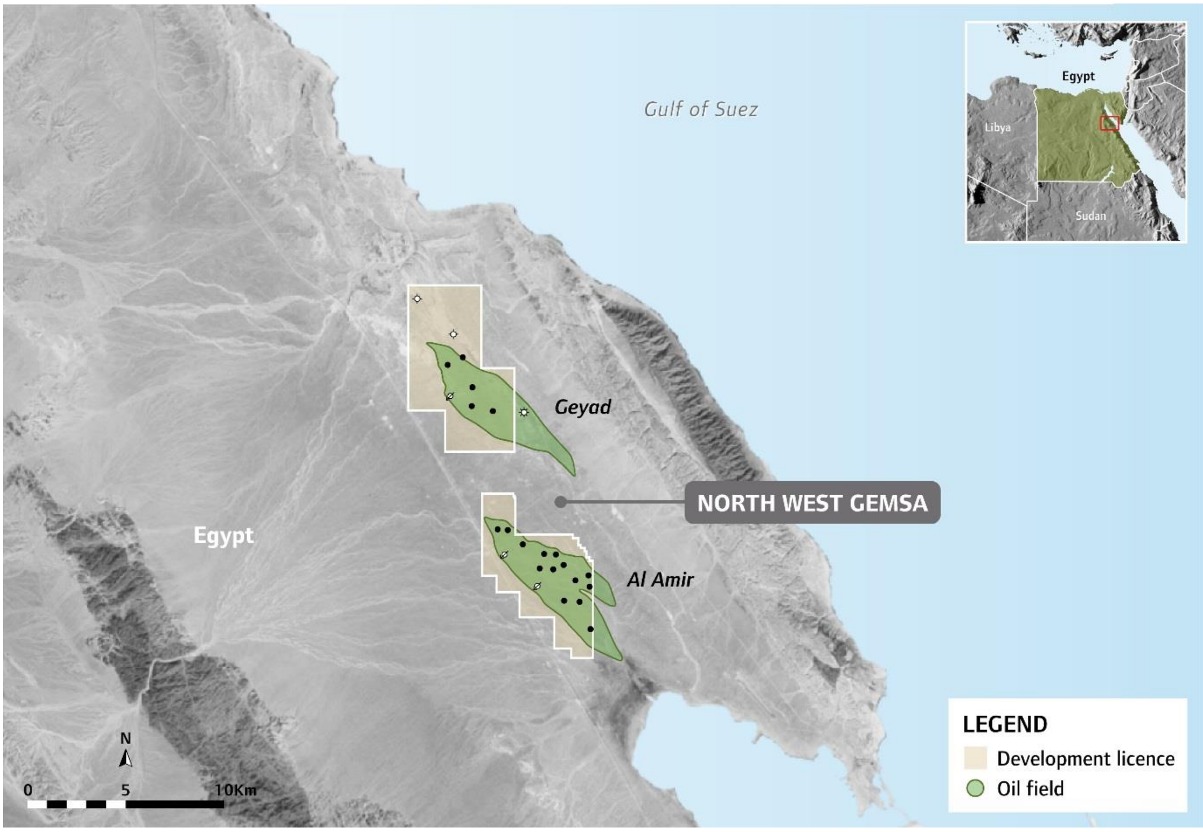

Figure 5.1: Location map showing the location of the NW Gemsa concession

5.2. Development History

Production from the Al Amir SE ("AASE") / Al Ola ("AO") fields began in February 2009. Peak production occurred in 2013 with an oil production rate of approximately 9000 bbl/day. At 31st December 2018, production had fallen to approximately 3,000 bbl/d and the watercut was approximately 65%. Cumulative oil production to this date was approximately 20.9 MMbbl.

The production history of the field is shown in Figure 5.2.

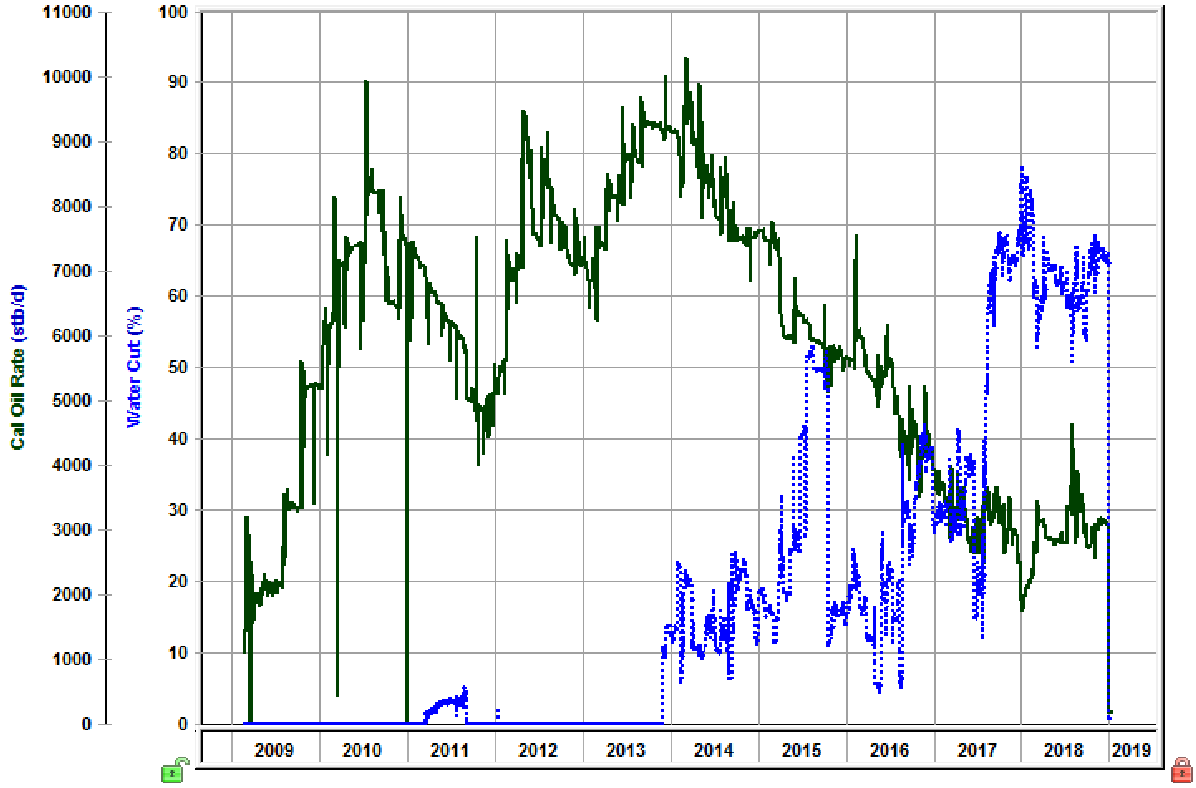

Figure 5.2: Oil production rate and watercut history of the Al Amir SE / Al Ola fields.

5.3. Geological Description

The Al Amir SE/Al Ola and Geyad fields contain oil trapped in downthrown tilted fault blocks to the SW of a major NW-SE trending fault complex. The AASE/AO accumulation is interpreted to be structurally closed to the north and east and dip closed to the west and south. The Geyad field is fault closed around most of its perimeter but with some degree of dip closure to the west. The degree of faulting and the very poor quality of the seismic over the fields (due to overlying anhydrite and halite layers) make structural interpretation complex and ambiguous.

The reservoir rocks in the fields are the Shagar and Rahmi sandstones within the Kareem formation. Vertical seal is provided by intra-formational mudstones and sealing across faults is against mudstones and tight carbonates in the underlying Rudeis formation.

Top structure maps for the Shagar sand at the AASE/AO and Geyad fields are presented in Figure 5.3 and Figure 5.4 respectively.

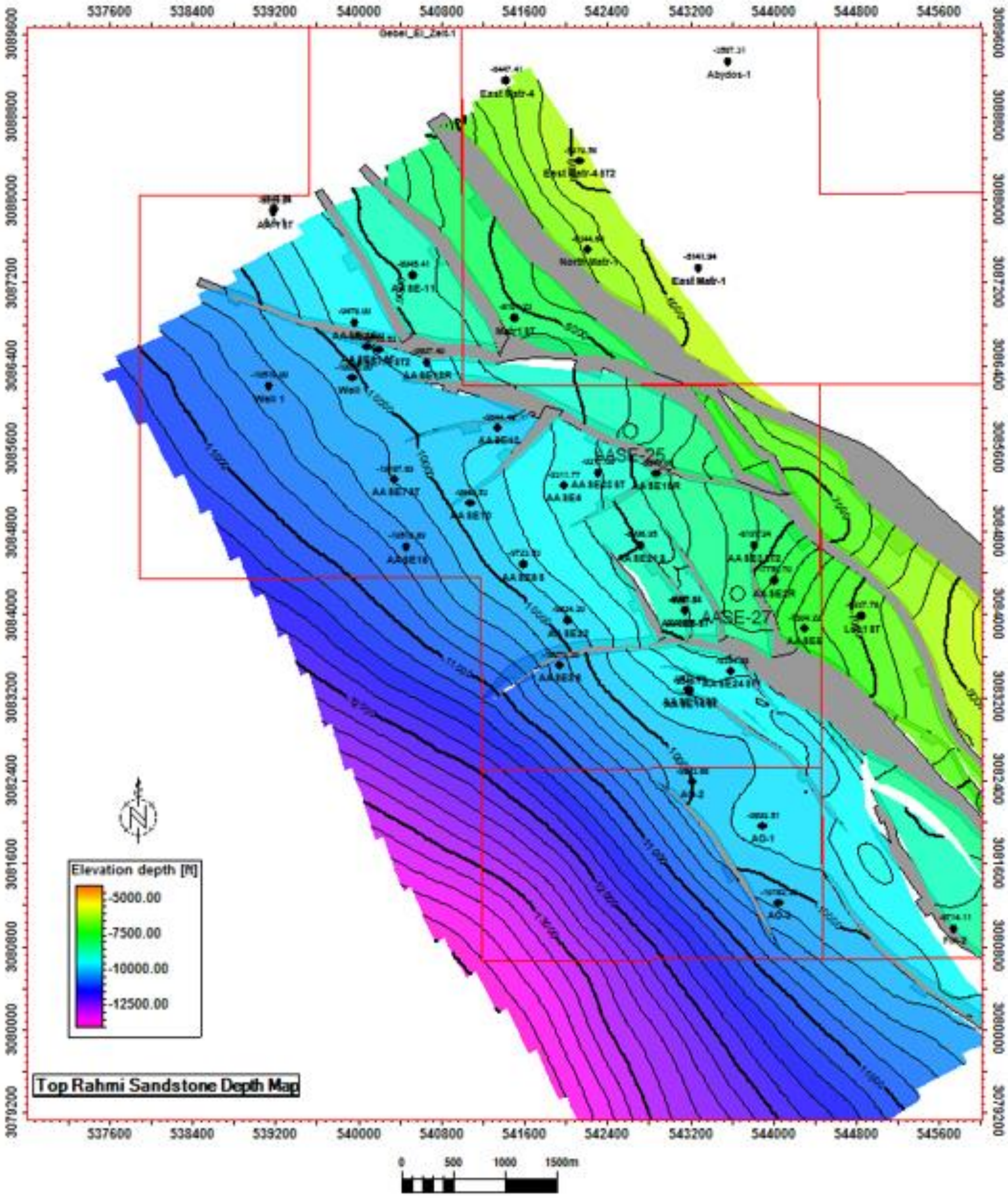

Figure 5.3: Top Shagar sand depth structure map for the AASE/AO field

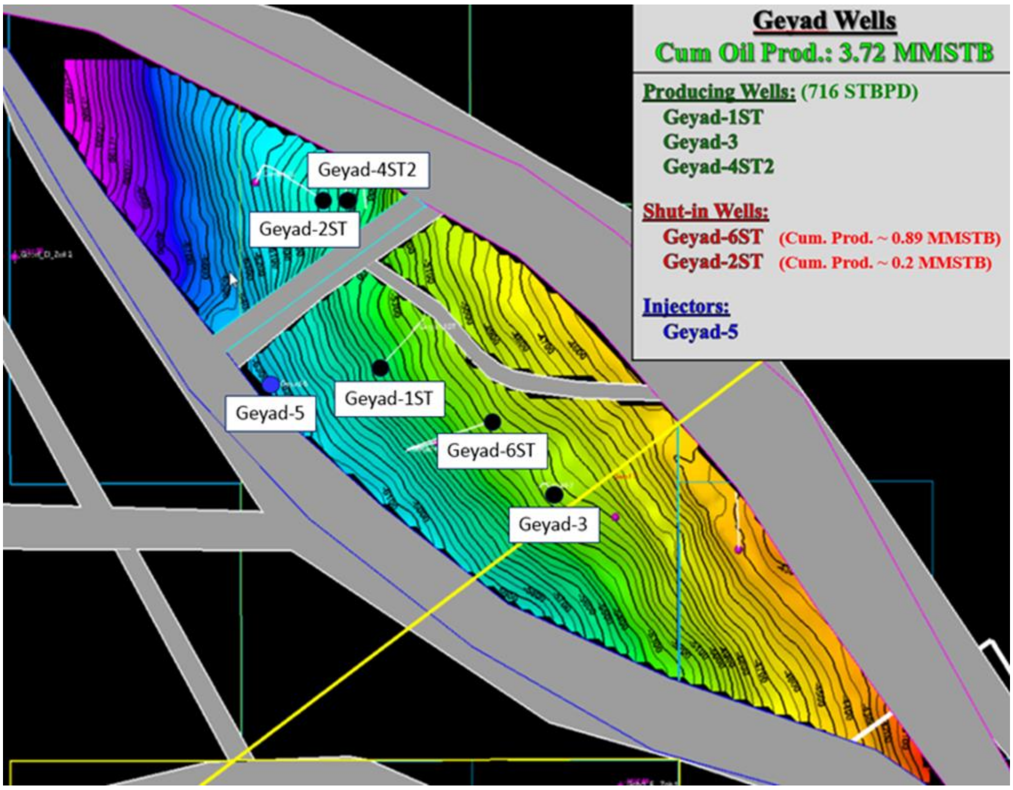

Figure 5.4: Top Shagar sand depth structure map for the Geyad field

5.4. Reservoir Engineering and Production Performance

The AASE / Al Ola field produces from the Shagar and Rahmi members.

Both intervals produce a black oil with a gas oil ratio of approximately 1,300 scf/stb, a bubble point pressure of approximately 2,300 psia and an oil formation volume factor of approximately 1.8 rb/stb. Oil viscosity at reservoir conditions is approximately 0.15 cP. The initial pressure was approximately 4,430 psia at a datum depth of 8500 ft TVDSS.

Production performance suggests that there is an extensive connected aquifer in both formations which provides pressure support. This is supplemented with downdip water injection. Consistent with the favourable mobility ratio, sweep is effective. In the Shagar in particular, once water breakthrough occurs, watercut increases rapidly.

5.5. Recoverable Resources

Of the wells currently producing, the majority are showing declining oil rates or increasing watercuts or both. Recoverable resources have therefore been estimated using production performance analysis partially supplemented by volumetrics based on the reservoir simulation models created by the Operator. The fields are mature with considerable production history which aids this approach. Hydrocarbons in place in general were not estimated due to the poor quality of the seismic over the AASE / AO and Geyad fields.

5.5.1. AASE / AO fields – Existing wells

A total of 26 wells have been drilled into the AASE / AO fields. (Well Al Ola-4 is considered a sidetrack of Well Al Ola-1). This includes five wells drilled as downdip injectors and two wells that started life as producers and were converted to water injectors. Some of the wells completed as Shagar producers have been recompleted in the Rahmi (or vice versa). At 31st December 2018, four wells were producing from the Shagar and seven from the Rahmi.

SDX provided a 2017 simulation model that does not incorporate the results of the 2018 drilling campaign, therefore DCA was used to generate the production forecast for producing wells which have started producing water. Assessment of the remaining resources attributable to producing wells which have not yet started producing water was guided by volumes in the simulation model and exponential decline in production rate.

During 2018, the Operator carried out the following activities in the AASE-Al Ola field.

5.5.1.1. Drilling of Well AASE-25, -25 ST1 and -25 ST2

Well AASE-25 was intended to test the undrained fault block to the north of the main AASE-Al Ola field. The location of the fault block and Well AASE-25 and its sidetracks are shown in Figure 5.5 below.

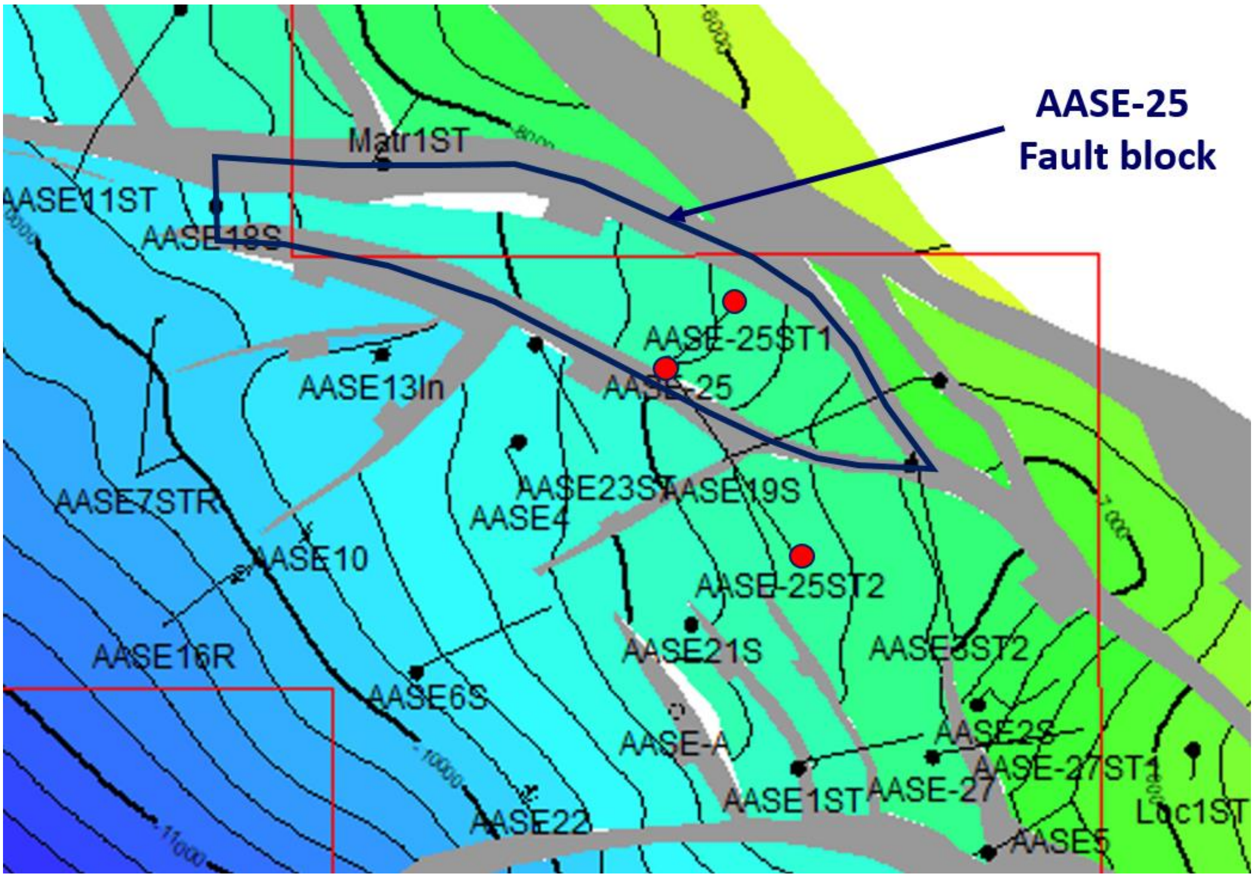

Figure 5.5: Well AASE-25, 25ST1 and 25ST2 locations

Well AASE-25 found that both Shagar and Rahmi reservoirs were missing at the well location. The well was sidetracked to the NE but the well again found the reservoirs to be missing. It was concluded that the fault block was not prospective, and the well was sidetracked to the south, back into the main field. The Shagar sandstone was found to be swept at the well location but the Rahmi sandstone was oil-bearing. The well was completed in the Rahmi sandstone and as at 31st December 2018 was producing dry oil at a rate of approximately 530 bbl/d.

5.5.1.2. **Drilling of Well AASE-27, -27 ST1**

The current seismic interpretation identifies a number of small faults running north from the main east-west fault in the field. It is considered that the presence of these faults may result in volumes of oil being bypassed by water being drawn to the crest of the field by production.

Well AASE-27 was drilled into the one of these compartments. The well encountered largely swept Shagar sandstone reservoir. The Rahmi sandstone was absent. The well was sidetracked to the east to a location near the crest of the field and close to the block boundary. The Shagar sandstone was partially swept at the well location but the well encountered and was completed in oil-bearing Rahmi sandstone reservoir. As at 31st December 2018, the well was producing dry oil at a rate of approximately 220 bbl/d.

5.5.1.3. Workover of Al Ola-1 / sidetrack to Al Ola-4 location

Well Al Ola-1 was lost in 2017 while producing at a rate of approximately 300 bbl/d and a watercut of approximately 50%. However, issues were encountered during the workover and instead the well was sidetracked to the east as Al Ola-4. The locations of the wells are shown in Figure 5.6 below.

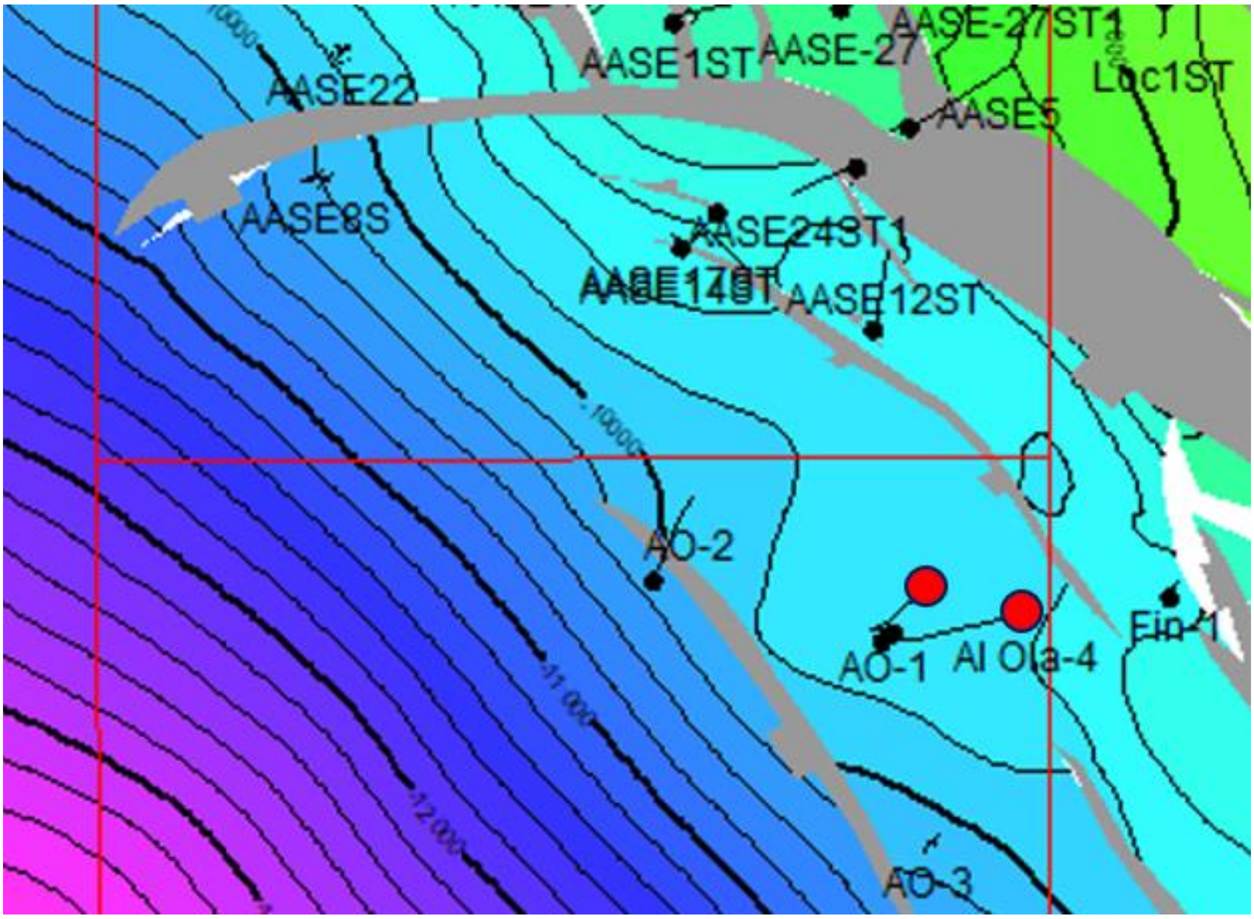

Figure 5.6: Location of Well Al Ola-4

Well Al Ola-4 was completed in the Rahmi sandstone and at 31st December 2018 was producing dry oil at a rate of approximately 1000 bbl/d.

5.5.1.4. Recompletion of Well AASE-18S

Well AASE-18S was re-completed from the Shagar sandstone to the Rahmi sandstone. The well initially produced dry oil at a rate of approximately 700 bbl/d but declined steeply. At 31st December 2018, the well was producting approximately 150 bbl/d of dry oil.

5.5.1.5. Production from Existing Wells

The list of wells on production at 31st July 2018 is shown in Table 5.1.

Table 5.1: AASE and Al Ola wells producing at 31st December 2018

AASE Shagar wells	AASE Rahmi wells	Al Ola Shagar wells	Al Ola Rahmi wells
12S	14R		4R
2S	18R		
23S	19R		
5S	21R		
	25R		
	27R		

ERCE's estimates of Developed Producing resources (oil plus condensate) attributable to the existing AASE-Al Ola wells are summarised in Table 5.2.

Table 5.2: Resources attributable to existing completions

Resources attributable to existing completions (MMbbl)		
Low	Best	High
1.6	2.1	2.6

5.5.2. AASE / AO fields – New wells

There are currently no plans to drill further wells in the field.

5.5.3. AASE / AO recompletions

The three wells in the concession area to the east of NW Gemsa and operated by Dana are producing oil from the AASE / AO field. In the absence of a unitisation agreement, this production is lost to the NW Gemsa partners. However, SDX believe only the Shagar member exists in the Dana wells. The Operator of NW Gemsa has therefore focused the field's crestal wells on production from the Shagar sandstone. As a consequence, there are believed to be significant untapped resources in the Rahmi sandstone in the area of the field crest.

Three wells were identified as candidates for recompletion to the Rahmi sandstone. Well AASE-18S was recompleted during 2018. It proved dry oil from the Rahmi sandstone but at 31st December 2018 was declining rapidly. Wells AASE-2S and AASE-5S have also been identified as recompletion candidates. However, the drilling of Well AASE-27ST1 into the area between the two wells has reduced the potential for these recompletions. ERCE has assumed that Well AASE-2S will now not be recompleted (as it is downdip of Well AASE-27ST1) and that Well AASE-5S will be recompleted. After assessing volumes in the updip portion of the Rahmi sandstone, ERCE has concluded that the potential incremental recovery from the re-completed well will be 0.32 MMbbl.

ERCE's estimates of resources (oil plus condensate) attributable to recompletions is shown in Table 5.3.

Table 5.3: Resources attributable to recompletion of Well AASE-5S

Resources attributable to re-completions (MMbbl)		
Low	Best	High
0.2	0.3	0.5

5.5.4. AASE / AO Remaining Resources

In estimating the remaining resources attributable to the AASE / AO fields, ERCE has summed the resources attributable to:

- The existing completions.
- The recompletion of Well AASE-5S to the Rahmi.

In developing the totals, ERCE has summed the individual estimates deterministically.

In calculating Developed resources, ERCE has considered only resources attributable to existing completions. ERCE has attributed resources associated with the recompletion of Well AASE-5S to the Developed Non-producing category. ERCE considers that there are currently no Undeveloped resources in the AASE-Al Ola field.

The resources (oil plus condensate) attributable to the AASE-Al Ola field are presented in Table 5.4.

Table 5.4: Resources attributable to the AASE / Al Ola fields

	Resources attributable to AASE-Al Ola field (MMbbl)		
	Low	Best	High
Developed producing	1.6	2.1	2.6
Developed Non-producing	0.2	0.3	0.5
Total recoverable resources	1.8	2.4	3.1

5.5.5. Geyad

In the Geyad field, all existing wells are producing water. A new well, Well Geyad-7 has been proposed but is not yet approved. No recompletions are planned. In estimating the remaining resources attributable to the Geyad field, ERCE has therefore used decline curve analysis of the existing wells.

ERCE's estimates of the resources (oil plus condensate) attributable to the Geyad field are shown in Table 5.5.

Table 5.5: Resources attributable to the Geyad field

	Resources attributable to the Geyad field (MMbbl)		
	Low	Best	High
Developed producing	1.0	1.4	2.2

5.6. Production Forecasting

ERCE has used decline based predictions for the existing wells based on the performance analysis used to estimate the recoverable resources. The recompletion of Well AASE-5S to the Rahmi is assumed to occur in October 2019.

The total PDP, PD, 1P, 2P and 3P forecasts of oil plus condensate production for the AASE / AO and Geyad fields prior to economic cut off are presented in Table 5.7 and Table 5.8 respectively.

A portion of revenue is derived from selling natural gas and NGLs. An associated natural gas forecast was derived from the oil forecasts based on the current producing GOR which during the past year has been approximately 1,300 scf/bbl. Historically, sales gas volumes have averaged around 95% of the produced gas volumes and hence a shrinkage was applied to derive a sales gas forecast. LPG (the NGLs) are produced at the EGAS gas processing facility and sold on behalf of the NW Gemsa partners. The LPG yield is 15.4 bbl/MMscf of sales gas.

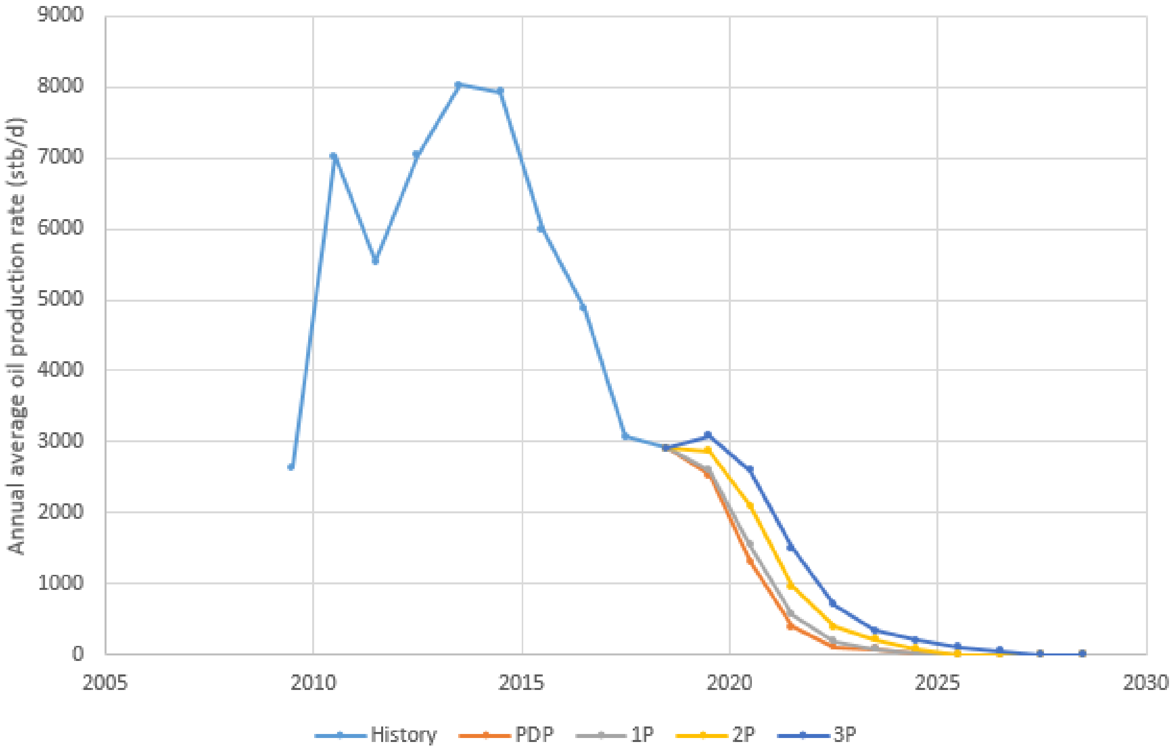

Figure 5.7: PDP, PD, 1P, 2P and 3P production forecasts for the AASE/AO field

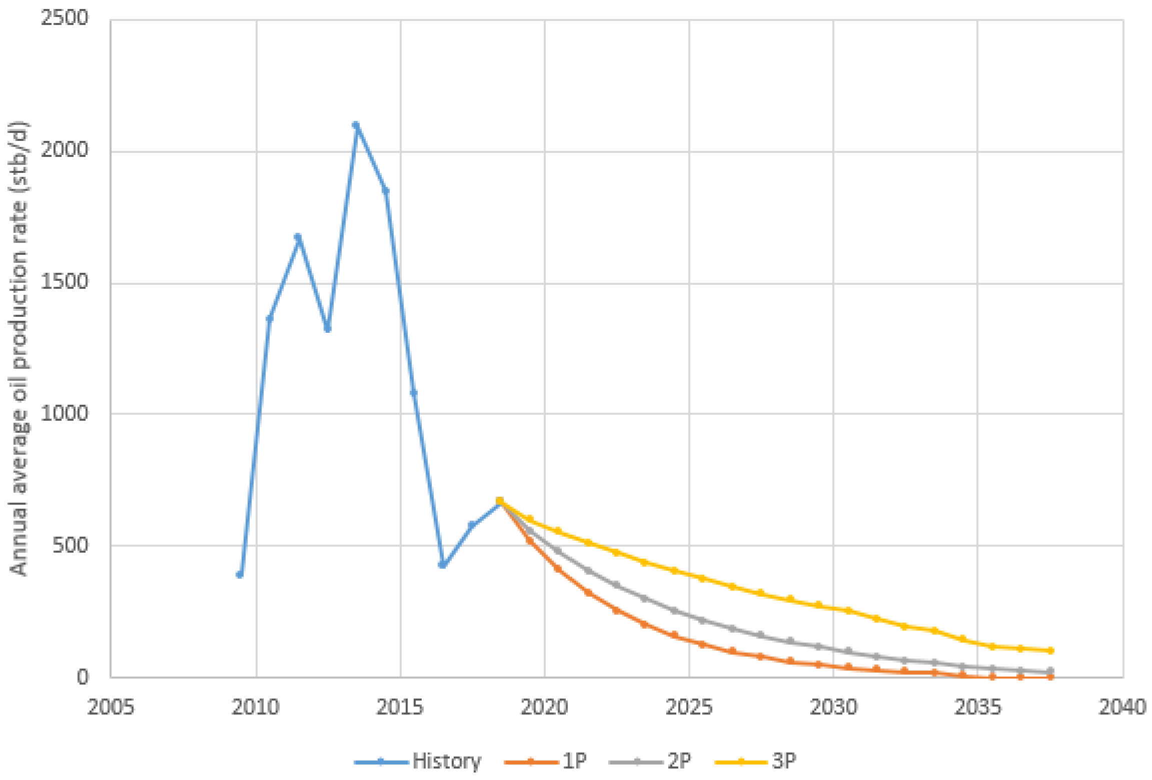

Figure 5.8: PDP, PD, 1P, 2P and 3P production forecasts for the Geyad field

5.7. Reserves and Net Present Values

The Reserves estimates were based on the NW Gemsa aggregated production forecasts cut off at the economic limit (or licence expiry) as determined by production and revenue analysis.

Oil plus condensate, natural gas and NGL revenue was derived from the production forecasts, discussed in Section 5.6, and the forecast prices presented in Table 2.2. Oil plus condensate and NGL prices were based on the average discount to Brent based on the 2017 and 2018 and actual sales and is 93% of the Brent price. Natural gas is sold under the terms of the concession agreement which specifies a cost gas price of US $1.6/Mscf and a profit gas price of US $1.0/Mscf.

The Operator of NW Gemsa allocates overhead costs to three concessions; Alam El Shawish West, East Ghazalt and NW Gemsa. SDX forecast a shift in overhead costs allocated to NW Gemsa, as activities ramp up in the other concessions. ERCE has relied upon SDX for the forecast cost associated with Operator overhead. Production and costs forecasts for the field can be found in Appendix 3.

Abandonment costs were not included as the facilities and wells revert to the government at the end on the licence.

Fiscal terms were based on the concession agreement which expires on 16 February 2029. The contractor revenue is based on a production sharing arrangement. A cost oil/gas recovery limit of 30% of revenue is applicable. Operating costs can be recovered immediately (subject to the recovery limit) but capital costs are amortized at 20% per year over 5 years. The contractor share of profit oil is 23% (for production rates <10,000 bopd) and the share of profit gas is based on production rate and oil price; over the life of the field the typical share is 35%. A production bonus of $1 million is also payable as the barrels of oil equivalent rate is forecast to go over 5,000 boe/d. Corporation tax of 22.5% is paid on behalf of the contractor by EGPC and this has been included when determining the net entitlement volumes. Costs were inflated at 2%.

A summary of the oil plus condensate, natural gas and NGL (LPG) Reserves are presented in Table 5.6, Table 5.7 and Table 5.8 respectively for each Reserves category. A summary of the Company share of the net present values is presented in Table 5.9.

Table 5.6: NW Gemsa oil plus condsensate Reserves estimates as of December 31, 2018

Category	Field Gross Mbbl	Company Gross WI Mbbl	Company Net Entitlement Mbbl
PDP	1,741	870	448
PD	1,850	925	476
PUD	-	-	-
1P	1,850	925	476
2P	2,686	1,343	691
3P	3,934	1,967	1,012

1. *Company gross working interest Reserves are based on 50% of the field gross Reserves*
2. *Company net entitlement Reserves are based on Company share of the cost and profit oil and the corporation tax paid on behalf of the Company by EGPC*

Table 5.7: NW Gemsa NGL Reserves estimates as of December 31, 2018

Category	Field Gross Mbbl	Company Gross WI Mbbl	Company Net Entitlement Mbbl
PDP	33	16	8
PD	35	18	9
PUD	-	-	-
1P	35	18	9
2P	51	25	13
3P	74	37	19

1. *Company gross working interest Reserves are based on 50% of the field gross Reserves*
2. *Company net entitlement Reserves are based on Company share of the cost and profit oil and the corporation tax paid on behalf of the Company by EGPC*

Table 5.8: NW Gemsa natural gas Reserves estimates as of December 31, 2018

Category	Field Gross MMscf	Company Gross WI MMscf	Company Net Entitlement MMscf
PDP	2,187	1,094	593
PD	2,275	1,137	617
PUD	-	-	-
1P	2,275	1,137	617
2P	3,302	1,651	896
3P	4,836	2,418	1,312

1. *Company gross working interest Reserves are based on 50% of the field gross Reserves*
2. *Company net entitlement Reserves are based on Company share of the cost and profit gas and the corporation tax paid on behalf of the Company by EGPC*

Table 5.9: NW Gemsa Net Present Values as of December 31, 2018

	Company Share of Net Present Values at various discount rates (US$ MM)				
Category	0%	5%	10%	15%	20%
PDP	13	12	12	11	11
PD	13	12	12	12	11
PUD	-	-	-	-	-
1P	13	12	12	12	11
2P	20	19	18	17	17
3P	30	28	26	25	23

1. *Based on forecast prices and costs as of 1 January 2019 (see Table 2.2)*
2. *Interest expenses, corporate overheads etc were not included.*
3. *The net present values may not represent the fair market value of the Reserves.*

6. Sebou, Lalla Mimouna Nord and Gharb Centre Exploration Concessions

6.1. Introduction

SDX has an interest in a number of exploration and exploitation concessions within onshore Morocco as presented in Figure 6.1. The concessions lie within the Gharb basin in northern Morocco. SDX acquired an interest in the Sebou Onshore and Lalla Mimouna permits with the purchase of Circle Oil. SDX then applied and was awarded the Sebou Central (after expiry of Sebou Onshore) and Gharb Centre exploration permits. SDX has a 75% working interest and is operator with the remaining 25% interest held by the Moroccan national oil and gas company ("ONHYM"). SDX carries ONHYM through the exploration phase but both parties pay their share of the development and operating costs.

This section covers an assessment of the Prospective Resources within the Sebou, Lalla Mimouna Nord and Gharb Centre Exploration Concessions; Section 7 covers the evaluation of the natural gas Reserves in the exploitation concessions. To carry out the assessment ERCE has audited the SDX identified prospects that lie within the boundaries of their 3 exploration concessions.

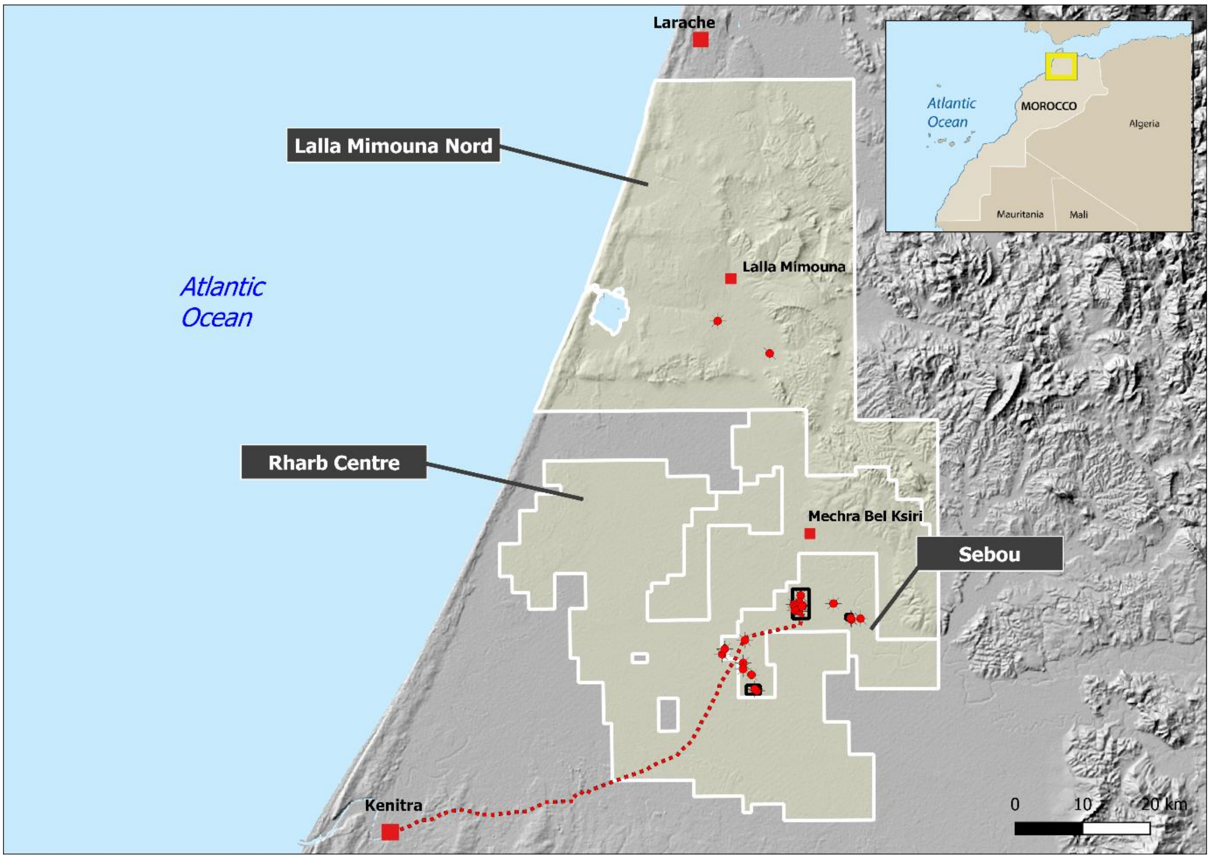

Figure 6.1: SDX Morocco Concession Location Map

6.2. Well and Seismic Database

The Sebou Concession covers an area of 210 km². The southwest and central area of the concession are covered by the Sebou, Gaddari and Guebbas 3D seismic volumes which are of good quality, while 2D lines of varying quality are present over the southeast area. The Lalla Mimouna Nord Concession comprises an area of 2,112 km², with 154 km² covered by the Lalla Mimouna 3D seismic volume of average quality. The basinal architecture outwith the 3D seismic is constrained by 2D lines. Two 3D seismic volumes of good quality are located over the Gharb Centre Concession, and the majority of the remaining area is covered by numerous 2D lines of varying vintage and quality. A regional seismic location map showing the concession areas is presented in Figure 6.2.

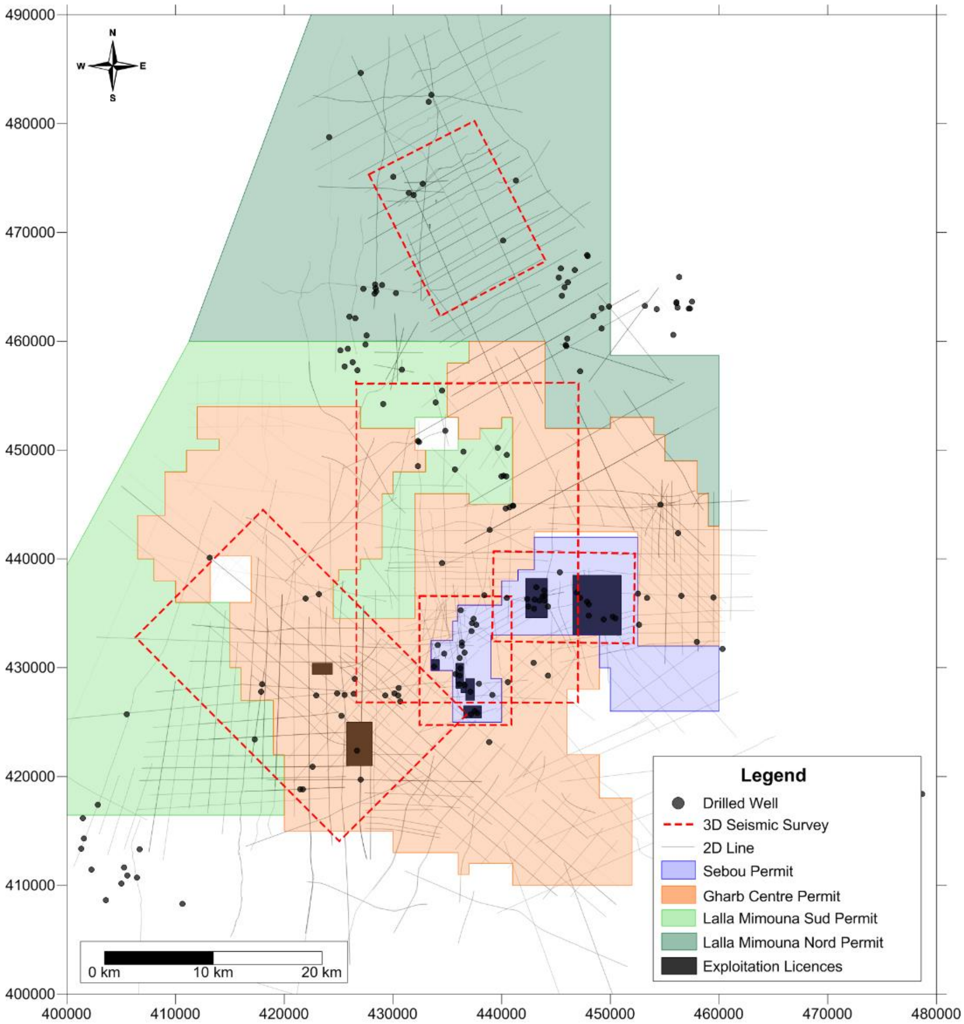

Figure 6.2: Regional Map displaying permit outlines, seismic and well locations

There are numerous wells located over Sebou and Gharb Centre of varying vintages and differing reservoir targets. ERCE was provided with sufficient digital log data over multiple wells to assess the prospects over, and nearby, the Sebou concession. However the available well data for the Gharb Centre is not as prolific in quantity and quality, so certain prospects evaluated in this area carry a higher risk which is reflected in our assigned change of success. The area of interest within the Lalla Mimouna Nord permit contains fewer analogous wells, with LMS-1, LNB-1, ANS-2 and LAM-1 being the only wells made available for analysis.

6.3. Geological Description

The target reservoirs in the Sebou and Gharb Centre areas are the Gaddari, Guebbas and Hoot turbidite sandstone formations of Upper Miocene age (Figure 6.3). The sands are highly porous and of excellent quality, however they are often interspersed with pelagic mud deposits, generally resulting in relatively thin net pay intervals. The reservoirs are thought to be charged primarily with biogenic gas, which is prolific across the region. When gas filled, the reservoirs typically appear as a bright amplitude anomaly which can be used to infer areal extent of the accumulation. Some of the larger accumulations can be compartmentalised and more than one well may be required to target a continuous amplitude anomaly. Where this is the case, the separating faults are clearly identifiable on seismic and have been accounted for in volumetric estimations of the prospects.

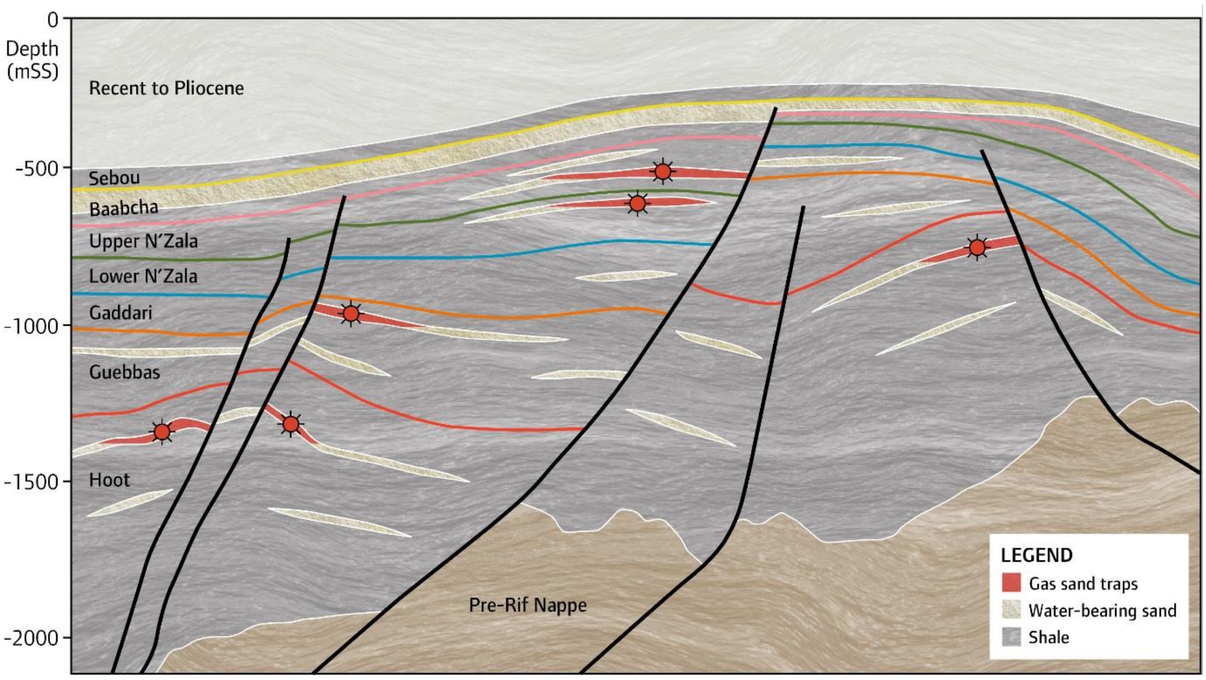

Figure 6.3: Schematic of the regional depositional environment

Net pays generally range between 0.5 – 14 m for the turbiditic sandstones, and the Gaddari, Guebbas and Hoot reservoirs display similar thicknesses and parameters to one another. The petrophysical CPI for Well CGD-11 is presented in Figure 6.4 as an example of the reservoir characteristics found in the Sebou and Gharb Centre area.

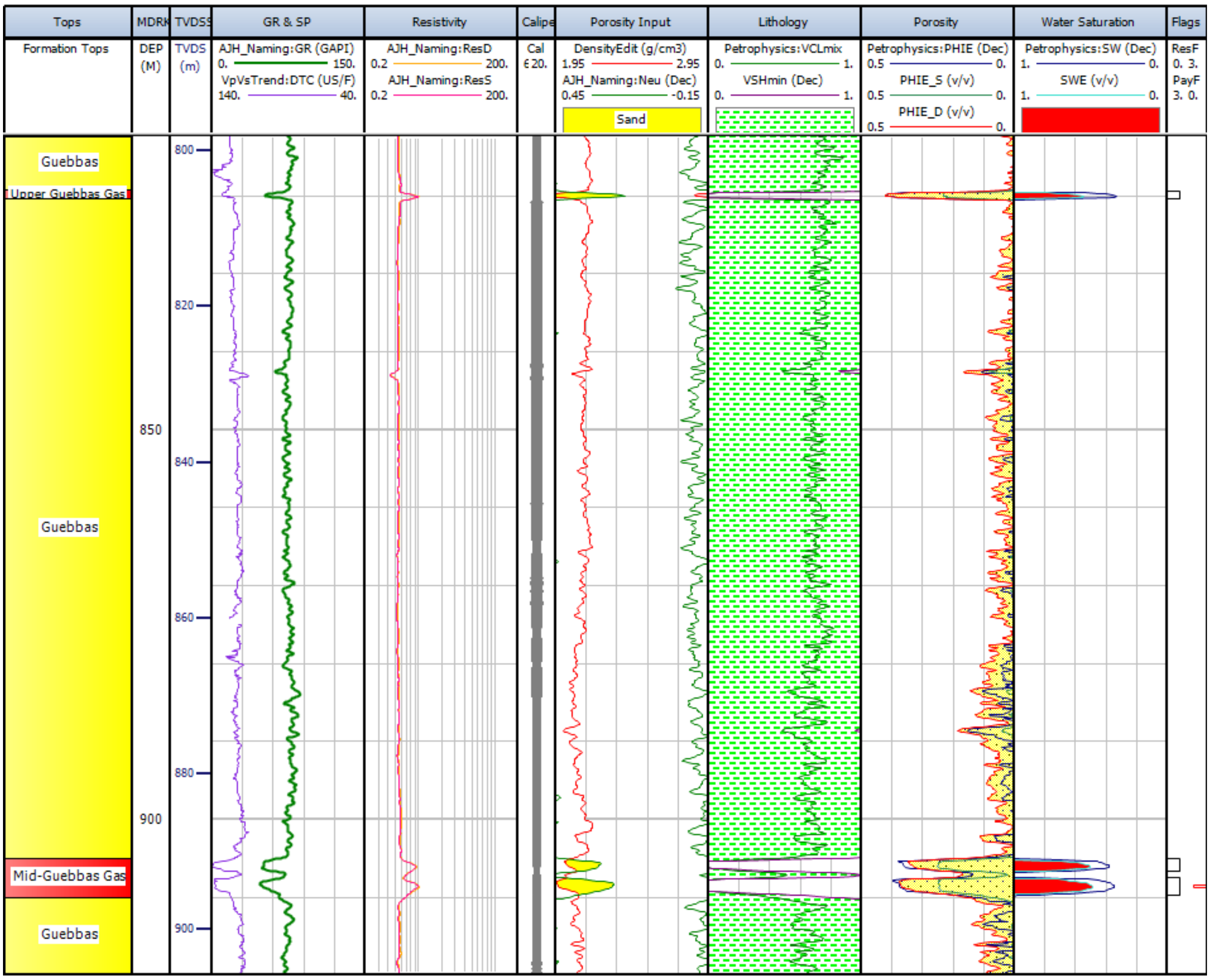

Figure 6.4: Well CGD-11 CPI. ERCE: colour filled logs; SDX: colour lines overlain

The Lalla Mimouna Nord area lies further to the north and is under explored relative to the southern prospects. Two discovery wells, LMS-1 and LNB-1, were drilled in 2018 and have found reservoir intervals in the Miocene Upper Dlalha and H9 units. The LMS-1 well CPI is displayed in Figure 6.5 as an example of expected reservoir in this area. In addition, LNB-1 also encountered a ~300 m gas bearing interval at the base of the well, however due to a technical issue no logs were taken over this section. A number of the prospects in the Lalla Mimouna Nord area are modelled using this interval as an analogue.

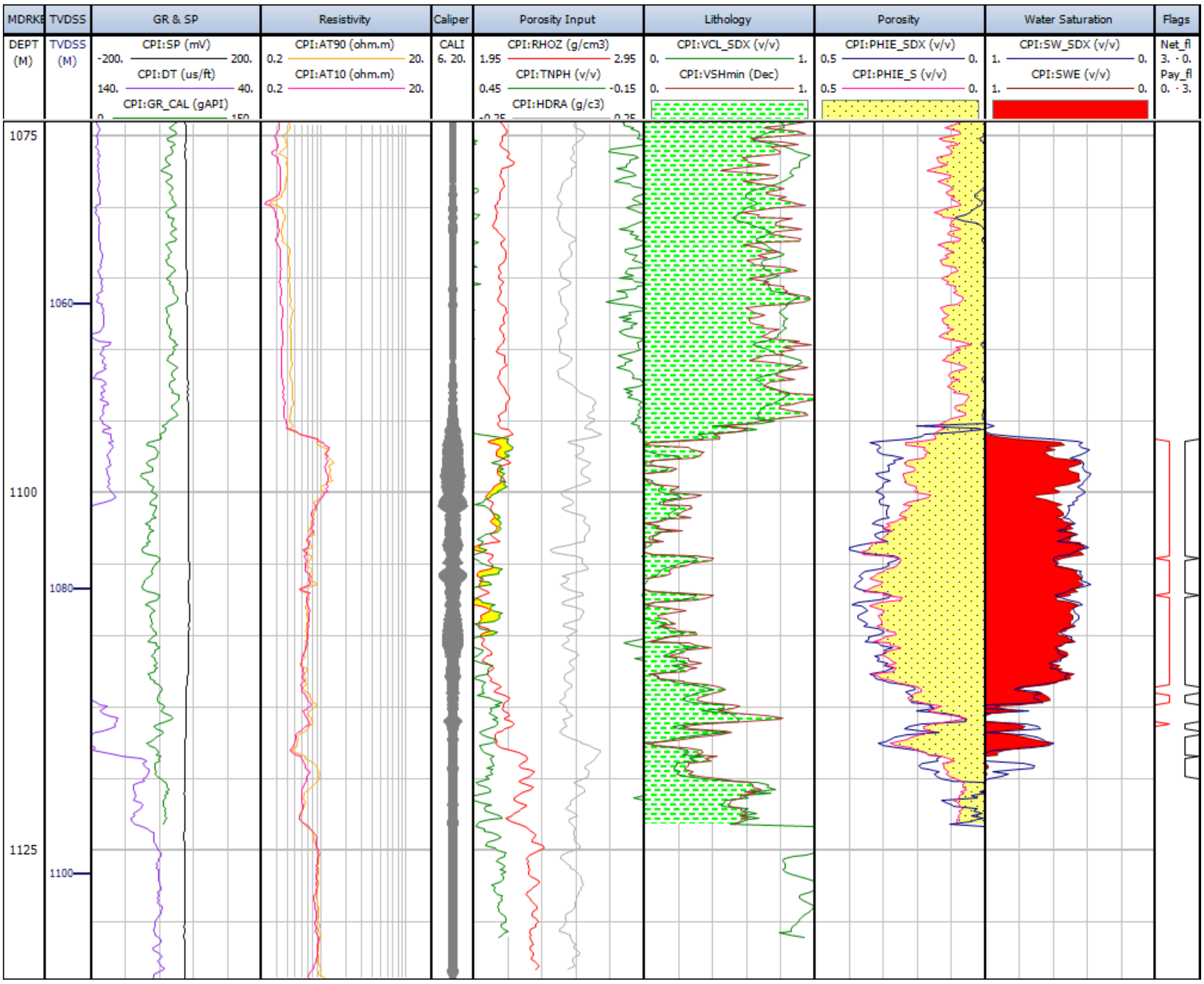

Figure 6.5 Well LMS-1 CPI. SDX: Blue, ERCE: red

6.4. Contingent Resources

We have evaluated Contingent Resources associated with the LMS-1 and LNB-1 wells, both drilled in 2018.

6.4.1. LMS-1 Discovery

LMS-1 encountered a Miocene fine-grained sandstone within the H9 stratigraphic sequence (Figure 6.5). ERCE conducted an independent petrophysical interpretation on the LMS-1. The density log in the reservoir interval is rather uncertain as the calliper log and relatively low density readings demonstrate, although the values are not unreasonable. ERCE therefore estimated volume of shale from gamma ray log, and we estimated the porosity from the sonic log, thus a relatively high degree of uncertainty remains when characterising the reservoir quality. No core data is available to calibrate the porosities, but they seem to be in a reasonable range. ERCE used Archie's equation to calculate water saturation, with an assumption of m=1.8, n=2 and a=1. The water resistivity of 0.021 was estimated by Pickett plot in relatively cleaner interval and the bottom of reservoir. Note there is an uncertainty in the water resistivity as no clean sand is present in this or neighbouring wells, and there is no water sample to calibrate it. ERCE used the reported reservoir temperature of 55.5 deg C. The pay summary over the reservoir interval is presented in the Table 6.1

Table 6.1 Petrophysical Averages for LMS-1 Discovery

Top	Bottom	Gross	Net Pay	Net Pay/Gross	Av Vcl (Pay)	Av Phi (Pay)	Av Sw (Pay)
MD m	MD m	TVDSS	TVDSS m	frac	frac	frac	frac
1,095.90	1,120.10	24.25	15.29	0.631	0.142	0.277	0.509

The reservoir is expressed on seismic as a strong negative impedance response in an upthrown structural culmination sitting at the Top Nappe seismic horizon (Figure 6.6).

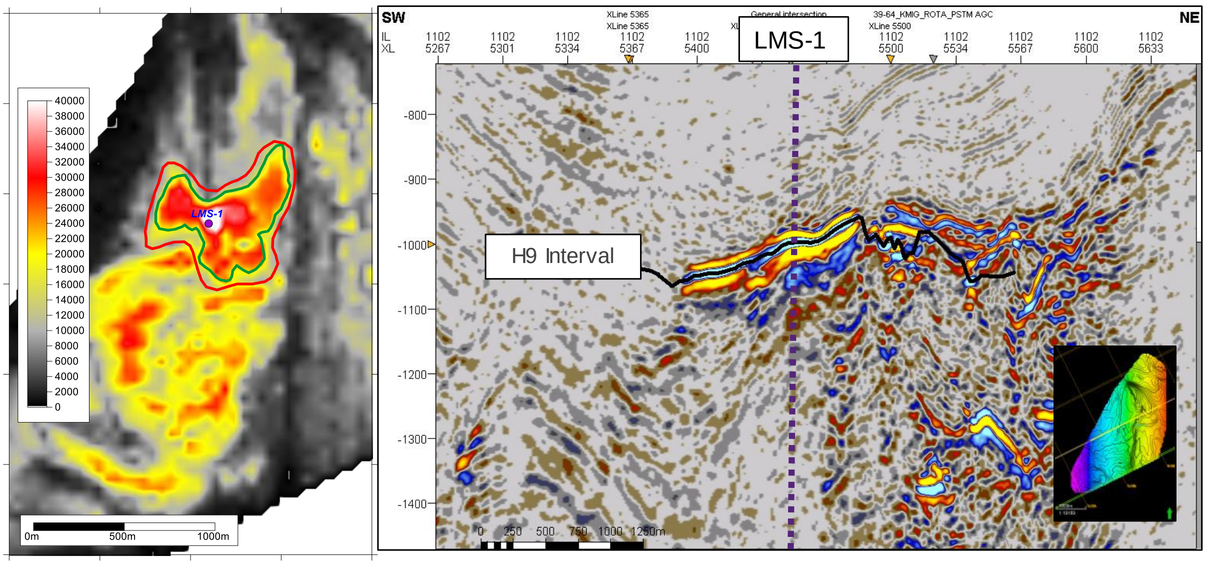

Figure 6.6 LMS-1 discovery areal extent and seismic expression

ERCE has constrained both the P90 and P10 areas to the known area of discovery, with the P90 area restricted to the brightest amplitudes and the P10 encapsulating the dimmer response around the periphery.

The petrophysical parameters were directly adopted from the sums and averages as calculated over the sandstone interval in the LMS-1. ERCE's parameters for the discovery are displayed in Table 6.2.

Table 6.2 ERCE parameters for the LMS-1 Discovery

Discovery	Area (km^2)			Net (m)			Shape Factor			Porosity			Sg			GEF		
	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
LMS-1	0.26	0.33	0.41	16.0	20.8	27.0	0.90	0.95	1.00	0.23	0.26	0.29	0.45	0.53	0.60	138	145	152

The Contingent Resources are displayed in Table 6.3. Chance of development is 100% and is subclassified as Contingent Resources, Development on Hold pending preparation of an field development plan and a final investment decision.

Table 6.3 Contingent Resources for the LMS-1 Discovery

Discovery	GIIP (Bscf)				Gas Contingent Resources (Bscf)			
	Low	Best	High	Mean	1C	2C	3C	Mean
LMS-1	3.0	4.5	6.6	4.7	2.2	3.4	5.2	3.6

6.4.2. LNB-1 Discovery

LNB-1 encountered a Miocene fine grained sandstone within the Upper Dlalha sequence (Figure 6.7). As discussed it also encountered a ~300 m gas bearing interval in a deeper unit, however as no logs were taken over this interval we have assigned the volumes associated with this to Prospective Resources.

ERCE conducted an independent petrophysical interpretation on the upper shallow interval of LNB-1, whether the log readings are available. The density reading is somewhat less reliable with no significant change from shale to sand, where the density correction is too high in the shale section. We estimated volume of shale from gamma ray log only as the borehole size is variable. We estimated the porosity from the sonic log, thus a relatively high degree of uncertainty remains when characterising the reservoir quality. No core data is available to calibrate the porosities, but they seem to be in a reasonable range. ERCE used Archie's equation to calculate water saturation, with an assumption of m=1.8, n=2 and a=1. Since no clean water sand is available, ERCE used the water resistivity estimated by Pickett plot in relatively cleaner interval. Therefore, there is an uncertainty in the water resistivity, and there is no water sample to calibrate it. ERCE used the estimated reservoir temperature of 52 deg C from measurements in LMS-1. The pay summary over the reservoir interval is presented in the Table 6.4

Table 6.4 Petrophysical Averages for LNB-1 Discovery

Top	Bottom	Gross	Net Pay	Net Pay/Gross	Av Vd (Pay)	Av Phi (Pay)	Av Sw (Pay)
MD m	MD m	TVDSS m	TVDSS m	frac	frac	frac	frac
955.60	1,022.80	66.73	2.59	0.039	0.179	0.26	0.645

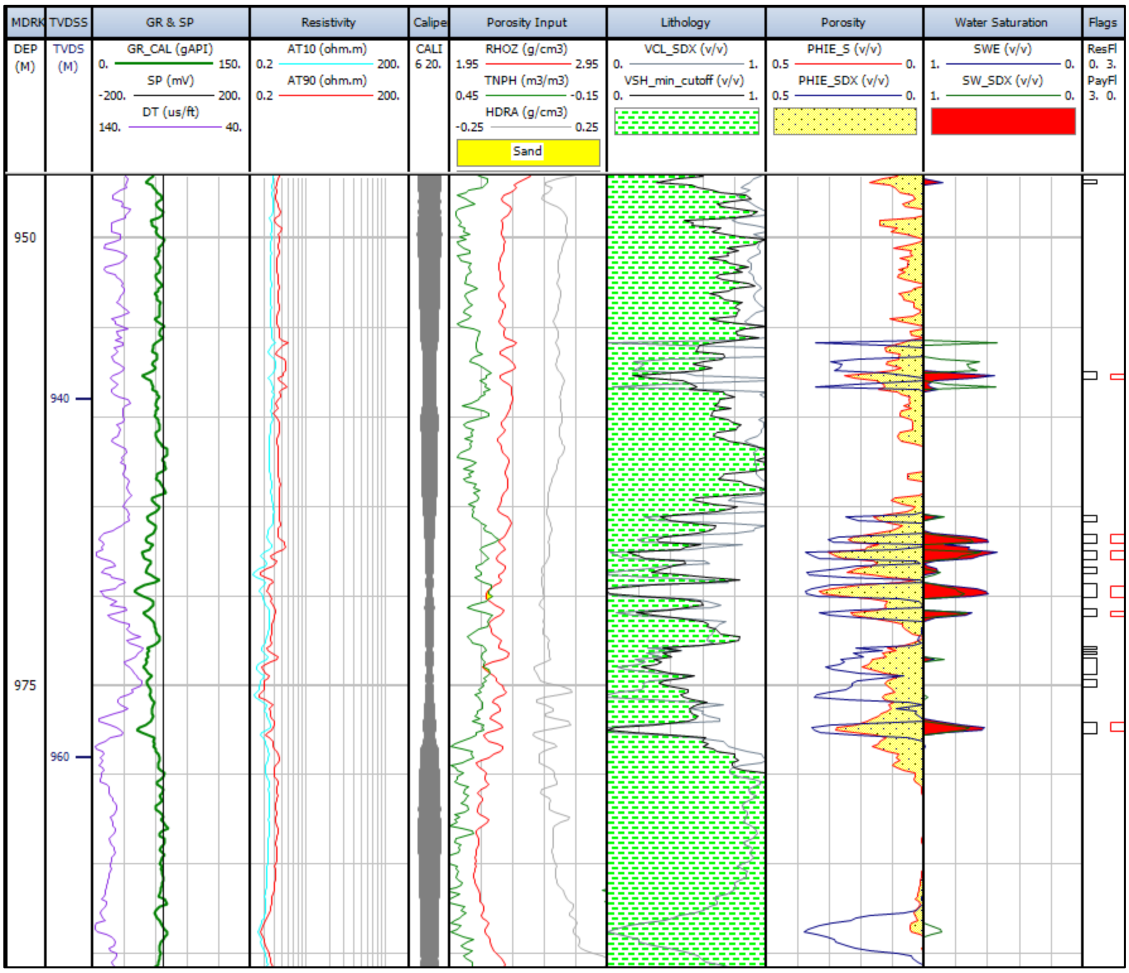

Figure 6.7 Well LNB-1 CPI

The amplitude extraction shows two bright areas within an elongated shape (Figure 6.8). ERCE have constrained our low case are to the well and the brightest amplitude in the NW, while the high case incorporates an additional area of bright amplitude to the SE.

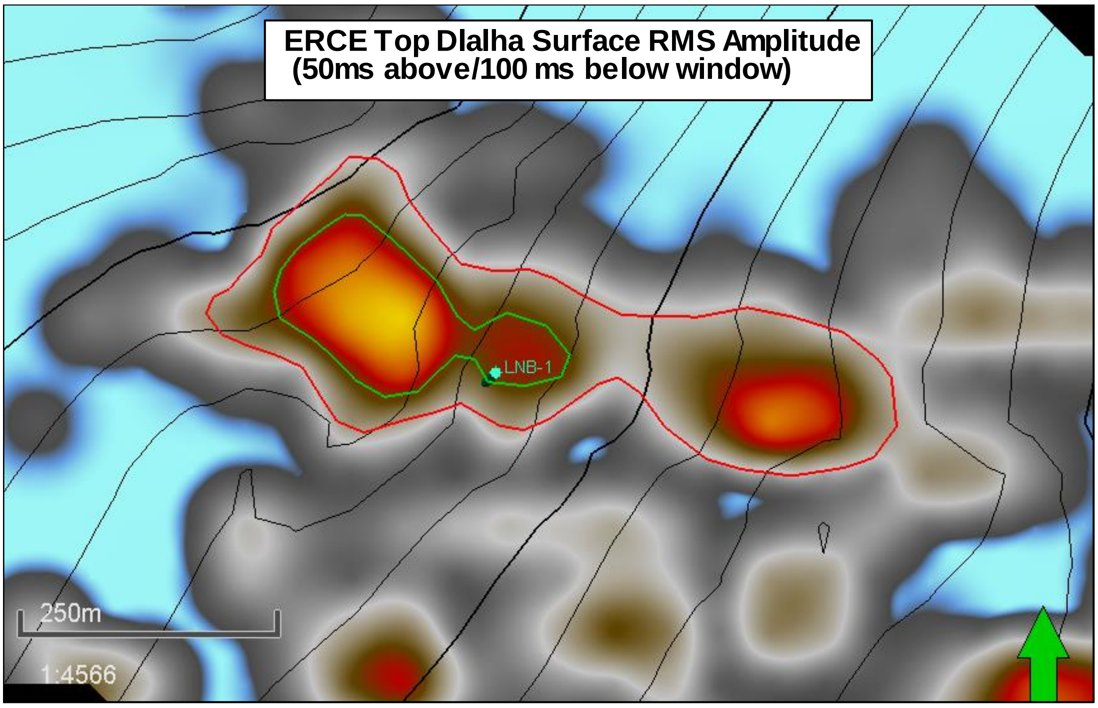

Figure 6.8 LNB-1 Upper discovery areal extent

The petrophysical parameters were directly adopted from the sums and averages as calculated over the sandstone interval in the LNB-1. ERCE's parameters for the discovery are displayed in Table 6.5.

Table 6.5 Parameters for the LNB-1 Upper Discovery

Discovery	Area (km^2)			Net (m)			Shape Factor			Porosity			Sg			GEF		
	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
LNB-1_Upper	0.03	0.05	0.09	5.5	7.6	10.5	0.90	0.95	1.00	0.20	0.26	0.32	0.35	0.53	0.70	100	110	120

The Contingent Resources are displayed in Table 6.6. A chance of development is calculated at 22% on a stand alone basis. This resource is subclassified as Contingent Resources, Development on Hold pending preparation of an field development plan and a final investment decision.

Table 6.6 Contingent Resources for the LNB-1 Upper Discovery

Discovery	GIIP (Bscf)				Gas Contingent Resources (Bscf)			
	Low	Best	High	Mean	1C	2C	3C	Mean
LNB-1_Upper	0.09	0.19	0.40	0.23	0.07	0.15	0.31	0.17

6.5. Unrisked Prospective Resources

ERCE has volumetrically assessed the Prospective Resources associated with 51 individual prospects as provided by SDX, of which nine have more than one prospective stratigraphic interval. Over half the prospects are situated within the Gharb Centre Permit and are located on both 2D and 3D data. Seven of these prospects are located within the Guebbas 3D seismic area which partially overlaps the existing Sebou and Gaddari 3D datasets. The remaining prospects are located within the Sebou and Lalla Mimouna Nord Permits, all of which are located within the 3D seismic coverage.

6.5.1. Gharb Centre and Sebou Permit

ERCE has reviewed SDX's TWT seismic interpretations of the prospective intervals and found them to be reasonable. SDX supplied ERCE with varying vintages of petrophysical interpretation. We have reviewed the petrophysics as generated by SDX for a selection of the contemporary wells and found it to be reasonable. Figure 6.4 displays an example of the comparison between these interpretations. For some of the prospects, the wells in closest proximity were drilled in the 1980s so digital logs were not available. In these instances, SDX provided ERCE with historical well reports which we used in conjunction with the petrophysics of more contemporary, distant wells to assess the reservoir parameters. No core data is available to calibrate petrophysical cut-offs.

ERCE has used an area-net pay method to define the net rock volume for all the prospects. For prospects located within 3D seismic, this involves amplitude analysis to define a low and high case area on a per layer per target well basis. The low case area was confined to the highest amplitudes, within a single compartment. The high case incorporated the full extent of the amplitude anomaly to allow for tuning effects. This was generally constrained to the targeted compartment, however where the fault offset was deemed small enough it would extend into adjacent compartments.

The low and high case net pay values were based on the surrounding wells, with thicknesses from proximal wells weighted higher than distal. The Vsh logs generally display sharp boundaries between the reservoir sands and the background shales and as such, the differing petrophysical interpretations are relatively close with respect to the thicknesses of these packages. For prospects located within the Gaddari seismic volume, the net pay thickness as indicated by a detuned seismic volume was also taken into account. ERCE then applied a lognormal distribution to our P10 and P90 net pay and areal values, and combined with a shape factor of 95% (the sands are thin relative to the likely gas column height).

An example of this methodology is shown in Figure 6.9, where the low and high case areas are displayed for the prospective interval associated with the DOB AAG prospect. The low case area is confined to the area of the brightest continuous reflector, while the high case includes bright amplitudes that may be discontinuous from the P90 area when accounting for tuning effects.

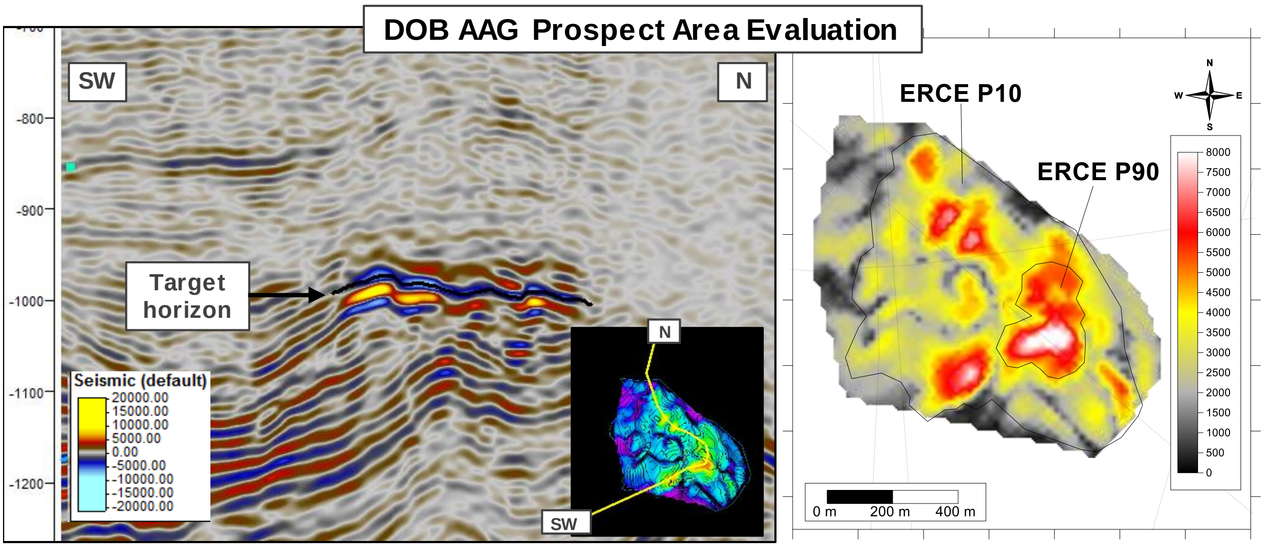

Figure 6.9: Areal analysis of prospect DOB AAG

It should be noted that the Gharb Centre 2D prospects are arealy more uncertain. To keep the assessment methodology consistent with the prospects located over 3D, a low case area was estimated on the basis of what might be a single fault compartment and a high case area was picked on the full extent of the amplitude bloom. As such this assesses the volume that would be connected to the drilled well. However, ERCE accepts this may underestimate the potential of further drilling; if it can be established that fault compartments are sufficiently large to yield economic wells, further wells would then be drilled to exploit the full extent of the amplitude anomaly (as is the case at Ksiri Centre).

The estimates of reservoir porosity and hydrocarbon saturation for the prospects were made with reference to any nearby wells. ERCE has adopted SDX's petrophysical logs as a basis for the pore volume parameters. Due to the absence of core data to calibrate cut offs, a relatively large range has been adopted across all prospects.

Gas expansion factors were estimated for a range of pressures and temperatures for each of the prospective intervals. The formation pressures and temperatures from the existing discoveries were used as the basis for predicting the prospect data. The Z factor was calculated from standard correlations based on the predicted temperature and pressure and a gas gravity of 0.65 (relative to air).

Recovery factors were estimated based on the recoveries seen to date in the nearby depleted fields (from 65% to 90%).

The estimates of GIIP and gross unrisked Prospective Resources for the Gharb Centre and Sebou prospects are presented in Table 6.7 and Table 6.8.

Table 6.7 Summary of unrisked GIIP and Prospective Resources for Gharb Centre

Permit	Prospect	Unrisked GIIP (Bscf)				Unrisked Gas Prospective Resources (Bscf)			
		Low	Best	High	Mean	1U	2U	3U	Mean
Gharb Centre 3D	LTO_2_AAA	0.3	0.8	2.1	1.1	0.2	0.6	1.7	0.8
	LTU_AAA	0.4	1.5	6.1	2.7	0.3	1.1	4.8	2.1
	LTU_AAB	0.6	1.8	5.6	2.7	0.5	1.4	4.4	2.1
	LTU_AAC	0.4	1.3	4.5	2.1	0.3	1.0	3.5	1.6
	LTU_AAD_Upper	0.1	0.3	1.0	0.5	0.1	0.3	0.8	0.4
	LTU_AAD_Lower	0.2	0.4	0.8	0.4	0.1	0.3	0.6	0.3
	LTU_AAD_Total	*0.3*	*0.7*	*1.8*	*0.9*	*0.2*	*0.5*	*1.4*	*0.7*
	DOB_AAC_Upper	0.1	0.4	1.3	0.6	0.1	0.3	1.0	0.5
	DOB_AAC_Lower	0.3	0.8	2.4	1.1	0.2	0.6	1.8	0.9
	DOB_AAC_Total	*0.4*	*1.2*	*3.7*	*1.8*	*0.3*	*0.9*	*2.8*	*1.4*
	DOB_AAD_Upper	0.2	0.5	1.2	0.6	0.2	0.4	1.0	0.5
	DOB_AAD_Lower	0.1	0.3	0.8	0.4	0.1	0.2	0.6	0.3
	DOB_AAD_Total	*0.3*	*0.8*	*2.1*	*1.0*	*0.2*	*0.6*	*1.6*	*0.8*
	DOB_AAG	0.2	0.8	3.1	1.4	0.2	0.6	2.4	1.1
	DOB_AAH	0.2	0.9	3.8	1.7	0.1	0.7	3.0	1.3
	DOB_AAI	0.5	1.1	2.5	1.3	0.3	0.8	1.9	1.0
	DOB_AAS_Upper	0.3	0.9	2.8	1.3	0.2	0.7	2.1	1.0
	DOB_AAS_Lower	0.3	1.1	3.5	1.6	0.3	0.8	2.7	1.3
	DOB_AAS_Total	*0.6*	*2.0*	*6.2*	*3.0*	*0.5*	*1.5*	*4.8*	*2.3*
	DRC_AAB	1.1	2.9	7.8	3.9	0.8	2.2	6.0	3.0
	DOB_AAB	0.8	2.8	10.5	4.8	0.6	2.2	8.1	3.7
	BFD-RE	0.4	1.1	3.0	1.5	0.3	0.8	2.4	1.2
	DOB_AAF_Upper	0.5	1.6	5.5	2.6	0.4	1.3	4.3	2.0
	DOB_AAF_Lower	0.8	2.8	9.8	4.5	0.6	2.2	7.6	3.5
	DOB_AAF Total	*1.3*	*4.5*	*15.4*	*7.1*	*1.0*	*3.4*	*11.9*	*5.5*
	LTO_AAE	0.6	1.6	4.3	2.2	0.5	1.3	3.4	1.7
	CGD-14	0.2	0.3	0.6	0.3	0.1	0.2	0.4	0.3
Gharb Center 3D Deterministic Total		**8.4**	**26.0**	**83.1**	**39.4**	**6.4**	**20.0**	**64.6**	**30.6**
Gharb Centre 2D	sm1005	0.6	2.6	11.5	5.1	0.4	2.0	8.9	3.9
	sm81	0.9	3.2	11.4	5.2	0.7	2.5	8.9	4.1
	p121	0.5	1.1	2.1	1.2	0.4	0.8	1.7	1.0
	sm77	0.2	0.8	2.9	1.3	0.2	0.7	2.2	1.0
	p122	0.6	2.2	7.8	3.6	0.5	1.7	6.1	2.8
	p142	0.6	1.9	6.3	2.9	0.4	1.4	4.9	2.3
	P141	0.7	1.9	5.1	2.5	0.5	1.4	4.0	2.0
	sm47	0.2	0.6	1.8	0.9	0.1	0.4	1.4	0.7
Gharb Center 2D Deterministic Total		**4.3**	**14.2**	**49.0**	**22.8**	**3.2**	**10.9**	**38.1**	**17.7**
Guebbas 3D	OYF Upper	0.34	0.70	1.45	0.82	0.26	0.54	1.13	0.64
	OYF Lower	0.24	0.53	1.13	0.63	0.19	0.40	0.88	0.49
	OYF Total	*0.6*	*1.2*	*2.6*	*1.5*	*0.4*	*0.9*	*2.0*	*1.1*
	BMK Upper	0.06	0.22	0.78	0.36	0.05	0.17	0.61	0.28
	BMK Lower	0.18	0.51	1.44	0.71	0.14	0.40	1.12	0.55
	BMK Total	*0.2*	*0.7*	*2.2*	*1.1*	*0.2*	*0.6*	*1.7*	*0.8*
	SAH-W	0.20	0.53	1.40	0.71	0.15	0.41	1.09	0.55
	ERM-1	0.05	0.15	0.44	0.21	0.04	0.12	0.34	0.17
	SAK-A	1.64	4.91	14.73	7.09	1.25	3.78	11.46	5.50
Guebbas 3D Deterministic Total		**2.72**	**7.55**	**21.38**	**10.53**	**2.07**	**5.81**	**16.64**	**8.16**

Table 6.8 Summary of unrisked GIIP and Prospective Resources for the Sebou Permit

Permit	Prospect	Unrisked GIIP (Bscf)				Unrisked Gas Prospective Resources (Bscf)			
		Low	Best	High	Mean	1U	2U	3U	Mean
Ksiri	KSR-E	0.5	0.9	1.5	0.9	0.4	0.7	1.2	0.7
	KSR-G	0.4	0.8	1.5	0.9	0.3	0.6	1.2	0.7
	KSR-H	0.6	1.1	1.9	1.2	0.4	0.8	1.5	0.9
	KSR-I	0.4	0.6	1.1	0.7	0.3	0.5	0.8	0.5
	KSR-F	0.4	0.9	1.7	1.0	0.3	0.7	1.3	0.8
	SW_KSR_29	0.2	0.7	1.7	0.9	0.2	0.5	1.4	0.7
Ksiri Total		**2.6**	**4.9**	**9.4**	**5.6**	**2.0**	**3.8**	**7.4**	**4.3**
No Concession	CGD-6_Upper	0.1	0.2	0.6	0.3	0.0	0.1	0.4	0.2
	CGD-6_Lower	0.2	0.3	0.6	0.3	0.1	0.2	0.4	0.3
	CGD-6_Total	*0.2*	*0.5*	*1.1*	*0.6*	*0.2*	*0.4*	*0.9*	*0.5*
	CGD-8_NE_Upper	0.1	0.3	0.9	0.5	0.1	0.3	0.7	0.4
	CGD-8_NE_Lower	0.0	0.1	0.2	0.1	0.0	0.0	0.2	0.1
	CGD-8_NE_Total	*0.1*	*0.4*	*1.1*	*0.6*	*0.1*	*0.3*	*0.9*	*0.4*
	SAH-3_Gaddari	0.0	0.1	0.2	0.1	0.0	0.1	0.2	0.1
	SAH-3_Guebbas	0.2	0.3	0.6	0.4	0.1	0.3	0.5	0.3
	SAH-3_U_Hoot	0.1	0.2	0.5	0.3	0.1	0.2	0.4	0.2
	SAH-3_Total	*0.3*	*0.7*	*1.3*	*0.8*	*0.3*	*0.5*	*1.0*	*0.6*
No Concession Total		**0.7**	**1.5**	**3.6**	**1.9**	**0.5**	**1.2**	**2.8**	**1.5**

6.5.2. Lalla Mimouna Nord Permit

There are two distinct groups of prospects that SDX are targeting within the Lalla Mimouna Nord area. These are based on a similar premise to the prospects found in the Gharb and Sebou Permits which ERCE has evaluated as described above, while the remaining are analogous to the ~300 m gas interval encountered in Well LNB-1.

Well LNB-1 drilled to a TD of 1861 mMD but the logging tool became lodged at 1390 mMD so no logs were recorded below this interval. However approximately 300 m of gas shows were observed over this deeper interval. In order to determine reservoir presence over this section, SDX have used a transform of the C1 gas readings to determine a range of possible NTG values over the interval of 5 – 25% (Figure 6.10). We have reviewed the methodology and accepted the transform as a possible representation of the NTG. As no logs were recorded, the volumes associated with the interval penetrated are considered as prospective with a relatively high chance of success and are thus incorporated in this section.

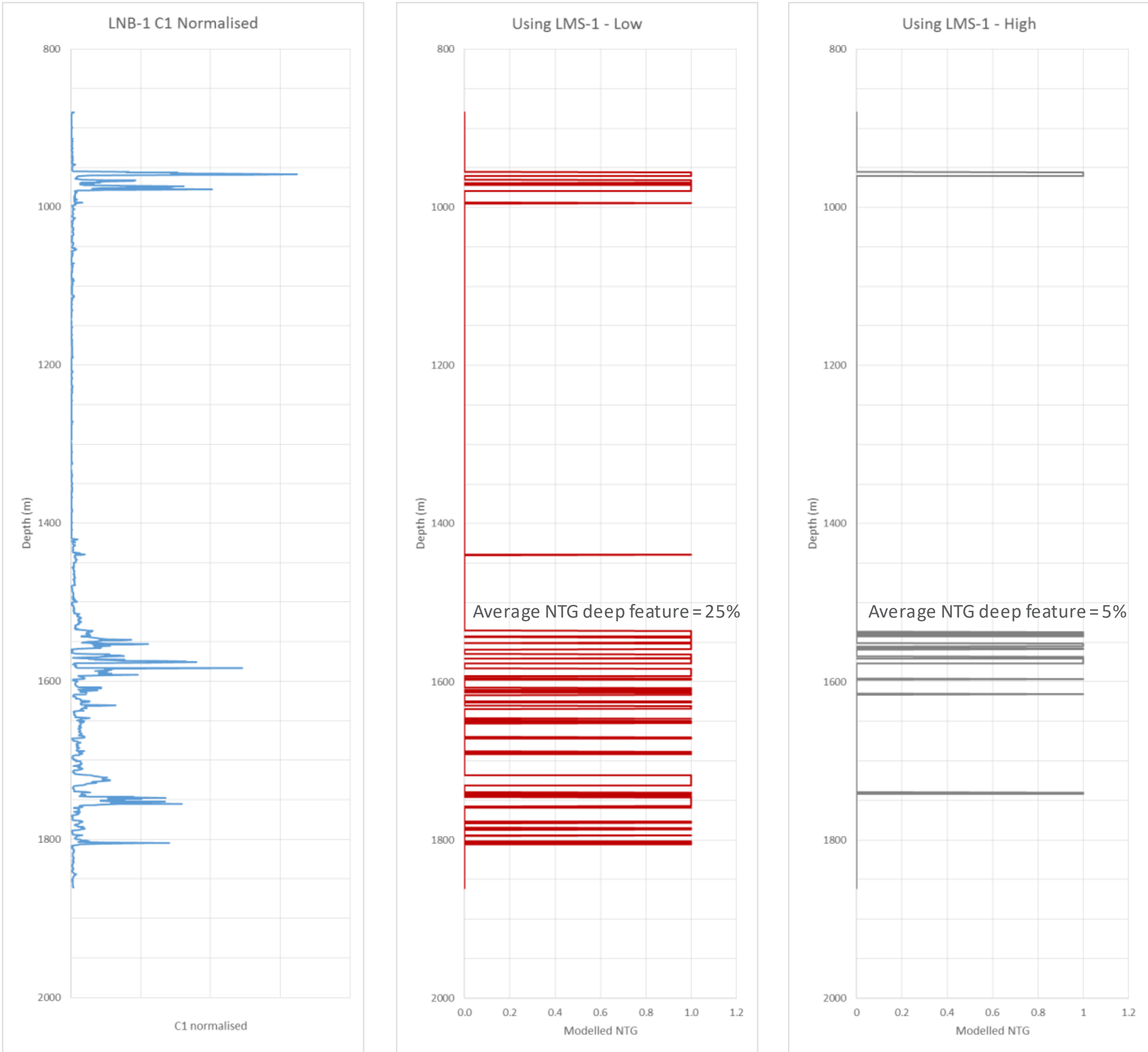

Figure 6.10: Well LNB-1 NTG approximation

For the prospects analogous to LNB-1, SDX provided ERCE with a base reservoir surface encompassing the deepest limit of elevated amplitudes. To evaluate the low case areas, ERCE extracted RMS amplitudes from this surface to an appropriate interval above, such that all the elevated amplitudes defining each prospect were captured. ERCE's P90 area was constrained to the brightest of these amplitudes. ERCE's high case was then based on a combination of these amplitude extractions in conjunction with the mapped fill to spill contour. An example of this methodology is displayed for LNB-F in Figure 6.11. In this example, the spill contour is chosen as an approximation of the P10 area. The P90 embraces the possibility of a lack of reservoir towards the northern and western extents of this area, as suggested by the dimmer response of the RMS amplitude extraction.

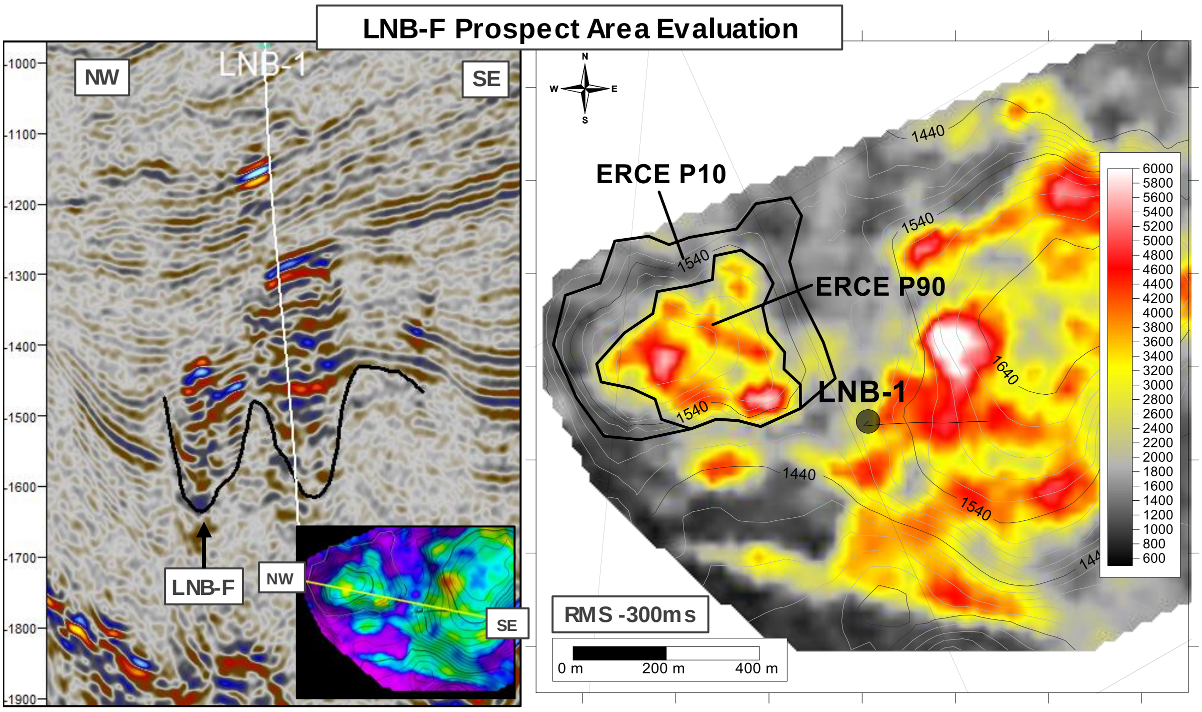

Figure 6.11 Areal analysis of prospect LNB-F

The gross thickness interval for each prospect was determined from the base of the surface to the top of the bright amplitudes and converted from time to depth using the time depth relationship observed in the wells. This gross package was then multiplied by a low and high case NTG of 5% and 25% respectively, which resulted in a low and high case net reservoir interval. In the case of LNB-F, the total interval of bright amplitudes was approximated at 230 ms, which translates to a gross thickness of 288 m. The resulting P90 and P10 net thicknesses calculate at 14 to 72 m. This was set to a log-normal distribution.

Unlike in the Gharb Centre and Sebou areas, the shape factors for these structures are unique to each prospect. Where the shapes of the structure resemble those of round bottomed cones, as in the LNB-F example, a shape factor of 30% to 70% was applied. Prospects where the structure was more flat were given a shape factor appropriate to their form.

The estimates of reservoir porosity and hydrocarbon saturation for the prospects were made with reference to LAM-1, LMS-1 and LNB-1. As there are no logs over the LNB-1 lower gas interval, the parameters observed over sands in different sections over the area have been used as a basis for this interval and a wide range applied.

Gas expansion factors were estimated for a range of pressures and temperatures for each of the prospective intervals. The formation pressures and temperatures from the existing discoveries were used as the basis for predicting the prospect data. The Z factor was calculated from standard correlations based on the predicted temperature and pressure and a gas gravity of 0.60 (relative to air).

Recovery factors were estimated based on the recoveries seen to date in the nearby depleted fields (from 65% to 90%).

The estimates of GIIP and gross unrisked Prospective Resources for the Lalla Mimouna Nord prospects are presented in Table 6.9.

Table 6.9 Summary of unrisked GIIP and Prospective Resources for the Lalla Mimouna Nord Permit

Permit	Prospect	Unrisked GIIP (Bscf)				Unrisked Gas Prospective Resources (Bscf)			
		Low	Best	High	Mean	1U	2U	3U	Mean
Lalla Mimouna	LAM-1_A	0.1	0.5	1.8	0.8	0.1	0.4	1.4	0.6
	LNB-C	0.6	2.4	9.3	4.2	0.5	1.8	7.2	3.3
	LNB-D	1.3	4.4	14.8	6.9	1.0	3.4	11.5	5.3
	LNB-E	0.6	1.7	5.1	2.5	0.4	1.3	4.0	1.9
	LNB-F	0.8	2.3	6.4	3.1	0.6	1.8	4.9	2.4
	LNB-G	0.4	1.2	3.3	1.6	0.3	0.9	2.6	1.3
	LNB-H	0.3	1.1	3.4	1.6	0.3	0.8	2.6	1.2
	NFA_WEST_A	1.7	5.3	16.5	7.9	1.3	4.1	12.8	6.1
	NFA_WEST_B	0.5	1.2	3.1	1.6	0.3	0.9	2.4	1.2
	LNB-2_Upper	0.8	2.2	6.4	3.1	0.6	1.7	5.0	2.4
	LNB-2_Lower	0.8	2.1	5.5	2.8	0.6	1.6	4.3	2.2
	LNB-2_Total	*1.6*	*4.3*	*12.0*	*5.9*	*1.2*	*3.3*	*9.3*	*4.6*
	LCG-1	1.0	2.7	7.1	3.6	0.8	2.1	5.6	2.8
	LNB-1_Lower [1]	3.0	7.0	16.4	8.7	2.3	5.4	12.8	6.8
LAM Total		**11.9**	**34.0**	**99.2**	**48.4**	**9.1**	**26.2**	**77.2**	**37.5**

1 This prospect was penetrated by well LNB-1. Elevated gas readings were recorded over the interval but no logs were taken.

6.6. Risking

ERCE has estimated the Geological Chance of Success (COS) associated with each of the prospects over the Gharb Centre, Sebou and Lalla Mimouna Nord permits.

ERCE uses a four component prospect risking system in our estimation of prospect COS (Table 6.10). Prospect risk is divided into four elements. Trap risk is defined as both definition and efficacy. Seal refers to the presence and efficacy of an identified seal, both top and side. Source risk reflects the presence and maturity of a suitable source rock, and the risk to migration of hydrocarbons from the source rock into the prospect. Reservoir risk reflects solely the presence and efficacy, (i.e. porosity and permeability), of any identified reservoir interval.

Table 6.10: Prospect risk matrix

Prospect Risk			
Source (Migration)	**Reservoir** (Efficacy)	**Trap** (Definition & Efficacy)	**Seal** (Presence & Efficacy)

The key risk for the area and applied to all prospects is the chance of low saturation gas, which can cause bright amplitude anomalies despite low gas saturation. The trap has been set at a maximum of 80% to acknowledge this. Reservoir has been risked with respect to proximity to wells and amplitude level. The seal is risked at a maximum of 80% over the Lalla Mimouna Nord area due to the lack of evidence for a regional sealing interval and the siltier interval present in the LAM-1 well.

The tables below present ERCE's risks associated with each of the prospects at the intervals evaluated.

Table 6.11 Risk Matrix - Gharb Centre Permit

Permit	Prospect	Source (Migration)	Reservoir (Efficacy)	Trap (Definition & Efficacy)	Seal (Presence & Efficacy)	COS
Gharb Centre 3D	LTO_2_AAA	100%	60%	70%	80%	34%
	LTU_AAA	100%	60%	70%	80%	34%
	LTU_AAB	100%	50%	70%	80%	28%
	LTU_AAC	100%	50%	70%	80%	28%
	LTU_AAD_Upper	100%	80%	70%	100%	56%
	LTU_AAD_Lower	100%	70%	70%	90%	44%
	DOB_AAC_Upper	100%	50%	70%	80%	28%
	DOB_AAC_Lower	100%	60%	70%	80%	34%
	DOB_AAD_Upper	100%	60%	70%	80%	34%
	DOB_AAD_Lower	100%	80%	70%	100%	56%
	DOB_AAG	100%	80%	70%	100%	56%
	DOB_AAH	100%	80%	70%	100%	56%
	DOB_AAI	100%	60%	70%	80%	34%
	DOB_AAS_Upper	100%	70%	70%	90%	44%
	DOB_AAS_Lower	100%	70%	70%	90%	44%
	DRC_AAB	100%	60%	70%	80%	34%
	DOB_AAB	100%	70%	70%	90%	44%
	BFD-RE	100%	90%	70%	100%	63%
	DOB_AAF_Upper	100%	50%	70%	80%	28%
	DOB_AAF_Lower	100%	70%	70%	90%	44%
	LTO_AAE	100%	70%	70%	100%	49%
	CGD-14	100%	90%	80%	100%	72%
Gharb Centre 2D	sm1005	100%	80%	50%	100%	40%
	sm81	100%	50%	50%	100%	25%
	p121	90%	60%	60%	80%	26%
	sm77	100%	70%	50%	100%	35%
	p122	90%	60%	60%	80%	26%
	p142	100%	80%	50%	100%	40%
	P141	100%	50%	60%	100%	30%
	sm47	100%	70%	50%	100%	35%
Guebbas 3D	OYF Upper	100%	90%	80%	100%	72%
	OYF Lower	100%	90%	80%	100%	72%
	BMK Upper	100%	70%	80%	90%	50%
	BMK Lower	100%	70%	80%	90%	50%
	SAH-W	100%	90%	80%	100%	72%
	ERM-1	100%	80%	80%	90%	58%
	SAK-A	100%	60%	80%	90%	43%

Table 6.12 Risk Matrix - Sebou Permit

Permit	Prospect	Source (Migration)	Reservoir (Efficacy)	Trap (Definition & Efficacy)	Seal (Presence & Efficacy)	COS
Sebou Permit Ksiri Concession	KSR-E	100%	100%	80%	100%	80%
	KSR-G	100%	100%	80%	100%	80%
	KSR-H	100%	100%	80%	100%	80%
	KSR-I	100%	100%	80%	100%	80%
	KSR-F	100%	100%	80%	100%	80%
	SW_KSR_29	100%	100%	80%	100%	80%
Sebou Permit No Concession	CGD-6_Upper	100%	100%	80%	100%	80%
	CGD-6_Lower	100%	100%	80%	100%	80%
	CGD-8_NE_Upper	100%	100%	80%	100%	80%
	CGD-8_NE_Lower	100%	100%	80%	100%	80%
	SAH-3_Gaddari	100%	50%	80%	100%	40%
	SAH-3_Guebbas	100%	100%	60%	100%	60%
	SAH-3_U_Hoot	100%	100%	80%	100%	80%

Table 6.13 Risk Matrix - Lalla Mimouna Nord Permit

Permit	Prospect	Source (Migration)	Reservoir (Efficacy)	Trap (Definition & Efficacy)	Seal (Presence & Efficacy)	COS
Lalla Mimouna	LAM-1_A	90%	60%	80%	80%	35%
	LNB-C	90%	60%	80%	80%	35%
	LNB-D	90%	40%	80%	80%	23%
	LNB-E	90%	50%	80%	60%	22%
	LNB-F	90%	60%	80%	80%	35%
	LNB-G	90%	60%	80%	80%	35%
	LNB-H	90%	50%	80%	60%	22%
	NFA_WEST_A	90%	60%	80%	80%	35%
	NFA_WEST_B	90%	50%	80%	80%	29%
	LNB-2_Upper	90%	60%	80%	80%	35%
	LNB-2_Lower	90%	60%	80%	80%	35%
	LCG-1	90%	50%	80%	80%	29%
	LNB-1_Lower	100%	80%	100%	100%	80%

As per COGEH requirements prospects must be risked for chance of development ("COD") as well as geological chance of success. The product of the COS and the COD being the chance of commerciality. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are out with the expertise of the evaluator they must be used with caution.

For the prospects assessed there is a very high chance of development. ERCE has estimated the COD based on the probability of the GIIP exceeding 0.3 Bscf which SDX believe is the minimum required to justify completing the well and hooking it up.

6.7. Risked Prospective Resources

A summary of the Gharb Centre, Sebou and LAM unrisked and risked Prospective Resources on a gross and working interest share basis are presented in Table 6.14, Table 6.15 and Table 6.16 respectively. The footnotes under Table 6.14 are also applicable to the other two tables.

Table 6.14: Summary of the Gharb Centre concession unrisked and risked Prospective Resources

Prospect	Gross Unrisked Gas Prospective Resources (Bscf)				SDX Working Interest	Net Unrisked Prospective Gas Resources (Bscf)				gCOS	COD	Net Risked Prospective Gas Resources (Bscf)			
	1U	2U	3U	Mean		1U	2U	3U	Mean			1U	2U	3U	Mean
LTO_2_AAA	0.23	0.62	1.66	0.83	75%	0.17	0.47	1.25	0.63	34%	100%	0.06	0.16	0.42	0.21
LTU_AAA	0.27	1.14	4.76	2.12	75%	0.20	0.85	3.57	1.59	34%	100%	0.07	0.29	1.20	0.53
LTU_AAB	0.45	1.41	4.39	2.09	75%	0.34	1.06	3.29	1.57	28%	100%	0.09	0.30	0.92	0.44
LTU_AAC	0.28	0.98	3.46	1.59	75%	0.21	0.73	2.60	1.19	28%	100%	0.06	0.21	0.73	0.33
LTU_AAD_Upper	0.09	0.26	0.78	0.38	75%	0.07	0.20	0.59	0.28	56%	85%	0.03	0.09	0.28	0.13
LTU_AAD_Lower	0.11	0.27	0.65	0.34	75%	0.09	0.20	0.49	0.26	44%	85%	0.03	0.08	0.18	0.10
DOB_AAC_Upper	0.10	0.31	1.00	0.47	75%	0.07	0.23	0.75	0.35	28%	100%	0.02	0.07	0.21	0.10
DOB_AAC_Lower	0.21	0.62	1.85	0.89	75%	0.16	0.47	1.38	0.67	34%		0.05	0.16	0.47	0.22
DOB_AAD_Upper	0.16	0.39	0.97	0.50	75%	0.12	0.29	0.73	0.38	34%	90%	0.04	0.09	0.22	0.11
DOB_AAD_Lower	0.07	0.21	0.64	0.30	75%	0.05	0.16	0.48	0.23	56%		0.03	0.08	0.24	0.11
DOB_AAG	0.16	0.61	2.38	1.07	75%	0.12	0.46	1.78	0.80	56%	80%	0.05	0.21	0.80	0.36
DOB_AAH	0.15	0.66	2.97	1.31	75%	0.11	0.50	2.22	0.98	56%	80%	0.05	0.22	1.00	0.44
DOB_AAI	0.34	0.82	1.93	1.02	75%	0.26	0.61	1.45	0.77	34%	100%	0.09	0.21	0.49	0.26
DOB_AAS_Upper	0.24	0.71	2.15	1.03	75%	0.18	0.54	1.61	0.77	44%	100%	0.08	0.24	0.71	0.34
DOB_AAS_Lower	0.26	0.83	2.69	1.26	75%	0.19	0.62	2.02	0.95	44%		0.08	0.27	0.89	0.42
DRC_AAB	0.82	2.23	6.05	3.02	75%	0.62	1.67	4.54	2.27	34%	100%	0.21	0.56	1.52	0.76
DOB_AAB	0.59	2.18	8.13	3.69	75%	0.44	1.64	6.10	2.77	44%	100%	0.19	0.72	2.69	1.22
BFD-RE	0.29	0.83	2.37	1.16	75%	0.22	0.62	1.78	0.87	63%	100%	0.14	0.39	1.12	0.55
DOB_AAF_Upper	0.37	1.26	4.31	2.00	75%	0.28	0.94	3.23	1.50	28%	100%	0.08	0.26	0.91	0.42
DOB_AAF_Lower	0.62	2.18	7.63	3.52	75%	0.47	1.64	5.72	2.64	44%		0.21	0.72	2.52	1.16
LTO_AAE	0.47	1.26	3.38	1.69	75%	0.35	0.94	2.54	1.27	49%	100%	0.17	0.46	1.24	0.62
CGD-14	0.12	0.23	0.45	0.26	75%	0.09	0.17	0.34	0.20	72%	50%	0.03	0.06	0.12	0.07
sm1005	0.44	1.99	8.92	3.95	75%	0.33	1.49	6.69	2.96	40%	100%	0.13	0.60	2.68	1.18
sm81	0.68	2.46	8.86	4.06	75%	0.51	1.84	6.65	3.04	25%	100%	0.13	0.46	1.66	0.76
p121	0.41	0.83	1.68	0.97	75%	0.31	0.62	1.26	0.73	26%	100%	0.08	0.16	0.33	0.19
sm77	0.19	0.65	2.25	1.04	75%	0.14	0.49	1.69	0.78	35%	85%	0.04	0.15	0.50	0.23
p122	0.46	1.67	6.09	2.78	75%	0.34	1.25	4.56	2.08	26%	100%	0.09	0.32	1.18	0.54
p142	0.42	1.43	4.86	2.26	75%	0.31	1.07	3.65	1.69	40%	100%	0.13	0.43	1.46	0.68
P141	0.51	1.43	3.97	1.96	75%	0.39	1.07	2.98	1.47	30%	100%	0.12	0.32	0.89	0.44
sm47	0.13	0.43	1.43	0.67	75%	0.10	0.32	1.07	0.50	35%	75%	0.03	0.08	0.28	0.13
OYF Upper	0.26	0.54	1.13	0.64	75%	0.19	0.40	0.85	0.48	72%	100%	0.14	0.29	0.61	0.34
OYF Lower	0.19	0.40	0.88	0.49	75%	0.14	0.30	0.66	0.37	72%		0.10	0.22	0.48	0.26
BMK Upper	0.05	0.17	0.61	0.28	75%	0.03	0.13	0.46	0.21	50%	85%	0.01	0.05	0.20	0.09
BMK Lower	0.14	0.40	1.12	0.55	75%	0.10	0.30	0.84	0.41	50%		0.04	0.13	0.36	0.18
SAH-W	0.15	0.41	1.09	0.55	75%	0.11	0.31	0.82	0.41	72%	75%	0.06	0.17	0.44	0.22
ERM-A	0.04	0.12	0.34	0.17	75%	0.03	0.09	0.26	0.12	58%	20%	0.00	0.01	0.03	0.01
SAK-A	1.25	3.78	11.46	5.50	75%	0.93	2.83	8.59	4.12	43%	100%	0.40	1.22	3.71	1.78
Determinstic Total	**11.7**	**36.7**	**119.3**	**56.4**		**8.8**	**27.5**	**89.5**	**42.3**			**3.4**	**10.4**	**33.7**	**16.0**

1. *Net unrisked Prospective Resources are based on the working interest share of the field gross resources and do not represent the net entitlement resources.*
2. *COS is the chance of geological success and COD is the chance of development. The product of COS x COD is the chance of commerciality.*
3. *Quantifying the COD requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are out with the expertise of ERCE they must be used with caution.*
4. *Net risked Prospective Resources are the product of the unrisked resources and the chance of commerciality*
5. *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*

Table 6.15: Summary of the Sebou concession unrisked and risked Prospective Resources

Prospect	Gross Unrisked Gas Prospective Resources (Bscf)				SDX Working Interest	Net Unrisked Prospective Gas Resources (Bscf)				gCOS	COD	Net Risked Prospective Gas Resources (Bscf)			
	1U	2U	3U	Mean		1U	2U	3U	Mean			1U	2U	3U	Mean
KSR-E	0.38	0.66	1.16	0.73	75%	0.28	0.50	0.87	0.54	80%	100%	0.23	0.40	0.69	0.44
KSR-G	0.32	0.61	1.17	0.70	75%	0.24	0.46	0.88	0.52	80%	100%	0.19	0.37	0.70	0.42
KSR-H	0.45	0.82	1.50	0.91	75%	0.33	0.61	1.12	0.69	80%	100%	0.27	0.49	0.90	0.55
KSR-I	0.29	0.49	0.83	0.54	75%	0.22	0.37	0.63	0.40	80%	100%	0.17	0.30	0.50	0.32
KSR-F	0.33	0.67	1.35	0.78	75%	0.25	0.50	1.01	0.58	80%	100%	0.20	0.40	0.81	0.47
SW_KSR_29	0.19	0.51	1.36	0.68	75%	0.14	0.38	1.02	0.51	80%	85%	0.10	0.26	0.69	0.35
CGD-6_Upper	0.04	0.13	0.44	0.21	75%	0.03	0.10	0.33	0.15	80%	80%	0.02	0.06	0.21	0.10
CGD-6_Lower	0.12	0.23	0.44	0.26	75%	0.09	0.17	0.33	0.20	80%		0.06	0.11	0.21	0.13
CGD-8_NE_Upper	0.10	0.27	0.72	0.36	75%	0.07	0.20	0.54	0.27	80%	65%	0.04	0.10	0.28	0.14
CGD-8_NE_Lower	0.01	0.05	0.16	0.07	75%	0.01	0.04	0.12	0.06	80%		0.01	0.02	0.06	0.03
SAH-3_Gaddari	0.02	0.05	0.16	0.08	75%	0.01	0.04	0.12	0.06	40%	100%	0.01	0.02	0.05	0.02
SAH-3_Guebbas	0.14	0.26	0.50	0.30	75%	0.11	0.20	0.37	0.22	60%		0.06	0.12	0.22	0.13
SAH-3_U_Hoot	0.09	0.18	0.36	0.21	75%	0.07	0.14	0.27	0.16	80%		0.06	0.11	0.22	0.13
Determinstic Total	**2.5**	**4.9**	**10.1**	**5.8**		**1.9**	**3.7**	**7.6**	**4.4**			**1.4**	**2.8**	**5.6**	**3.2**

Table 6.16: Summary of the Lalla Mimouna Nord concession unrisked and risked Prospective Resources

Prospect	Gross Unrisked Gas Prospective Resources (Bscf)				SDX Working Interest	Net Unrisked Prospective Gas Resources (Bscf)				gCOS	COD	Net Risked Prospective Gas Resources (Bscf)			
	1U	2U	3U	Mean		1U	2U	3U	Mean			1U	2U	3U	Mean
LAM-1_A	0.09	0.36	1.42	0.64	75%	0.07	0.27	1.06	0.48	35%	65%	0.02	0.06	0.24	0.11
LNB-C	0.45	1.81	7.24	3.25	75%	0.34	1.36	5.43	2.44	35%	100%	0.12	0.47	1.88	0.84
LNB-D	1.00	3.39	11.51	5.35	75%	0.75	2.55	8.63	4.01	23%	100%	0.17	0.59	1.99	0.92
LNB-E	0.44	1.32	3.96	1.91	75%	0.33	0.99	2.97	1.43	18%	100%	0.06	0.18	0.53	0.26
LNB-F	0.63	1.77	4.95	2.44	75%	0.47	1.32	3.71	1.83	35%	100%	0.16	0.46	1.28	0.63
LNB-G	0.33	0.91	2.55	1.26	75%	0.25	0.69	1.92	0.95	35%	100%	0.08	0.24	0.66	0.33
LNB-H	0.26	0.83	2.63	1.24	75%	0.20	0.62	1.97	0.93	18%	100%	0.04	0.11	0.36	0.17
NFA_WEST_A	1.32	4.12	12.81	6.09	75%	0.99	3.09	9.61	4.57	35%	100%	0.34	1.07	3.32	1.58
NFA_WEST_B	0.35	0.92	2.43	1.23	75%	0.26	0.69	1.83	0.92	29%	100%	0.08	0.20	0.53	0.27
LNB-2_Upper	0.58	1.71	5.01	2.43	75%	0.44	1.28	3.76	1.82	35%	100%	0.15	0.44	1.30	0.63
LNB-2_Lower	0.60	1.60	4.31	2.16	75%	0.45	1.20	3.23	1.62	35%		0.15	0.42	1.12	0.56
LCG-1	0.76	2.06	5.55	2.78	75%	0.57	1.54	4.17	2.08	29%	100%	0.16	0.44	1.20	0.60
LNB-1_Lower	2.26	5.38	12.80	6.76	75%	1.69	4.03	9.60	5.07	80%	100%	1.36	3.23	7.68	4.06
Deterministic Total	**9.1**	**26.2**	**77.2**	**37.5**		**6.8**	**19.6**	**57.9**	**28.1**			**2.9**	**7.9**	**22.1**	**10.9**

7. Sebou Area Exploitation Concessions

7.1. Introduction

As discussed in Section 6.1, SDX has an interest in a number of exploitation concessions in Morocco. The concessions have been carved out of the Sebou Exploration Concession area as and when commercial discoveries have been made. ONHYM treats all new wells as exploration wells until they have established commerciality. This Audit has evaluated the existing wells within the Ksiri Centre, Gaddari South Sidi al Harati South West, Sidi Al Harati West and Oulad N’Zala Central Exploitation Concessions (Figure 7.1).

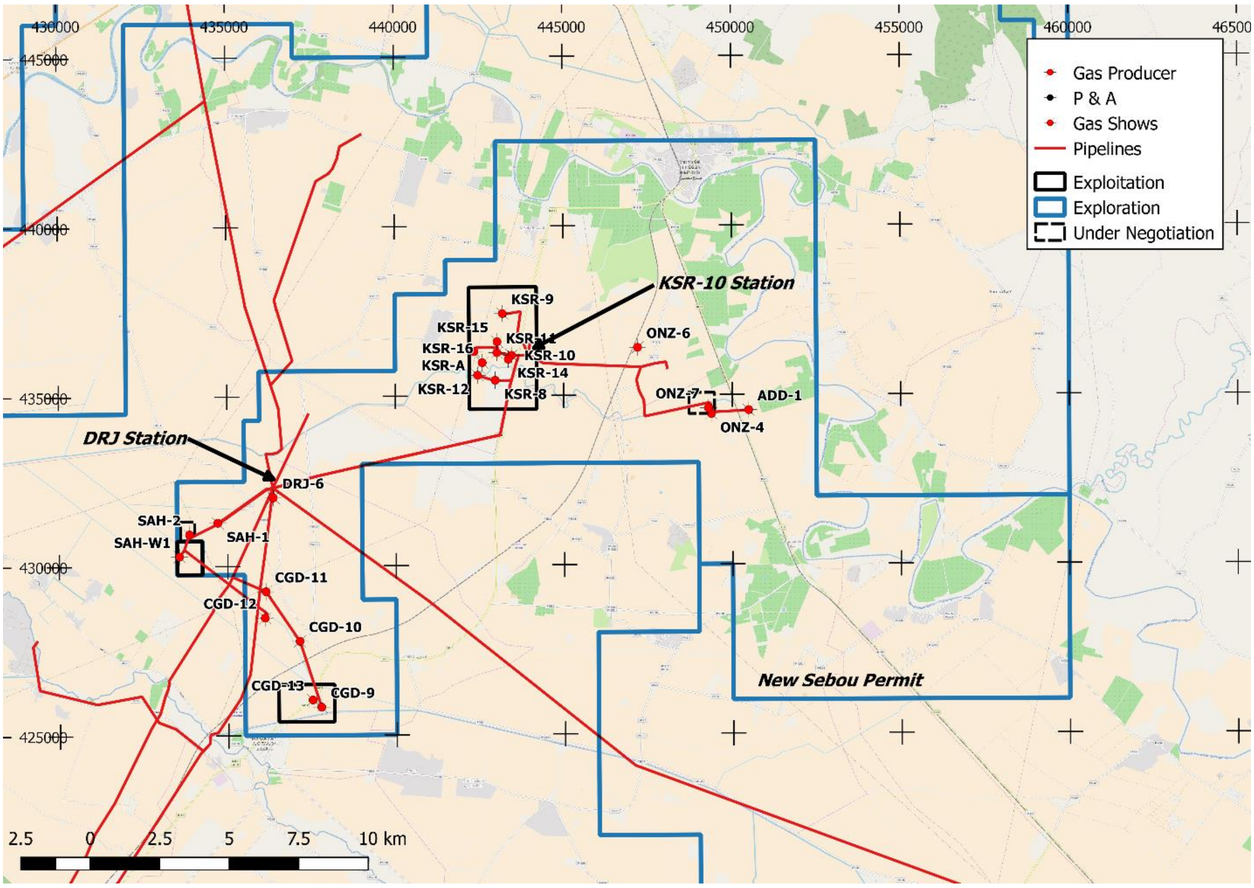

Figure 7.1: Location map for Sebou Exploitation Concessions

7.2. Development History

The development of the Sebou area has occurred during the previous 10 years. In all wells except the recent discoveries from LMS-1 and LNB-1 in Lalla Mimouna Nord, the natural gas is biogenic and virtually all methane (99%) and as such needs no dew point control. Gas from wells is fed directly into the Kenitra pipeline system. As of the effective date of this report SDX has gas contracts with a number of suppliers including CMCP, Super Serame, SETEXAM, Extralait and Peugeot. It also is in late stage negotiations with Omnium Plastic.

Exploration wells are targeted at seismic bright amplitude anomalies which are often indicative of gas. When present the gas is in good quality, thin turbidite sands within the Gaddari, Guebbas and Hoot formations of the Upper Miocene. Each well appears to drain a separate pool with in-place volumes around 1 Bscf. However, because of excellent commercial terms, SDX considers anything larger than 0.3 Bscf to be commercial.

7.3. Production Performance

Gas production records from 2009 were provided by SDX. All records are received in SI units of normal cubic metres (Nm^3). To convert to field units a conversion rate of 1 Nm^3 = 37.3 scf was applied. A production plot by well is presented in Figure 7.2.

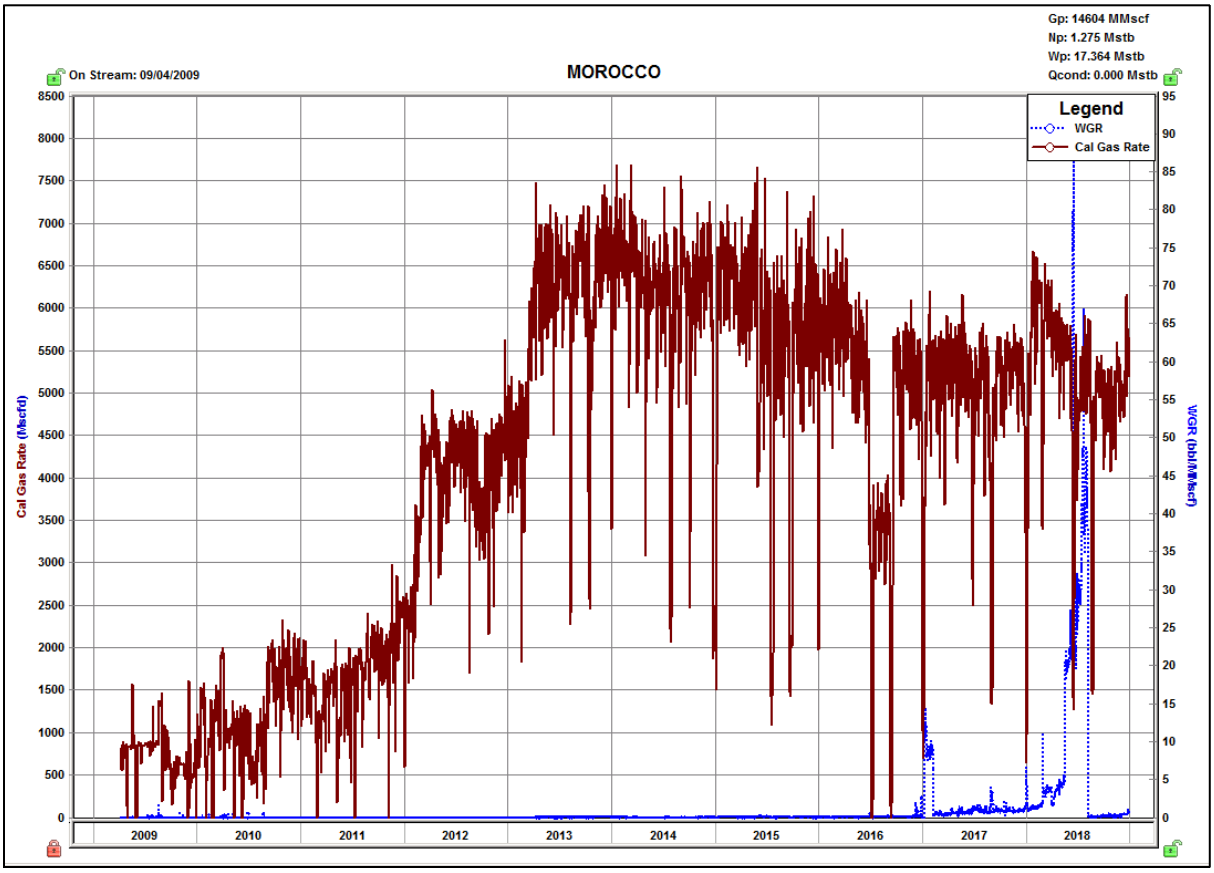

Figure 7.2: Production history for the Sebou area wells

Wells typically cease to produce either when they become depleted or when they cut water and are unable to sustain production.

7.4. Reservoir Engineering

The gas properties are straightforward to estimate given the dry nature of the gas. Reservoir temperature and pressure are used with standard gas correlations to estimate the gas deviation factor and where necessary the gas expansion factor (“GEF”).

Wellhead pressure data for the wells is recorded on a daily basis. Historically not all the wells were needed to meet the gas demand and so it was possible to carry out regular pressure build ups to establish a closed in tubing head pressure (“CITHP”). This was the primary data for carrying out material balance (p/z) analysis.

7.5. Recoverable Resources

Recoverable resources for most wells could be determined through a combination of material balance to determine the likely GIIP and application of representative recovery factors. Analysis of the historical wells shows that recoveries can vary between 60% and 95% depending on the drive mechanism. It is difficult to predict in advance whether a well will cease production due to early water which in turn results in a much lower recovery factor. Standard p/z plots do not appear to provide early evidence of water drive. The best approach, and the one adopted, appears to be to carry out a p/z analysis to determine GIIP and then to assign an appropriate recovery factor range based on the cumulative recovery to date and wellhead pressure constraints of the system. This methodology has been used for most of the producing wells. Wellhead pressures and z factors calculated at downhole temperature were used for the generating the p/z plots (this avoided conversion to downhole pressures and still extrapolates to the same GIIP).

For pools where there is no production to date, probabilistic volumetric estimates were used. This applied both to the new discoveries recently drilled and also to behind pipe (developed non-producing) intervals. The uncertainty in pool area was based on the extent of the seismic anomaly at the well location as constrained by likely faulting which compartmentalizes the reservoir. Reservoir parameters were based on the well, and surrounding well results. GEF was based on the estimated reservoir pressure and temperature. A recovery factor range of 60 to 95% was used.

Wellhead raw volumes were converted to sales volumes assuming a low shrinkage (1%) to account for a small amount of fuel and flare.

A summary of the recoverable volumes are presented in Table 7.1.

Table 7.1: A summary of the Sebou area raw recoverable volumes

Name	Reserves Classification	1P Technical EUR MMscf	2P Technical EUR MMscf	3P Technical EUR MMscf	Cumulative Production as at 31 December 2018 (MMscf)
CGD-13	Developed Producing	448	485	522	391
KSR-10	Developed Producing	2437	2769	3101	2265
KSR-12	Developed Producing	2131	2250	2400	1454
KSR-14	Developed Producing	180	190	200	145
KSR-15	Developed Producing	400	908	1592	213
KSR-16	Developed Producing	807	1215	1829	28
KSR-8	Developed Producing	5910	6150	6490	5688
KSR-A	Developed Producing	780	840	880	751
SAH-W1	Developed Producing	1001	1073	1144	921
SAH-2 (Hoot)	Developed Non-Producing	170	280	450	3
KSR-12 (T Hoot)	Developed Non-Producing	254	490	935	0
KSR-8 (M. Guebbas)	Developed Non-Producing	51	84	138	0
ONZ-7	Developed Non-Producing	260	480	900	0
SAH-2 (Guebbas)	Developed Non-Producing	80	170	360	0

1. *Note in the above table gas shrinkage and economic limits have not been applied.*

7.6. Production Forecasting

SDX gas sales and realised gas price is dependent on a number of contracts they have entered into, which have varying lengths. ERCE has based our production forecast on these contracts, accounting for both volumes and length of contract. The gas production forecasts have changed since YE 2017 due a number of new contracts that SDX has entered into. These new contracts will allow the sales rate to increase above recent rates. ERCE has relied on SDX with regards to the forecasted contracted gas sales volumes.

The 2P and 3P cases were modelled allowing on 85% of the production occurring on plateau for a given well and the 1P was based on a more conservative 70%. Accounting for well deliverability, we then allowed the gas forecast to be on plateau as long as possible.

The various production forecasts are presented in Figure 7.3

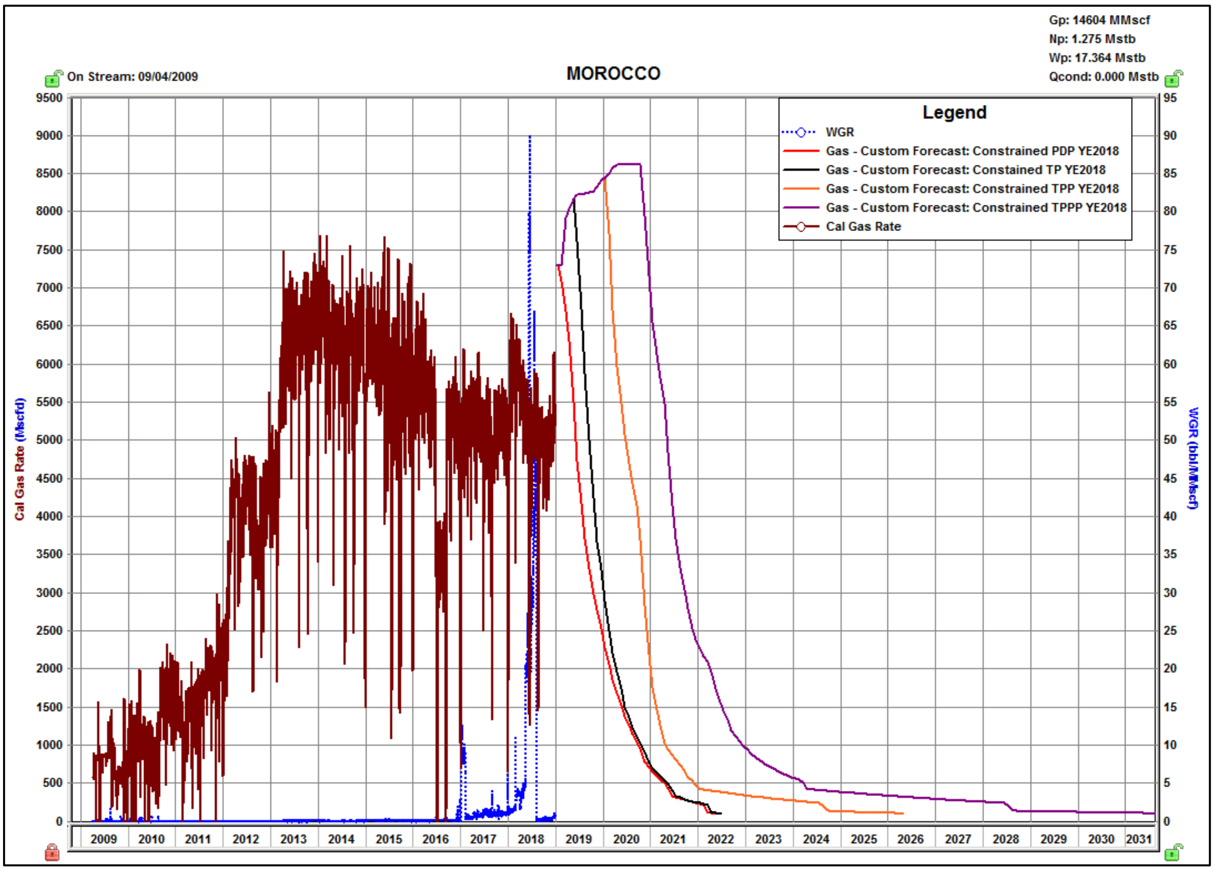

Figure 7.3: PDP, 1P, 2P and 3P Sebou area production forecasts

7.7. Reserves and Net Present Values

The Reserves estimates were based on the Sebou area production forecasts (Figure 7.3) cut off at the economic limit as determined by production and revenue analysis.

Natural gas revenue was derived from the production forecasts and the forecast sales gas price presented in Table 2.2. As described in Section 7.3, sales in Morocco actually occur on a MAD/Nm^3 basis. Gas prices for economic modelling have been determined using a volume conversion of 37.3 scf/Nm^3 and the currency conversion rate stated in Table 2.3.

Forecasts of production and costs can be found in Appendix 3.

Fiscal terms are based on the tax-royalty arrangements applicable to these licences. A 5% gas royalty is payable when the cumulative production is greater than 10 Bscf. Each development area has a separate 10 Bscf allowance with only Ksiri Centre exploitation concession exceeding this threshold. Corporate income tax is 30% but there is an initial 10-year tax holiday which for the Ksiri Centre exploitation concession ends in 2021. For the purposes of the evaluation, ERCE has assumed that the tax holiday will end in 2021 for all concessions. The impact though is limited as only in the 3P case is any corporate tax paid.

A summary of the natural gas and Reserves are presented in Table 7.2 for each Reserves category. A summary of the Company share of the net present values is presented in Table 7.3.

Table 7.2: Sebou area natural gas Reserves estimates as of December 31, 2018

Category	Field Gross MMscf	Company Gross WI MMscf	Company Net Entitlement MMscf
PDP	2,217	1,662	1,588
PD	2,838	2,129	2,029
PUD	-	-	-
1P	2,838	2,129	2,029
2P	5,096	3,822	3,641
3P	8,604	6,453	6,144

1. *Company gross working interest Reserves are based on 75% of the field gross Reserves*
2. *Company net entitlement Reserves are based on Company share of the gross Reserves after deduction of royalties*

Table 7.3: Sebou area Net Present Values as of December 31, 2018

	Company Share of Net Present Values at various discount rates (US$ MM)				
Category	0%	5%	10%	15%	20%
PDP	10	10	10	10	9
PD	15	14	14	14	13
PUD	-	-	-	-	-
1P	15	14	14	14	13
2P	30	29	27	26	25
3P	52	48	45	42	40

1. *Based on forecast prices and costs as of 1 January 2019 (see Table 2.2)*
2. *Interest expenses, corporate overheads etc were not included.*
3. *The net present values may not represent the fair market value of the Reserves.*

8. Certificates of Qualification

This section contains the Certificates of Qualification for:

1. Paul Chernik, Professional Engineer registered with the Association of Professional Engineers and Geoscientists of Alberta (APEGA), Member of the Society of Petroleum Evaluation Engineers (SPEE)
2. Adam Law, Member of the Geological Society of London, Member of the Society of Petroleum Evaluation Engineers (SPEE)

Certificate of Qualification

I, Paul Stephen Chernik, Professional Engineer, in the Province of Alberta, Canada HEREBY CERTIFY:

1. That I am a registered Professional Engineer in the Province of Alberta, Canada, and practice in the district of Croydon, London, United Kingdom.
2. That I am an employee of ERC Equipoise Limited, which company did prepare a detailed analysis of the international oil and gas properties of SDX Energy Inc. The effective date of this evaluation is December 31, 2018.
3. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of SDX Energy Inc or its affiliated companies.
4. That I attended the University of Calgary and that I graduated with a Bachelor of Science Degree in Chemical Engineering in 2003; that I attended the University of Alberta and graduated with a Master's of Science Degree in Chemical Engineering in 2005; that I am a Registered Professional Engineer in the Province of Alberta, registered with the Association of Professional Engineers and Geoscientists of Alberta (APEGA); that I am a registered Member of the Society of Petroleum Evaluation Engineers (SPEE); and, that I have in excess of 15 years' experience in engineering studies relating to Canadian and International oil and gas fields.
5. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records and the files of SDX Energy Inc.

Paul S. Chernik, P.Eng

APEGA Membership Number: # 66938
SPEE Membership Number: # 776

Certificate of Qualification

I, Adam Law, Professional Geoscientist of 6th Floor, Stephenson House, 2 Cherry Orchard Rd, Croydon, UK HEREBY CERTIFY:

1. That I am a Geoscience Director of ERC Equipoise Limited, which company did prepare a detailed analysis of the international oil and gas properties of SDX Energy Inc. The effective date of this evaluation is December 31, 2018.
2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of SDX Energy Inc or its affiliated companies.
3. That I attended London University and that I graduated with a Bachelor of Science Degree in Geophysics in 1990; that I attended the University of Cambridge, and graduated with a PhD in Geophysics in 1993; that I am a registered Member of the Society of Petroleum Evaluation Engineers (SPEE); and, that I have in excess of 24 years' experience in geological and geophysical studies relating to International oil and gas fields.
4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records and the files of SDX Energy Inc.

Dr. Adam Law,

SPEE Membership Number: # 726

9. Appendix 1: Nomenclature

9.1. Units

°C	degrees Celsius
°F	degrees Fahrenheit
bbl	barrel
bbl/d	barrels per day
Bscf	thousands of millions of standard cubic feet
boe	barrels of oil equivalent, where 6000 scf of gas = 1 bbl of oil
cm	centimetres
cp	centipoises
ft	feet
ftMDRKB	feet below Kelly Bushing
ftTVDSS	feet subsea
g	gram
km	kilometres
m	metres
M or MM	thousands and millions respectively
m/s	metres per second
m/s*g/cc	AI units
md	millidarcy
mgal	milligal where 1 mgal is one thousandth of 1cm/s2
MTe	Megatonne equivalent
mTVDSS	metres subsea
Nm3	normal cubic metres measured at 1 bar absolute and 0°C = 37.3 scf.
ppm	parts per million
psia	pounds per square inch absolute
psig	pounds per square inch gauge
pu	porosity unit
rcf	cubic feet at reservoir conditions
rb	reservoir barrels
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
scf/d	standard cubic feet per day
stb	a stock tank barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
stb/d	stock tank barrels per day

9.2. Reserves and Resources Classifications

1P or P	Total Proved
2P or P+P	Total Proved + Probable
3P or P+P+P	Total Proved + Probable +Possible
Possible	Possible, as defined in COGE Handbook
Probable	Probable, as defined in COGE Handbook
Proved	Proved, as defined in COGE Handbook
1C	Low Estimate of Contingent Resources, as defined in in COGE Handbook
2C	Best Estimate of Contingent Resources, as defined in COGE Handbook
3C	High Estimate of Contingent Resources, as defined in COGE Handbook
Low	Low estimate of Prospective Resources, as defined in COGE Handbook
Best	Best estimate of Prospective Resources, as defined in COGE Handbook
High	High estimate of Prospective Resources, as defined in COGE Handbook
COS	Geological Chance of Success associated with Prospective Resources
P10	10 per cent probability = Proved + Probable + Possible, or 3P
P50	50 per cent probability = Proved + Probable, or 2P
P90	90 per cent probability = Proved, or 1P
PDP	Proved Developed Producing
PPDP	Proved plus Probable Developed Producing
PPPDP	Proved plus Probable plus Possible Developed Producing
PDNP	Proved Developed Non-Producing
PPDNP	Proved plus Probable Developed Non-Producing
PPPDNP	Proved plus Probable plus Possible Developed Non-Producing
PUD	Proved Undeveloped
PPUD	Proved plus Probable Undeveloped
PPPUD	Proved plus Probable plus Possible Undeveloped
remaining	when stating Reserves of petroleum, the total amount of petroleum that is expected to be produced from the reference date (in the report) to the end of production

9.3. Abbreviations

AAI	absolute acoustic impedance
AVO	amplitude variation with offset
Bg	gas formation volume factor
Bo	oil shrinkage factor or formation volume factor, in rb/stb
CGR	condensate gas ratio
CPF	central processing facility
CPI	computer processed information log
DST	drill stem test
EEI	extended elastic impedance
Eg	gas expansion factor
ESP	electric submersible pump
FBHP	Flowing bottom hole pressure
FDP	field development plan
FPSO	floating production storage and offloading vessel
FTHP	flowing tubing head pressure
FVF	formation volume factor
FY	financial year
FWL	free water level
GDT	gas down to
GEF	gas expansion factor
GIIP	gas initially in place
GOC	gas oil contact
GR	gamma ray
GRV	gross rock volume
GWC	gas water contact
Kair	air permeability
KB	kelly bushing
kh	permeability thickness
Kl	liquid permeability
Kr	relative permeability
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MBAL	material balance computer programme
MD	measured depth
MDT	modular formation dynamic tester

MSL	mean sea level
NTG	net to gross ratio
NMO	normal move-out
Np	cumulative oil production
NPV xx	net present value at xx discount rate
ODT	oil down to
OWC	oil water contact
P/Z	pressure divided by gas deviation factor (material balance)
Phi	porosity
Phie	effective porosity
Phit	total porosity
POD	plan of development
PR	poisson's ratio
PSDM	post stack depth migration
PSTM	post stack time migration
PVT	pressure volume temperature experiment
RAI	relative acoustic impedance
RCA	routine core analysis
RFT	repeat formation tester
RNMO	residual move-out
Rs	solution gas oil ratio
Rt	true resistivity
Rw	formation water resistivity
SCAL	special core analysis
Sg	gas saturation
So	oil saturation
Soi	initial oil saturation
Sor	residual oil saturation
SRP	sucker rod pump
STOIIP	stock tank oil initially in place
Sw	water saturation
Swc	connate water saturation
TD	total depth
TOC	total organic carbon
TVD	true vertical depth
TWT	two way time
Vp	P wave velocity

Vs	shear wave velocity
Vsh	shale volume
WF	water-flood
WGR	water gas ratio
WOR	water oil ratio
WUT	water up to

10. Appendix 2: Cash Flow Tables

SDX Energy Inc.
Total West Gharib Block H - Egypt
Forecast of Production, Costs and Revenues
Proved Developed Producing Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Meseda Avg. Daily Rate bbl/d	Rabul Avg. Daily Rate bbl/d	Total Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Crude Oil Price US$/bbl	Total Sales Revenue US$MM
2019	3,230	553	3,783	1,381	49.33	68.1
2020	2,023	115	2,138	783	51.84	40.6
2021	1,524	35	1,559	569	52.87	30.1
2022	1,218	-	1,218	444	54.72	24.3
2023	1,005	-	1,005	367	55.82	20.5
2024	848	-	848	310	57.76	17.9
2025	728	-	728	266	58.92	15.6
2026	625	-	625	228	60.09	13.7
2027	514	-	514	188	61.30	11.5
2028	-	-	-	-	-	-
2029	-	-	-	-	-	-
2030	-	-	-	-	-	-
2031	-	-	-	-	-	-
2032	-	-	-	-	-	-
2033	-	-	-	-	-	-
Rem.	-	-		-	-	-
Total				4,535		242.3

Concession Gross Share of Cost and Profit Revenues

Year	State Royalties US$MM	Total Royalties %	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM
2019	-	-	7.6	5.51	-	3.3	-	57.2
2020	-	-	5.7	7.29	-	0.4	-	34.5
2021	-	-	5.1	8.98	-	0.3	-	24.6
2022	-	-	4.8	10.72	-	0.3	-	19.2
2023	-	-	4.6	12.49	-	0.3	-	15.6
2024	-	-	4.5	14.38	-	0.3	-	13.2
2025	-	-	4.4	16.54	-	0.3	-	11.0
2026	-	-	4.3	18.98	-	0.3	-	9.1
2027	-	-	4.2	22.63	-	0.3	0.7	6.3
2028	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-
Total	-	-	45.2	9.97	-	5.9	0.7	190.6

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Service Fee Revenue US$MM	Tariff Fee US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Other Income US$MM	Income Tax US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	690	263	13.0	0.3	3.8	1.7	0.9	1.7	6.3	6.0
2020	391	150	7.8	0.2	2.9	0.2	0.4	0.8	4.0	3.5
2021	285	109	5.8	0.1	2.6	0.2	0.4	0.4	2.8	2.2
2022	222	85	4.7	0.1	2.4	0.2	0.2	0.2	2.0	1.5
2023	183	71	3.9	0.1	2.3	0.2	0.2	0.1	1.5	1.0
2024	155	60	3.5	0.1	2.2	0.2	0.1	0.2	0.9	0.5
2025	133	51	3.0	0.1	2.2	0.1	0.1	0.1	0.5	0.3
2026	114	44	2.6	0.1	2.2	0.1	0.0	0.1	0.2	0.1
2027	94	36	2.2	0.0	2.1	0.5	-	-	(0.4)	(0.2)
2028	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	2,268	869	46.4	1.1	22.6	3.3	2.2	3.7	17.9	14.9

SDX Energy Inc.
Total West Gharib Block H - Egypt
Forecast of Production, Costs and Revenues
Total Proved Developed Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Meseda Avg. Daily Rate bbl/d	Rabul Avg. Daily Rate bbl/d	Total Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Crude Oil Price US$/bbl	Total Sales Revenue US$MM
2019	3,263	553	3,816	1,393	49.33	68.7
2020	2,089	115	2,204	807	51.84	41.8
2021	1,617	35	1,652	603	52.87	31.9
2022	1,334	-	1,334	487	54.72	26.6
2023	1,141	-	1,141	417	55.82	23.3
2024	1,001	-	1,001	366	57.76	21.2
2025	896	-	896	327	58.92	19.3
2026	806	-	806	294	60.09	17.7
2027	707	-	707	258	61.30	15.8
2028	632	-	632	231	62.52	14.5
2029	590	-	590	215	63.77	13.7
2030	-	-	-	-	-	-
2031	-	-	-	-	-	-
2032	-	-	-	-	-	-
2033	-	-	-	-	-	-
Rem.	-	-		-	-	-
Total				5,398		294.4

Concession Gross Share of Cost and Profit Revenues

Year	State Royalties US$MM	Total Royalties %	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM
2019	-	-	7.7	5.49	-	5.0	-	56.1
2020	-	-	5.8	7.17	-	0.6	-	35.5
2021	-	-	5.2	8.65	-	0.3	-	26.3
2022	-	-	4.9	10.09	-	0.3	-	21.4
2023	-	-	4.8	11.43	-	0.3	-	18.2
2024	-	-	4.7	12.74	-	0.3	-	16.2
2025	-	-	4.6	14.13	-	0.3	-	14.3
2026	-	-	4.6	15.56	-	0.3	-	12.8
2027	-	-	4.5	17.51	-	0.3	-	11.0
2028	-	-	4.5	19.43	-	0.3	-	9.7
2029	-	-	4.5	20.98	-	0.3	0.8	8.2
2030	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-
Total	-	-	55.7	10.32	-	8.2	0.8	229.7

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Service Fee Revenue US$MM	Tariff Fee US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Other Income US$MM	Income Tax US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	696	266	13.1	0.3	3.8	2.5	0.9	1.7	5.6	5.3
2020	403	154	8.0	0.2	2.9	0.3	0.4	0.8	4.2	3.6
2021	302	115	6.1	0.2	2.6	0.2	0.4	0.5	3.1	2.5
2022	243	93	5.1	0.1	2.5	0.2	0.3	0.3	2.4	1.7
2023	208	80	4.5	0.1	2.4	0.2	0.2	0.1	1.9	1.2
2024	183	71	4.1	0.1	2.3	0.2	0.2	0.3	1.3	0.8
2025	163	63	3.7	0.1	2.3	0.1	0.1	0.3	1.0	0.6
2026	147	57	3.4	0.1	2.3	0.1	0.1	0.2	0.8	0.4
2027	129	50	3.0	0.1	2.3	0.1	0.1	0.1	0.5	0.2
2028	116	45	2.8	0.1	2.2	0.1	0.0	0.1	0.3	0.1
2029	108	41	2.6	0.1	2.3	0.5	0.0	0.0	(0.2)	(0.1)
2030	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	2,699	1,034	56.4	1.4	27.9	4.5	2.6	4.4	20.9	16.3

SDX Energy Inc.
Total West Gharib Block H - Egypt
Forecast of Production, Costs and Revenues
Total Proved Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Meseda Avg. Daily Rate bbl/d	Rabul Avg. Daily Rate bbl/d	Total Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Crude Oil Price US$/bbl	Total Sales Revenue US$MM
2019	3,785	894	4,679	1,708	49.33	84.2
2020	2,560	528	3,088	1,130	51.84	58.6
2021	1,811	174	1,985	725	52.87	38.3
2022	1,369	47	1,415	517	54.72	28.3
2023	1,079	16	1,094	399	55.82	22.3
2024	868	2	870	318	57.76	18.4
2025	706	-	706	258	58.92	15.2
2026	575	-	575	210	60.09	12.6
2027	445	-	445	163	61.30	10.0
2028	-	-	-	-	-	-
2029	-	-	-	-	-	-
2030	-	-	-	-	-	-
2031	-	-	-	-	-	-
2032	-	-	-	-	-	-
2033	-	-	-	-	-	-
Rem.	-	-		-	-	-
Total				5,427		287.8

Concession Gross Share of Cost and Profit Revenues

Year	State Royalties US$MM	Total Royalties %	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM
2019	-	-	8.8	5.13	-	7.7	-	67.7
2020	-	-	7.0	6.16	-	0.6	-	51.0
2021	-	-	5.7	7.82	-	0.3	-	32.3
2022	-	-	5.0	9.76	-	0.3	-	22.9
2023	-	-	4.7	11.79	-	0.3	-	17.3
2024	-	-	4.5	14.12	-	0.3	-	13.6
2025	-	-	4.4	16.91	-	0.3	-	10.5
2026	-	-	4.3	20.30	-	-	-	8.3
2027	-	-	4.1	25.49	-	-	0.7	5.1
2028	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-
Total	-	-	48.4	8.92	-	9.9	0.7	228.8

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Service Fee Revenue US$MM	Tariff Fee US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Other Income US$MM	Income Tax US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	854	325	16.1	0.4	4.4	3.9	1.1	2.2	6.3	6.0
2020	565	216	11.2	0.3	3.5	0.3	0.6	1.3	6.5	5.6
2021	362	139	7.3	0.2	2.8	0.2	0.5	0.6	4.0	3.2
2022	258	99	5.4	0.1	2.5	0.2	0.3	0.3	2.7	1.9
2023	200	77	4.3	0.1	2.4	0.2	0.2	0.0	1.8	1.2
2024	159	61	3.5	0.1	2.2	0.2	0.1	0.2	0.9	0.6
2025	129	50	2.9	0.1	2.2	0.1	0.1	0.1	0.5	0.3
2026	105	40	2.4	0.1	2.1	-	0.0	0.0	0.2	0.1
2027	81	31	1.9	0.0	2.1	0.4	-	-	(0.6)	(0.3)
2028	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	2,713	1,038	55.1	1.4	24.2	5.3	2.9	4.8	22.4	18.6

SDX Energy Inc.
Total West Gharib Block H - Egypt
Forecast of Production, Costs and Revenues
Total Proved + Probable Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Meseda Avg. Daily Rate bbl/d	Rabul Avg. Daily Rate bbl/d	Total Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Crude Oil Price US$/bbl	Total Sales Revenue US$MM
2019	4,420	1,018	5,438	1,985	49.33	97.9
2020	3,364	1,010	4,374	1,601	51.84	83.0
2021	2,433	523	2,956	1,079	52.87	57.0
2022	1,856	317	2,173	793	54.72	43.4
2023	1,508	214	1,723	629	55.82	35.1
2024	1,332	155	1,487	544	57.76	31.4
2025	1,192	100	1,292	472	58.92	27.8
2026	1,080	68	1,147	419	60.09	25.2
2027	988	47	1,035	378	61.30	23.1
2028	911	38	949	347	62.52	21.7
2029	846	32	878	320	63.77	20.4
2030	792	27	819	299	65.05	19.4
2031	678	-	678	247	66.35	16.4
2032	-	-	-	-	-	-
2033	-	-	-	-	-	-
Rem.	-	-		-	-	-
Total				9,113		502.0

Concession Gross Share of Cost and Profit Revenues

Year	State Royalties US$MM	Total Royalties %	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM
2019	-	-	9.7	4.87	-	7.7	-	80.5
2020	-	-	8.6	5.39	-	0.6	-	73.8
2021	-	-	6.9	6.43	-	0.3	-	49.8
2022	-	-	6.1	7.64	-	0.3	-	37.0
2023	-	-	5.6	8.89	-	0.3	-	29.2
2024	-	-	5.4	9.89	-	0.3	-	25.8
2025	-	-	5.2	11.03	-	0.3	-	22.3
2026	-	-	5.1	12.15	-	0.3	-	19.8
2027	-	-	5.0	13.30	-	0.3	-	17.8
2028	-	-	5.0	14.33	-	0.3	-	16.5
2029	-	-	5.0	15.49	-	0.3	-	15.2
2030	-	-	5.0	16.62	-	-	-	14.5
2031	-	-	4.9	19.73	-	-	0.8	10.7
2032	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-
Total	-	-	77.4	8.49	-	11.0	0.8	412.9

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Service Fee Revenue US$MM	Tariff Fee US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Other Income US$MM	Income Tax US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	992	378	18.6	0.5	4.8	3.9	1.4	2.7	8.2	7.8
2020	801	305	15.8	0.4	4.3	0.3	1.0	2.1	9.7	8.4
2021	539	206	10.9	0.3	3.5	0.2	0.8	1.2	6.5	5.1
2022	397	152	8.3	0.2	3.0	0.2	0.5	0.8	4.7	3.4
2023	314	120	6.7	0.2	2.8	0.2	0.4	0.5	3.5	2.3
2024	272	104	6.0	0.1	2.7	0.2	0.3	0.7	2.7	1.6
2025	236	91	5.3	0.1	2.6	0.1	0.3	0.6	2.2	1.2
2026	209	80	4.8	0.1	2.5	0.1	0.2	0.5	1.8	0.9
2027	189	73	4.5	0.1	2.5	0.1	0.2	0.4	1.5	0.7
2028	174	67	4.2	0.1	2.5	0.1	0.1	0.3	1.3	0.5
2029	160	62	3.9	0.1	2.5	0.1	0.1	0.3	1.1	0.4
2030	149	58	3.7	0.1	2.5	-	0.1	0.2	1.0	0.3
2031	124	48	3.2	0.1	2.4	0.4	0.0	0.1	0.2	0.0
2032	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	4,556	1,743	96.0	2.3	38.7	5.9	5.4	10.3	44.3	32.6

SDX Energy Inc.
Total West Gharib Block H - Egypt
Forecast of Production, Costs and Revenues
Total Proved + Probable + Possible Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Meseda Avg. Daily Rate bbl/d	Rabul Avg. Daily Rate bbl/d	Total Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Crude Oil Price US$/bbl	Total Sales Revenue US$MM
2019	5,005	1,200	6,204	2,265	49.33	111.7
2020	4,305	1,163	5,468	2,001	51.84	103.7
2021	3,241	861	4,102	1,497	52.87	79.2
2022	2,572	681	3,253	1,187	54.72	65.0
2023	2,120	494	2,614	954	55.82	53.3
2024	1,798	397	2,196	804	57.76	46.4
2025	1,550	334	1,884	688	58.92	40.5
2026	1,296	288	1,584	578	60.09	34.7
2027	1,185	254	1,439	525	61.30	32.2
2028	1,093	227	1,320	483	62.52	30.2
2029	1,015	205	1,221	446	63.77	28.4
2030	950	187	1,138	415	65.05	27.0
2031	813	157	971	354	66.35	23.5
2032	-	-	-	-	-	-
2033	-	-	-	-	-	-
Rem.	-	-		-	-	-
Total				12,197		675.8

Concession Gross Share of Cost and Profit Revenues

Year	State Royalties US$MM	Total Royalties %	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM
2019	-	-	10.6	4.68	-	7.7	-	93.4
2020	-	-	9.9	4.97	-	0.6	-	93.2
2021	-	-	8.4	5.63	-	0.3	-	70.4
2022	-	-	7.5	6.32	-	0.3	-	57.2
2023	-	-	6.8	7.12	-	0.3	-	46.2
2024	-	-	6.4	7.92	-	0.3	-	39.7
2025	-	-	6.1	8.83	-	0.3	-	34.1
2026	-	-	5.8	9.99	-	0.3	-	28.7
2027	-	-	5.7	10.82	-	0.3	-	26.2
2028	-	-	5.6	11.58	-	0.3	-	24.3
2029	-	-	5.5	12.45	-	0.3	-	22.6
2030	-	-	5.5	13.29	-	-	-	21.5
2031	-	-	5.4	15.13	-	-	0.8	17.3
2032	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-
Total	-	-	89.2	7.31	-	11.0	0.8	574.9

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Service Fee Revenue US$MM	Tariff Fee US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Other Income US$MM	Income Tax US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	1,132	431	21.3	0.5	5.3	3.9	1.6	3.1	10.0	9.6
2020	1,001	381	19.8	0.5	5.0	0.3	1.4	2.9	12.5	10.9
2021	749	285	15.1	0.4	4.2	0.2	1.1	2.0	9.5	7.5
2022	594	227	12.4	0.3	3.8	0.2	0.9	1.5	7.5	5.4
2023	477	182	10.2	0.2	3.4	0.2	0.7	1.1	6.0	3.9
2024	402	154	8.9	0.2	3.2	0.2	0.5	1.2	4.7	2.8
2025	344	132	7.8	0.2	3.0	0.1	0.4	1.0	3.8	2.1
2026	289	111	6.7	0.1	2.9	0.1	0.3	0.8	3.0	1.5
2027	263	101	6.2	0.1	2.8	0.1	0.3	0.7	2.7	1.2
2028	242	93	5.8	0.1	2.8	0.1	0.3	0.6	2.4	1.0
2029	223	86	5.5	0.1	2.8	0.1	0.2	0.5	2.1	0.8
2030	208	80	5.2	0.1	2.8	-	0.2	0.5	2.0	0.7
2031	177	68	4.5	0.1	2.7	0.4	0.1	0.4	1.1	0.3
2032	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-
Total	6,099	2,329	129.1	3.0	44.6	5.9	8.0	16.3	67.3	47.4

SDX Energy Inc.
South Disouq PSC - Egypt
Forecast of Production, Costs and Revenues
Total Proved Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	Cond. Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Cond. Price US$/bbl	Cond. Sales Revenue US$MM	Total Sales Revenue US$MM
2019	27,172	9,918	2.85	28.3	107	39	66.66	2.6	30.87
2020	53,900	19,727	2.85	56.3	458	168	70.05	11.7	67.99
2021	36,608	13,362	2.85	38.1	175	64	71.45	4.6	42.67
2022	9,027	3,295	2.85	9.4	24	9	73.95	0.7	10.05
2023	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-
Rem.		-	-	-		-	-	-	-
Total		46,302		132.0		279		19.6	151.6

Concession Gross Share of Production and Gross Revenues

Year	Operating Costs US$MM	Operating Costs US$/Mscf	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Recovery Limit US$MM	Cost Revenues US$MM	Cost Bal. at End of Year US$MM	Profit Revenues US$MM	Cont. Share of Profit Revenues frac
2019	4.7	0.5	-	29.2	-	(3.0)	7.7	7.7	24.7	23.2	0.33
2020	4.9	0.2	1.0	3.5	-	58.5	17.0	17.0	19.2	51.0	0.33
2021	4.8	0.4	-	2.1	1.8	34.0	10.7	10.7	22.1	32.0	0.33
2022	4.8	1.5	-	-	1.8	3.4	2.5	2.5	33.1	7.5	0.33
2023	-	-	-	-	-	-	-	-	33.1	-	-
2024	-	-	-	-	-	-	-	-	33.1	-	-
2025	-	-	-	-	-	-	-	-	33.1	-	-
2026	-	-	-	-	-	-	-	-	33.1	-	-
2027	-	-	-	-	-	-	-	-	33.1	-	-
2028	-	-	-	-	-	-	-	-	33.1	-	-
2029	-	-	-	-	-	-	-	-	33.1	-	-
2030	-	-	-	-	-	-	-	-	33.1	-	-
2031	-	-	-	-	-	-	-	-	33.1	-	-
2032	-	-	-	-	-	-	-	-	33.1	-	-
2033	-	-	-	-	-	-	-	-	33.1	-	-
Rem.	-	-	-	-	-	-		-		-	
Total	19.2		1.0	34.8	3.6	92.9		37.9		113.7	

Company Share of Production and Revenues

Year	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Gross Ann. Cond. Production Mbbl	Net Ann. Cond. Production Mbbl	Cost Revenues US$MM	Profit Revenues US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Total Bonuses US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	5,455	3,079	21	13	4.2	4.2	2.6	16.1	-	(10.2)	(9.7)
2020	10,850	6,125	92	54	9.3	9.2	2.7	1.9	0.6	13.4	11.6
2021	7,349	4,149	35	21	5.9	5.8	2.6	2.1	-	6.9	5.4
2022	1,812	1,023	5	3	1.4	1.4	2.6	1.0	-	(0.9)	(0.6)
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-
Total	25,466	14,376	154	90	20.8	20.5	10.6	21.1	0.6	9.1	6.6

SDX Energy Inc.
South Disouq PSC - Egypt
Forecast of Production, Costs and Revenues
Total Proved + Probable Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	Cond. Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Cond. Price US$/bbl	Cond. Sales Revenue US$MM	Total Sales Revenue US$MM
2019	27,172	9,918	2.85	28.3	137	50	66.66	3.3	31.61
2020	53,900	19,727	2.85	56.3	493	181	70.05	12.7	68.90
2021	53,512	19,532	2.85	55.7	364	133	71.45	9.5	65.19
2022	28,614	10,444	2.85	29.8	114	42	73.95	3.1	32.85
2023	9,669	3,529	2.85	10.1	26	9	75.43	0.7	10.78
2024	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-
Rem.		-	-	-		-	-	-	-
Total		63,150		180.1		414		29.3	209.3

Concession Gross Share of Production and Gross Revenues

Year	Operating Costs US$MM	Operating Costs US$/Mscf	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Recovery Limit US$MM	Cost Revenues US$MM	Cost Bal. at End of Year US$MM	Profit Revenues US$MM	Cont. Share of Profit Revenues frac
2019	4.7	0.5	-	29.2	-	(2.3)	7.9	7.9	24.5	23.7	0.33
2020	5.0	0.3	1.0	3.5	-	59.4	17.2	17.2	18.8	51.7	0.33
2021	5.0	0.3	-	2.1	1.8	56.4	16.3	16.3	16.2	48.9	0.33
2022	4.9	0.5	-	-	0.9	27.1	8.2	8.2	20.7	24.6	0.33
2023	4.9	1.4	-	-	0.9	5.0	2.7	2.7	30.8	8.1	0.33
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-		-		-	
Total	24.4		1.0	34.8	3.6	145.5		52.3		157.0	

Company Share of Production and Revenues

Year	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Gross Ann. Cond. Production Mbbl	Net Ann. Cond. Production Mbbl	Cost Revenues US$MM	Profit Revenues US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Total Bonuses US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	5,455	3,079	27	16	4.3	4.3	2.6	16.1	-	(10.0)	(9.5)
2020	10,850	6,125	99	58	9.5	9.4	2.7	1.9	0.6	13.6	11.8
2021	10,742	6,064	73	43	9.0	8.8	2.7	2.1	-	12.9	10.2
2022	5,744	3,243	23	13	4.5	4.4	2.7	0.5	-	5.8	4.1
2023	1,941	1,096	5	3	1.5	1.5	2.7	0.5	-	(0.3)	(0.2)
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-
Total	34,732	19,607	228	134	28.8	28.4	13.4	21.1	0.6	22.1	16.4

SDX Energy Inc.
South Disouq PSC - Egypt
Forecast of Production, Costs and Revenues
Total Proved + Probable + Possible Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	Cond. Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Cond. Price US$/bbl	Cond. Sales Revenue US$MM	Total Sales Revenue US$MM
2019	27,172	9,918	2.85	28.3	162	59	66.66	3.9	32.21
2020	53,900	19,727	2.85	56.3	495	181	70.05	12.7	68.94
2021	53,900	19,674	2.85	56.1	458	167	71.45	11.9	68.04
2022	50,095	18,285	2.85	52.1	293	107	73.95	7.9	60.04
2023	26,638	9,723	2.85	27.7	102	37	75.43	2.8	30.53
2024	12,511	4,579	2.85	13.1	35	13	78.05	1.0	14.06
2025	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-
Rem.		-	-	-		-	-	-	-
Total		81,905		233.5		564		40.3	273.8

Concession Gross Share of Production and Gross Revenues

Year	Operating Costs US$MM	Operating Costs US$/Mscf	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Recovery Limit US$MM	Cost Revenues US$MM	Cost Bal. at End of Year US$MM	Profit Revenues US$MM	Cont. Share of Profit Revenues frac
2019	4.7	0.5	-	29.2	-	(1.7)	8.1	8.1	24.4	24.2	0.33
2020	5.0	0.3	1.0	3.5	-	59.5	17.2	17.2	18.6	51.7	0.33
2021	5.0	0.3	-	2.1	1.8	59.1	17.0	17.0	15.4	51.0	0.33
2022	5.0	0.3	-	-	0.9	54.1	15.0	15.0	13.3	45.0	0.33
2023	5.0	0.5	-	-	0.9	24.6	7.6	7.6	18.5	22.9	0.33
2024	5.0	1.1	-	-	-	9.1	3.5	3.5	21.1	10.5	0.33
2025	-	-	-	-	-	-	-	-	21.1	-	-
2026	-	-	-	-	-	-	-	-	21.1	-	-
2027	-	-	-	-	-	-	-	-	21.1	-	-
2028	-	-	-	-	-	-	-	-	21.1	-	-
2029	-	-	-	-	-	-	-	-	21.1	-	-
2030	-	-	-	-	-	-	-	-	21.1	-	-
2031	-	-	-	-	-	-	-	-	21.1	-	-
2032	-	-	-	-	-	-	-	-	21.1	-	-
2033	-	-	-	-	-	-	-	-	21.1	-	-
Rem.	-	-	-	-	-	-		-		-	
Total	29.6		1.0	34.8	3.6	204.8		68.5		205.4	

Company Share of Production and Revenues

Year	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Gross Ann. Cond. Production Mbbl	Net Ann. Cond. Production Mbbl	Cost Revenues US$MM	Profit Revenues US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Total Bonuses US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	5,455	3,079	32	19	4.4	4.4	2.6	16.1	-	(9.8)	(9.4)
2020	10,850	6,125	100	59	9.5	9.4	2.7	1.9	0.6	13.6	11.8
2021	10,820	6,108	92	54	9.4	9.2	2.8	2.1	-	13.7	10.8
2022	10,057	5,677	59	35	8.3	8.1	2.8	0.5	-	13.1	9.4
2023	5,348	3,019	20	12	4.2	4.1	2.7	0.5	-	5.1	3.3
2024	2,518	1,422	7	4	1.9	1.9	2.7	-	-	1.1	0.6
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-
Total	45,048	25,430	310	183	37.7	37.1	16.3	21.1	0.6	36.8	26.6

SDX Energy Inc.
North West Gemsa PSC - Egypt
Forecast of Production, Costs and Revenues
Proved Developed Producing Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	AASE & Al Ola Oil Rate bbl/d	Geyad Oil Rate bbl/d	Total Annual Volume Mbbl	Crude Oil Price US$/bbl	Crude Oil Sales Revenue US$MM	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	NGL Sales Revenue US$MM	Total Sales Revenue US$MM
2019	2,534	519	1,114	61.99	69.1	3,800	1,387	1.44	2.0	1.31	72.38
2020	1,303	409	626	65.15	40.8	2,187	800	1.44	1.1	0.77	42.73
2021	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.			-	-	-		-	-	-	-	-
Total			1,741		109.9		2,187		3.1	2.1	115.1

Concession Gross Share of Cost and Profit Revenues

Year	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Recovery Limit US$MM	Cost Revenues US$MM	Cost Bal. at End of Year US$MM	Profit Revenues US$MM	Cont. Share of Profit Revenues frac
2019	14.1	12.68	-	1.1	-	57.1	21.8	21.8	10.7	50.2	0.231
2020	12.1	19.33	-	0.1	-	30.5	12.9	12.9	21.2	29.7	0.231
2021	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-		-	-	-	
Total	26.2	15.08	-	1.2	-	87.6		34.6		79.9	

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Cost Revenues US$MM	Profit Revenues US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Total Bonuses US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	557	287	693	376	10.9	5.8	7.1	0.6	-	9.0	8.6
2020	313	161	400	217	6.4	3.4	6.1	0.1	-	3.7	3.2
2021	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-
Total	870	448	1,094	593	17.3	9.2	13.1	0.6	-	12.8	11.9

SDX Energy Inc.
North West Gemsa PSC - Egypt
Forecast of Production, Costs and Revenues
Proved Developed Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	AASE & Al Ola Oil Rate bbl/d	Geyad Oil Rate bbl/d	Total Annual Volume Mbbl	Crude Oil Price US$/bbl	Crude Oil Sales Revenue US$MM	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	NGL Sales Revenue US$MM	Total Sales Revenue US$MM
2019	2,601	519	1,139	61.99	70.6	3,835	1,400	1.44	2.0	1.34	73.95
2020	1,535	409	712	65.15	46.4	2,390	875	1.44	1.3	0.88	48.49
2021	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.			-	-	-		-	-	-	-	-
Total			1,850		116.9		2,275		3.3	2.2	122.4

Concession Gross Share of Cost and Profit Revenues

Year	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Recovery Limit US$MM	Cost Revenues US$MM	Cost Bal. at End of Year US$MM	Profit Revenues US$MM	Cont. Share of Profit Revenues frac
2019	14.2	12.46	-	3.8	-	56.0	22.3	22.3	10.8	51.3	0.231
2020	12.3	17.33	-	0.1	-	36.1	14.6	14.6	20.4	33.7	0.231
2021	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-		-	-	-	
Total	26.5	14.33	-	3.9	-	92.0		36.8		85.0	

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Cost Revenues US$MM	Profit Revenues US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Total Bonuses US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	569	293	700	380	11.1	5.9	7.1	1.9	-	8.1	7.7
2020	356	183	437	237	7.3	3.9	6.2	0.1	-	5.0	4.3
2021	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-
Total	925	476	1,137	617	18.4	9.8	13.3	1.9	-	13.0	12.0

SDX Energy Inc.
North West Gemsa PSC - Egypt
Forecast of Production, Costs and Revenues
Total Proved Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	AASE & Al Ola Oil Rate bbl/d	Geyad Oil Rate bbl/d	Total Annual Volume Mbbl	Crude Oil Price US$/bbl	Crude Oil Sales Revenue US$MM	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	NGL Sales Revenue US$MM	Total Sales Revenue US$MM
2019	2,601	519	1,139	61.99	70.6	3,835	1,400	1.44	2.0	1.34	73.95
2020	1,535	409	712	65.15	46.4	2,390	875	1.44	1.3	0.88	48.49
2021	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.			-	-	-		-	-	-	-	-
Total			1,850		116.9		2,275		3.3	2.2	122.4

Concession Gross Share of Cost and Profit Revenues

Year	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Recovery Limit US$MM	Cost Revenues US$MM	Cost Bal. at End of Year US$MM	Profit Revenues US$MM	Cont. Share of Profit Revenues frac
2019	14.2	12.46	-	3.8	-	56.0	22.3	22.3	10.8	51.3	0.231
2020	12.3	17.33	-	0.1	-	36.1	14.6	14.6	20.4	33.7	0.231
2021	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-		-	-	-	
Total	26.5	14.33	-	3.9	-	92.0		36.8		85.0	

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Cost Revenues US$MM	Profit Revenues US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Total Bonuses US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	569	293	700	380	11.1	5.9	7.1	1.9	-	8.1	7.7
2020	356	183	437	237	7.3	3.9	6.2	0.1	-	5.0	4.3
2021	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-
Total	925	476	1,137	617	18.4	9.8	13.3	1.9	-	13.0	12.0

SDX Energy Inc.
North West Gemsa PSC - Egypt
Forecast of Production, Costs and Revenues
Total Proved + Probable Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	AASE & Al Ola Oil Rate bbl/d	Geyad Oil Rate bbl/d	Total Annual Volume Mbbl	Crude Oil Price US$/bbl	Crude Oil Sales Revenue US$MM	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	NGL Sales Revenue US$MM	Total Sales Revenue US$MM
2019	2,869	557	1,251	61.99	77.5	4,212	1,537	1.44	2.2	1.47	81.21
2020	2,090	476	939	65.15	61.2	3,155	1,155	1.44	1.7	1.16	64.01
2021	953	407	496	66.45	33.0	1,672	610	1.44	0.9	0.62	34.48
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.			-	-	-		-	-	-	-	-
Total			2,686		171.7		3,302		4.7	3.3	179.7

Concession Gross Share of Cost and Profit Revenues

Year	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Recovery Limit US$MM	Cost Revenues US$MM	Cost Bal. at End of Year US$MM	Profit Revenues US$MM	Cont. Share of Profit Revenues frac
2019	14.5	11.57	-	3.8	-	63.0	24.4	24.4	8.9	56.4	0.231
2020	12.9	13.74	-	0.1	-	51.0	19.3	19.3	14.4	44.5	0.231
2021	10.9	22.05	-	0.1	-	23.4	10.4	10.4	23.6	24.0	0.231
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-		-	-	-	
Total	38.3	14.27	-	4.0	-	137.4		54.1		124.8	

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Cost Revenues US$MM	Profit Revenues US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Total Bonuses US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	625	322	769	417	12.2	6.5	7.2	1.9	-	9.6	9.2
2020	470	242	577	313	9.6	5.1	6.5	0.1	-	8.2	7.2
2021	248	128	305	166	5.2	2.8	5.5	0.1	-	2.4	1.9
2022	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-
Total	1,343	691	1,651	896	27.0	14.4	19.2	2.0	-	20.3	18.2

SDX Energy Inc.
North West Gemsa PSC - Egypt
Forecast of Production, Costs and Revenues
Total Proved + Probable + Possible Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	AASE & Al Ola Oil Rate bbl/d	Geyad Oil Rate bbl/d	Total Annual Volume Mbbl	Crude Oil Price US$/bbl	Crude Oil Sales Revenue US$MM	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	NGL Sales Revenue US$MM	Total Sales Revenue US$MM
2019	3,079	597	1,341	61.99	83.2	4,518	1,649	1.44	2.4	1.57	87.11
2020	2,595	552	1,152	65.15	75.0	3,868	1,416	1.44	2.0	1.42	78.47
2021	1,500	510	734	66.45	48.8	2,471	902	1.44	1.3	0.92	50.97
2022	700	472	428	68.78	29.4	1,440	526	1.44	0.8	0.56	30.72
2023	330	436	280	70.15	19.6	942	344	1.44	0.5	0.37	20.48
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.			-	-	-		-	-	-	-	-
Total			3,934		256.0		4,836		6.9	4.8	267.8

Concession Gross Share of Cost and Profit Revenues

Year	Operating Costs US$MM	Operating Costs US$/bbl	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Revenues US$MM	Cost Recovery Limit US$MM	Cost Revenues US$MM	Cost Bal. at End of Year US$MM	Profit Revenues US$MM	Cont. Share of Profit Revenues frac
2019	14.7	10.96	-	3.8	-	68.6	26.2	26.2	7.4	60.5	0.231
2020	13.5	11.68	-	0.1	-	64.9	23.6	23.6	9.0	54.5	0.231
2021	11.6	15.76	-	0.1	-	39.3	15.3	15.3	13.9	35.4	0.231
2022	10.1	23.51	-	0.1	-	20.6	9.2	9.2	19.5	21.3	0.231
2023	9.0	32.35	-	0.1	-	11.3	6.2	6.2	23.8	14.2	0.231
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-		-	-	-	
Total	58.8	14.95	-	4.2	-	204.8		80.6		186.0	

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Cost Revenues US$MM	Profit Revenues US$MM	Operating Costs US$MM	Capital & Aband. Costs US$MM	Total Bonuses US$MM	Net Revenues US$MM	NPV 10.0% US$MM
2019	671	345	825	447	13.1	7.0	7.3	1.9	-	10.8	10.3
2020	576	296	708	384	11.8	6.3	6.7	0.1	-	11.3	9.8
2021	367	189	451	245	7.7	4.1	5.8	0.1	-	5.9	4.7
2022	214	110	263	143	4.6	2.5	5.0	0.1	-	2.0	1.4
2023	140	72	172	93	3.1	1.6	4.5	0.1	-	0.1	0.1
2024	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-
Total	1,967	1,012	2,418	1,312	40.3	21.4	29.4	2.1	-	30.2	26.3

SDX Energy Inc.
Sebou Area Concessions - Morocco
Forecast of Production, Costs and Revenues
Proved Developed Producing Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	Cond. Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Cond. Price US$/bbl	Cond. Sales Revenue US$MM	Total Sales Revenue US$MM
2019	4,697	1,715	10.00	17.1	-	-	-	-	17.1
2020	1,372	502	10.09	5.1	-	-	-	-	5.1
2021	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-
Rem.		-	-	-		-	-	-	-
Total		2,217		22.2		-		-	22.2

Concession Gross Share of Cost and Profit Revenues

Year	Oil Royalties US$M	Oil Royalties %	Gas Royalties US$MM	Gas Royalties %	Operating Costs US$MM	Operating Costs US$/Mscf	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net BT Revenues US$MM	Corp. Tax US$MM	Net AT Revenues US$MM
2019	-	-	0.77	4.50	1.5	0.90	-	2.4	-	12.4	-	12.4
2020	-	-	0.23	4.50	1.5	3.07	-	-	1.8	1.5	-	1.5
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	-		1.0		3.1	-	-	2.4	1.8	13.9		13.9

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Net Sales Revenue US$MM	Net Gas Royalties US$MM	Operating Costs US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Cash Flow BT US$MM	Corp. Tax US$MM	Net Cash Flow AT US$MM
2019	-	-	1,286	1,228	12.9	0.6	1.2	1.80	-	9.3	-	9.3
2020	-	-	376	360	3.8	0.2	1.2	-	1.4	1.1	-	1.1
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	1,662	1,588	16.7	0.7	2.3	1.8	1.4	10.4	-	10.4

SDX Energy Inc.
Sebou Area Concessions - Morocco
Forecast of Production, Costs and Revenues
Proved Developed Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	Cond. Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Cond. Price US$/bbl	Cond. Sales Revenue US$MM	Total Sales Revenue US$MM
2019	6,191	2,260	10.00	22.6	-	-	-	-	22.6
2020	1,580	578	10.09	5.8	-	-	-	-	5.8
2021	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-
Rem.		-	-	-		-	-	-	-
Total		2,838		28.4		-		-	28.4

Concession Gross Share of Cost and Profit Revenues

Year	Oil Royalties US$M	Oil Royalties %	Gas Royalties US$MM	Gas Royalties %	Operating Costs US$MM	Operating Costs US$/Mscf	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net BT Revenues US$MM	Corp. Tax US$MM	Net AT Revenues US$MM
2019	-	-	1.06	4.69	1.5	0.68	-	2.5	-	17.5	-	17.5
2020	-	-	0.27	4.69	1.5	2.67	-	-	1.8	2.2	-	2.2
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	-		1.3		3.1	-	-	2.5	1.8	19.7		19.7

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Net Sales Revenue US$MM	Net Gas Royalties US$MM	Operating Costs US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Cash Flow BT US$MM	Corp. Tax US$MM	Net Cash Flow AT US$MM
2019	-	-	1,695	1,615	16.9	0.8	1.2	1.88	-	13.1	-	13.1
2020	-	-	434	413	4.4	0.2	1.2	-	1.4	1.6	-	1.6
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	2,129	2,029	21.3	1.0	2.3	1.9	1.4	14.8	-	14.8

SDX Energy Inc.
Sebou Area Concessions - Morocco
Forecast of Production, Costs and Revenues
Total Proved + Probable Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	Cond. Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Cond. Price US$/bbl	Cond. Sales Revenue US$MM	Total Sales Revenue US$MM
2019	7,978	2,912	10.00	29.1	-	-	-	-	29.1
2020	5,057	1,851	10.09	18.7	-	-	-	-	18.7
2021	912	333	10.13	3.4	-	-	-	-	3.4
2022	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-
Rem.		-	-	-		-	-	-	-
Total		5,096		51.2		-		-	51.2

Concession Gross Share of Cost and Profit Revenues

Year	Oil Royalties US$M	Oil Royalties %	Gas Royalties US$MM	Gas Royalties %	Operating Costs US$MM	Operating Costs US$/Mscf	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net BT Revenues US$MM	Corp. Tax US$MM	Net AT Revenues US$MM
2019	-	-	1.38	4.73	1.5	0.53	-	2.5	-	23.7	-	23.7
2020	-	-	0.88	4.73	1.5	0.83	-	-	-	16.2	-	16.2
2021	-	-	0.16	4.73	1.5	4.59	-	-	1.9	(0.2)	-	(0.2)
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	-		2.4		4.6	-	-	2.5	1.9	39.8		39.8

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Net Sales Revenue US$MM	Net Gas Royalties US$MM	Operating Costs US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Cash Flow BT US$MM	Corp. Tax US$MM	Net Cash Flow AT US$MM
2019	-	-	2,184	2,081	21.8	1.0	1.2	1.88	-	17.8	-	17.8
2020	-	-	1,388	1,323	14.0	0.7	1.2	-	-	12.2	-	12.2
2021	-	-	250	238	2.5	0.1	1.1	-	1.4	(0.1)	-	(0.1)
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	3,822	3,641	38.4	1.8	3.5	1.9	1.4	29.8	-	29.8

SDX Energy Inc.
Sebou Area Concessions - Morocco
Forecast of Production, Costs and Revenues
Total Proved + Probable + Possible Reserves
Forecast Price Case as of 1 January 2019

Concession Gross Share of Production and Gross Revenues

Year	Total Avg. Daily Rate Mscf/d	Total Annual Volume MMscf	Natural Gas Price US$/Mscf	Nat. Gas Sales Revenue US$MM	Cond. Avg. Daily Rate bbl/d	Total Annual Volume Mbbl	Cond. Price US$/bbl	Cond. Sales Revenue US$MM	Total Sales Revenue US$MM
2019	7,978	2,912	10.00	29.1	-	-	-	-	29.1
2020	8,330	3,049	10.09	30.8	-	-	-	-	30.8
2021	4,177	1,525	10.13	15.4	-	-	-	-	15.4
2022	1,554	567	10.43	5.9	-	-	-	-	5.9
2023	726	265	10.69	2.8	-	-	-	-	2.8
2024	431	158	11.44	1.8	-	-	-	-	1.8
2025	351	128	11.44	1.5	-	-	-	-	1.5
2026	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-
Rem.		-	-	-		-	-	-	-
Total		8,604		87.3		-		-	87.3

Concession Gross Share of Cost and Profit Revenues

Year	Oil Royalties US$M	Oil Royalties %	Gas Royalties US$MM	Gas Royalties %	Operating Costs US$MM	Operating Costs US$/Mscf	Total Bonuses US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net BT Revenues US$MM	Corp. Tax US$MM	Net AT Revenues US$MM
2019	-	-	1.39	4.78	1.5	0.53	-	2.5	-	23.7	-	23.7
2020	-	-	1.47	4.78	1.5	0.51	-	-	-	27.7	-	27.7
2021	-	-	0.74	4.78	1.5	1.00	-	-	-	13.2	-	13.2
2022	-	-	0.28	4.78	1.4	2.51	-	-	-	4.2	-	4.2
2023	-	-	0.14	4.78	1.3	4.99	-	-	-	1.4	-	1.4
2024	-	-	0.09	4.78	1.2	7.81	-	-	-	0.5	-	0.5
2025	-	-	0.07	4.78	1.3	9.82	-	-	2.0	(1.9)	-	(1.9)
2026	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	-		4.2		9.8	-	-	2.5	2.0	68.8		68.8

Company Share of Production and Revenues

Year	Gross Annual Oil Production Mbbl	Net Annual Oil Production Mbbl	Gross Annual Gas Production MMscf	Net Annual Gas Production MMscf	Net Sales Revenue US$MM	Net Gas Royalties US$MM	Operating Costs US$MM	Capital Costs US$MM	Aband. Costs US$MM	Net Cash Flow BT US$MM	Corp. Tax US$MM	Net Cash Flow AT US$MM
2019	-	-	2,184	2,080	21.8	1.0	1.2	1.88	-	17.8	-	17.8
2020	-	-	2,287	2,177	23.1	1.1	1.2	-	-	20.8	-	20.8
2021	-	-	1,143	1,089	11.6	0.6	1.1	-	-	9.9	-	9.9
2022	-	-	425	405	4.4	0.2	1.1	-	-	3.2	-	3.2
2023	-	-	199	189	2.1	0.1	1.0	-	-	1.0	-	1.0
2024	-	-	118	113	1	0.1	0.9	-	-	0.4	-	0.4
2025	-	-	96	92	1	0.1	0.9	-	1.5	(1.4)	-	(1.4)
2026	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	6,453	6,144	65.5	3.1	7.4	1.9	1.5	51.6	-	51.6