THIS SUPPLEMENTARY ADMISSION DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt about the contents of this document or as to the action you should take, you are recommended to seek your own personal financial advice immediately from your stockbroker, bank manager, solicitor, accountant or other independent financial adviser authorised under the Financial Services and Markets Act 2000 (as amended) if you are in the United Kingdom or, if not, from another authorised independent financial adviser.

This document, which comprises a supplementary AIM admission document drawn up in accordance with the AIM Rules, has been issued in connection with the application for admission to trading of the Company's Ordinary Shares on AIM. This document is supplemental to, and should be read in conjunction with the admission document issued by the Company and dated 30 November 2017 (the "**Admission Document**"), being the admission document relating to the proposed acquisition by Serica UK of BP interests in the Bruce, Keith and Rhum fields and associated infrastructure in the North Sea and the Admission of the Company's Ordinary Shares to trading on AIM. This document contains no offer to the public within the meaning of section 102B of FSMA, the Act or otherwise. Accordingly, this document does not comprise a prospectus within the meaning of section 85 of FSMA and has not been drawn up in accordance with the Prospectus Rules or approved by or filed with the Financial Conduct Authority or any other competent authority.

AIM is a market designed primarily for emerging or smaller companies to which a higher investment risk tends to be attached than to larger or more established companies. AIM securities are not admitted to the Official List of the UK Listing Authority. A prospective investor should be aware of the risks of investing in such companies and should make the decision to invest only after careful consideration and, if appropriate, consultation with an independent financial adviser. Each AIM company is required pursuant to the AIM Rules for Companies to have a nominated adviser. The nominated adviser is required to make a declaration to the London Stock Exchange on Admission in the form set out in Schedule Two to the AIM Rules for Nominated Advisers. The London Stock Exchange has not itself examined or approved the contents of this document. It is emphasised that no application is being made for admission of these securities to the Official List of the UK Listing Authority.

The Company, the Directors (whose names and functions appear in paragraph 12 of Part I (*Letter from the Chairman of Serica*) of the Admission Document) and the Proposed Directors (whose names and functions appear in paragraph 9 of Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document) accept responsibility for the information contained in this document and for compliance with the AIM Rules for Companies. To the best of the knowledge of the Company, the Directors and the Proposed Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and contains no omission likely to affect its import.

Prospective investors should read the whole of this document, any documents incorporated herein by reference and the Admission Document, and any documents incorporated in the Admission Document by reference. In particular, prospective investors attention is drawn to the risk factors described in Part IV (*Risk Factors*) of the Admission Document and the further risk factors described in Part II (*Further Risk Factors*) of this Supplementary Admission Document.

Save as provided in this Supplementary Admission Document, or unless the context otherwise requires, the definitions and glossary of technical terms used in the Admission Document also apply in this Supplementary Admission Document.

SERICA ENERGY PLC

(*Incorporated and registered in England and Wales under the Companies Act 1985 with registered number 05450950*)

SUPPLEMENTARY ADMISSION DOCUMENT

Proposed acquisition of BP interests in the Bruce, Keith and Rhum fields in the North Sea[1]

Proposed acquisition of Total E&P, BHP and Marubeni interests in the Bruce and Keith fields in the North Sea[2]

Admission of the Company's Ordinary Shares to trading on AIM

Nominated Adviser & Broker

Peel Hunt LLP

The existing Ordinary Shares are admitted to trading on AIM, a market operated by the London Stock Exchange. As the BKR Acquisition constitutes a reverse takeover under the AIM Rules, admission of the Ordinary Shares will be cancelled on completion of the BKR Acquisition. Application will be made for the Company's Ordinary Shares to be re-admitted to trading on AIM. It is expected that Admission will become effective and that dealings in the Ordinary Shares will commence on AIM at 8.00 a.m. on 30 November 2018. No application has been made or is currently intended to be made for the existing Ordinary Shares to be admitted to listing or trading on any other exchange.

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1 BP will retain a 1% interest in the Bruce field on completion of the BKR Acquisition.

2 Total E&P will retain a 1% interest in the Bruce field on completion of the BK Transactions.

Peel Hunt LLP (**"Peel Hunt"**), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting as nominated adviser and broker to the Company in connection with the Proposals and in connection with the BK Transactions and will not regard any other person as its client in relation to the Proposals or the BK Transactions nor will it be responsible to any person other than the Company for providing the protections afforded to its clients or for advising any other person in respect of the Proposals or in connection with the BK Transactions other than the Company. Peel Hunt's responsibilities as the Company's nominated adviser under the AIM Rules are owed solely to the London Stock Exchange and are not owed to the Company or to any Director or Proposed Director or to any other person in respect of such person's decision to acquire shares in the Company in reliance on any part of the Admission Document and this Supplementary Admission Document. Peel Hunt has not authorised the contents of any part of the Admission Document or this Supplementary Admission Document and neither accepts liability for the accuracy of any information or opinions contained in the Admission Document or this Supplementary Admission Document nor for the omission of any material information from the Admission Document or this Supplementary Admission Document for which the Company, the Directors and the Proposed Directors are responsible. No representation or warranty, express or implied, is made by Peel Hunt as to any of the contents of the Admission Document or this Supplementary Admission Document (without limiting the statutory rights of any person to whom the Admission Document or this Supplementary Admission Document is issued).

The distribution of this Supplementary Admission Document in certain jurisdictions may be restricted by law and therefore persons into whose possession this document comes should inform themselves about and observe any such restriction. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction.

Copies of this Supplementary Admission Document will be available free of charge during normal business hours on any weekday (except Saturdays, Sundays and public holidays) from the Company's registered office from the date of this document until the date which is one month from the date of Admission. A copy of this document will also be available for viewing on the Company's website at www.serica-energy.com.

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IMPORTANT INFORMATION

FORWARD LOOKING STATEMENTS

This document includes statements that are, or may be deemed to be, "forward-looking statements". These forward-looking statements can be identified by the use of forward-looking terminology, including the terms "believes", "envisages", "estimates", "anticipates", "projects", "expects", "intends", "may", "will", "could", "seeks" or "should" or, in each case, their negative or other variations or comparable terminology, or by discussions of strategy plans, objectives, goals, future events or intentions. These forward-looking statements include statements regarding the Company's, the Directors' and the Proposed Directors' current intentions, beliefs or expectations concerning, amongst other things, investment strategy, financing strategy, performance, results of operations, financial condition, liquidity, prospects, growth, strategies and the industry in which the Enlarged Group will operate.

By their nature, forward-looking statements involve risks (including unknown risks) and uncertainties because they relate to events and depend on circumstances that may or may not occur in the future. Forward-looking statements are not an assurance of future performance. The Company's and the Group's and, following completion of the BKR Acquisition and the BK Transactions, the Enlarged Group's actual performance, results of operations, financial condition, liquidity and dividend policy and the development of the business sector in which the Enlarged Group will operate, may differ materially from those suggested by the forward-looking statements contained in this document. In addition, even if the Company's and the Group's and, following completion of the BKR Acquisition and the BK Transactions, the Enlarged Group's performance, results of operations, financial condition, liquidity and dividend policy and the development of the industry in which the Enlarged Group will operate, are consistent with the forward-looking statements contained in this document, those results or developments may not be indicative of results or developments in subsequent periods.

Prospective investors are advised to read the Admission Document and this Supplementary Admission Document, including Part IV (*Risk Factors*) of the Admission Document and Part II (*Further Risk Factors*) of this Supplementary Admission Document, for a more complete discussion of the factors that could affect the Company's and the Group's and, following completion of the BKR Acquisition and the BK Transactions, the Enlarged Group's future performance and the industry in which the Enlarged Group will operate. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements in this document may or may not occur.

Any forward-looking statements in this document reflect the Company's, the Directors' and the Proposed Directors' current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the matters referred to above. Prospective investors should specifically consider the factors identified in this document which could cause actual results to differ before making an investment decision. Other than in accordance with the Company's obligations under the AIM Rules for Companies, neither the Company nor Peel Hunt undertakes any obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

SOURCES

Save where otherwise specified, information in this document pertaining to the petroleum assets in which the Enlarged Group will be interested is derived from the Updated BKR CPR and the Updated Serica CPR which are included in their entirety in Part III (*Updated Competent Person's Report on the BKR Assets*) and Part IV (*Updated Competent Person's Report on Serica's Assets*) of this Supplementary Admission Document, respectively.

Various market data and forecasts used in this document have been obtained from independent industry sources. Neither the Company nor Peel Hunt has verified the data, statistics or information obtained from these sources and cannot give any guarantee of the accuracy or completeness of the data. Forecasts and other forward-looking information obtained from these sources are subject to the same qualifications, risks and uncertainties as above.

Various figures and percentages in tables in this document have been rounded. Certain financial data has also been rounded. As a result of this rounding, the totals of data presented in this document may vary slightly from the actual arithmetical totals of such data.

All times referred to in this document are, unless otherwise stated, references to London time.

CURRENCIES

Unless otherwise indicated in this document, all references to "US$" or "US dollar" are to be lawful currency from time to time of the United States and "£" or "pounds sterling" are to the lawful currency from time to time of the United Kingdom.

RESERVES AND RESOURCES

Unless otherwise stated, references in this document to Reserves are on a 2P basis, to contingent resources are on a 2C basis and to prospective resources are on a "Best" estimate (P50) basis.

Unless otherwise stated, where amounts are expressed on a boe basis, natural gas volumes have been converted to boe at a ratio of 6,000 cubic feet of natural gas to one boe in relation to existing Serica assets and 5,800 cubic feet of natural gas to one boe in relation to the BKR Assets and the BK Assets.

OTHER NOTICES

Apart from the responsibilities and liabilities, if any, which may be imposed on Peel Hunt by the FSMA or the AIM Rules, Peel Hunt makes no representation, express or implied, with respect to the accuracy or completeness of any information contained in this document or any other statement made or purported to be made by it or on its behalf, in connection with the Company or the BKR Acquisition or the BK Transactions. Peel Hunt accepts no responsibility and does not authorise the contents of this document and disclaims any and all liability, whether arising in tort, contract or otherwise (save as referred to above), which it might otherwise have in respect of this document or any such statement.

Neither Peel Hunt nor any person acting on its behalf, accepts any responsibility or obligation to update, review or revise the information in this document or to publish or distribute any information which comes to its attention after the date of this document, and the distribution of this document shall not constitute a representation by Peel Hunt, or any such person, that this document will be updated, reviewed or revised or that any such information will be published or distributed after the date hereof.

The contents of this document should not be construed as legal, business or tax advice. Each prospective investor should consult his, her or its legal adviser, financial adviser or tax adviser for advice. Neither the Company nor Peel Hunt nor any of their respective representatives, are making any representation to any offeree or purchaser or acquirer of Ordinary Shares regarding the legality of an investment in the Ordinary Shares by such offeree or purchaser or acquirer under the laws applicable to such offeree or purchaser or acquirer.

Recipients of this document acknowledge that: (i) they have not relied on Peel Hunt or any of its affiliates in connection with any investigation of the accuracy of any information contained in this document or in connection with their investment decision; and (ii) they have relied only on the information contained in the Admission Document and this Supplementary Admission Document. In making an investment decision, each investor must rely on their own examination, analysis and enquiry of the Company, including the merits and risks involved.

No person has been authorised to give any information or make any representations other than those contained in the Admission Document and this Supplementary Admission Document and, if given or made, such information or representations must not be relied upon as having been authorised by the Company or by Peel Hunt. Neither the delivery of the Admission Document and this Supplementary Admission Document shall, under any circumstances, create any implication that there has been no change in the affairs of the Company or the Group since the date of this Supplementary Admission Document or that the information in this Supplementary Admission Document is correct as at any time subsequent to its date.

SHARE CAPITAL

Number of Ordinary Shares in issue[3]	264,757,819

EXPECTED TIMETABLE OF PRINCIPAL EVENTS[4]

Publication of this document	26 November 2018
Admission..	8.00 a.m. on 30 November 2018
Completion of the BKR Acquisition	8.00 a.m. on 30 November 2018
Completion of the BK Transactions	30 November 2018

3 As at 23 November 2018, being the latest practicable date prior to the date of this document. The Company also has in issue one A Share of £50,000 as at 23 November 2018.

4 Each of the times and dates set out in the expected timetable of principal events and mentioned throughout this document, is subject to change at the absolute discretion of the Company. Any such change will be notified by an announcement on a Regulatory Information Service.

PART I – MATTERS ARISING SINCE THE PUBLICATION OF THE ADMISSION DOCUMENT

1. Introduction

This Supplementary Admission Document has been published to provide an update to the information presented in the Admission Document. In particular, this Supplementary Admission Document provides an update regarding the BKR Acquisition, the subsequent BK Transactions and in relation to Serica's assets. This Supplementary Admission Document is supplemental to and should be read in conjunction with the Admission Document.

2. Additional information in relation to the BKR Assets

2.1 Changes to Key Licences Relating to the BKR Assets

Since the date of the Admission Document, the following key licences relating to the BKR Assets have been amended:

- Licence P.209 (relating to the Bruce and Keith fields) was amended pursuant to a deed of amendment dated 9 March 2018 (effective 11 March 2018). Licence P.209 will now remain extant until it terminates in accordance with its terms (as amended) being, generally, after a period of 12 consecutive months of either production below an agreed level or zero production.

- Licence P.198 (relating to the Rhum field) was amended pursuant to a deed of amendment dated 9 March 2018 (effective 11 March 2018). Licence P.198 will now remain extant until it terminates in accordance with its terms (as amended) being, generally, after a period of 12 consecutive months of either production below an agreed level or zero production.

Further details of the amendments are set out in Part IX (*Summary of New Key Licences and Agreements Since the Date of the Admission Document*) of this Supplementary Admission Document.

2.2 Summary of Reserves and Resources of the BKR Assets

The following table summarises the Reserves and resources of the BKR Assets. This information has been extracted from the Updated BKR CPR which can be found in its entirety in Part III (*Updated Competent Person's Report on the BKR Assets*) of this Supplementary Admission Document.

Summary of estimated gross and net Reserves and income data attributable to the BKR Assets (as of 1 August 2018)

	Gross			Net Attributable		
	Proved	**Proved & Probable**	**Proved, Probable & Possible**	**Proved**	**Proved & Probable**	**Proved, Probable & Possible**
Oil & Liquids reserves						
From production to planned for development (mbbls)	7,691	11,412	12,232	3,162	4,723	5,133
Gas reserves						
From production to planned for development (mmcf)	326,161	501,006	581,362	153,515	236,263	276,441
Income Data (US$'000)						
Future Gross Revenue	–	–	–	US$1,166,873	US$1,835,407	US$2,137,685
Deductions	–	–	–	US$792,963	US$954,995	US$981,470
Undiscounted Net Present Value (NPV)	–	–	–	US$373,910	US$880,412	US$1,156,216
Discounted NPV 10 Post Tax (10%)	–	–	–	US$246,598	US$436,777	US$543,187

Source: *Updated BKR CPR, page 3.*

2.3 **Summary historic BKR Assets production by product volume and sales value**

The following tables summarise historic BKR Assets production volumes by product and the sales values of each product type for the year ended 31 December 2017 and the six months ended 30 June 2018, all net to BP.[5] This information has been based on information extracted from BP's SAP Systems and has been prepared by the Company.

	Six months ended 30 June 2018	**Year ended 31 December 2017**
Production Volumes		
Oil (mbbls)	214	518
NGL (mboe)	151	428
Gas (mmcf)	12,879	30,073
Total Production (mboe)	**2,586**	**6,131**

	Six months ended 30 June 2018	**Year ended 31 December 2017**
	US$'000	***US$'000***
Revenue by product		
Oil	14,924	29,538
NGL	5,397	13,763
Gas	87,223	171,718
Other	6,886	13,955
Total Revenue	**114,430**	**228,974**

5 In respect of BP's interest in the Bruce field, calculated on the basis of a 37% interest.

3. Information in relation to the BK Transactions

3.1 Background to, and reasons for, the BK Transactions

Since the date of the Admission Document, the Company has reached agreement with each of Total E&P, BHP and Marubeni to conditionally acquire the Total E&P Assets, the BHP Assets and the Marubeni Assets, being the remaining interests in the Bruce and Keith fields not currently held by BP (save for a 1% interest in the Bruce field which Total E&P is retaining):

- the Total E&P Assets comprise Total E&P's 42.25% interest in the Bruce field and 25% interest in the Keith field along with associated infrastructure in the UK North Sea;
- the BHP Assets comprise BHP's 16% interest in the Bruce field and 31.83% interest in the Keith field along with associated infrastructure in the UK North Sea; and
- the Marubeni Assets comprise Marubeni's 3.75% interest in the Bruce field and 8.33% interest in the Keith field along with associated infrastructure in the UK North Sea.

The BK Transactions have an effective date of 1 January 2018, and completion of the BK Transactions is expected to take place immediately following BKR Completion.

Details of the Bruce and Keith fields are set out in the Admission Document.

Following completion of the BKR Acquisition and the BK Transactions, Serica UK will be the operator of each of the Bruce and Keith fields and hold a 98% interest in the Bruce field and a 100% interest in the Keith field. The BK Transactions present Serica with an opportunity to further increase its Reserves and production base by assuming a greater interest in assets already well known to the Company and its shareholders. Like the BKR Acquisition, the Total E&P Transaction and the BHP Transaction are also structured in a way that minimises downside risk for Serica and dilution for Serica Shareholders, whilst also maintaining the Company's balance sheet resilience. In contrast to the Total E&P Transaction and BHP Transaction, through the Marubeni Transaction, Serica is acquiring the decommissioning liabilities associated with the Marubeni Assets. However, given Marubeni only holds a 3.75% interest in the Bruce field and platform and an 8.33% interest in the Keith field, these liabilities are relatively small and they are reflected in the consideration structure whereby on Marubeni Completion Marubeni will pay Serica US$1 million plus net cash flow from the Marubeni assets from 1 January 2018 and will not be entitled to a share of future cash flows.

Serica's pro forma net 2P reserves as of 1 August 2018[6] are expected to increase by approximately 15.2 mmboe from approximately 48.5 mmboe following completion of the BKR Acquisition to approximately 63.7 mmboe following completion of the BK Transactions. The table below summarises Serica's pro forma net 2P reserves as of 1 August 2018 following completion of the BKR Acquisition and the BK Transactions. These estimates are derived from the Updated BKR CPR and the Updated Serica CPR and are shown on an equivalent unit basis where natural gas is converted to oil equivalent.

6 As of 1 August 2018 in respect of the BKR Assets and BK Assets and as of 31 October 2018 in respect of Serica's assets.

Net 2P Reserves	Serica[1]	BKR Assets[2][3]	BK Assets[2][4]	Enlarged Group[5]
Oil & Liquids (mbbls)	1,579	4,723	4,345	10,647
Gas (mmcf)	8,737	236,263	63,021	308,021
Combined (mboe)[6]	3,035	45,458	15,211	63,704

Notes:

(1) Source: *Updated Serica CPR, Technical Discussion, page 3.*

(2) Source: *Updated BKR CPR, page 3.*

(3) Calculated on the basis of a 36% interest in the Bruce field, a 34.83% interest in the Keith field and a 50% interest in the Rhum field.

(4) Calculated on the basis of a 62% interest in the Bruce field and a 65.17% interest in the Keith field.

(5) As of 1 August 2018 in respect of the BKR Assets and BK Assets and as of 31 October 2018 in respect of Serica's assets.

(6) Shown on an equivalent unit basis where natural gas is converted to oil equivalent.

3.2 Impact of the BK Transactions on Serica

(a) *The BK Transactions are structured to control risk and minimise Shareholder dilution*

The Total E&P Transaction has been structured primarily on a deferred cash/contingent consideration basis and the BHP Transaction has been structured primarily on a deferred cash consideration basis, in each case leaving Serica UK with a relatively small initial consideration (US$5 million and £1 million, respectively). The initial consideration in each case is expected to be funded from Serica UK's share of net cash flow from the Total E&P Assets and the BHP Assets, respectively, during the period from 1 January 2018 to completion of the respective transactions. In relation to the Total E&P Transaction and the BHP Transaction, the Directors expect to be able to meet the future deferred cash/contingent consideration from Serica UK's share of the net cash flows from the BK Assets following completion of the BK Transactions. The level of future payments is linked to the performance of the BK Assets thereby allowing the parties to share the benefits of improving field recoveries and production efficiencies.

The consideration in respect of the Marubeni Transaction is a cash amount due from Marubeni of US$1 million, to be adjusted for working capital and interim period cash flows from the effective date of 1 January 2018 and is payable by Marubeni to Serica UK at Marubeni Completion. There is no deferred or contingent consideration payable by Serica UK to Marubeni.

(b) *Maintains the Company's balance sheet resilience*

The consideration structure for each of the Total E&P Transaction and the BHP Transaction with its emphasis on future payments related to asset performance will assist Serica in maintaining its balance sheet resilience with net cash resources and limited borrowings. The Company's only borrowings at completion of the BK Transactions are expected to be drawings under the prepayment facility provided by BP Gas in respect of the BKR Acquisition. In addition, the arrangements on decommissioning, under which each of Total E&P and BHP is retaining all of the decommissioning liabilities of existing facilities related to the Total E&P Assets and the BHP Assets, respectively, will assist Serica in maintaining financial capability to support its future operations.

Through the Marubeni Transaction, Serica is acquiring the decommissioning liabilities associated with the Marubeni Assets. However, given Marubeni holds only a 3.75% interest in the Bruce field and platform and an 8.33% interest in the Keith field, these liabilities are relatively small and are reflected in the consideration structure whereby on Marubeni Completion Marubeni will pay Serica UK US$1 million plus net cash flow from the Marubeni Assets from 1 January 2018. Marubeni will not be entitled to a share of future cash flows.

(c) *The BK Transactions are expected to be cash flow and value accretive*

The BK Transactions are expected to be immediately cash flow and value accretive post-completion, with upfront consideration exceeded by Serica's share of interim period cash flows from the BK Assets and deferred/contingent payments expected to be funded out of post-completion net sales revenues.

Based on the Updated BKR CPR and the Updated Serica CPR, pro forma net 2P reserves per Serica share are anticipated to increase by around 31.4%, from approximately 48.5 mmboe following completion of the BKR Acquisition to approximately 63.7 mmboe following completion of the BK Transactions.

(d) *Efficient use of tax pool*

Serica UK is expected to be able to optimise the value of its pool of carried forward UK tax allowances by accelerating their use against taxable profits from the additional interests in the Bruce and Keith fields. The value of the pool stood at approximately US$146.5 million at 1 January 2018.

(e) *Increased scale*

The Directors believe that scale is important in the international oil and gas industry. The BK Transactions will further increase Serica's prominence and profile, improving its ability to attract new investment funding when required. This increased scale places the Company in a strong position to grow both organically through application of technology and operational efficiencies and inorganically through further acquisitions.

3.3 Summary of Reserves and Resources of the BK Assets

The following table summarises the Reserves and resources of the BK Assets. This information is based on information extracted from the Updated BKR CPR. The Updated BKR CPR can be found in its entirety in Part III (*Updated Competent Person's Report on the BKR Assets*) of this Supplementary Admission Document.

Summary of estimated gross and net Reserves and income data attributable to the BK Assets (as of 1 August 2018)

	Gross[1]			**Net Attributable[2]**		
	Proved	**Proved & Probable**	**Proved, Probable & Possible**	**Proved**	**Proved & Probable**	**Proved, Probable & Possible**
Oil & Liquids reserves						
From production to planned for development (mbbls)	4,852	6,988	6,988	3,021	4,346	4,346
Gas reserves						
From production to planned for development (mmcf)	68,141	101,536	101,536	42,316	63,021	63,021
Income Data (US$'000)						
Future Gross Revenue	–	–	–	US$479,563	US$714,412	US$714,412
Deductions	–	–	–	US$600,243	US$631,338	US$617,903
Undiscounted Net Present Value (NPV)	–	–	–	US$(120,681)	US$83,074	US$96,509
Discounted NPV 10 Post Tax (10%)	–	–	–	US$39,590	US$124,070	US$129,452

Notes:

(1) Source: *Updated BKR CPR, pages 3 and 4.*

(2) Calculated on the basis of a 62% interest in the Bruce field and a 65.17% interest in the Keith field. Total E&P will retain a 1% interest in the Bruce field on completion of the BK Transactions.

3.4 Summary historic BK Assets production by product volume and sales value

The following tables summarise the historical production volumes of each of the Total E&P Assets, the BHP Assets and the Marubeni Assets by product and sales volumes of each product type for the year ended 31 December 2017 and for the six months ended 30 June 2018.

(a) *Total E&P Assets*

The following production volume information are all net to Total E&P. This information has been based on information extracted from Total E&P's accounting records and has been prepared by the Company.

	Six months ended 30 June 2018	Year ended 31 December 2017
Production Volumes		
Oil (mbbls)	184	516
NGL (mboe)	57	126
Gas (mmcf)	3,606	8,783
Total Production (mboe)	**863**	**2,156**

	Six months ended 30 June 2018[(1)]	Year ended 31 December 2017[(2)]
Revenue by product	*US$'000*	*US$'000*
Oil	12,717	22,812
NGL	3,947	5,057
Gas	24,519	46,139
Total Revenue	**41,183**	**74,008**

Notes:

(1) Reported by Total E&P in pounds sterling, converted at an exchange rate of £1: US$1.3762, which was the average exchange rate prevailing over the six months ended 30 June 2018.

(2) Reported by Total E&P in pounds sterling, converted at an exchange rate of £1: US$1.2884, which was the average exchange rate prevailing over the year ended 31 December 2017.

(b) *BHP Assets*

The following production volume information are all net to BHP. This information has been based on information extracted from BHP's accounting records and has been prepared by the Company.

	Six months ended 30 June 2018	Year ended 31 December 2017
Production Volumes		
Oil (mbbls)	78	196
NGL (mboe)	40	88
Gas (mmcf)	1,307	3,176
Total Production (mboe)	**343**	**832**

	Six months ended 30 June 2018	Year ended 31 December 2017
Revenue by product	*US$'000*	*US$'000*
Oil	2,360	7,667
NGL	1,352	3,165
Gas	10,298	19,222
Total Revenue	**14,010**	**30,054**

(c) *Marubeni Assets*

The following production volume information is all net to Marubeni. This information has been based on information extracted from Marubeni's accounting records and has been prepared by the Company.

	Six months ended 30 June 2018	Year ended 31 December 2017
Production Volumes		
Oil (mbbls)	19	42
NGL (mboe)	12	32
Gas (mmcf)	325	862
Total Production (mboe)	**87**	**223**

	Six months ended 30 June 2018	Year ended 31 December 2017
Revenue by product	*US$'000*	*US$'000*
Oil	1,098	2,590
NGL	681	884
Gas	2,561	4,871
Total Revenue	**4,340**	**8,345**

3.5 **Principal terms of the BK Transactions**

(a) *Total E&P Transaction*

Pursuant to the Total E&P SPA, Serica UK has conditionally agreed to acquire the entire interests of Total E&P in the Bruce and Keith fields and associated infrastructure, save for a 1% interest in the Bruce field which is proposed to be retained by Total E&P.

The consideration for the Total E&P Transaction is to be entirely funded by cash, with the bulk of the consideration being deferred/contingent and the initial cash consideration of US$5 million expected to be financed from Serica UK's share of the net post-tax cash flows from the Total E&P Assets during the period from the effective date of the Total E&P Transaction (1 January 2018) to the date of Total E&P Completion. The Directors anticipate that Serica UK's share of cash flow in this period will be more than the amount of the Total E&P Initial Consideration resulting in a net amount paid to Serica UK by Total E&P at Total E&P Completion. Total E&P will then be entitled to 60% of pre-tax net cash flows from the Total E&P Assets for the remainder of 2018, 50% in 2019 and 40% in each of 2020 and 2021. Up to a further US$15 million in aggregate is payable in three equal instalments approximately 8, 16 and 24 months following Total E&P Completion and, should Rhum production be interrupted due to the application of US sanctions limiting Rhum operations, the relevant instalments will be deferred.

Total E&P will retain liability for all the costs of decommissioning facilities and wells existing at Total E&P Completion relating to the Total E&P Assets. Serica UK will pay for the costs of decommissioning new facilities. Serica UK will pay additional consideration equal to 30% of Total E&P's retained share of decommissioning costs when due, reduced by the tax relief that Total E&P receives on those costs. This element of consideration is capped by the amount of net cash flow received by Serica UK as a result of the Total E&P Transaction.

Total E&P Completion is conditional *inter alia* on:

- Serica UK confirming that the BP SPA is capable of completion;
- the OGA's consent to the assignment of the Total E&P Assets to Serica UK and the transfer of operatorship of Licence P.090 to Serica UK;
- the approval of Total E&P's partners in the Total E&P Assets to the assignment of the Total E&P Assets and the transfer of operatorship of Licence P.090 to Serica UK (the requirement for such approval is customary for transactions of this nature);

- clearance being sought by Serica UK and received from HMRC relating to the tax treatment of the transactions pursuant to the Total E&P Net Cash Flow Sharing Deed; and
- the amendment of certain decommissioning security agreements and operating agreements in relation to the Total E&P Assets.

Subject to the satisfaction of the conditions, completion of the Total E&P SPA will take place immediately following completion of the BP SPA, which is expected to occur on 30 November 2018.

In addition to the conditions under the Total E&P SPA, Serica UK has the right to terminate the Total E&P SPA prior to Total E&P Completion in the event of catastrophic damage to the whole or a material element of facilities relating to the Bruce field and/or the Keith field. The Total E&P SPA also contains warranties in relation to the Total E&P Assets from Total E&P that are customary for a transaction of this nature.

Serica has provided a guarantee to Total E&P in respect of Serica UK's obligations under the Total E&P SPA.

Further details of the Total E&P SPA and other key agreements relating to the Total E&P Transaction are set out in paragraph 9.1(a) of Part X (*Further Additional Information*) of this Supplementary Admission Document.

(b) *BHP Transaction*

Pursuant to the BHP SPA, Serica UK has conditionally agreed to acquire the entire interests of BHP in the Bruce and Keith fields. BHP has the right to elect to repurchase a 1% interest in the Bruce field in the event it so requires. BHP's right to receivables pursuant to the BHP SPA (including the BHP Net Cash Flow Sharing Deed) has been assigned to BHP BK Limited. BHP BK Limited is a UK based affiliate of BHP.

The consideration for the BHP Transaction is to be entirely funded by cash, with the bulk of the consideration being deferred consideration and the initial cash consideration of £1 million expected to be financed from the Serica UK's share of the net post-tax cash flows from the BHP Assets during the period from the effective date of the BHP Transaction (1 January 2018) to the date of BHP Completion. The Directors anticipate that Serica UK's share of cash flow in this period will be more than the amount of the BHP Initial Consideration resulting in a net amount paid to Serica UK by BHP at BHP Completion. BHP will then be entitled to 60% of pre-tax net cash flows from the BHP Assets for the remainder of 2018, 50% in 2019 and 40% in each of 2020 and 2021.

Serica has provided a guarantee to BHP BK Limited (as a result of the assignment by BHP of its right to receivables arising pursuant to the BHP SPA) in respect of Serica UK's obligations under the BHP SPA.

BHP will retain liability for all the costs of decommissioning facilities and wells existing at BHP Completion relating to the BHP Assets. Serica UK will pay for the costs of decommissioning new facilities. Serica UK will pay additional consideration equal to 30% of BHP's retained share of decommissioning costs when due, reduced by the tax relief that BHP receives on those costs. This element of consideration is capped by the amount of net cash flow received by Serica UK as a result of the BHP Transaction.

BHP Completion is conditional *inter alia* on:

- Serica UK confirming that the BP SPA is capable of completion;
- the OGA's consent to the assignment of the BHP Assets to Serica UK;
- the approval of BHP's partners in the BHP Assets to the assignment of the BHP Assets to Serica UK (the requirement for such approval is customary for transactions of this nature);
- clearance being sought by Serica UK and received from HMRC that the tax treatment of the sharing of the net cash flows from the BHP Assets pursuant to the BHP Net Cash Flow Sharing Deed will be applied as intended; and

- the amendment of certain decommissioning security agreements and operating agreements in relation to the BHP Assets to give effect to the retention by BHP of its liability for decommissioning and voting rights on decommissioning matters pursuant to the BHP Transaction.

Subject to the satisfaction of the conditions, completion of the BHP SPA will take place immediately following completion of the BP SPA and the Total E&P SPA, which is expected to occur on 30 November 2018.

In addition to the conditions under the BHP SPA, Serica UK has the right to terminate the BHP SPA prior to BHP Completion in the event of catastrophic damage to the whole or a material element of facilities relating to the Bruce field and/or the Keith field. The BHP SPA also contains warranties in relation to the BHP Assets from BHP that are customary for a transaction of this nature.

Further details of the BHP SPA and other key agreements relating to the BHP Transaction are set out in paragraph 9.1(b) of Part X (*Further Additional Information*) of this Supplementary Admission Document.

(c) *Marubeni Transaction*

Pursuant to the Marubeni SPA, Serica UK has conditionally agreed to acquire the entire interests of Marubeni in the Bruce and Keith fields.

Cash consideration payable by Marubeni to Serica UK at the date of Marubeni Completion is US$1 million. The Marubeni Transaction is structured such that Serica UK is entitled to all of the net post-tax cash flows from the Marubeni Assets during the period from the effective date of the Marubeni Transaction (being 1 January 2018) to the date of Marubeni Completion, which is expected to be 30 November 2018.

Marubeni will not receive a share of cash flow from the Marubeni Assets following completion and there is no other deferred or contingent consideration.

Unlike with the BKR Acquisition, the Total E&P Transaction and the BHP Transaction, Serica UK will at Marubeni Completion assume liability for all the costs of decommissioning facilities and wells relating to the Marubeni Assets. Serica UK will also be responsible for the provision of its share of security against future obligations calculated in accordance with the decommissioning security agreements relating to the Bruce and Keith fields. It is expected that BP and Serica will, prior to Marubeni Completion, enter into an agreement whereby BP may provide such decommissioning security at Marubeni Completion up to the end of 2019 with Serica having the option of providing security itself in place of BP before then. Interest will be charged by BP on the amount of the security. This arrangement requires the agreement of all the parties to the decommissioning security agreements in respect of the Bruce and Keith fields, which is anticipated to be received prior to Marubeni Completion.

Marubeni Completion is conditional *inter alia* on:

- Serica UK confirming that the BP SPA is capable of completion;
- the OGA's consent to the assignment of the Marubeni Assets to Serica UK; and
- the approval of Marubeni's partners in the Marubeni Assets to the assignment of the Marubeni Assets to Serica UK (the requirement for such approval is customary for transactions of this nature).

Subject to the satisfaction of the conditions, completion of the Marubeni SPA will take place immediately following completion of the BP SPA, the Total E&P SPA and the BHP SPA, which is expected to occur on 30 November 2018.

In addition to the conditions under the Marubeni SPA, Serica UK has the right to terminate the Marubeni SPA prior to Marubeni Completion in the event of catastrophic damage to the whole or a material element of facilities relating to the Bruce field and/or the Keith field. The Marubeni SPA also contains warranties in relation to the Marubeni Assets from Marubeni that are customary for a transaction of this nature.

Further details of the Marubeni SPA and other key agreements relating to the Marubeni Transaction are set out in paragraph 9.1(c) of Part X (*Further Additional Information*) of this Supplementary Admission Document.

4. Additional information in relation to Serica's assets

4.1 Columbus

The Company has continued to progress the development of the Columbus field. In June 2018, following completion of the evaluation of development options, Serica announced the submission of a field development plan for Columbus. The OGA indicated that its approval of the FDP would be subject to certain standard requirements including approval of the environmental statement in respect of the Columbus field. The environmental statement was approved by BEIS on 2 October 2018. In light of recent changes to equity interests in the Arran partnership and other matters, the OGA has confirmed an extension of the current licence term to mid-January 2019. On 30 October 2018, the OGA confirmed final approval of the FDP. Further information on developments in respect of the Columbus field is set out below in paragraph 5 of this Part I (*Matters Arising Since the Publication of the Admission Document*).

4.2 Licence Awards in the UK's 30th Offshore Licensing Round

The Company has been awarded three new exploration licence areas (four licences) on the UK Continental Shelf in the UK's 30th Offshore Licensing Round:

- Rowallan South P.2385 – Blocks 22/24g and 22/25f (Serica UK: 20% interest);
- Columbus West P.2388 – Block 23/21b (Serica UK: 50% interest); and
- Skerryvore P.2400 – Blocks 30/12c, 30/13c, 30/17h and 30/18c, and Ruuval P.2402 – Block 30/19c (both Serica UK: 20% interest).

See below at paragraph 5.4 of this Part I (*Matters Arising Since the Publication of the Admission Document*) and Part IX (*Summary of New Key Licences and Agreements Since the Date of the Admission Document*) of this Supplementary Admission Document for further details in relation to the new licences that have been awarded.

4.3 Licence P.2124

Licence P.2124 has been relinquished by Serica UK, the initial licence term having expired in December 2017 with none of the licensees requesting that Licence P.2124 continue into the second licence term.

4.4 Rockall Basin

As at the date of the Admission Document and as disclosed in the Admission Document, the first phase of the Group's Irish licence (FEL 1/09) relating to the Rockall Basin had expired and while confirmation had been received that the first phase of the licence will be extended for an 18-month period, the extension had not been formalised. Since the date of the Admission Document, formal consent was granted on 21 March 2018 by the Minister of State at the Department of Communications, Climate Action and Environment, by way of an addendum to the licence, to an extension of the first phase of Licence 1/09 to 20 January 2019, subject to completion of the programme of work over the relevant licensed area during the period from the execution of the addendum to the end of the first phase, being 20 January 2019.

In addition, Serica is holding discussions with the Irish authorities about securing an extension of the first phase of licence 4/13, the current term of which will expire at the end of November 2018.

4.5 Slyne Basin

Serica is holding discussions with the Irish authorities about securing an extension of licence 1/06, the current term of which will expire at the end of November 2018.

4.6 Licence in relation to the Luderitz Basin

As disclosed in the Admission Document, Serica has progressed to the first renewal exploration period of the licence in relation to the Luderitz Basin in Namibia, which runs until the end of 2018. Since the date of the Admission Document, the Company applied for, and has been granted by the Ministry of Mines and Energy in Namibia, a one-year extension to the first renewal exploration period of the licence to 18 December 2019.

5. Developments since the date of the Admission Document in relation to Serica's assets

5.1 Erskine

Erskine production during 2018 has been significantly impacted as field production was suspended from mid-January to late October following a blockage in a condensate export pipeline. During this time, a 26-kilometre section of new pipeline was laid to bypass the length of pipe affected by wax deposits. Production from Erskine restarted at the end of October 2018 following completion of the remedial action, and flow rates have been optimised, with all wells back on production. Production in the first half of 2018 averaged 168 boepd net to Serica, compared to 2,800 boepd net to Serica for the first half of 2017 during which period high uptime performance from export facilities and good performance from the Erskine wells was achieved. Production to date in November 2018 has averaged over 3,400 boepd net to Serica.

During cleaning operations in January 2018, a blockage occurred in the Lomond to CATS Riser Platform pipeline, through which Erskine condensate is exported to market. The blockage occurred during activities designed to maintain the export route by passing soft gel pigs through the pipeline. Chrysaor, the operator of this pipeline, attempted various procedures to resolve this issue whilst also commencing a previously agreed pipeline bypass plan.

In April 2018, as remedial procedures to remove the blockage had not achieved a significant breakthrough, Chrysaor made the decision to cease clearance operations and instead concentrate on accelerating the pipeline bypass programme. An extended maintenance programme on the Lomond platform, designed to improve future performance of the facilities through reducing production interruptions and potentially reducing the duration and frequency of future planned shut-downs in the coming years was also carried out.

The pipeline bypass project involved the laying of a new 26-kilometre length of pipeline to bypass the zone affected by wax deposits. A route survey was completed and approvals for the work from the authorities were received in July 2018. Pipeline construction began in August 2018 and following the conclusion of tie-ins and testing, the pipeline work was completed at the end of September 2018. There was a delay in commissioning the new pipeline due to the formation of a gas hydrate in a pipeline from Erskine to Lomond. This was cleared and production export restarted on 26 October 2018.

A proactive cleaning programme has now commenced in order to keep the pipeline free of wax through high frequency pigging. Serica is working with the operators of Erskine and Lomond to improve uptime of the export facilities and return to performance levels seen at the beginning of 2017.

5.2 Columbus

The Company has continued to progress the Columbus development. Two options were evaluated, a subsea well into Columbus connected to a proposed pipeline between the nearby Arran field and the Shearwater platform, and an extended-reach development well into Columbus drilled directly from the Lomond platform. Serica and its partners chose the subsea well option and informed the OGA of this decision in March 2018.

Following this development option selection, in June 2018 Serica announced the submission of an FDP for the Columbus development. This provides for the supply of up to 40 mmcf of gas per day (gross) at peak to the UK gas market and 1,150 barrels per day (gross) of condensate and NGLs.

Under the FDP, the development area will be drained by a single subsea horizontal well. The well will be connected to the proposed Arran-Shearwater pipeline, through which Columbus production will be exported along with Arran field production. Columbus development timing is dependent on the Arran-Shearwater pipeline being tied into the Shearwater platform which is targeted to occur in the third quarter of 2020. Columbus start-up is targeted for the second quarter of 2021.

The OGA indicated that its approval of the FDP would be subject to certain standard requirements including approval of the environmental statement in respect of Columbus, which was submitted to BEIS and was approved by BEIS on 2 October 2018. On 30 October 2018, the OGA confirmed final approval of the FDP.

5.3 Rowallan

Preparations for the exploration well on the Rowallan Prospect are at an advanced stage with drilling targeted to commence in December 2018. A vessel was deployed in December 2017 to complete a site survey in preparation for drilling and the operator, ENI UK Limited, has now contracted the Ensco 121, a modern high specification jack-up rig, to drill this high pressure, high temperature prospect located close to the Erskine and Columbus fields. Serica is fully carried on all costs relating to the well. The rig is undergoing final checks in Dundee Harbour and is due to mobilise to the drilling site in early December 2018.

5.4 Other assets

Since the date of the Admission Document, Serica has been awarded four licences in three new exploration areas on the UK Continental Shelf in the UK's 30th Offshore Licensing Round.

- Rowallan South P.2385 covering Blocks 22/24g and 22/25f (Serica UK: 20% interest) was awarded with a start date of 1 October 2018 on condition of partners taking a 'drill-or-drop' decision before entering into the next phase.
- Columbus West P.2388 covering Block 23/21b (Serica UK: 50% interest) was awarded with a start date of 1 October 2018 on condition of partners taking a 'drill-or-drop' decision before entering into the next phase.
- Skerryvore P.2400 covering Blocks 30/12c, 30/13c, 30/17h and 30/18c and Ruuval P.2402 covering Block 30/19c (both Serica UK: 20% interest) were awarded with a start date of 1 October 2018 and, in the case of P.2402 on condition of partners taking a 'drill-or-drop' decision before entering into the next phase.

In the Rockall Basin in Ireland, Serica is holding discussions with the authorities about securing an extension of licence 4/13 (Serica 100%) beyond the November 2018 expiry of the current term and secured an extension of Licence 1/09 to January 2019. A further extension may also be requested for FEL 1/09.

Serica is seeking a partner to participate in drilling a well in one or both of blocks 1/09 and 4/13.

In the Slyne Basin in Ireland, Serica is holding discussions with the authorities about securing an extension of licence 1/06 beyond its current November 2018 expiry and is seeking to identify a farm-in partner to participate in drilling one of the oil and gas prospects on the licence.

In the Luderitz basin in Namibia, Serica obtained a one-year extension running until the end of 2019 of its licence covering Blocks 2512A, 2513A, 2513B and 2612A (part) (Serica 85%). Serica is seeking partners to participate in a further exploration and has secured the services of a specialist acquisitions and divestitures company to assist in marketing these opportunities.

5.5 Financial position

As at 30 June 2018 the Company held cash and cash equivalents and term deposits of in aggregate approximately US$21.0 million. Cash and term deposits reduced to US$13.7 million by 26 September 2018. As at 30 June 2018, the Company had borrowings of approximately US$4 million and no material unfinanced exploration or drilling commitments. Following OGA approval for the Columbus development, Serica, as operator, plans to initiate the programme with the main capital spend expected in 2020/2021. Serica expects its share of costs to be financed from its future cash flows.

6. Developments since the date of the Admission Document in relation to the BKR Assets and the BK Assets

Gross (100% interest) production for the second half of 2017, as reported to the OGA, for the Bruce, Keith and Rhum fields averaged approximately 9,230 boepd, approximately 1,000 boepd and approximately 20,000 boepd, respectively. Production in 2018 up to the end of August for the Bruce, Keith and Rhum fields averaged approximately 11,000 boepd, approximately 800 boepd and approximately 20,700 boepd, respectively, based on BP reports, notwithstanding interruptions due to the impact of the Forties Pipeline outage lasting into January 2018, extreme weather conditions in the first quarter of 2018 and some pipeline operator restrictions on Rhum arising from third party field production outages. There was also a planned maintenance shut-in carried out during June 2018. Production in September and October 2018 has averaged approximately 29,000 boepd (gross) for the Rhum field and approximately 13,400 boepd (gross) for the Bruce and Keith fields. Net production to date in 2018 from BKR Assets and the BK Assets has averaged in excess of 23,000 boepd.

Commodity prices have remained strong during 2018 with year to date Brent oil prices averaging approximately US$72.50 per barrel and year to date NBP gas prices averaging approximately 59 pence per therm. Realised prices for production in respect of the BKR Assets and the BK Assets (which is over 80% gas) exceed US$45 per boe for 2018 year to date. Cash operating, processing and transportation costs in respect of the BKR Assets and the BK Assets were approximately US$18 per barrel for 2018 year to date.

Baker Hughes were contracted to carry out well intervention on four wells on the Bruce field and equipment was placed on Bruce in August/September 2017 in order to start work. Due to delays and to poor initial results when the first well was brought back onto production, work was completed on only one well. However, by March 2018, improved results were observed.

In March 2018, approval was received from Ofgem to increase the levels of CO_2 allowed into the National Transmission System at St Fergus terminal enabling the Rhum field owners to terminate arrangements under which they have been paying for the availability of blending gas. In addition, a dispute between the Bruce and Rhum partners regarding the switch from a tariff basis to cost-sharing basis for the provision of Bruce services was resolved with effect from 1 January 2018. Under the terms of the settlement, it is agreed that cost sharing shall apply from 1 January 2018 subject to an aggregate cap on IOC's share of costs.

A workover on the Rhum R3 well was planned to be carried out in May 2018. However, following the announcement by the United States Government of the withdrawal of the United States from the Joint Comprehensive Plan of Action in May 2018 and the re-imposition of so called "secondary sanctions" in relation to Iran (further information in respect of which is provided at paragraph 7 of this Part I (*Matters Arising Since the Publication of the Admission Document*) and the associated uncertainties with regard to contractor availability, BP took the decision to defer the work.

The Rhum reservoir continued to demonstrate tank-like properties, with a steady pressure decline relating to produced volumes. The pressure gauge on the R3 well was reinstated to monitor the pressure of the field. The Rhum R2 well continued to produce at good rates following a chemical treatment carried out in 2017 to remove scale within the well. Serica intends to conduct a thorough review of the R3 workover plans and will select the optimum time to carry out the work when a suitable rig becomes available. Remedial work related to conductor pipes that connect the individual wells on the seabed to the production facilities on the platform was successfully completed in summer 2018.

7. Matters affecting IOC's Rhum Licence Interest

Iranian Oil Company (UK) Limited (IOC) owns a 50% interest in the Rhum field pursuant to licence P.198. The other 50% interest in the field is currently owned by BP and, pursuant to the BKR Acquisition, will, following Admission, be owned by Serica.

Following the announcement of the withdrawal of the United States from the Joint Comprehensive Plan of Action on 8 May 2018, the United States re-imposed so-called "secondary sanctions" in relation to Iran with effect from 5 November 2018. These sanctions expose non-US persons to the risk of being targeted by sanctions for acting inconsistently with US sanctions by engaging in specified activities involving Iran or Iranian entities. Pursuant to US sanctions, US persons and non-US entities owned or controlled by US persons cannot have any dealings with IOC without a licence from OFAC.

However, following applications and supplements to those applications submitted by BP and Serica, on 5 October 2018 OFAC issued a conditional licence to BP and to Serica permitting specified US entities and non-US entities owned or controlled by US persons to deal with IOC and its 50% interest in the Rhum field and also provided a written assurance that non-US persons involved in the activities and transactions related to the Rhum field or the Bruce platform will not be exposed to US sanctions with respect to Iran provided the OFAC licence is valid.

The conditions of the licence issued by OFAC required the implementing of arrangements which provide that all benefits accruing from and relating to IOC's interest in the Rhum field will be held in escrow for such period as US sanctions apply and ensure that neither IOC nor any direct or indirect parent company of IOC will derive any economic benefit from the Rhum field during that period. IOC will also exercise no decision-making powers in respect of Rhum during the same period.

As announced by the Company on 5 November 2018, the conditions of the OFAC licence were met in full prior to the licence deadline. The arrangements described above, therefore, enable third party service providers to continue to provide services unhindered and production from the Rhum field to continue uninterrupted.

Licences issued by OFAC typically run for one year and the licence issued in respect of Rhum runs until 31 October 2019, provided that its conditions continue to be met.

If the licence is terminated or not renewed, this would likely result in the cessation of the Rhum field operations and the field being shut-in. This could also lead to the cessation of production and decommissioning of the Bruce and Keith fields earlier than is otherwise expected.

The arrangements referred to above include a management company being established to manage all the affairs of IOC in relation to its interest in the Rhum field. Accordingly, following BKR Completion, Serica will, in respect of Rhum joint venture matters, be dealing with the management company.

8. **Summary financial information on Serica, the BKR Assets and the BK Assets**

Set out below is a summary of the audited consolidated results of Serica for the year ended 31 December 2017 and the unaudited financial information of Serica for the six month period ended 30 June 2018.

The summary audited consolidated financial information of Serica for (i) the year ended 31 December 2017 has been extracted without material adjustment from the consolidated financial statements included in the Serica Group's 2017 annual report and accounts; and (ii) the six month period ended 30 June 2018 has been extracted without material adjustment from the unaudited financial statements included in the Serica Group's 2018 interim financial statements, each of which has been incorporated by reference in Part VII (*Further Historical Financial Information on Serica*) of this Supplementary Admission Document.

Investors should read the whole of the Company's published audited historical financial information and unaudited financial statements and should not rely solely on the summarised information set out below.

Also set out below is a summary of the unaudited financial information in respect of the BKR Assets and the BK Assets for the year ended 31 December 2017 and for the six month period ended 30 June 2018.

The summary unaudited financial information in respect of the BKR Assets has been based on information extracted from BP's BKR Assets accounts. Additional financial information on the BKR Assets can be found in Part V (*Further Unaudited Historical Financial Information on the BKR Assets*) of this Supplementary Admission Document.

The summary unaudited financial information in respect of the BK Assets has been based on information extracted from the BK Assets accounts of each of Total E&P, BHP and Marubeni. Additional financial information on the BK Assets can be found in Part VI (*Unaudited Historical Financial Information on the BK Assets*) of this Supplementary Admission Document.

8.1 **Serica**

	Six months ended 30 June 2018 (Unaudited)	**Year ended 31 December 2017 (Audited)**
	US$'000	***US$'000***
Revenue	4,587	31,966
Operating Profit/(Loss) before Net Finance Revenue Tax and Transaction Costs	(10,950)	14,126
Profit/(Loss) after Tax	(8,402)	17,103
Cash and cash equivalents	18,374	28,279
Net assets	94,278	102,296

8.2 **BKR Assets**

	Six months ended 30 June 2018 (Unaudited)	**Year ended 31 December 2017 (Unaudited)**
	US$'000	***US$'000***
Revenue	114,430	228,974
Operating expenditure	(82,029)	(115,379)
EBITDA	32,401	113,595
Impairment, depreciation, decommissioning accretion	(21,997)	(23,692)
Profit Before Tax	10,404	89,903

8.3 **BK Assets**

(a) *Total E&P Assets*

	Six months ended 30 June 2018(1) (Unaudited)	**Year ended 31 December 2017(2) (Unaudited)**
	US$'000	***US$'000***
Revenue	41,183	74,008
Operating expenditure	(23,247)	(40,238)
EBITDA	17,936	33,770
Impairment, depreciation, decommissioning accretion	(3,448)	(32,471)
Profit Before Tax	14,488	1,299

Notes:

(1) Reported by Total E&P in pounds sterling, converted at an exchange rate of £1: US$1.3762, which was the average exchange rate prevailing over the six months ended 30 June 2018.

(2) Reported by Total E&P in pounds sterling, converted at an exchange rate of £1: US$1.2884, which was the average exchange rate prevailing over the year ended 31 December 2017.

(b) *BHP Assets*

	Six months ended 30 June 2018 (Unaudited)	Year ended 31 December 2017 (Unaudited)
	US$'000	***US$'000***
Revenue	14,010	30,054
Operating expenditure	(6,125)	(15,372)
EBITDA	7,885	14,682
Impairment, depreciation, decommissioning accretion	2,295	(8,488)
Profit Before Tax	10,180	6,194

(c) *Marubeni Assets*

	Six months ended 30 June 2018 (Unaudited)	Year ended 31 December 2017 (Unaudited)
	US$'000	***US$'000***
Revenue	4,340	8,345
Operating expenditure	(1,706)	(4,698)
EBITDA	2,634	3,647
Impairment, depreciation, decommissioning accretion	(617)	(4,834)
Profit/(loss) Before Tax	2,017	(1,187)

9. Directors, Senior Manager and employees

9.1 Appointment of new non-executive directors

The Company previously proposed, as disclosed in the Admission Document, to appoint two further non-executive directors prior to BKR Completion. The Company now intends that each of Trevor Garlick and Malcolm Webb will be appointed to the Board as a non-executive director of the Company with effect from BKR Completion. Details relating to the Proposed Directors are set out below.

Trevor William Garlick, *Proposed Independent Non-Executive Director (aged 61)*

Trevor Garlick will join the Board as an independent Non-Executive Director, subject to BKR Completion. He started his career in 1982 with Marathon Oil International, before joining BP in 1986, where he worked for 30 years, latterly as Regional President for BP in UK and Norway from 2010 until his retirement in 2016. He was the Operator's Chair of the industry association, Oil & Gas UK, from 2014 to 2016. Trevor is currently a director of Opportunity North East Limited and Vice Chairman of the Oil & Gas Technology Centre. He holds a BSc in Geology and an MEng in Petroleum Engineering.

Malcolm Webb, *Proposed Independent Non-Executive Director (aged 69)*

Malcolm Webb will join the Board as an independent Non-Executive Director, subject to BKR Completion. He started his career with Burmah Oil Company in 1974, before joining the British National Oil Corporation in 1976 and Charterhouse Petroleum in 1981, as a solicitor working in various legal roles. Between 1986 and 1999 he worked in the Petrofina SA Group in various senior management roles, leaving as Managing Director of Fina plc. In 2001 he joined the UK Petroleum Industry Association as Director General. Between 2004 and 2015 he served as Chief Executive to the industry association, Oil & Gas UK.

The Proposed Directors hold, and have during the five years preceding the date of this document held, the following directorships or partnerships (other than the Company):

Proposed Director	Current directorships/ partnerships	Previous directorships/ partnerships
Trevor Garlick	The Scottish Council for Development and Industry	Arco British Limited, LLC
	Transition Extreme Sports Limited	Amoco (U.K.) Exploration Company, LLC
	The Oil & Gas Technology Centre Limited	The UK Oil and Gas Industry Association Limited (trading as Oil & Gas UK)
	Opportunity North East Limited	BP Exploration (Greenland) Limited
		BP Amoco Exploration (Faroes) Limited
		Grangemouth Holdings Limited
		Grangemouth Properties Limited
		Amoco U.K. Petroleum Limited
		BP Exploration (Alpha) Limited
		BP Exploration Operating Company Limited
		Britoil Limited
		BP Exploration Beta Limited
		Cats North Sea Limited
		Central North Sea Fibre Telecommunications Company Limited
Malcolm Webb	None	Ashtead Park Estate Management Co Ltd
		The UK Oil and Gas Industry Association Limited (trading as Oil & Gas UK)
		UKCS Administrator Limited
		Common Data Access Limited
		Crine Limited
		OPITO Strategic Limited
		OPITO Training Management Limited
		OPITO Enterprises Limited

Neither of the Proposed Directors currently holds any interest in the issued share capital of the Company.

Neither of the Proposed Directors has:

(a) any unspent convictions relating to indictable offences (including fraudulent offences);

(b) any bankruptcies or entered into any individual voluntary arrangements with his creditors;

(c) been a director of any company at the time of, or within the 12 months preceding, any receivership, compulsory liquidation, creditors' voluntary liquidation, administration, company voluntary arrangement or composition or any composition or arrangement with its creditors generally or any class of its creditors of such company;

(d) been a partner of any partnership at the time of, or within the 12 months preceding, any compulsory liquidation, administration or partnership voluntary arrangement;

(e) had any of their assets made the subject of any receivership or have been a partner of a partnership at the time of or within the 12 months preceding any assets thereof being the subject of a receivership;

(f) received any public criticism by any statutory or regulatory authorities (including recognised professional bodies) or have been disqualified by a court from acting as a director of a company or from acting in the management or conduct of the affairs of any company.

9.2 New senior manager

It is expected that Mike Killeen will join Serica from BP as VP Operations. Details relating to Mike Killeen are set out below.

Mike Killeen*, Proposed Senior Manager (VP Operations)*

Mike Killeen has over 25 years of experience in the oil, gas and chemicals industry in operational management roles and front-line operations. Mike Killeen is expected to transfer upon BKR Completion to Serica from BP, where he was BP's Operations Manager for Bruce, Magnus, ETAP and Sullom Voe Terminal. Before that, Mike Killeen was Operations Manager for the Coryton Refinery for Petroplus. He is a Chartered Chemical Engineer and member of the Institution of Chemical Engineers.

9.3 Additional employees

In addition to the 111 employees who will transfer across to Serica with the BKR Assets, Serica is recruiting 21 employees for the Enlarged Group.

10. Employee Incentive Schemes

The Board approved and adopted the Sharesave Plan on 6 September 2018. Further information on the Sharesave Plan, including a summary of the key terms of the plan, is set out at paragraph 8.7 of Part XII (*Additional Information*) of the Admission Document.

In addition, since the date of the Admission Document, the Company has approved the establishment of the Serica Energy plc Employee Benefit Trust (the **"EBT"**), which is a discretionary employee benefit trust. The EBT will primarily be used in conjunction with the Serica Energy plc Long Term Incentive Plan, although it may also be used to satisfy options under the Serica Energy plc 2017 Company Share Option Plan, Serica Energy plc Share Option Plan 2005 and the Sharesave Plan. Further information on the EBT is set out at paragraph 7.2 of Part X (*Further Additional Information*) of this Supplementary Admission Document.

11. Corporate governance

Since the date of the Admission Document, the Company has adopted the Quoted Company Alliance Corporate Governance Code 2018 (the **"QCA Code"**), which is tailored to meet the needs of small and mid-sized quoted companies. The Board believes that the QCA Code is more appropriate for a company of Serica's size with shares admitted to trading on the AIM market of the London Stock Exchange than the UK Corporate Governance Code published by the Financial Reporting Council.

The Board fully endorses the importance of good corporate governance and considers that a strong corporate governance foundation provides an important building block for a successful business. The QCA Code has ten principles that companies should look to apply within their business. Serica seeks to adhere to these principles to the highest level possible.

Set out below is an explanation at a high level of how the Company applies the principles of the QCA Code, and those areas where the Company's corporate governance structures and practices differ from the expectations set out in the QCA Code. These statements are in addition to the disclosures set out in Part I (*Letter from the Chairman of Serica*) of the Admission Document in connection with the Company's corporate governance and share dealing code.

11.1 **Principle One - Establish a strategy and business model which promotes the long-term value for Shareholders**

The Company's strategy lies in exploring for, developing and producing from oil and gas assets in the North Sea although it also looks elsewhere where opportunities arise. The Enlarged Group's strategy is set out in Part I (*Letter from the Chairman of Serica*) of the Admission Document. The Enlarged Group's assets will provide opportunities for the business to grow and add Shareholder value. Following Admission, the Company will continue to consider new opportunities in the oil and gas sector to deliver Shareholder value. The exploration for, development and production of oil and gas provides a myriad of challenges and risks, the principal ones in respect of the Enlarged Group are set out in Part IV (*Risk Factors*) of the Admission Document and Part II (*Further Risk Factors*) of this Supplementary Admission Document.

11.2 **Principle Two - Seek to understand and meet Shareholder needs and expectations**

The Company seeks to engage with its Shareholders through updates to the market via regulatory news flow, providing operational updates and additional news flow when there is a deviation from the operational updates or on matters of a regulatory nature or of material importance.

Whilst being mindful of the requirements of the AIM Rules and the Market Abuse Regulations, the Chairman and Chief Executive Officer engage with Shareholders directly from time to time in relation to questions that they may have and other matters.

Copies of the Company's annual report, interim report and other regulatory documents are made available to all Shareholders.

The Company's annual general meeting is a regular opportunity for Shareholders to meet with the Company, and a corporate presentation on recent developments is always given by the Chairman and Chief Executive Officer at each meeting. There is also an opportunity for Shareholders to ask questions during the formal business of the meeting and informally following the meeting.

At the annual general meeting separate resolutions are proposed for each matter under consideration. Shareholders are given the opportunity to vote in advance of the meeting by proxy if they are unable to attend the meeting and vote in person. The Company's registrar monitors the voting at all general meetings. The results of Shareholder meetings are announced through a regulatory information service.

The Board ensures that the voting decisions of Shareholders are reviewed and monitored and that approvals sought at the Company's annual general meeting are within the recommended corporate guidelines of the QCA Code.

11.3 **Principle Three - Stakeholder and social responsibilities and their implications for long term success**

The Company has many key relationships with stakeholders both externally with its suppliers, customers, regulators and others and internally with its employees. Key stakeholders are referred to in the Admission Document and elsewhere in this document. The Company engages with its key stakeholders through various channels depending upon who they are and values the feedback it receives from them. The Company takes every opportunity to ensure that where possible the views of stakeholders are considered and acted on. The Company seeks to be an equal opportunity employer at all levels.

Employees across the business work closely together, and the Board seeks to engender an environment of openness.

11.4 **Principle Four - Embed effective risk management, considering both opportunities and threats throughout the organisation**

The Company recognises that effective risk management forms an integral part of its business strategy and a key component in achieving success. The Board conducts periodic reviews of significant business risks and considers appropriate mechanisms for their mitigation. In addition, when new investments including acquisitions and disposals are proposed, detailed risk analyses are carried out to identity the potential impact of any significant associated risks and balance these against the potential benefits.

In addition to specific risk identification and mitigation, the Company recognises that a balanced portfolio with diversification of assets and revenue sources provides a robust platform from which to manage risk and support business growth.

11.5 Principle Five - Maintaining the Board as a well-functioning, balanced team led by the chair

Reference is made to the make-up of the Board and its committees, the independence of the Non-Executive Directors and the role of the Board and its structures all of which are set out in Part I (*Letter from the Chairman of Serica*) of the Admission Document.

The Board currently has an Executive Chairman, which the Board recognises is not regarded as best practice. However, prior to the recent appointment of Mitch Flegg as Chief Executive Officer, the Board did not have any executive representation apart from the Chairman, so the Board regarded it as vital for the chairman role to be executive in nature. The Company is currently going through a transformational phase in its development and continues to have a lean team at Board level. The Board therefore considers that in the medium-term it is in the Company's best interests for Antony Craven Walker to continue as Chairman in an executive capacity during this phase with Neil Pike acting as senior independent non-executive director. Both Neil Pike and Ian Vann have held office for over ten years and therefore they stand for re-election at every annual general meeting due their length of service. Trevor Garlick and Malcolm Webb will join the Board as independent Non-Executive Directors following BKR Completion.

The Executive Chairman and Chief Executive Officer are expected to devote substantially the whole of their time to their duties within the Company. The Non-Executive Directors have a lesser time commitment and it is expected that Non-Executive Directors will each dedicate 12 days service each year, in addition to their duties as board members. However, this time commitment may be exceeded by them on an as-needed basis from time to time.

The Board currently meets monthly, with ad hoc Board meetings as and when the business requires. The Audit Committee meets three times a year and the Remuneration Committee generally meets twice a year, the HSE Committee meets at least three times a year and the Reserves Committee and Nomination Committee as and when required.

11.6 Principle Six – Directors' necessary up to date experience, skills and capabilities

The Board is currently comprised of the Executive Chairman, Chief Executive Officer and two Non-Executive Directors, both of whom are considered independent as explained in the Admission Document. Trevor Garlick and Malcolm Webb will also join the Board following BKR Completion as independent Non-Executive Directors. The Board has significant industry, financial, public markets and governance experience, possessing the necessary mix of skills to deliver on the Enlarged Group's strategy. Further details of each Director, their roles and their skills and experience are set out in Part I (*Letter from the Chairman of Serica*) of the Admission Document. Details of the Proposed Directors are set out in Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document.

It is intended that the composition of the Board will be expanded following Admission in parallel with the Company's growth. Any appointment made will be focused on ensuring that the candidate offers the required experience and skills that will be needed by the Enlarged Group whilst also bringing a mix of backgrounds, experience and external relationships that are essential for the efficient functioning of a balanced board.

11.7 Principle Seven - Evaluate Board performance based on clear and relevant objectives, seeking continuous improvement

The Board considers that its effectiveness, and the individual performance of its Directors is vital to the success of the Company.

The Board meets monthly for formal Board meetings and ad hoc meetings take place from time to time. Informal communications between Board members take place frequently as and when the business demands.

The Board considers that it functions effectively and given the size of the Company and the current lean nature of the Board the need for formal Board evaluation has not been considered necessary. However, it is recognised that in parallel with the anticipated expansion of the Company's activities and the need to meet the requirements of the QCA Code, a formal annual process will be necessary following Admission. The Company will introduce a structure to set clear targets and objectives for improving and monitoring performance of an enlarged Board and will introduce a formal evaluation process for all Board members to monitor their individual contribution and commitment. The evaluation process will set out criteria against which Board, committee and individual effectiveness is measured.

The Directors have a wide knowledge of the Company's business and understand their duties as directors of a company quoted on AIM. The Directors have access to the Company's Nominated Adviser, auditors and solicitors as and when required. These advisers provide formal support and advice to the Board from time to time and do so in accordance with good practice. The Directors are also able, at the Company's expense to obtain advice from external advisers if required. The Board is mindful of the need for succession planning and the length of service of the Executive Chairman and existing Non-Executive Directors. As set out in paragraph 9 of this Part I (*Matters Arising Since the Publication of the Admission Document*), the Company proposes to appoint Trevor Garlick and Malcolm Webb to the Board as independent Non-Executive Directors with effect from BKR Completion.

The Corporate Governance and Nomination Committee will continue to meet and monitor the requirements for succession planning and Board appointments to ensure that the Board is fit for purpose and evolves in line with the Company's anticipated expansion. If external training or assistance with recruitment is required by the committee, this will be made available.

11.8 Principle Eight - Promote a corporate culture based on ethical values and behaviours

The Company is committed to a corporate culture that is based on sound ethical values and behaviours and it seeks to instil these values across the organisation as a whole. The Company's commitment to high standards of health and safety and the environment is set out in Part I (*Letter from the Chairman of Serica*) of the Admission Document. The Company promotes its commitment to sound ethical values and behaviours through its public statements on its website, in its reports and accounts and internally through its communications to its employees and other stakeholders.

The Company has a zero-tolerance approach to bribery and corruption and has adopted an anti-bribery policy to protect the Group and, following Admission, the Enlarged Group, its employees and those third parties with which the Company engages.

The Company has adopted a whistleblowing policy, which enables employees to raise any concerns that they may have in confidence with the Chief Executive Officer or the senior independent non-executive director.

11.9 Principle Nine - Maintain governance structures and processes that are fit for purpose and support good decision-making by the Board

The Board strives to maintain good governance structures. The role of the Board and its committees including those matters which are reserved for decision by the full Board are set out in Part I (*Letter from the Chairman of Serica*) of the Admission Document.

The Executive Chairman leads the Board and works with the Chief Executive Officer and the Non-Executive Directors to grow the Company and develop its business. The Executive Chairman is a member of the HSE Committee and the Corporate Governance and Nomination Committee and attends the other Board committees if requested. As Executive Chairman, Antony Craven Walker is primarily responsible for engaging with Shareholders and other stakeholders.

Mitch Flegg was appointed to the Board in November 2017 as Chief Executive Officer. Mitch Flegg is accountable to the Board for the financial and operational performance of the Group and, following Admission, the Enlarged Group. Mitch Flegg is a member of the Reserves Committee but does not sit on any of the corporate governance committees.

Neil Pike is the senior independent non-executive director and chairman of the Audit Committee. Neil Pike also chairs the Corporate Governance and Nomination Committee and is a member of the Remuneration and Compensation Committee and the Reserves Committee.

Ian Vann is a non-executive director of the Company and chairman of the HSE Committee, Reserves Committee and Remuneration and Compensation Committee. Ian Vann is also a member of the Audit Committee and Corporate Governance and Nomination Committee.

Further information in relation to the Board's practices and each of the Board's committees is summarised at paragraph 15 of Part I (*Letter from the Chairman of Serica*) of the Admission Document.

As the Company grows, the Board will monitor the effectiveness of the governance framework and committee membership to ensure that it remains fit for purpose to support the development of the Enlarged Group.

11.10 Principle Ten - Communicate how the Company is governed and performing by maintaining a dialogue with shareholders and other relevant stakeholders

The Board maintains a healthy dialogue between the Board and its stakeholders including its Shareholders. The Executive Chairman is primarily responsible for communicating with Shareholders, but the Chief Executive Officer will also maintain dialogue from time to time as required in conjunction with the Executive Chairman. The senior independent non-executive director, Neil Pike, is also available to communicate with Shareholders if required.

Copies of the Company's report and accounts, and all other shareholder communications are maintained on the Company's website.

Historically, the Company has not announced the detailed results of shareholder voting at its general meetings to the market. The Company will provide this detail in the future. Should there be a situation where there is a significant vote against a resolution at a general meeting the Company will provide an explanation of what action it intends to take to understand the reasons behind the vote result and any action it has taken or will take as a result of the vote.

12. Admission and dealings

The Ordinary Shares are expected to continue to trade on AIM up to the time of BKR Completion. Application will also be made to the London Stock Exchange for the Ordinary Shares to be re-admitted to trading on AIM. It is expected that Admission will become effective and that dealings in the Ordinary Shares will commence at 8.00 a.m. on 30 November 2018.

PART II – FURTHER RISK FACTORS

*Any investment in the Company is subject to a number of risks. Accordingly, investors and prospective investors should carefully consider all of the information set out in the Admission Document and this Supplementary Admission Document. The Group's and, following completion of the BKR Acquisition and the BK Transactions, the Enlarged Group's business, financial condition or results of operations could be materially and adversely affected by any of the risks described in the Admission Document and the additional risks described in this Part II (Further Risk Factors) (together "**Risks**"). In such cases, the market price of the Ordinary Shares may decline and investors may lose all or part of their investment.*

The Risks should not be regarded as a complete and comprehensive statement of all potential risks and uncertainties nor are they listed in order of magnitude or probability. Additional risks and uncertainties that are not presently known to the Directors and the Proposed Directors, or which they currently deem immaterial, may also have an adverse effect on the Enlarged Group's operating results, financial condition and prospects. The Risks are as of the date of this document and, except as required by the AIM Rules or any other law or regulation, will not be updated.

Investors and prospective investors should consider carefully whether an investment in the Company is suitable for them in light of the information set out in the Admission Document and this Supplementary Admission Document and the financial resources available to them.

1. Risks Relating to the BK Transactions

The BK Transactions may not complete, and there are certain post-completion risks relating to the BK SPAs

Completion of the BK Transactions is subject to various conditions precedent, including various third party consents and approvals being obtained. The BK Transactions will also not complete unless the BKR Acquisition completes. At the date of this document, the conditions to completion of the BK Transactions have already largely been satisfied, but there is nevertheless the remote possibility that one or more of the BK Transactions will not be completed.

Although the Company has carried out due diligence on the BK Assets (most of which is the same due diligence that has been conducted in relation to the BKR Acquisition), in the event that such enquiries or subsequent responses were insufficient, the Company may not have been able to assess properly the risks associated with, and the value of, the BK Assets.

The Company has negotiated what it considers to be appropriate warranty protection under each of the BK SPAs, but provisions in the BK SPAs may be unenforceable or may be insufficient to cover potential liabilities relating to the BK Assets and, as a result, the value of the BK Assets may be less than the amount that the Company pays for them, although this has been mitigated in the structure of the BK Transactions, as most of the consideration due to be paid by Serica UK under them, is deferred/contingent, and will only become payable to the extent the BK Assets generate positive cash flows.

Total E&P and BHP have agreed to retain the decommissioning liabilities in relation to their working interest in the BK Assets in place at Total E&P Completion and BHP Completion. The Company will assume Marubeni's decommissioning liability in relation to Marubeni's working interest in the BK Assets. In light of Total E&P and BHP retaining such liabilities, Serica has agreed with Total E&P and BHP that Total E&P and BHP will control the voting rights of Serica UK in relation to decommissioning matters that concern existing facilities. Whilst Serica UK's interests in relation to decommissioning are likely to be aligned to Total E&P's and BHP's interests, Total E&P and/or BHP could vote in a way which is not in the best interests of Serica UK. Serica UK will be liable for the cost of decommissioning facilities installed on the BK Assets after the BK SPAs complete.

2. Risks Relating to the US Sanctions on Iran

Following BKR Completion, the US government could withdraw the licence and assurances that have been provided by OFAC in relation to the Rhum field

Whilst OFAC has provided a licence to certain US persons and non-US entities owned or controlled by US persons and assurances to non-US persons to enable the Rhum field to continue to operate following the re-imposition of further US sanctions on 5 November 2018 (as disclosed in Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document) following BKR Completion, OFAC could withdraw (or not renew) such licence and/or assurances. In particular, the licence and assurance will terminate in the event that the conditions of the licence are breached or do not continue to be met. In addition, the US government could, following BKR Completion, introduce changes and/or additions to US sanctions policy in relation to Iran which could be to the detriment of Rhum field operations. Were OFAC to withdraw or not renew the licence and/or assurances (or the US government were to introduce changes and/or additions to US sanctions policy to the detriment of Rhum field operations), and alternative solutions with OFAC could not be found, this would likely make it impossible for Rhum field operations to continue. This outcome would likely lead to a shut-in of the Rhum field and the Bruce and Keith fields facing an earlier cessation of production and decommissioning than would otherwise be expected. This would have a material adverse effect on the operations, financial condition and prospects of the Enlarged Group.

Were OFAC to withdraw or not renew the licence and assurance, the Company could also find itself the target of US sanctions due to its operatorship of the Rhum field. This scenario is considered very unlikely but would have a material adverse effect on the operations, financial condition and prospects of the Enlarged Group.

Following BKR Completion, service providers and counterparties may be reluctant to deal with the Rhum field

Following BKR Completion, notwithstanding the OFAC license and assurance to non-US persons provided by OFAC, some service providers and other counterparties may nevertheless be reluctant to participate in any dealings with the Rhum field due to US sanctions. This outcome could have a material adverse effect on the operation of the Rhum field.

Following BKR Completion the UK/EU could impose sanctions against Iran

Currently, neither the UK nor EU has sanctions in place that affect the Rhum field. So far as the Directors are aware, there is no prospect of such sanctions being imposed. Were sanctions to be imposed on Iran or Iranian entities by the UK or the EU in the future, the Directors anticipate that the arrangements put in place in order to comply with the OFAC licence would mean that in all likelihood the Rhum field would not be exposed to such sanctions. If this were not the case and if other assurances in relation to UK or EU sanctions could not be obtained from the relevant authorities, it could lead to a shut-in of the Rhum field and the possibility of the Bruce and Keith fields ceasing production and being decommissioned earlier than is otherwise expected. This would have a material adverse effect on the operations, financial condition and prospects of the Enlarged Group.

Financial support that could have been provided by NICO or NIOC to the Rhum field is no longer available

Under the escrow arrangements implemented in respect of IOC's interest in the Rhum field, the share of costs arising from IOC's interest in the field must be met entirely from revenues generated from hydrocarbon sales in respect of IOC's interest in Rhum. Any financial support that could have been provided by NICO or NIOC to meet cash calls in respect of IOC's share of Rhum field operations expenses or to provide additional investment into the Rhum field will no longer be available. Given the circumstances of the Rhum field, it is expected that there will be ample revenue to more than cover future costs in respect of IOC's interest. Following BKR Completion, however, this situation could increase Serica's potential liability for Rhum field expenses.

Difficulties could be encountered in processing banking transactions which could increase Serica's liability for Rhum field expenses

Alongside the implementation of arrangements to meet the conditions of the OFAC licence, banking arrangements have been put in place to allow payments to be made in respect of IOC's interest in the Rhum field and for those payments to be received by Serica as operator of the Rhum field. It is hoped that these banking arrangements will alleviate difficulties encountered in the past in relation to IOC paying cash calls and other field expenses. There remains a risk, however, that difficulties are encountered in processing transactions which could increase Serica's potential liability for Rhum field expenses.

3. **Update of Certain Risks from the Admission Document**

Production volumes from the Rhum field are from time to time restricted if blending gas from other gas fields is not available which can result in some inconsistent production from the Rhum field

Gas produced from the Rhum field has a high CO_2 content and requires blending from other gas fields. Following approval from Ofgem, the Rhum owners are no longer required to pay a fee for the availability of blending gas to keep the commingled gas stream at the St Fergus terminal within the CO_2 threshold for entry into the National Transmission System. However, the Rhum owners remain reliant on blending gas being available from other gas fields to keep the commingled gas stream within the CO_2 threshold. From time to time blending gas is not available in sufficient quantities from other fields which can cause the Rhum field to reduce production for such periods. Furthermore, should the approval from Ofgem referred to above be varied or withdrawn in the future, then the fee may be reinstated and blending gas would need to be identified which could add considerable cost for the Rhum owners, or Rhum production might have to be restricted or shut-in. Were this outcome to materialise, this could have a material adverse effect on the Enlarged Group's results of operations, financial condition and prospects.

Cost share under the terms of the Bruce-Rhum Transportation and Processing Agreement

The dispute between IOC and the Bruce field owners regarding the switch to sharing overall pooled costs of the Bruce field facilities based on their respective proportionate production volumes existing at the date of the Admission Document has been settled subsequently. Under the terms of the settlement agreements between IOC and each of the Bruce partners, it is agreed that cost sharing shall apply from 1 January 2018 subject to an aggregate annual cap of pooled costs applied to IOC's contribution.

Following BKR Completion the Company's partner in the Rhum field may have different objectives to the Company which may lead to challenges as the Bruce, Keith and Rhum fields share the same infrastructure

The Bruce platform controls, processes and transports products from the Bruce, Keith and Rhum fields. It has been operating since 1993 and so needs a continuing programme of maintenance to ensure full operating capability. The Rhum field has the greatest production potential out of the Bruce, Keith and Rhum fields, but the Company's partner in the Rhum field does not have a working interest in the Bruce and Keith fields. As described in Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document, IOC's interest in Rhum field operations will be managed by a management company on behalf of IOC which could have different objectives to the Company. This could lead to challenges in approving increases in investment in Rhum or in the Bruce infrastructure. A failure to manage this risk could have a material adverse effect on the Enlarged Group's financial condition, results of operations and prospects.

4. **Additional risks not included in the Admission Document**

Impact of Brexit on the oil and gas industry in the UK

On 23 June 2016, the UK held a referendum to decide whether the UK should remain a member of the EU. The outcome of that referendum is that the UK has decided to terminate its membership of the EU (referred to as Brexit). On 29 March 2017 the UK Government served notice under Article 50 of the Treaty on European Union of the UK's intention to withdraw from the EU, formally commencing the process by which the UK will leave the EU. The UK's withdrawal from the EU will occur on 29 March 2019 (which will be two years from the date on which the UK served notice), unless otherwise agreed. The European Union (Withdrawal) Bill, which was passed by Parliament on 20 June 2018, is the main statutory instrument implementing the UK's withdrawal from the EU on "exit day". The European Union (Withdrawal) Bill provides that after "exit day", any EU-derived domestic legislation, which was already in place before the exit, will continue to apply, but it is contemplated that any "gaps" in legislation arising from the UK's withdrawal will be dealt with by regulations to be made pursuant to the European Union (Withdrawal) Bill.

It seems likely that the European Union (Withdrawal) Bill will not have a significant impact on the fundamental structure of the UK upstream oil and gas industry and its governing legal regime, including the licensing system (although there may be indirect impacts on the industry, such as a lessening of workforce flexibility). It should be noted that the regulatory framework applying to the upstream industry, and in particular environmental and health and safety regulation, is highly developed independently of EU law, and, at this stage, the industry view is that any impact is likely to be minor. The offshore decommissioning regime mainly stems from international conventions and domestic legislation, and it is therefore expected to be largely unaffected. However, some changes to domestic legislation which implements EU requirements, particularly legislation which refers to EU institutions or processes, are inevitable.

The timing of Columbus start-up may be delayed beyond the target date of the second quarter of 2021

The Company has continued to progress the Columbus development. Two options were evaluated, a subsea well into Columbus connected to a proposed pipeline between the nearby Arran field and the Shearwater platform, and an extended-reach development well into Columbus drilled directly from the Lomond platform. In March 2018, Serica and its partners chose the subsea well option.

Following this development option selection, in June 2018, Serica announced the submission of an FDP. This provides for the development area to be drained by a single subsea horizontal well. The well will be connected to the proposed Arran-Shearwater pipeline, through which Columbus production will be exported along with Arran field production. The FDP is therefore dependent on development of Arran, which received approval shortly before Columbus in October 2018.

Columbus development timing is dependent on the Arran-Shearwater pipeline being tied into the Shearwater platform, which is targeted to occur in the third quarter of 2020. Any delay on the riser being available or slippage in the timing of the Arran project has the potential to impact Columbus start-up timing.

5. Clarification of Certain Statements in Part IV (*Risk Factors*) of the Admission Document

IOC did not exercise its right of pre-emption under the Joint Operating Agreement in relation to the Rhum field but has entered into the arrangements as described in paragraph 7 of Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document.

BP's partners in the Bruce and Keith fields, being Total E&P, BHP and Marubeni have entered into sale and purchase agreements with Serica UK as described in Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document for Serica UK to acquire their working interests in the Bruce and Keith fields. It is expected that Serica UK will complete the acquisition of these interests on the date of Admission.

PART III – UPDATED COMPETENT PERSON'S REPORT ON THE BKR ASSETS

BP Exploration and Production

Estimated Future Reserves,
Income and 2C Contingent Resources
Attributable to Certain Net Interests in the
Bruce, Keith and Rhum Fields
North Sea
SPE-PRMS Escalated Parameters

As of August 1, 2018

Guale Ramirez, P.E. TBPE License No. 48318 Executive Vice President	Mario A. Ballesteros, P.E. TBPE License No. 107132 Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

BP Exploration and Production

Estimated

Future Reserves, Income and 2C Contingent Resources

Attributable to Certain Net Interests in the

Bruce, Keith and Rhum Fields

North Sea

SPE-PRMS Escalated Parameters

As of

August 1, 2018

Guale Ramirez, P.E.
TBPE License No. 48318
Executive Vice President

Mario A. Ballesteros, P.E.
TBPE License No. 107132
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

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October 10, 2018

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Middlesex, TW16 7LN
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Serica Energy plc
52 George Street
London, W1U 7EA
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Peel Hunt LLP
120 London Wall
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Gentlemen:

1.0 Executive Summary

At the request of BP Exploration and Production (BP), Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved, proved plus probable (2P) and proved plus probable plus possible (3P) reserves, and future production and income, and 2C contingent resources attributable to certain properties/assets of BP in the North Sea region as of August 1, 2018. Three fields, namely the Bruce, Keith and Rhum fields, were included in this evaluation, which are located in offshore waters of the United Kingdom.

We have been informed by Serica Energy plc (Serica Energy) that it proposes through its wholly-owned subsidiary Serica Energy (UK) Limited to acquire the Bruce, Keith and Rhum fields (BKR Assets). We have also been informed that the proposed acquisition will constitute a reverse takeover of Serica Energy under the AIM Rules for Companies (AIM Rules) and is conditional, inter alia, upon the approval of Serica Energy's shareholders. We have been informed that Serica Energy shareholders have approved the acquisition of the BKR Assets and, as part of the process, will need to seek re-admission on the AIM Market of the London Stock Exchange plc. We understand that this Competent Person's Report (CPR) will be included in a supplementary Admission Document in connection with the re-admission to AIM.

This CPR has been prepared in accordance with the AIM Rules, specifically the "Note for Mining, Oil and Gas Companies" dated June 2009 and the content requirements at Appendix 2 and the summaries set out in Appendices 1 and 3.

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The reserves and contingent resources volumes included herein were estimated based on the definitions and disclosure guidelines contained in the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and Society of Petroleum Evaluation Engineers (SPEE) Petroleum Resources Management System (SPE-PRMS) based on escalated price and cost parameters (SPE-PRMS forecast case) provided by BP.

In this report, the reserve volumes were estimated based on escalated cost and price parameters as provided by BP which may reasonably exist during the life of the properties. We refer to this case, using escalated cost and price parameters, as the SPE-PRMS Forecast Case. Such forecasts were based on projected escalations or other forward-looking changes to current prices and/or costs as noted. These parameters were used to estimate the economic limit and thus the CoP (cessation of production) dates for each field.

At the request of BP, we include Proved (1P), aggregated BP's proved plus probable (2P) and aggregated proved plus probable plus possible (3P) reserves for presentation purposes as shown below. Proved, probable and possible reserves are characterized as having varying degrees of risk associated with them and are not comparable. We emphasize that the 2P and 3P reserves presented below represent aggregations of different reserve categories that are characterized by significantly different levels of uncertainty and have not been adjusted to reflect the varying levels of associated risk. As requested by BP, we evaluated the 2C Contingent Resources but not the Prospective Resources pertaining to the subject properties.

BP has informed us that all decommissioning costs related to the subject properties will remain the responsibility of BP after Serica Energy acquires the interests assessed in this report. The results of our economic appraisal are presented herein both with the inclusion of decommissioning costs and without. The economic results are shown on an after tax basis. At your request, we have used a 40 percent flat corporate tax rate and no provision was made for Petroleum Revenue Taxes (PRT). Although in the future PRT will likely be paid by the working interest owners of these properties, it was beyond the scope of work of this report to determine the amounts of such taxes and the proportionate liability to each working interest owner. The results of our third party study, completed on September 5, 2018, are presented as follows.

PRMS ESCALATED PARAMETERS

Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Bruce, Keith and Rhum** Fields
BP Exploration and Production
As of August 1, 2018

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	7,691	11,412	12,232	3,162	4,723	5,133	BP
Gas reserves per asset							
From production to planned for development - MMcf	326,161	501,006	581,362	153,515	236,263	276,441	BP
Income Data (M$)							
Future Gross Revenue				$1,166,873	$1,835,407	$2,137,685	BP
Deductions				$792,963	$954,995	$981,470	BP
Undiscounted Net Present Value (NPV)				$373,910	$880,412	$1,156,216	BP
Discounted NPV10 Post Tax				$246,598	$436,777	$543,187	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS

Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Bruce** Field
BP Exploration and Production
As of August 1, 2018

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	4,441	6,577	6,577	1,599	2,368	2,368	BP
Gas reserves per asset							
From production to planned for development - MMcf	65,973	99,368	99,368	23,750	35,773	35,773	BP
Income Data (M$)							
Future Gross Revenue				$263,062	$399,426	$399,426	BP
Deductions				$306,556	$324,611	$316,810	BP
Undiscounted Net Present Value (NPV)				($43,494)	$74,815	$82,616	BP
Discounted NPV10 Post Tax				$28,686	$77,739	$80,864	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS
Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Rhum** Field
BP Exploration and Production
As of August 1, 2018

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	2,840	4,424	5,244	1,420	2,212	2,622	BP
Gas reserves per asset							
From production to planned for development - MMcf	258,021	399,470	479,826	129,010	199,735	239,913	BP
Income Data (M$)							
Future Gross Revenue				$889,642	$1,421,811	$1,724,090	BP
Deductions				$447,773	$591,751	$626,026	BP
Undiscounted Net Present Value (NPV)				$441,868	$830,061	$1,098,064	BP
Discounted NPV10 Post Tax				$223,158	$364,283	$467,569	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS
Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Keith** Field
BP Exploration and Production
As of August 1, 2018

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	411	411	411	143	143	143	BP
Gas reserves per asset							
From production to planned for development - MMcf	2,168	2,168	2,168	755	755	755	BP
Income Data (M$)							
Future Gross Revenue				$14,169	$14,169	$14,169	BP
Deductions				$38,633	$38,633	$38,633	BP
Undiscounted Net Present Value (NPV)				($24,464)	($24,464)	($24,464)	BP
Discounted NPV10 Post Tax				($5,245)	($5,245)	($5,245)	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS

Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Bruce, Keith and Rhum** Fields
BP Exploration and Production (No Decommissioning Costs)
As of August 1, 2018

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	7,691	11,412	12,232	3,162	4,723	5,133	BP
Gas reserves per asset							
From production to planned for development - MMcf	326,161	501,006	581,362	153,515	236,263	276,441	BP
Income Data (M$)							
Future Gross Revenue				$1,166,873	$1,835,407	$2,137,685	BP
Deductions				$456,686	$618,718	$645,193	BP
Undiscounted Net Present Value (NPV)				$710,188	$1,216,689	$1,492,493	BP
Discounted NPV10 Post Tax				$328,166	$518,345	$624,755	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS

Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Bruce** Field
BP Exploration and Production (No Decommissioning Costs)
As of August 1, 2018

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	4,441	6,577	6,577	1,599	2,368	2,368	BP
Gas reserves per asset							
From production to planned for development - MMcf	65,973	99,368	99,368	23,750	35,773	35,773	BP
Income Data (M$)							
Future Gross Revenue				$263,062	$399,426	$399,426	BP
Deductions				$84,428	$102,483	$94,682	BP
Undiscounted Net Present Value (NPV)				$178,634	$296,943	$304,744	BP
Discounted NPV10 Post Tax				$83,036	$132,089	$135,214	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS
Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Rhum** Field
BP Exploration and Production (No Decommissioning Costs)
As of August 1, 2018

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	2,840	4,424	5,244	1,420	2,212	2,622	BP
Gas reserves per asset							
From production to planned for development - MMcf	258,021	399,470	479,826	129,010	199,735	239,913	BP
Income Data (M$)							
Future Gross Revenue				$889,642	$1,421,811	$1,724,090	BP
Deductions				$367,528	$511,505	$545,780	BP
Undiscounted Net Present Value (NPV)				$522,114	$910,307	$1,178,310	BP
Discounted NPV10 Post Tax				$240,596	$381,721	$485,007	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS
Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Keith** Field
BP Exploration and Production (No Decommissioning Costs)
As of August 1, 2018

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	411	411	411	143	143	143	BP
Gas reserves per asset							
From production to planned for development - MMcf	2,168	2,168	2,168	755	755	755	BP
Income Data (M$)							
Future Gross Revenue				$14,169	$14,169	$14,169	BP
Deductions				$4,730	$4,730	$4,730	BP
Undiscounted Net Present Value (NPV)				$9,440	$9,440	$9,440	BP
Discounted NPV10 Post Tax				$4,534	$4,534	$4,534	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

The Discounted Net Present Value (NPV) in the above table represents the post-tax cashflow of the Future Net Income (FNI) of the subject properties.

The estimated 2C contingent resources are summarized below. BP estimates the risk of development for these contingent resources to be 50 percent.

BRUCE FIELD	GROSS		NET (BP 36% WI)	
	2C		2C	
	MBBL	MMCF	MBBL	MMCF
VOLUMES ATTRIBUTED TO PERIOD BEYOND 2P CoP	49	261	17	94

KEITH FIELD	GROSS		NET (BP 34.83% WI)	
	2C		2C	
	MBBL	MMCF	MBBL	MMCF
VOLUMES ATTRIBUTED TO PERIOD BEYOND 2P CoP	-	-	-	-

RHUM FIELD	GROSS		NET (BP 50% WI)	
	2C		2C	
	MBBL	MMCF	MBBL	MMCF
VOLUMES ATTRIBUTED TO PERIOD BEYOND 2P CoP	361	73,072	181	36,536

Liquid hydrocarbons are expressed in thousands of standard 42 U.S. gallon barrels (MBarrels). All gas volumes are reported on an "as sold" basis expressed in millions of cubic feet (MMCF) at the official temperature and pressure base of the areas in which the gas reserves are located. Those gas volumes that are consumed as fuel in operations are also reported separately herein. The remaining reserves and contingent resources are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 5,800 cubic feet of natural gas per one barrel of oil equivalent which does include fuel gas. MMBOE means million barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (M$).

The estimates provided above are consistent with BP's field development plans, which were provided to us by BP with its assurance that such plans will be implemented.

Ryder Scott served as independent evaluator in the conduct and analyses described and in the determination of professional opinions expressed herein. Ryder Scott and the management and staff of Ryder Scott are independent of BP and of Serica Energy and have no interest in any assets or share capital of BP or Serica Energy or in the promotion of BP or Serica Energy. Neither Ryder Scott nor its staff will receive any pecuniary or other benefits in connection with this assignment other than a normal fixed consultancy fee and no part of the fee is contingent on the conclusions reached. Ryder Scott is professionally qualified and a member in good standing of an appropriate recognized professional association under the AIM Rules with at least five years relevant experience in the estimation, assessment and evaluation of oil and gas assets.

Ryder Scott confirms that, to the best of its knowledge, there has been no material change in the information contained in this CPR since August 1, 2018 being the date to which we have estimated the reserves and resources contained in this report.

This report was prepared for BP Exploration and Production, Serica Energy and Peel Hunt LLP (in its capacity as nominated adviser to Serica Energy) and should not be used for purposes other than those for which it is intended without our prior written consent. The data and work papers used in the preparation of this report are available for examination in our offices by parties with written authorization from BP Exploration and Production. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Guale Ramirez, P.E.
TBPE License No. 48318
Executive Vice President

Mario A. Ballesteros, P.E.
TBPE License No. 107132
Managing Senior Vice President

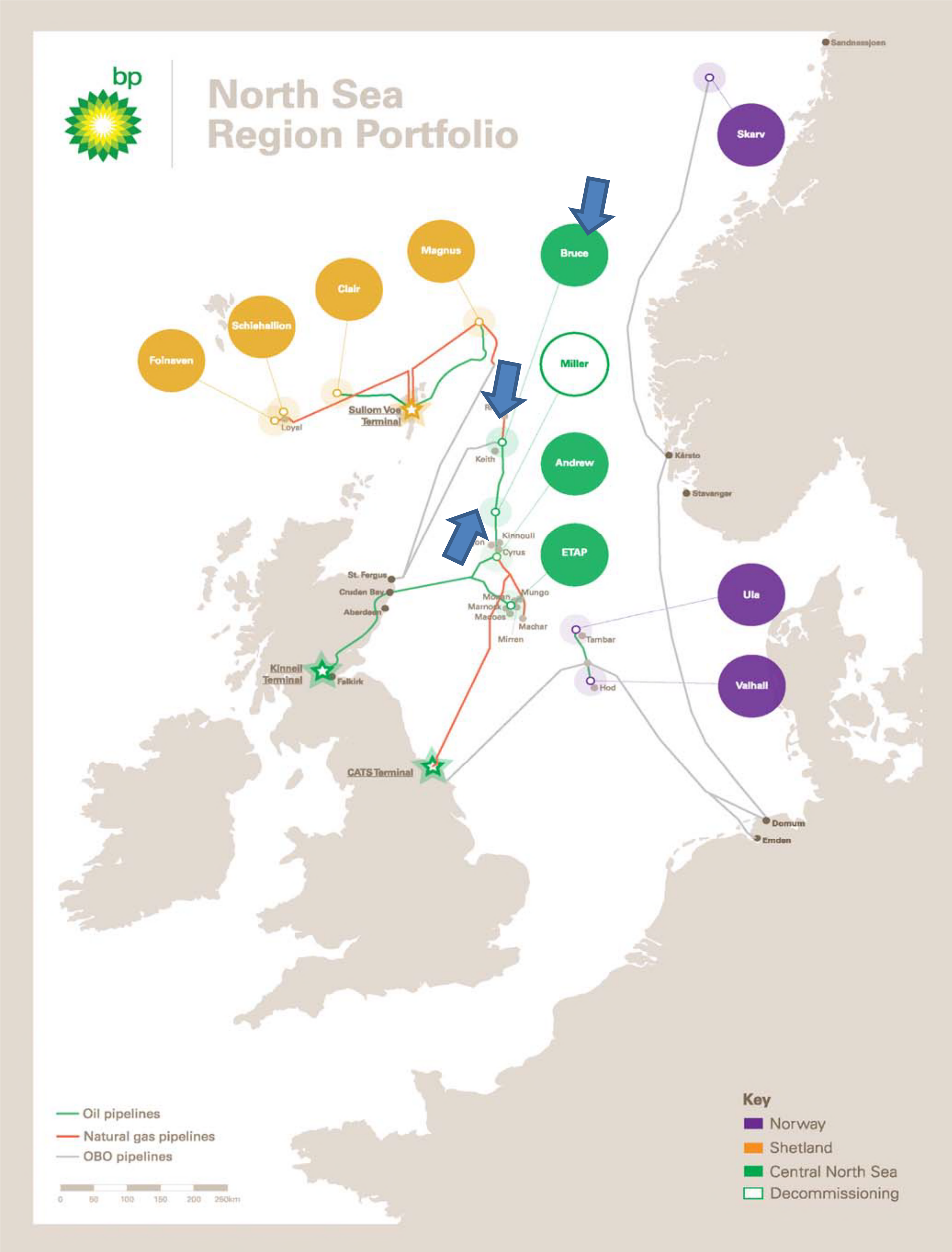
GR-MAB (FWZ)/pl

2.0 Introduction

At the request of BP, Ryder Scott has completed an evaluation of three oil and gas fields in which BP owns an interest located in British waters of the North Sea. The fields that we evaluated are the Bruce, Keith and Rhum fields, all of which are operated by BP. A summary table of the assets evaluated by us is shown below, followed by a map showing the relative position of these fields in the North Sea area.

	Oil and Gas Assets in the British North Sea						
Field Name	**Operator**	**Interest**	**Status**	**License Expiry Date**	**License Area**	**License Area Km2**	**Comments**
Bruce	BP	36.00%	Producing	2 years after CoP	9/8a, 9/9a, 9/9b	104 km2	None
Keith	BHP to BP in 2015	34.83%	Producing	None	9/8a	7 km2	None
Rhum	BP	50.00%	Producing	None	3/24b, 3/29a, 3/29b, 3/29d	141 km2	None

The report details the license interests and the reserves and contingent resources attributable to the assets. It consists of a technical evaluation of the BKR producing assets, including planned further development, but prospectivity was not included in the scope of the report. The gross and net reserves and resources as of August 1, 2018 are detailed in Sections 3, 4 and 5 of this report. Field abandonment (decommissioning) plans, other liabilities and any specific environmental protection issues or obligations are noted in the asset description sections of this report. BP has informed us that all decommissioning costs taken into consideration in this report will remain the responsibility of BP after Serica Energy acquires the interests assessed herein.


bp
North Sea
Region Portfolio
Skarv
Magnus
Bruce
Clair
Schiehallion
Foinaven
Miller
Loyal
Sullom Voe Terminal
Keith
Andrew
Kinnoull
Cyrus
ETAP
St. Fergus
Cruden Bay
Aberdeen
Mungo
Marnock
Madoes
Machar
Mirren
Tambar
Ula
Valhall
Hod
Kinneil Terminal
Falkirk
CATS Terminal
Sandnessjoen
Kårstø
Stavanger
Dornum
Emden
Oil pipelines
Natural gas pipelines
OBO pipelines
0 50 100 150 200 250km
Key
Norway
Shetland
Central North Sea
Decommissioning

Two of the blocks are approaching the expiry date; however, based on past experience with the UK government, BP is confident that licenses will be extended as needed. In this report, it was assumed that such contract extensions will be realized before the Cessation of Production (CoP) is reached.

As we have stated in the Executive Summary section of this report, we have prepared our estimates of reserves, future production and income based on CoP estimates for each field using escalated future price and cost parameters supplied by BP. We refer to this case using escalated cost and price parameters as the SPE-PRMS Forecast Case. Such forecasts were based on projected escalations or other forward looking changes to current prices and/or costs as noted herein. The results of our third party study are presented above in the "Executive Summary" section of this report and below in Section 5.0, "Summary of Total Reserves and Contingent Resources."

3.0 Description of Reserves and Contingent Resources

3.1.1 Reserves and Contingent Resources Included in this Report

The proved, probable and possible reserves, and 2C contingent resources included herein conform to the definitions of reserves and contingent resources sponsored and approved by the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE) as set forth in the 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (SPE-PRMS). Abridged versions of the SPE/WPC/AAPG/SPEE reserves terms and definitions used herein are included as attachments to this report and entitled "Petroleum Reserves and Resources Classification and Definitions" and "Petroleum Reserves and Resources Status Definitions and Guidelines."

3.1.2 Reserves and Resources Classification

Recoverable petroleum resources may be classified according to the SPE-PRMS into one of three principal resource classifications: prospective resources, contingent resources, or reserves. Discovered petroleum resources may be classified as either contingent resources or as reserves depending on the chance that if a project is implemented, it will reach commercial producing status (i.e. chance of commerciality). The distinction between various "classifications" of resources and reserves relates to their discovery status and increasing chance of commerciality. Commerciality is not solely determined based on the economic status of a project which refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation. Conditions addressed in the determination of commerciality also include technological, economic, legal, environmental, social, and governmental factors. While economic factors are generally related to costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms and taxes. At BP's request, this report addresses those quantities that may be classified as reserves and 2C contingent resources.

3.1.3 Reserves and Resources Uncertainty

All reserve and resource estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater than or less than the estimated quantities determined as-of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. Estimates will generally be revised only as additional geologic or engineering data becomes available or as economic conditions change.

Reserves are "those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions." The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved.

Proved oil and gas reserves are "those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations."

Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Probable reserves are "those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves." For probable reserves, it is "equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves" (cumulative 2P volumes). Possible reserves are "those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than probable reserves." For possible reserves, the "total quantities ultimately recovered from the project have a low probability to exceed the sum of the proved plus probable plus possible reserves" (cumulative 3P volumes).

The reserves included herein were estimated using deterministic methods and are presented as cumulative quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. For reserves using the deterministic cumulative approach, quantities of reserves are aggregated as proved (1P), proved+probable (2P), and proved+probable+possible (3P) based on their individual level of uncertainty. Under the deterministic cumulative approach, 1P denotes the low estimate, 2P denotes the best estimate and 3P denotes the high estimate.

Contingent resources are "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies."

The contingent resources included herein were estimated using deterministic methods and presented as cumulative quantities. For contingent resources estimated using the deterministic cumulative approach, quantities of contingent resources are estimated and assigned as 1C, 2C or 3C based on their individual level of uncertainty for the cumulative volume. Under the deterministic cumulative approach, 1C denotes the low estimate, 2C denotes the best estimate and 3C denotes the high estimate. According to the scope of work of this report, only the 2C contingent resources were estimated.

The reserves and resource volumes attributable to the different reserve and resource classifications that are included herein have not been adjusted to reflect these varying degrees of risk associated with them and thus are not comparable. Petroleum quantities classified as reserves, contingent resources, or prospective resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing contingent or prospective resources will not achieve commercial production. Moreover, estimates of reserves and resources may increase or decrease as a result of future operations, effects of regulation by governmental agencies or geopolitical risks. As a result, the estimates of oil and gas reserves and resources have an intrinsic uncertainty. The reserves and contingent resources included in this report are therefore estimates only and should not be construed as being exact quantities. They may or may not be actually recovered; and if recovered, they could be more or less than the estimated amounts.

3.1.4 Possible Effects of Regulation

Ryder Scott did not evaluate country and geopolitical risks associated with the areas in which these assets are located. BP's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include matters relating to land tenure and leasing, the legal rights to produce hydrocarbons including the granting, extension or termination of production sharing contracts, the fiscal terms or various production sharing contracts, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and foreign trade and investment and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves and contingent resources actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

At your request, we have used a 40 percent flat corporate tax rate and no provision was made for Petroleum Revenue Taxes (PRT). Although in the future PRT will likely be paid by the working interest owners of these properties, it was beyond the scope of work of this report to determine the amounts of such taxes and the proportionate liability to each working interest owner.

The estimates of reserves and contingent resources presented herein were based upon a detailed study of the subject properties; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices

3.1.5 Methodology Employed for Estimates of Reserves and Resources

The estimation of reserve and resource quantities involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas, and the second determination results in the estimation of the uncertainty associated with those estimated quantities. The process of estimating the quantities of recoverable oil and gas reserves and resources relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves and/or resources. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data, and the subsequent interpretation of this data, may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of recoverable hydrocarbons is identified, the evaluator must determine the uncertainty associated with the incremental quantities of those recoverable hydrocarbons. If the quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity is addressed by the reserve or resource category assigned by the evaluator. Therefore, it is the categorization of incremental recoverable quantities that addresses the inherent uncertainty in the estimated quantities reported.

Estimates of reserve and resource quantities and their associated categories or classifications may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of the recoverable quantities and their associated categories or classifications may also be revised due to other factors, such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks, as previously noted herein.

The methodology employed was specific for each field/asset is summarized below and discussed in more detail under separate tabs in this report.

Bruce: Performance methods were used, primarily decline curve analysis of rate versus time and rate versus cumulative production.

Keith: The performance method, decline curve analysis, was utilized.

Rhum: The volumetric method was the main method used to determine the 1P Original Gas in Place (OGIP) and the material balance method to determine the 2P and 3P OGIP for this field. The recovery factors (RFs) used were 70 percent, 74 percent and 78 percent for the 1P, 2P and 3P reserve volumes, respectively. These factors were estimated using a BP simulation study and a nodal analysis model on the delivery system.

3.1.6 Assumptions and Data Considered for Estimates of Reserves

To estimate recoverable oil and gas reserves and resources and related future net cashflows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly. Under the SPE-PRMS Section 2.2.2 and Table 3, proved reserves must be demonstrated to be commercially recoverable under defined economic conditions, operating methods and governmental regulations from a given date forward. We apply the same criteria for economic producibility to the 2P and 3P reserves.

BP has informed us that they have furnished us with all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecasts of future production, we have relied upon data furnished by BP with respect to production and well tests from examined wells, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data supplied by BP.

Below is the list of BP professionals that furnished all the information for this evaluation:

Name	Role	Data / Info Provided
Gary Hepburn	BKR Reservoir Engineer	Production history data, Rhum Full Field Simulation model
Niels Nouwens	BKR Base and Res Management Team Lead	Description & detail of future Projects
Zoë Sayer	Lead Geologist	Static sub-surface description, maps etc.
Roger Skinner	BP North Sea Reserves Authority	Reserves & Resources Montages collated key exhibits & text supporting booked volumes
Bernice Walker	BKR Commercial Lead	Commercial Issues
Alex Beaney	BKR Commercial Analyst	Economic Inputs & Model

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves and contingent resources reported herein.

3.1.7 Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were estimated by using the results of the nodal analysis which included the deliverability information from each of the wells. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BP. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

3.1.8 Hydrocarbon Prices

Future income projections are included in this report and are based on an Excel economic model provided by BP. We have reviewed this economic model and believe it to be a reasonable estimate of the fiscal regime and conditions governing the production from the fields. Ryder Scott cash flow projections were used to determine the assessment of the CoP and economic limit of each field. The product prices which were actually used for each property reflect adjustments for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BP. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BP to determine these differentials.

SPE-PRMS Forecast Case Prices

For the Forecast Case, the future hydrocarbon price parameters and escalations used were specified by BP are noted below and were used by Ryder Scott in the economic assessment of each field.

Year	Oil / Condensate $/bbl	NGL $/bbl	Gas GBp/therm	Gas $/MMbtu
2018	65.16	43.44	53.25	6.99
2019	66.46	44.31	54.32	7.13
2020	67.79	45.19	55.40	7.27
2021	69.15	46.10	56.51	7.42
2022	70.53	47.02	57.64	7.57
2023	71.94	47.96	58.79	7.72
2024	73.38	48.92	59.97	7.87
2025	74.85	49.90	61.17	8.19
2026	76.34	50.90	62.39	8.35
2027	77.87	51.91	63.64	8.52
2028	79.43	52.95	64.91	8.69
2029	81.02	54.01	66.21	8.87
2030	82.64	55.09	67.53	9.04
2031	84.29	56.19	68.88	9.22

The BP NGL price stream is based on 66.7 percent of the BP Brent oil price. The above gas price is adjusted for each field based on the gas quality energy factor. In this analysis, the exchange rate from GBP to US$ is held constant at $1.313/GBP.

Gas Quality Energy Factor	Bruce	Rhum	Keith
Therm/mcf	11.10	9.8	11.10
Btu/scf	1110	980	1110

3.1.9 Costs

Operating costs for the properties included in this report were furnished by BP and are based on their operating expense reports. Such costs include only those costs directly applicable to the properties. The operating costs include a portion of general and administrative costs allocated directly to the properties. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by BP. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the properties. These costs were used by Ryder Scott in the assessment of CoP, in determining economic viability of development projects, economic analysis and for the purpose of classifying volumes as reserves.

Development costs were furnished to us by BP and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. Decommissioning costs were furnished to us by BP and are based on its assessment of works required to comply with current legislative requirements.

Because of the direct relationship between volumes of undeveloped reserves and resources and development plans, we include in the undeveloped category only reserves and resources assigned to undeveloped locations that we have been assured will definitely be executed. BP has assured us of their intent and ability to proceed with the development activities included in this report, and that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans.

SPE-PRMS Forecast Case Costs

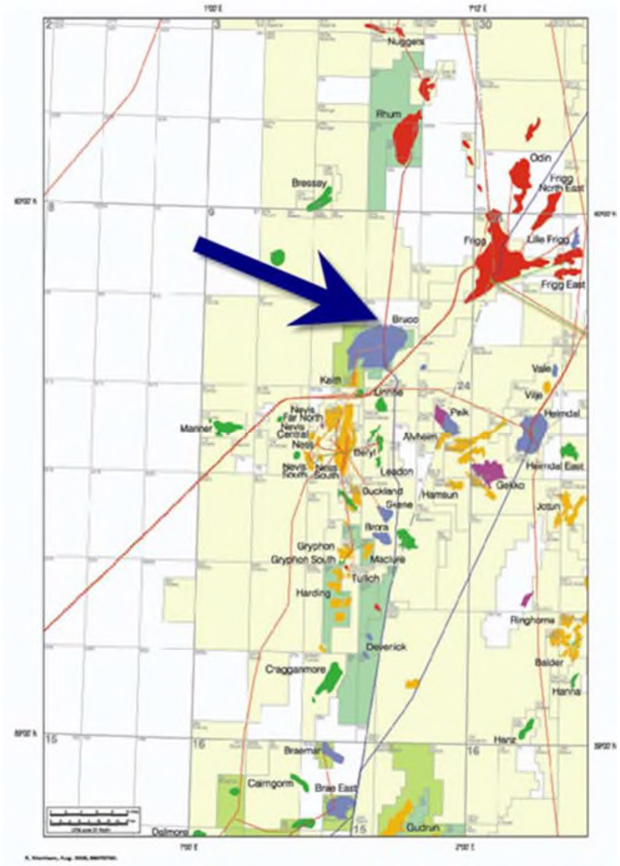
For the Forecast Case, current costs were held constant for the remainder of 2018 and then beginning in 2019 they were escalated annually at the rate of 2.0 percent until the major hydrocarbon product reaches its final price. Projected costs vary each year based upon maintenance schedules and other factors.

4.0 Overview of the Region, Location and Assets

Ryder Scott has not visited the fields or their facilities; however, based on information provided by BP, the facilities can be described as stated below.

4.1 Bruce Field

The Bruce field is operated by BP (37 percent ownership) and was discovered in June 1974. It is located 350 km NE of Aberdeen in Quad 9 of the United Kingdom Continental Shelf (UKCS) at a water depth of 122 m. The Bruce field has an area of approximately 75 km^2 (18,533 acres). The interest for the Bruce field that is evaluated in this report is 36 percent since BP is planning to retain a 1 percent interest in this property.



Bruce Field Location (BP)

Field development was sanctioned in 1990, and production started in May 1993. Production peaked in 1995 at 760 million cubic feet of gas per day (MMCFD) and 67,000 barrels per day (bpd) of condensate and oil. This liquid production is primarily condensate. NGL is also extracted through downstream processing. The field produces from 11 reservoir units separated by faulting and had a cumulative production of approximately 3.1 trillion cubic feet of gas (TCF) at August 1, 2018. Production from January to August 2018 averaged 50 MMCFD of gas and 1,857 barrels per day (bpd) of oil and condensate. The field utilizes 3 platforms and a sub-sea manifold for production. Gas compression was installed in 2004. The Rhum field is also tied back to the Bruce complex and was re-started in late 2014 after being shut-in since November 2010 due to EU sanctions because of partial Iranian ownership. Gas from the Bruce, Keith and Rhum fields is processed at the Bruce complex and then transported through the Frigg pipeline (operated by TOTAL) to St. Fergus for NGL extraction. The condensate is separated at the Bruce complex and then exported through the Forties Pipeline System to Cruden Bay. Current single compression capabilities for handling of the three fields, is set at 250 MMCFD. It is expected that export gas deliveries from other fields between 2018 and 2020 will increase the pressure in the system from approximately 115 barg to 140 barg. This will reduce the capacity of the compressor to approximately 210 MMSCFD. With the dual compression system available in the complex the delivery of gas can reach 420 MMSCFD. There is sufficient capacity to handle all the volumes unconstrained from the three fields.

The Bruce installation comprises three separate platforms, PUQ, D and CR. The PUQ is bridge linked to D, which in turn is bridge linked to CR. The cellar decks stab directly into the jacket structures and are welded out. The PUQ platform comprises the four legged, tubular steel P80 jacket, piled to the seabed, supporting topsides which consists of three large modules. The P10 Cellar Deck contains the platform utilities, export equipment and Central Control Room. Located above P10 on the east side is the P20 process module, which houses the power generation plant and all major production equipment. P20 in turn supports P30, the flare tower, at its northeast corner. The P40 accommodation module is located above, and to the west end of P10. P40 supports the helideck. The drilling (D) platform is a four legged, tubular steel structure, piled to the seabed. The D80 jacket supports the D10 module which contains the drilling facilities and the wellbay area. This module in turn supports the D20 drilling substructure, skid base and derrick on its northern side.

The D platform is located above a subsea template. The piled subsea template was placed on the seabed in 1990 to permit the drilling of 11 wells prior to the installation of the jacket. The template is an all welded steel structure, used to control the plan relationship, levelness and verticality of the production wellheads installed at the seabed. It additionally provided temporary support for the wellheads which were tied back to the platform after the jacket and topsides had been installed. The template measures 14 m x 8 m. The structure contains 16 wellhead receptacles, arranged in a 4 x 4 array at 2.59 m centers.

The CR platform comprises the four legged, tubular steel C30 jacket, piled to the seabed. It supports module C10 containing pig receivers/launchers, slug catcher, decommissioned gas turbine driven compressor, chemical injection facilities and an associated local equipment room, and module C60 containing the Rhum separator and subsea chemical injection facilities, two gas turbine driven compressors and associated inlet scrubbers, suction and discharge coolers and an associated local equipment room. An inboard deck crane is supported on the southwest corner. The Rhum riser is located within a dry, vented caisson supported outboard off the northeast leg of the CR jacket. Three risers are supported inboard off the southwest corner leg. C10 comprises a two-deck module. C60 comprises two main decks, a mezzanine level and weather deck.

PUQ and D are joined by the P60 bridge which spans from P10 to D10 at El +31.5 m. The bridge is a tubular steel structure which carries pipelines containing hydrocarbons, and has a span of approximately 48 m. D and CR are linked by the C40 bridge at El +32.6 m. It is a tubular steel structure carrying a walkway, piping and cable trays. Its span is approximately 37.5 m. Pancake structures on top of the bridge structures support the pipework required to transfer Rhum fluids from CR to the PUQ and Bruce/Western Area Development (WAD)/Keith fluids from the PUQ to the booster compression equipment on CR and then returning them to the PUQ for further compression, drying and export.

Gas is exported from the PUQ platform via a 5 km long, 32" diameter pipeline to the Frigg Gas Export Pipeline System. The gas then flows to the St Fergus Terminal for treatment to sales specification and export. Liquids are exported from the PUQ platform via a 254 km long, 24" diameter pipeline to the Forties Unity platform, and into the Forties Pipeline System for subsequent treatment at the Kinneil Terminal. Production of oil started in May 1993 with the first sales of contracted gas starting in October 1993.

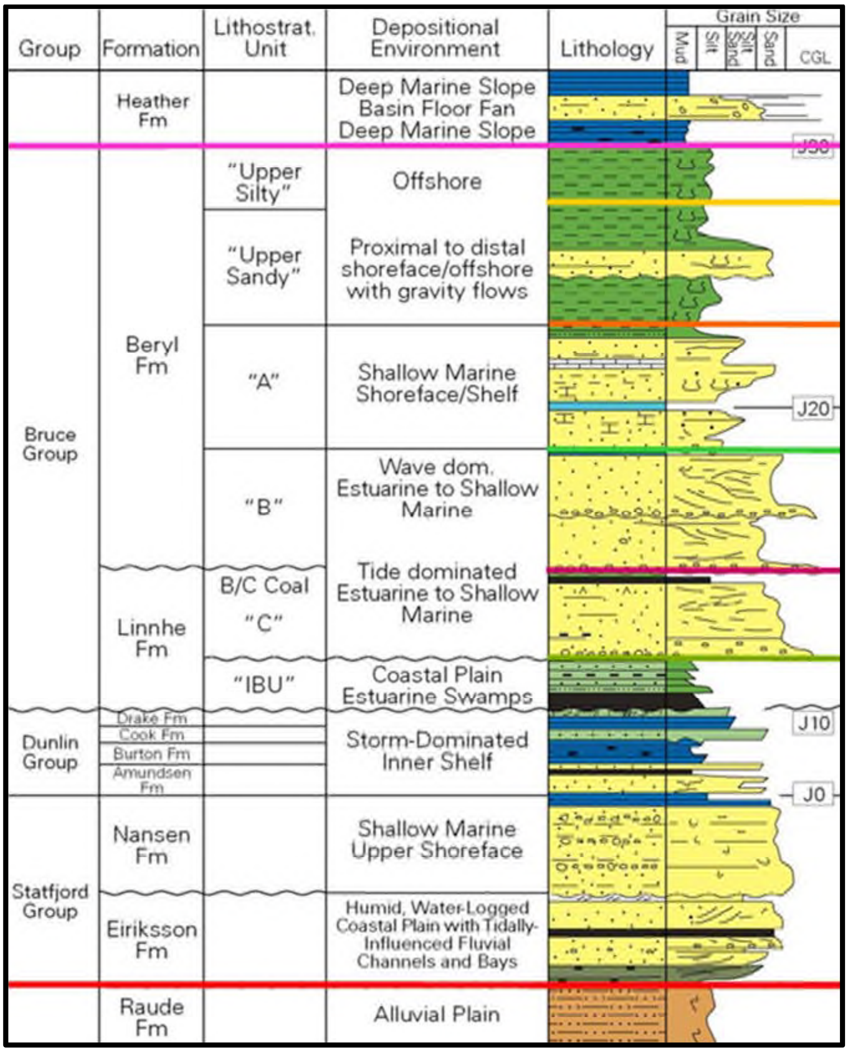
4.1.1 Reserves Discussion

4.1.1.1 Geological Discussion

Stratigraphy and Deposition

Production of hydrocarbons in Bruce is confined to the five reservoir quality lithostratigraphic layers of the Middle Jurassic Bruce group: the Upper Silty, Upper Sandy, A, B, and C units. These units are made up of siltstones and sandstones deposited as part of the middle-Jurassic Brent delta system. This system produced deposits in Offshore, Shelf, Shallow Marine, and Estuary environments in accordance to changes in sea-level. These units follow an upward fining trend which results in vertically degrading reservoir quality from the C unit to the Upper Silty. In general, stratigraphy in the field is fairly continuous with wells encountering all five units, with the exception of cases where post depositional faulting has created portions of missing section. Production is generally comingled across all five reservoir units when encountered.

The figure below shows the stratigraphic column for the Bruce field.

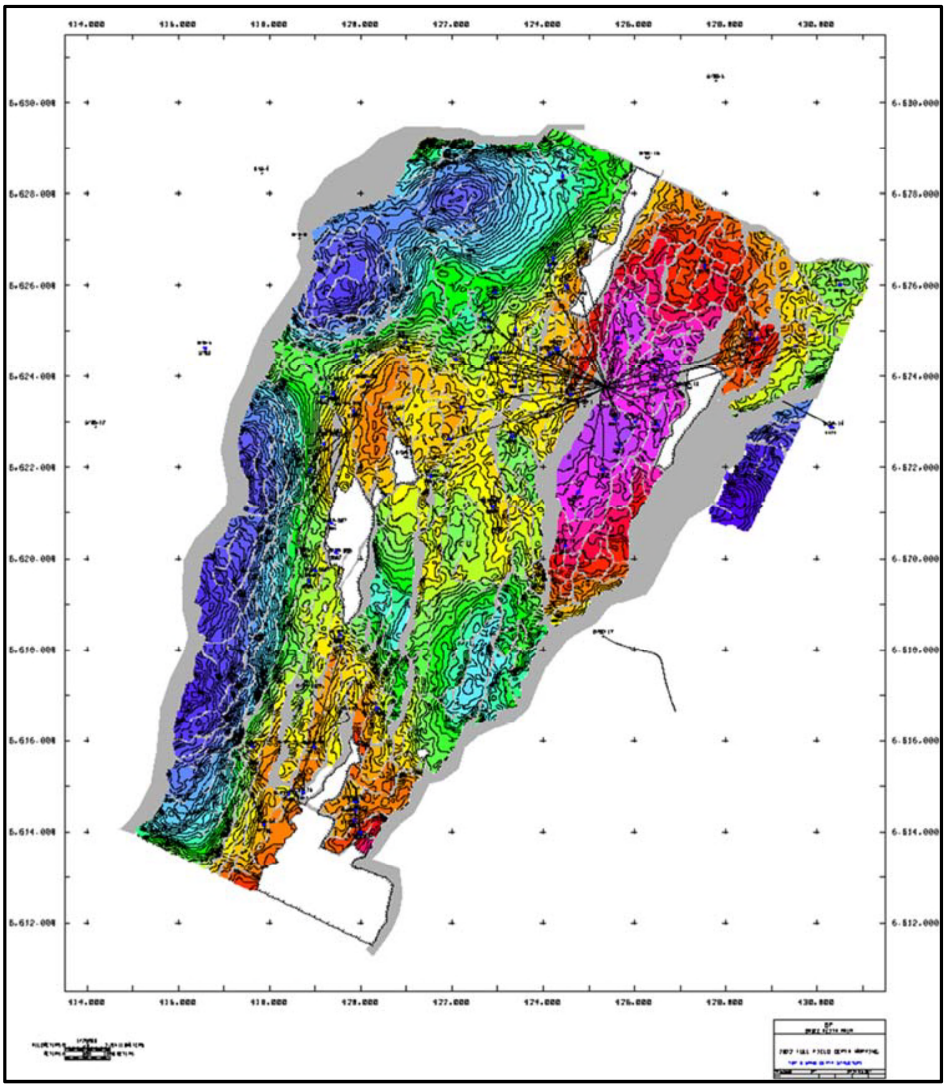


Bruce Field Stratigraphic Column (source - BP)

Structure

Unlike the stratigraphic distribution in the unit, the structural model in Bruce is very complex, with 11 primary reservoir panels (fault blocks) and potential for more localized compartmentalization within each panel. Multiple episodes of geologic movement in the reservoir have left the field dominated by large north-south trending faults cut by smaller NW-SE trending faults. The WAD rollover is defined by its collapse into a large listric fault forming the field's western boundary. In general, faults in the field are considered sealing and given their frequency in the field, compartmentalization is common. Given the significant amount of depletion in the field, fault seal breakdown may be present, but has not been proven. Originally, the field was seismically surveyed using streamer data, but the installation of an ocean bottom cable (OBC) in 2002 has resulted in a much greater definition of the structural features of the field. This OBC data has also allowed for the use of 4D seismic to identify isolated compartments. As of the date of this study, the seismic data for the field had not been assimilated into one integrated model. This fragmentation is also present in the simulation model and is based on the presence of large sealing faults in the field.

The figure below is a depth structure map of the top of the B Sand in the Bruce field.



Top of the B Sand Depth Structure Map (BP)

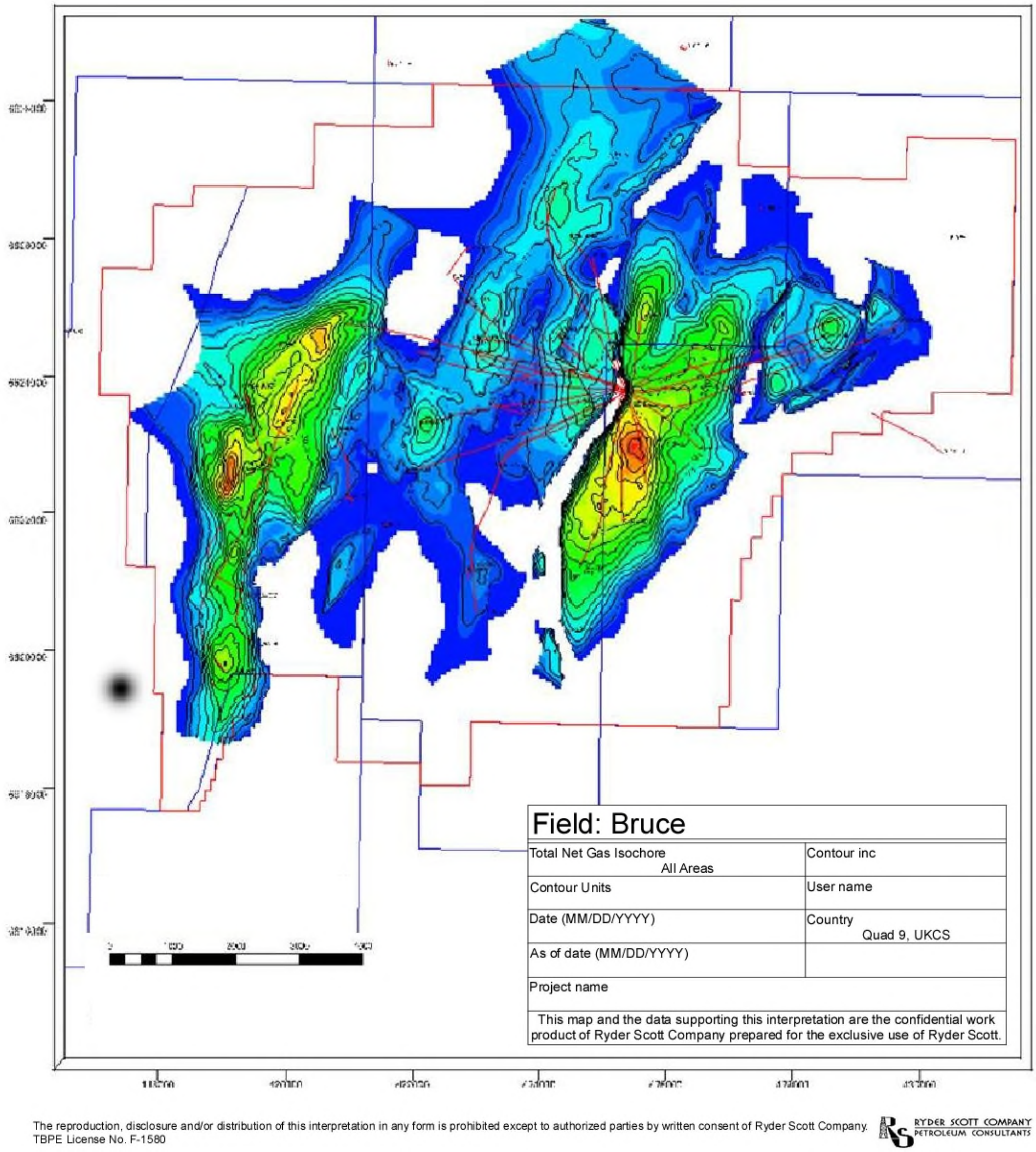
Fluid Contacts

The hydrocarbons in the field consist of a large column of gas condensate surrounded by an oil rim of varying thickness. Compartmentalization within the field has resulted in a diversity of fluid contacts attributed to 11 regional trends based on structural complexity as well as the depletion of the reservoirs. Evaluation of fluid contacts within the reservoirs is generally localized to individual fault compartments. RFT data obtained across the field indicate that there are three distinct reservoir pressure gradients, the Eastern High plus Central areas, the WAD, and the Eastern terraces.

Petrophysical Properties

Review of the petrophysical interpretation provided by BP demonstrates a fairly good tie between core and log derived porosity values; however, we observed that BP utilized the effective porosity values, as appropriate, for the upper units, whereas total porosity values were used to describe the lower units. Considering the reserve evaluation of the field is performance driven, the deviation in porosity estimation techniques is inconsequential. Porosity values observed in the units range from 8 percent to 16 percent and are consistent with the fining upward trend of the Bruce Group. Water saturation is described through the use of capillary pressure functions to tie back to height above the free water level. This is considered a reasonable method for describing saturation in the simulation models and should take into account movement in the free water level based on compartmentalization in the reservoir. Water saturation values range from 20-60 percent, depending on the formation and fault block. Review of the core data demonstrates a good general trend between porosity and permeability, which is further refined when tied back to facies type.

Below is a total net gas isochore map across all developed reservoirs.



Bruce Field - Total Net Gas Isochore Map (BP)

4.1.1.2 Current Field Development and Future Plans

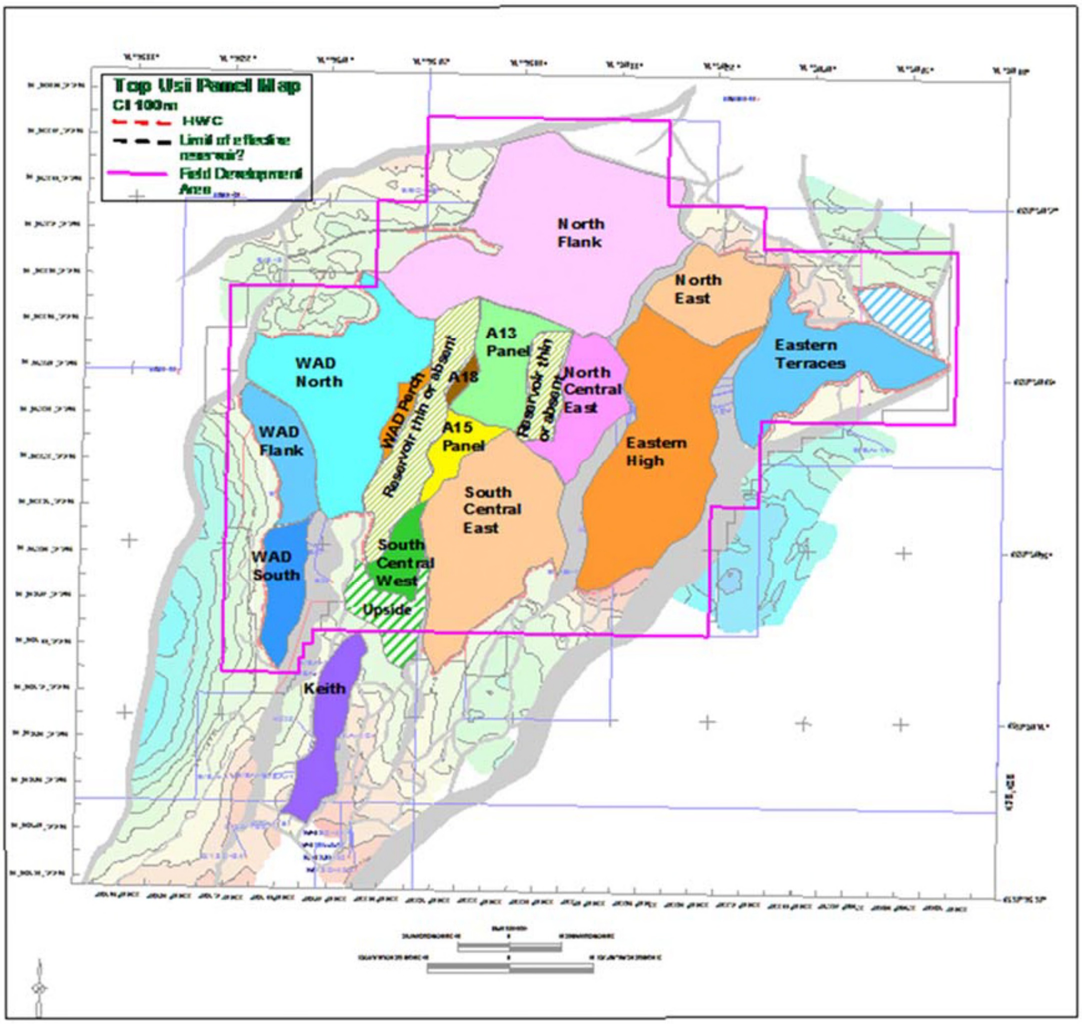
The first phase (Phase 1) of the Bruce field development was sanctioned in 1990, on the basis that all of the gas condensate present within the Bruce Group and the Turonian Limestone Reservoir would be developed under blowdown. The Phase 1 facilities comprised a drilling and wellhead platform (D) with 32 slots, bridge-linked to a process, utilities and quarters (PUQ) platform. The PUQ platform has accommodation for a maximum of 168 people.

The second phase of development of the Bruce field commenced in 1998. This development of the Western and South Central Areas of the field comprised a subsea well scheme, (the Western Area Development - WAD) tied back to a reception module sited on a small additional reception/compression platform (CR), bridge-linked to the existing D platform. There are 7 subsea wells in the Western Area Development which are tied back to the WAD subsea manifold, one of the wells was dry and is suspended. To maintain well deliverability, Booster Compression was completed in 2000. This involved an extra MP compression unit on all three existing compression trains on PUQ platform and a change in operating pressures of the process plant allowing a reduction in wellhead flowing pressure from 70 to 35 bara.

The field was originally discovered in 1974 and was delineated with 26 appraisal wells. Development commenced in 1990 with the first of production coming on in 1993. To date there are over 60 well penetrations in the field with 21 active production wells. For this evaluation BP presented a hydraulic fracturing project for 3 wells in 2019. These wells were A12z, A17y and the A26y.

There are no current projects in the contingent resources categories. There was one well to be drilled in the Bruce area that was classified as exploratory and therefore was not included in this report as being beyond the scope of this study. Additionally to the fracturing project, Ryder Scott estimated incremental volumes for a work project being done by BP to lower the suction pressure 1.8 bars at the compression system. Some of the incremental volumes were located in the 1P category and the rest of the volumes were assigned in the 2P category to reflect greater uncertainty in recovery. This work is scheduled to take place in October 2018.

The panels map shown below shows the compartmentalization in the Bruce field.



BP Development Panels Map (BP)

4.1.1.3 Reserves Estimation Methodology

The Bruce field is a complex structure composed of 11 fault-separated reservoir units. The field is quite mature, and no undeveloped reserves for new wells were projected. The only undeveloped reserves projected were attributed to the three hydraulic fractures scheduled for 2019. The methodology used in estimating the incremental volumes from the hydraulic fractures was analogy with other gas wells of similar conditions. In 2018 BP performed the hydraulic fracture for A14 well in which Ryder Scott estimated split volumes for the proved and probable category. The fracture was successful and the Ryder Scott estimated volumes came close to the results. The incremental volumes from the job have been added to the producing profile. The estimated volumes from the other three hydraulic fractures of wells A12z, A17y and the A26y are classified as probable undeveloped. Ryder Scott estimated the incremental volumes resulting from the reduction in suction pressure using analogy with the historical results of similar operations. These reserves were assigned to the proved and probable developed producing category depending upon the certainty of recovery. Producing reserves were projected from decline curve analysis using rate versus time and rate versus cumulative historical production. Ryder Scott did not map or perform an independent volumetric analysis of this field but used the BP volumetric data as a means for estimating the recovery factors. The total field gas recovery factor was estimated to be 62 percent.

4.1.1.4 Reserves Summary

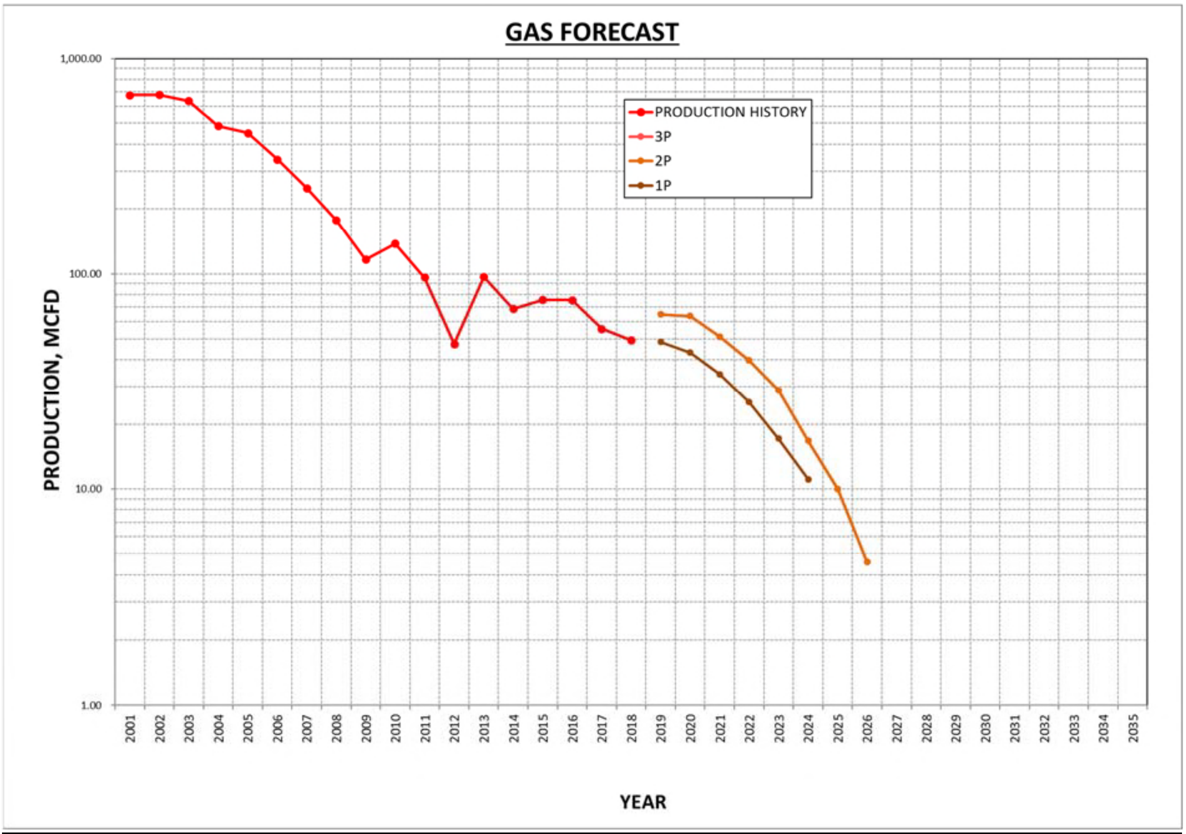
The table below presents the Gross reserves for the Bruce field.

BRUCE FIELD - GROSS RESERVES AS OF AUGUST 1, 2018									
		PROVED (1P) Reserves							
		Developed			Total	Cumulative	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	Proved	Production	Recovery	Factor
OIL/COND	– MBarrels	2,066	331	0	2,397			
PLANT PRODUCTS	– MBarrels	1,738	306	0	2,044			
GAS	– MMCF	58,139	10,332	0	68,471	3,086,056	3,158,876	62%
FUEL GAS	– MMCF	3,741	608	0	4,349			
Total	– MMBOE	14.5	2.5	0.0	17.0			
		Proved + Probable (2P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	2P	Probable	Recovery	Factor
OIL/COND	– MBarrels	2,223	618	633	3,474	1,077		
PLANT PRODUCTS	– MBarrels	1,831	601	671	3,102	1,059		
GAS	– MMCF	61,123	20,385	22,893	104,401	35,930	3,195,864	62%
FUEL GAS	– MMCF	4,800	608	0	5,407	1,059		
Total	– MMBOE	15.4	4.8	5.3	25.5	8.3		
		Proved + Probable+Possible (3P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	3P	Possible	Recovery	Factor
OIL/COND	– MBarrels	2,223	618	633	3,474	0		
PLANT PRODUCTS	– MBarrels	1,831	601	671	3,102	0		
GAS	– MMCF	61,123	20,385	22,893	104,401	0	3,195,864	62%
FUEL GAS	– MMCF	4,800	608	0	5,407	0		
Total	– MMBOE	15.4	4.8	5.3	25.5	0.0		
Used CoP of YE2024 for 1P and YE2026 for 2P. Note that gas above needs to be reduced by 10% shrinkage factor before sales.								

Table of Bruce Field Gross Reserves as of August 1, 2018

4.1.1.5 Reserves Forecast

Below is a graph showing the historical and gas forecast production profile for the Bruce field 1P and 2P reserves.



Plot of Bruce Gas Production History and Forecast

The profile of gross 1P production is shown in the table below. Ryder Scott estimated the 1P CoP at year-end 2024 for this field based on economics. The volumes from 2024 until the end of 2026 are considered to be 2P reserves. The CoP for the 2P scenario was assigned at 2026 for operational reasons. Economic production beyond this year can be achieved but a detailed evaluation of the integrity of the platform will have to be conducted to make sure that operations can be continued safely. BP has a 37 percent ownership in this field and is the operator; however, in this report a 36 percent interest is appraised in consideration of BP’s retention of 1 percent interest.

	BRUCE FIELD			
1P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF AUGUST 1, 2018			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2018	272	211	7,013	336
2019	601	502	16,777	845
2020	508	448	15,063	721
2021	386	352	11,874	643
2022	294	257	8,615	621
2023	206	169	5,652	602
2024	130	104	3,478	581
2025	95	67	2,204	541
2026	62	26	780	518
2027	49	11	261	477
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
1P TO YE2024	2,397	2,044	68,471	3,767
CUM (08/01/2018)			3,086,056	
ULTIMATE TO YE2024			3,158,294	
RS estimated CoP at 2024. Note that gas above needs to be reduced by 10% shrinkage factor before sales. BP has a 36% Working Interest in this field.				

A table of the 2P production profile is shown below. Ryder Scott assigned the 2P CoP at year-end 2026 for this field based on operational reasons. Economic production beyond this year can be achieved but a detailed evaluation of the integrity of the platform will have to be conducted to make sure that operations can be continued safely. BP has assured Ryder Scott that it does not expect any material Capex expenditure (over and above normal operating expenditure) to maintain production until 2026. Production thereafter is classified as 2C resources.

	BRUCE FIELD			
2P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF AUGUST 1, 2018			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2018	286	224	7,422	336
2019	769	679	22,816	845
2020	731	669	22,560	721
2021	563	534	18,056	643
2022	438	409	13,834	621
2023	314	293	9,911	602
2024	176	164	5,543	581
2025	122	94	3,103	541
2026	76	37	1,155	518
2027	49	11	261	477
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
2P TO YE2026	3,474	3,102	104,401	5,407
CUM (08/01/2018)			3,086,056	
ULTIMATE TO YE2026			3,195,864	
RS estimated CoP at 2024. Note that gas above needs to be reduced by 10% shrinkage factor before sales. BP has a 36% Working Interest in this field.				
2C RESOURCES (>2026)	49		261	

4.1.2 Contingent Resources Discussion

4.1.2.1 General Objective of Contingent Resource Projects

The descriptions of the structural and stratigraphic features of the reservoir areas where the resources are located in Bruce field are described in the section associated with reserves. The general objectives of the contingent resources in Bruce field are primarily commercial and are associated with the economic feasibility of further development.

4.1.2.2 Resources Estimation Methodology

In general, future resource volumes associated with further commercial development of the current producing wells and projects, were estimated by using the same methodologies as used for the estimation of reserves. There are no contingent resource volumes associated with new projects.

For the period of production beyond the CoP, the production decline forecast was extended from year-end 2026 (CoP 2P) to year-end 2027 and the incremental volume was classified as contingent resources. This results in one extra year of production for this field beyond the 2P CoP of 2026.

4.1.2.3 Contingencies

For the resource projects in the Bruce field, volumes attributed to the period beyond the CoP are contingent upon economic conditions in the future which would result in the commercial recovery of these volumes. Due to the age of the Bruce facilities, extension of Bruce production beyond the 2P CoP may require facility upgrades.

4.1.2.4 Resources Summary

Below is a table summarizing the 2C Contingent Resources of the Bruce field.

GROSS VOLUMES - BRUCE FIELD (8/8 THS)						
	1C		2C		3C	
Project	MBBL	MMCF	MBBL	MMCF	MBBL	MMCF
VOLUMES ATTRIBUTED TO PERIOD BEYOND 2P CoP			49	261		
TOTALS			49	261		

Table of Bruce Field 2C Contingent Resources

4.2 Keith Field

The Keith field is located 6.8 km south of the Bruce field platform at a water depth of 120 meters. It is comprised of a single subsea gas lifted well, K01, which is tied back to the Bruce Platform. The field was discovered in 1983, but was not developed and put on production until 2000. Until recently, the field was on record operated by BHP although it is tied to the Bruce platform, which is operated by BP. Recently, BHP transferred operatorship to BP. Several appraisal wells tested oil from DSTs in this field, but were never completed. Additionally, six dry holes were drilled in the field. The current producing well is nearing end of life, which is projected in 2024. Production from January to July 2018 averaged 373 barrels of oil per day (bopd).

4.2.1 Reserves Discussion

4.2.1.1 Geological Discussion

The Keith field is a panel inside of the larger Bruce complex, lying southwest of the Bruce South Central West panel. Description of Keith's geological features is encompassed in the Bruce Geological Description in section 4.1.1.1.

4.2.1.2 Current Field Development and Future Plans

There are no development projects planned for this field.

4.2.1.3 Reserves Estimation Methodology

The Keith field is quite mature with little remaining production life and no undeveloped reserves. Reserves were projected from decline curve analysis using a rate versus time projection. Ryder Scott did not map or perform an independent volumetric analysis of this field but used the BP volumetric data as a means for estimating the recovery factor. For the total field, the oil recovery factor for proved reserves was estimated to be 21 percent.

4.2.1.4 Reserves Summary

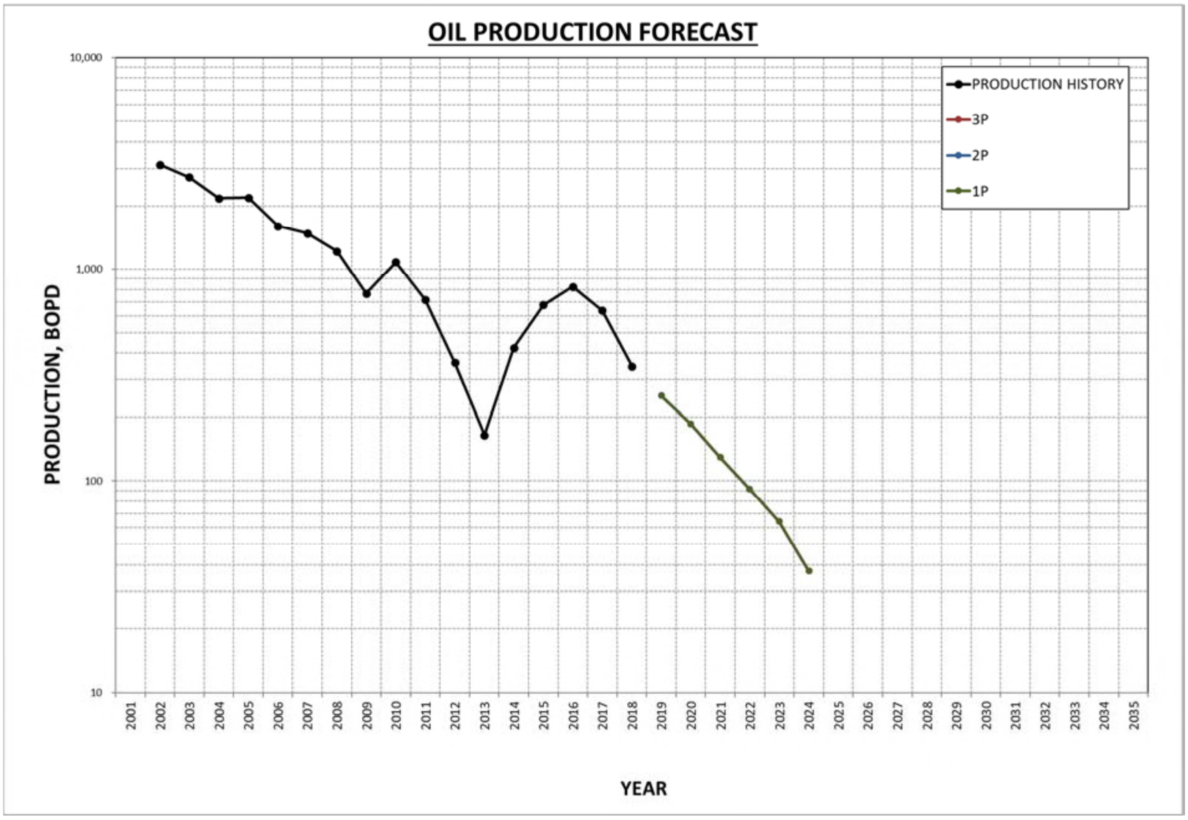
The table below shows the gross reserves for the Keith field.

KEITH FIELD - GROSS RESERVES AS OF AUGUST 1, 2018									
		PROVED (1P) Reserves							
		Developed			Total	Cumulative	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	Proved	Production	Recovery	Factor
OIL/COND	– MBarrels	325	0	0	325	10,135	10,460	21%
PLANT PRODUCTS	– MBarrels	86	0	0	86			
GAS	– MMCF	2,174	0	0	2,174			
FUEL GAS	– MMCF	59	0	0	59			
Total	– MMBOE	0.8	0.0	0.0	0.8			
		Proved + Probable (2P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	2P	Probable	Recovery	Factor
OIL/COND	– MBarrels	325	0	0	325	0	10,460	21%
PLANT PRODUCTS	– MBarrels	86	0	0	86	0		
GAS	– MMCF	2,174	0	0	2,174	0		
FUEL GAS	– MMCF	59	0	0	59	0		
Total	– MMBOE	0.8	0.0	0.0	0.8	0.0		
		Proved + Probable+Possible (3P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	3P	Possible	Recovery	Factor
OIL/COND	– MBarrels	325	0	0	325	0	10,460	21%
PLANT PRODUCTS	– MBarrels	86	0	0	86	0		
GAS	– MMCF	2,174	0	0	2,174	0		
FUEL GAS	– MMCF	59	0	0	59	0		
Total	– MMBOE	0.8	0.0	0.0	0.8	0.0		
Used CoP of YE2024 for 1P and 2P. Note that gas above needs to be reduced by 3% shrinkage factor before sales.								

Table of Keith Field Gross Reserves as of August 1, 2018

4.2.1.5 Reserves Forecast

Below is a graph showing the production history and forecast production profile for the Keith field 1P reserves. There were no future work projects planned for this field that would result in incremental reserves. There is no 2P projection for this field beyond 2024.



Plot of Keith Oil Production History and Forecast

The profile of gross 1P production is shown in the table below. Ryder Scott estimated the 1P CoP at year-end 2024 for this field based on economics. BP has a 34.83 percent ownership in this field and became the operator in mid-2015.

	KEITH FIELD			
1P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF AUGUST 1, 2018			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2018	47	13	330	18
2019	92	24	617	40
2020	68	18	468	-
2021	47	13	317	-
2022	33	9	215	-
2023	23	6	146	-
2024	14	3	82	-
2025	-	-	-	-
2026	-	-	-	-
2027	-	-	-	-
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
1P TO YE2024	325	86	2,174	59
CUM (08/01/2018)	10,135			
ULTIMATE TO YE2024	10,460			
RS estimated CoP at 2024. Note that gas above needs to be reduced by 3% shrinkage factor before sales. BP has a 34.83% Working Interest in this field.				

A table of the 2P production profile is shown below. Ryder Scott estimated the 2P CoP at year-end 2024 for this field. There is no production beyond 2024 categorized as 2C resources.

2P - SPE-PRMS	KEITH FIELD ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF AUGUST 1, 2018			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2018	47	13	330	18
2019	92	24	617	40
2020	68	18	468	-
2021	47	13	317	-
2022	33	9	215	-
2023	23	6	146	-
2024	14	3	82	-
2025	-	-	-	-
2026	-	-	-	-
2027	-	-	-	-
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
2P TO YE2024	325	86	2,174	59
CUM (08/01/2018)	10,135			
ULTIMATE TO YE2024	10,460			
RS estimated CoP at 2024. Note that gas above needs to be reduced by 3% shrinkage factor before sales. BP has a 34.83% Working Interest in this field.				
2C RESOURCES (>2024)	0		0	

4.2.2 Contingent Resources Discussion

4.2.2.1 General Objective of Contingent Resource Projects

The are no general objectives of the contingent resources in Keith field associated with the economic feasibility of further development.

4.2.2.2 Resources Estimation Methodology

There are no contingent volumes associated with new projects.

4.2.2.3 Contingencies

The are no resources in the Keith field attributed to the period beyond the CoP.

4.2.2.4 Resources Summary

There are no contingent resources of the Keith field.

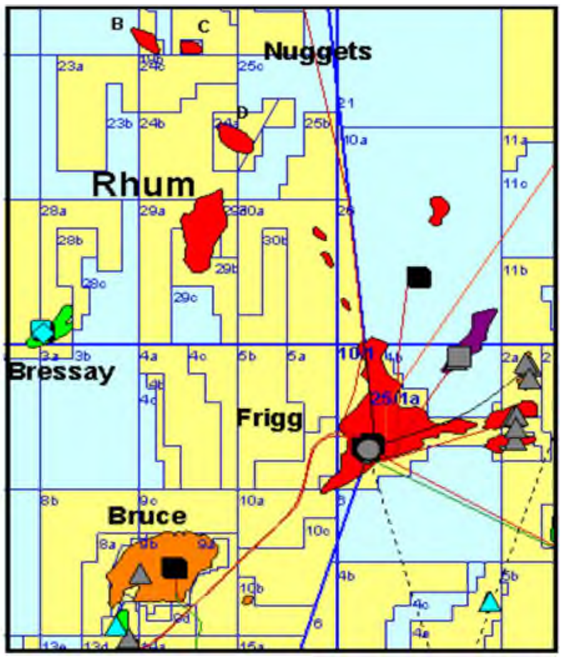
GROSS VOLUMES - KEITH FIELD (8/8 THS)						
	1C		2C		3C	
Project	MBBL	MMCF	MBBL	MMCF	MBBL	MMCF
KP-1			-	-		
TOTALS			-	-		

Table of Keith Field 2C Contingent Resources

4.3 Rhum Field

The Rhum field is operated by BP with a 50 percent ownership interest. The remaining 50 percent is held by the Iranian Oil Company (IOC) UK. This field was discovered in August 1977 and is located 380 km NE of Aberdeen in the United Kingdom Continental Shelf (UKCS) at a water depth of 109 m. The location of Rhum is shown below.

Rhum Field Location (BP)



Rhum Field – 44 km North of Bruce (BP)

Field development was sanctioned in 2003 and production started in December 2005. Production briefly peaked at 300 million cubic feet per day (MMCFD) of gas shortly after start-up, but the field has generally produced gas in the range of 200-230 MMCFD and condensate at 1300-1500 bpd until the field was shut-in in November 2010. NGLs are extracted through downstream processing at St. Fergus terminal. The field produces gas and condensate from two high pressure (12,423 psia initial pressure), high temperature (296 deg. F) late Jurassic thinly-bedded turbidite sand reservoirs. The gas is sour and corrosive containing both hydrogen sulfide (10-20 ppm) and carbon dioxide (4.0-8.5 percent). Production was shut-in in November 2010 as a result of European Union sanctions due to the 50 percent ownership by IOC UK, but was restarted in October 2014. Production in 2018 has averaged 118 MMCFD and 800 bpd of condensate. During the last quarter of 2017 there was a code change for maximum percentage of CO_2 concentration that can be delivered at St Fergus terminal. The CO_2 percentage acceptable for delivery went up from 3.8 percent to 5.5 percent. This change allows Rhum to flow unconstrained for the remainder of its life if compressor capabilities permit. Cumulative production is approximately 418 billion cubic feet (BCF) of gas and 2,805 MBarrels of condensate as of August 1, 2018.

Rhum has subsea completions which are tied back to the Bruce platform complex, which lies 44 km south of Rhum. The gas is processed at the Bruce complex and then transported through the Frigg pipeline (operated by TOTAL) to St. Fergus for NGL extraction. The condensate is separated at the Bruce complex and then exported through the Forties Pipeline System to Cruden Bay.

Three wells were completed in the field (R-1, R-2 and R-3); however, one well (R-3) does not produce due to problems related to hydrates buildup. There are plans to bring R3 to production after the well has been re-completed.

4.3.1 Reserves Discussion

4.3.1.1 Geological Discussion

<u>Stratigraphy & Deposition</u>

Rhum is comprised of low density turbidite sands deposited during the Upper Jurassic within the Kimmeridge clay. These deposits override the Jurassic Heather formation and maintain fairly uniform thickness. Feeder channels located to the west appear to be the primary mechanism of control in the distribution of sand across the unit. The location of these channels on the East Shetland platform is believed to have transported the main sand deposits to the west with Rhum receiving deposits under a depletive flow regime from west to east. The reservoir in Rhum consists of a primary unit identified as the Upper Main Reservoir (UMR) which contains 88 percent of the hydrocarbon volume in the field. This unit is further subdivided into three sub-units identified as UMR1, UMR2, and UMR3. Located below the UMR is the Lower Main Reservoir (LMR). These two units are present across the entire field and vary in thickness from 60 m at the crest of the reservoir to 200 m along the flanks. The units tend to be comprised of clean fine grain sands interbedded with shale. Above the UMR exists an additional unit identified as the Upper Reservoir (UR). This unit is generally thin and pinches out to the north of the field as demonstrated by the lack of sand in the 3/29a-5 well.

<u>Structure</u>

The Rhum field is structurally defined by two major north-south trending extensional faults, located at the southern tail of the North Viking Graben that form a terrace which is overlaid with the reservoir units. This graben is made up of a western dipping tilted fault block that forms the crest of the asymmetric anticlinal feature. This feature allowed hydrocarbons sourced from the Kimmeridge and Heather

Claystones to be contained within a four-way dip closure capped by the Kimmeridge Clay Formation. Faulting within the reservoir units is dominated by NNE-SSW trending faults following the crest of the anticline. Movement in the field is described by BP as a westward prograding extensional fault system that primarily was in motion after deposition of the reservoir turbidities during the deposition of the Valhall Formation and Shetland D unit. Structural features in the field are described using 3-D seismic data tied to well control.

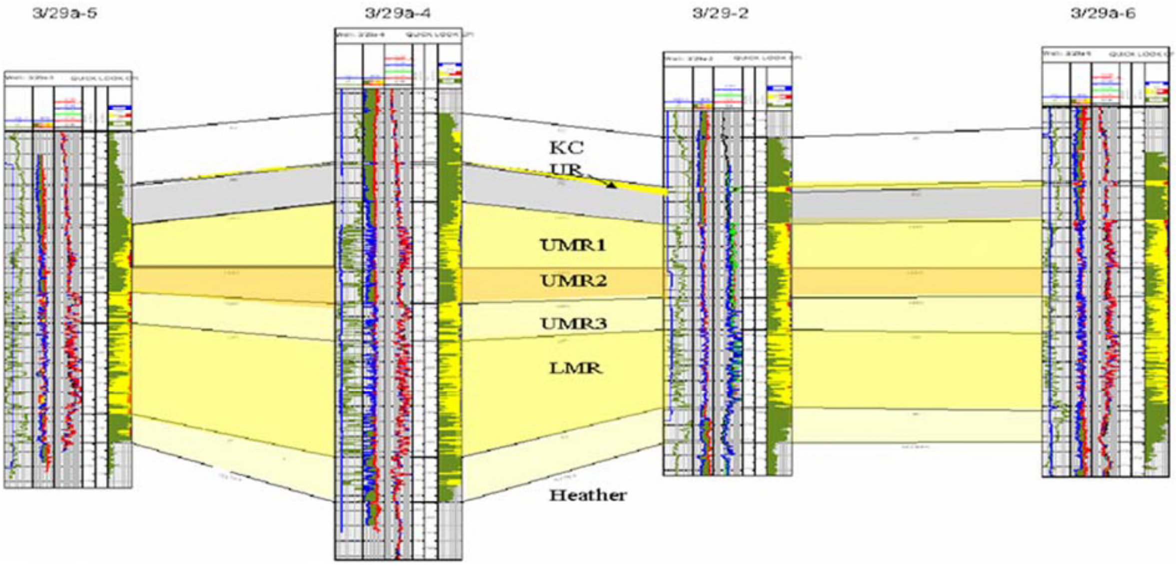
Fluid Contacts

Production of hydrocarbons in the Rhum field consists of gas and gas condensate from 3 production wells. The lower limit of hydrocarbons is defined by a gas-water contact observed in the 3/29a-4 well at a depth of -4745 m-ss. This contact is determined from well log data and is further verified by core and pressure data. RFT data also were used to demonstrate the hydrocarbon column as having one common pressure gradient that is in hydraulic communication across all of the units. Faulting in the field is not believed to compartmentalize the main area into isolated units based on well test data as well as supplemental coherency extraction from the reprocessed 3-D seismic survey. These faults often exhibit throws of 50 m to 150 m with only small portions fully offsetting the reservoir units.

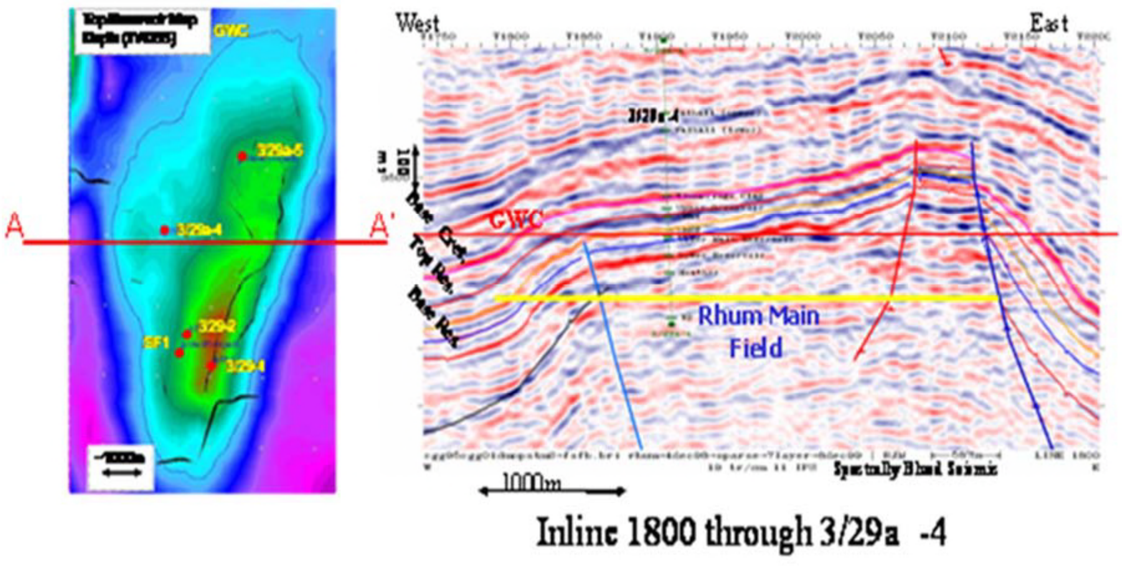
Petrophysical Properties

The Rhum field is primarily made up of generally clean fine grain sandstones with quartz-cement. Analyses of well log and core data show porosity distribution in the 4-16 percent range. In Rhum, the collection of core data has allowed for the measurement of air-brine capillary pressure to create a capillary pressure saturation model. This is particularly beneficial in the modeling of the reservoir for simulation purposes, since the water saturation values can be reliably correlated to the height above the free water level. Special core analysis shows irreducible water saturation to be approximately 14 percent. Permeability in the reservoir ranges from 45 md to a maximum of 600 md.

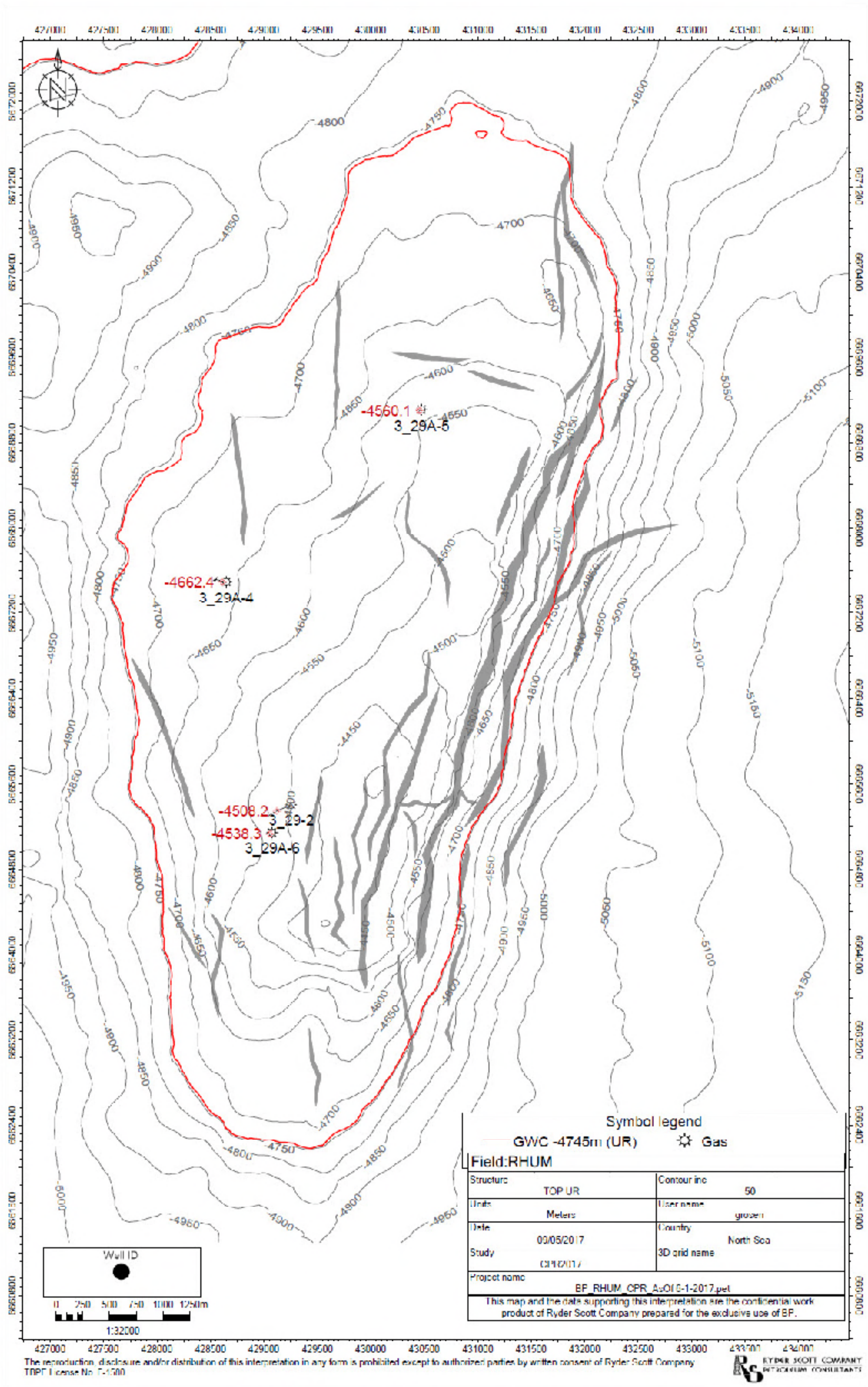
The figures below show west-east well log and seismic cross-sections. Also below is a structure map of the Rhum field.



Rhum West-East Cross-Section (BP)



Rhum West-East Cross-Section (BP)



Structure - Top of UR (RSC)

4.3.1.2 Current Field Development and Future Plans

The Rhum field was first discovered in 1977 with the drilling of the 3/29a-2 well. Prior to this well the 3/29-1 well was drilled in 1973 along the crest of the reservoir but was abandoned due to the high pressures that were encountered. The field was sanctioned for development in 2003 after the successful flow test of the 3/29a-4 exploration well, which was later converted into a production well. First gas production occurred in 2005 from wells 3/29a-4 (R-1) and 3/29a-5 (R-2). A third well, the 3/29a-6 (R-3), has not produced due to hydrate problems. As a consequence of the imposed European Union sanctions on the IOC, the field was shut-in from November 2010 to October 2014. Approval was gained to re-start production, and in the future BP expects to be allowed to produce unhindered from this issue.

For the future forecast BP presented an additional project in their exploitation plan. A workover related with a recompletion of the R-3 well is proposed by BP. This workover is planned to be initiated by midyear of 2019. The new completion should alleviate the hydrate formation problem in this well. Ryder Scott estimated undeveloped volumes for the 1P, 2P and 3P scenarios for this recompletion.

For the summary of activities in the previous year in the Rhum field, a stimulation workover was performed in well R-2. The well had shown a continuous drop in production since July 2016. A previous study done pertaining to the produced water from R-2 identified the risk of calcium carbonate scale deposition once the flowing bottomhole pressure in the wellbore begins to drop. The scale build up at the subsurface level was treated with a well intervention. The results of the workover have been favorable and the estimated increase in rates and volumes have been successfully accomplished. Ryder Scott added these volumes to the 1P, 2P and 3P developed streams of the field profiles.

4.3.1.3 Reserves Estimation Methodology

The reserves in the Rhum field are based upon the estimation of the original gas-in-place for each of the 5 identified reservoirs (UR, UMR1, UMR2, UMR3, and LMR). Gross volumes were calculated for each reservoir for the aerial extent within the gas-water contact (-4,745 m-ss). Net-to-Gross values calculated at the well locations were spatially distributed across the reservoir to derive the net volumes. While a current fault model was not available, years of production data indicate that the N-S trending faults are not sealing and provide little impedance to the flow of gas through the reservoir.

Porosity values were calculated at the well locations for each reservoir and used to determine weighted averages representative of the formation. Capillary pressure models were used to calculate Sw throughout each well and the weighted averages were used to determine representative values of each reservoir.

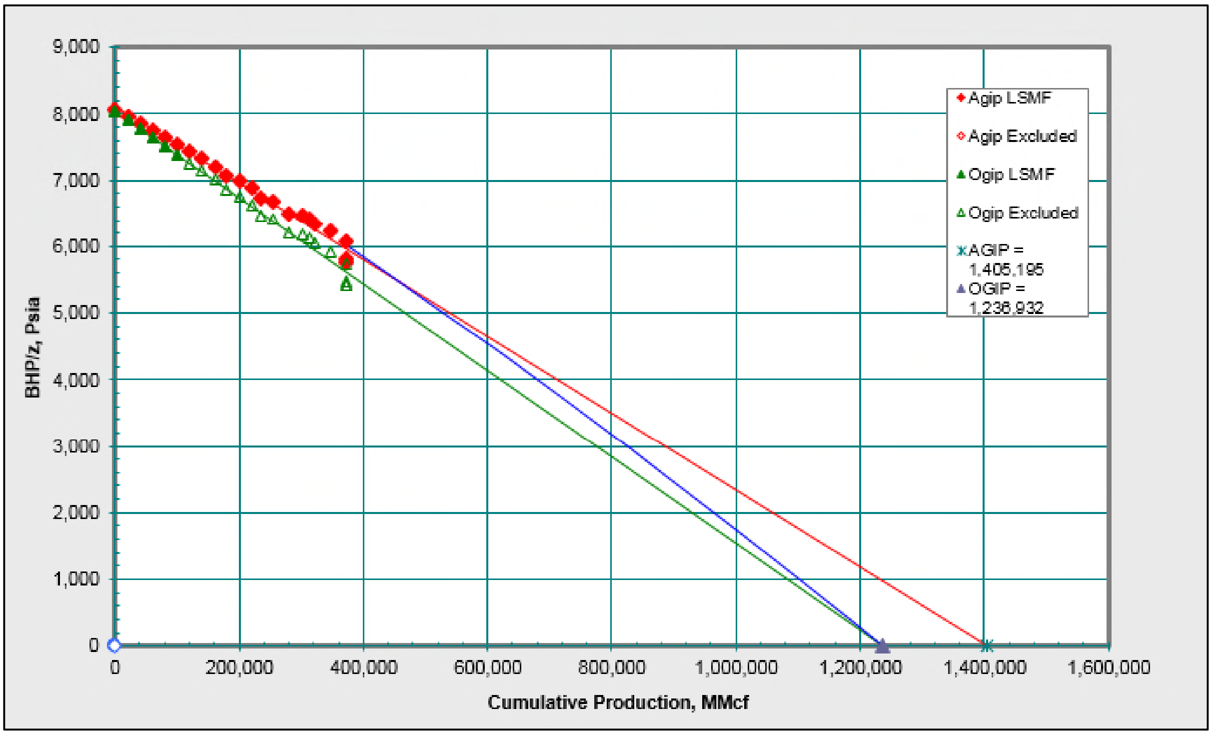
Projections were made to 2031 when the full 3P production is forecasted to be recovered. The reserves projections were terminated at year-end 2026 which was determined to be the operational limit for the 2P category of the Bruce platform complex (BKR), which includes the Bruce, Keith and Rhum fields. Also of note, the Rhum field gas contains CO_2 of approximately 6 percent, which exceeded the old limits allowed into the Frigg Transportation System (FTS) and further downstream to the UK national grid (UTS). However, this gas is blended with Bruce field gas and other gas through an agreement with Statoil to supply blended gas through the Vesterland system. BP has indicated that there was a code change at St. Fergus terminal sometime during the second part of the year 2017. This code change involved raising the CO_2 percentage concentration at which gas can now be delivered from the terminal. This will allow Rhum to flow unconstrained from 2018 forward. Additionally, BP has indicated that significant gas supply from another two fields beyond 2018 through the new SIRGE system, will allow Rhum to produce without CO_2 restrictions. These blending issues were reviewed with BP assuring Ryder

Scott that, while we cannot verify the other third party volumes, there is reasonable certainty that the operations will developed as planned.

For the purpose of the evaluation of the reserves in this study Ryder Scott used a combination of the volumetric and performance methods such as the Material Balance evaluation, in order to estimate recoverable volumes in the 1P, 2P and 3P category. For the 1P scenario Ryder Scott used its own geological mapping which indicated a smaller volume than the one estimated by the Material Balance plot of P/Z vs. cumulative production. A summary of the volumetric results obtained from our geologic model is shown below:

Variable	UR	UMR1	UMR2	UMR3	LMR
Area, acres	7,247	5,988	4,773	4,651	4,045
Porosity, %	14.42%	11.68%	8.49%	8.34%	7.30%
Water Saturation, %	13.14%	16.16%	18.73%	14.84%	15.76%
OGIP, MMSCF	84,752	384,900	23,539	169,566	337,118

The total estimated OGIP volume derived from this volumetric analysis was 999,875 MMSCF. Ryder Scott also verified that there is communication among all these reservoirs by performing a Material Balance analysis using the produced fluids and available pressure data in the field. The production is predominately from the 2 wells down dip of R-3, the R-1 and R-2. Little water production has been measured from these wells. Current water to gas ratios oscillate between 1.3 to 1.4 bbls/ MMSCF. The pressure measurements are from the shut in well R-3 which has a gauge at the bottom wellbore at the reservoir level of -4,044 m-ss. With the combination of the two sets of information, a P/Z vs. cumulative production plot was created and is illustrated below:



The corrected wet OGIP for an abnormal pressure gradient was estimated at 1,237 bcf. This value translated to a separator level volume of OGIP of 1,228 bcf. This volume was selected for the 2P scenario. An upside case of the P/Z plot shown above was evaluated indicating a volume of 1,309 bcf of separator gas for the 3P scenario. As of July 2018 the cumulative recovery factor was calculated at 42 percent. BP provided a numerical simulation model with estimated recovery factors of approximately 75 percent. Ryder Scott reviewed the recovery factors results from this model and found it within an acceptable range. Ryder Scott estimated recovery factor of 70 percent, 74 percent and 78 percent for the 1P, 2P and 3P scenarios respectively and used these values for our forecast predictions. Nodal analysis was performed with the deliverability data provided by BP and estimated unconstrained gas rates for the remainder of the life of the field.

In the forecast of all 1P, 2P and 3P scenarios, the R-3 recompletion in 2019 were added. These volumes were classified in the undeveloped category. These volumes were estimated by the combination of the volumetric and performance methods. The simulation study provided by BP was reviewed and we found their forecasts for these two projects to be within acceptable ranges.

	Units	**1P**	**2P**	**3P**
GIP	BCF	1,000	1,228	1,309
RF %	%	70%	74%	78%
EUR	BCF	700	909	1,021
Method		Volumetrics	Material Balance	Material Balance

The recovery factors presented in the following sections were calculated using the CoP of 2024 for 1P and 2026 for the 2P scenarios and therefore differ slightly from the ones estimated technically in this section.

4.3.1.4 Reserves Summary

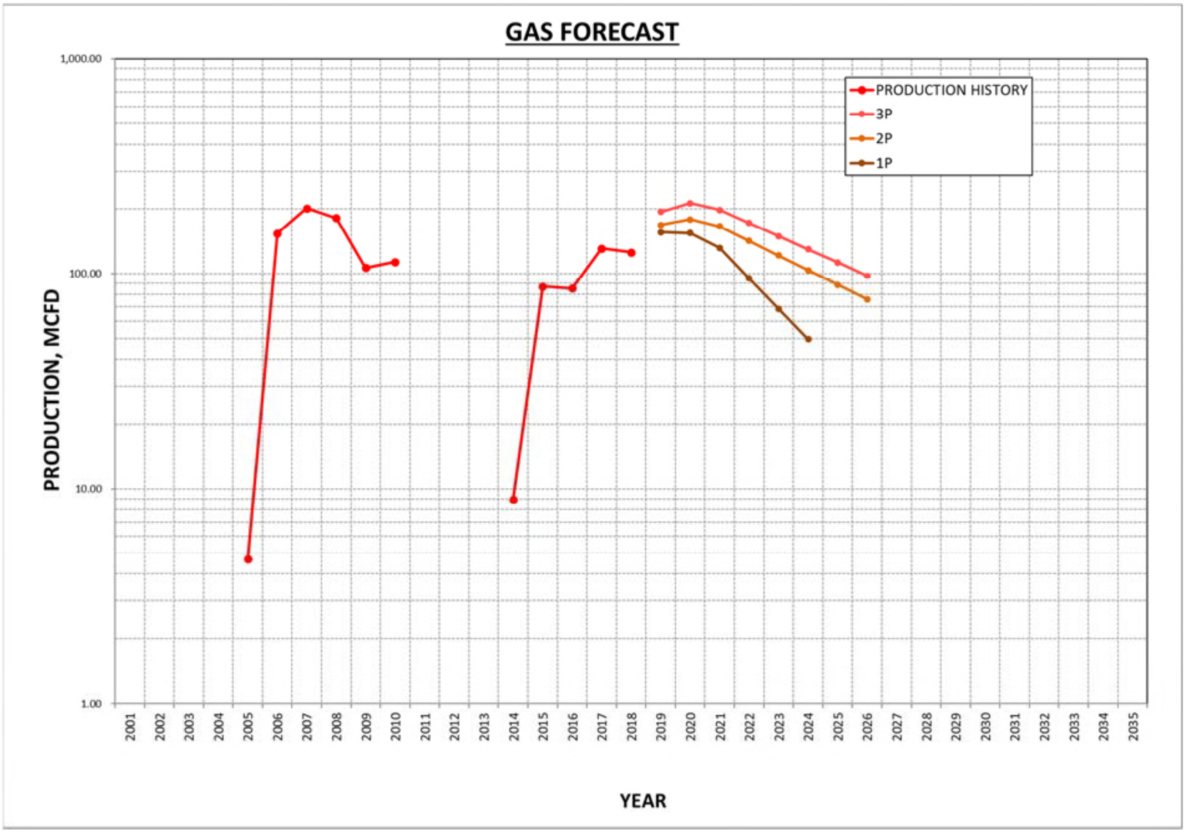
The table below shows the Gross reserves for the Rhum field.

RHUM FIELD - GROSS RESERVES AS OF AUGUST 1, 2018									
		PROVED (1P) Reserves							
		Developed			Total	Cumulative	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	Proved	Production	Recovery	Factor
OIL/COND	– MBarrels	1,112	0	364	1,476			
PLANT PRODUCTS	– MBarrels	1,028	0	335	1,364			
GAS	– MMCF	183,818	0	59,942	243,760	417,916	678,374	68%
FUEL GAS	– MMCF	12,375	0	4,323	16,698			
Total	– MMBOE	36.0	0.0	11.8	47.7			
		Proved + Probable (2P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	2P	Probable	Recovery	Factor
OIL/COND	– MBarrels	1,720	0	573	2,292	816		
PLANT PRODUCTS	– MBarrels	1,601	0	531	2,132	768		
GAS	– MMCF	286,221	0	94,851	381,072	137,312	821,197	67%
FUEL GAS	– MMCF	16,291	0	5,918	22,209	5,511		
Total	– MMBOE	55.5	0.0	18.5	74.0	25.3		
		Proved + Probable+Possible (3P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	3P	Possible	Recovery	Factor
OIL/COND	– MBarrels	1,996	0	665	2,660	368		
PLANT PRODUCTS	– MBarrels	1,940	0	644	2,584	452		
GAS	– MMCF	347,097	0	115,143	462,240	81,168	902,365	69%
FUEL GAS	– MMCF	16,291	0	5,918	22,209	0		
Total	– MMBOE	66.6	0.0	22.2	88.8	14.8		
Used CoP of YE2024 for 1P and YE2026 for 2P. Note that gas above needs to be reduced by 1% shrinkage factor before sales.								

Table of Rhum Field Gross Reserves as of August 1, 2018

4.3.1.5 Reserves Forecast

Below is a graph showing the production history and forecasted production profile for the Rhum field 1P, 2P and 3P reserves. After returning to production in late 2014 and new gas becoming available in late 2015 for CO_2 blending, Rhum production is expected to increase to previous levels during 2018.



Plot of Rhum Gas Production History and Forecast

A table of the 1P production profile is shown below. Ryder Scott estimated the 1P CoP at year-end 2024 for this field based on economics. The volumes from 2024 until the end of 2026 are considered to be 2P reserves. The CoP for the 2P scenario was assigned at 2026 for operational reasons. Economic production beyond this year can be achieved but a detailed evaluation of the integrity of the platform will have to be conducted to make sure that operations can be continued safely. BP has a 50 percent ownership in this field.

	RHUM FIELD			
1P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF AUGUST 1, 2018			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2018	139	111	19,823	1,023
2019	347	306	54,565	2,400
2020	330	302	54,041	2,573
2021	267	255	45,517	2,642
2022	183	179	32,065	2,664
2023	125	125	22,360	2,683
2024	85	86	15,389	2,713
2025	58	57	10,268	2,744
2026	35	32	5,760	2,767
2027	-	-	-	-
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
1P TO YE2024	1,476	1,364	243,760	16,698
CUM (08/01/2018)			417,916	
ULTIMATE TO YE2024			678,374	
RS estimated CoP at 2024. Note that gas above needs to be reduced by 1% shrinkage factor before sales. BP has a 50% Working Interest in this field.				

A table of the 2P production profile is shown below. Ryder Scott assigned the 2P CoP at year-end 2026 for this field based on operational reasons. Economic production beyond this year can be achieved but a detailed evaluation of the integrity of the platform will have to be conducted to make sure that operations can be continued safely. BP has assured Ryder Scott that it does not expect any material Capex expenditure (over and above normal operating expenditure) to maintain production until 2026. Production from 2027 to 2031 is categorized as 2C resources.

	RHUM FIELD			
2P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF AUGUST 1, 2018			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2018	143	114	20,312	1,023
2019	381	331	59,115	2,400
2020	393	352	62,971	2,573
2021	350	324	57,887	2,642
2022	292	275	49,133	2,664
2023	241	233	41,642	2,683
2024	199	197	35,314	2,713
2025	162	166	29,701	2,744
2026	132	140	24,998	2,767
2027	111	117	20,951	2,808
2028	89	98	17,523	2,860
2029	70	81	14,509	2,883
2030	55	67	12,002	2,881
2031	37	45	8,087	2,881
2032	-	-	-	-
2P TO YE2026	2,292	2,132	381,072	22,209
CUM (08/01/2018)			417,916	
ULTIMATE TO YE2026			821,197	
RS estimated CoP at 2026. Note that gas above needs to be reduced by 1% shrinkage factor before sales. BP has a 50% Working Interest in this field.				
2C RESOURCES (>2026)	361		73,072	

A table of the 3P production profile is shown below. Ryder Scott assigned the 3P CoP at year-end 2026 for this field for operational reasons. Economic production beyond this year can be achieved but a detailed evaluation of the integrity of the platform will have to be conducted to make sure that operations can be continued safely.

	RHUM FIELD			
3P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF AUGUST 1, 2018			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2018	143	114	20,312	1,023
2019	431	384	68,520	2,400
2020	455	421	75,325	2,573
2021	408	390	69,801	2,642
2022	343	337	60,227	2,664
2023	286	290	51,915	2,683
2024	238	250	44,807	2,713
2025	196	214	38,389	2,744
2026	161	184	32,943	2,767
2027	136	157	28,193	2,808
2028	110	134	24,122	2,860
2029	88	114	20,473	2,883
2030	70	97	17,395	2,881
2031	53	80	14,455	2,881
2032	-	-	-	-
3P TO YE2026	2,660	2,584	462,240	22,209
CUM (08/01/2018)			417,916	
ULTIMATE TO YE2026			902,365	
RS estimated CoP at 2024. Note that gas above needs to be reduced by 1% shrinkage factor before sales. BP has a 50% Working Interest in this field.				

4.3.2 Contingent Resources Discussion

4.3.2.1 General Objective of Contingent Resource Projects

The descriptions of the structural and stratigraphic features of the reservoir areas where the resources are located in Rhum are described in the section associated with reserves. The general objectives of the contingent resources in Rhum field are primarily commercial and are associated with the economic feasibility of further development.

4.3.2.2 Resources Estimation Methodology

The only contingent resources projected for the Rhum field are the production volumes forecasted beyond the 2P CoP of 2026. These total volumes were based upon projected volumes from years 2027 to 2031.

4.3.2.3 Contingencies

Volumes attributed to the production period beyond the CoP are contingent upon conditions in the future which would result in economic production. Due to the age of the Rhum and associated Bruce facilities, extended production beyond the CoP may require facility upgrades.

4.3.2.4 Resources Summary

The table below shows the 2C Contingent Resource volumes projected for the Rhum field.

GROSS VOLUMES - RHUM FIELD (8/8 THS)						
	1C		2C		3C	
Project	MBBL	MMCF	MBBL	MMCF	MBBL	MMCF
VOLUMES ATTRIBUTED TO PERIOD BEYOND CoP			361	73,072		
TOTALS			361	73,072		

Table of Rhum Field 2C Contingent Resources

5.0 Summary of Total Reserves and Contingent Resources

A summary of the total estimates of net reserves is presented below for the combined properties. Also shown below is our summary of the total 2C contingent resources for all the properties.

5.1 Summary of Net Reserves – SPE-PRMS Escalated Parameters

SPE-PRMS Escalated Parameters
Estimated Net Reserves and Contingent Resources Volumes
Attributable to Certain Interests in the Bruce, Keith and Rhum Fields
BP Exploration and Production
As of August 1, 2018

	Proved (1P)	Proved+ Probable (2P)	Proved+ Probable+Possible (3P)
Net Remaining Reserves			
Oil/Condensate – MBarrels	1,714	2,510	2,694
Plant Products – MBarrels	1,448	2,213	2,439
Sales Gas – MMCF	143,581	223,191	263,369
Fuel Gas – MMCF	9,935	13,072	13,072

5.2 Summary of Contingent Resources (2C) – SPE-PRMS Escalated Parameters

A summary of our estimated total net 2C Contingent Resources is shown below.

	Contingent Resources (2C)
Net Contingent Resources	
Oil/Condensate – MBarrels	198
Gas – MMCF	36,630

Liquid hydrocarbons are expressed in thousands of standard 42 U.S. gallon barrels (MBarrels). All gas volumes are reported on an “as sold” basis expressed in millions of cubic feet (MMCF) at the official temperature and pressure base of the areas in which the gas reserves are located. Those gas volumes that are consumed as fuel in operations are also reported separately herein.

6.0 Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to BP, Serica and Peel Hunt. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves and resources for the properties which were reviewed. Ryder Scott is professionally qualified and a member in good standing of an appropriate recognized professional association under the AIM Rules with at least five years relevant experience in the estimation, assessment and evaluation of oil and gas assets

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves and resource information discussed in this report, are included below.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Guale Ramirez
Guale Ramirez, P.E.
TBPE License No. 48318
Executive Vice President

STATE OF TEXAS
GUADALUPE RAMIREZ
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LICENSED
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Managing Senior Vice President

GR-MAB (FWZ)/pl

STATE OF TEXAS
MARIO A. BALLESTEROS
107132
LICENSED
PROFESSIONAL ENGINEER

7.0 Professional Qualifications of Primary Technical Person

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mario A. Ballesteros was the primary technical person responsible for overseeing the independent estimation of reserves, future production and income to render the audit conclusions of the report presented herein.

Mr. Ballesteros, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President and also serves as an Engineering Group Leader responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Ballesteros served in a number of engineering positions with Chevron. For more information regarding Mr. Ballesteros geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Ballesteros earned a Bachelor of Science degree in Mechanical Engineering in 1991 and a Masters of Petroleum Engineering degree in 1993 from the University of Tulsa. He also earned a Masters in Finance in 2000 from the Meta University in Colombia. He is a registered Professional Engineer in the State of Texas.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Ballesteros fulfills. Mr. Ballesteros has attended formalized training and conferences including dedicated to the subject of the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register.

Based on his educational background, professional training and more than 21 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Ballesteros has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

8.0 Petroleum Reserves and Resources Classification and Definitions

As Adapted From:
2007 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)[1]
Sponsored by:
SOCIETY OF PETROLEUM ENGINEERS (SPE),
WORLD PETROLEUM CONGRESS (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
AND
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserve and resource classification systems are intended to allow the evaluator to follow the progression of changes in the exploration and production life cycle of a reservoir, field, or project that arise as a result of obtaining more technical information or as a result of a change in the economic status. Most systems incorporate terminology to describe the progression of a project from the delineation of an initial prospect, to the confirmation of the prospect through exploration drilling, onto the appraisal and development phase, and finally from initial production through depletion. These reserve and resource definitions thus provide the decision making framework to manage risk and uncertainty through the classification and categorization of the recoverable hydrocarbon volumes.

The term “resources” is generally applied to “all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth’s crust, discovered and undiscovered, plus those quantities already produced”.

The term “reserves” is a subset of resources generally applied to the discovered “quantities of petroleum anticipated to be commercially recoverable from known accumulations from a given date forward under defined conditions”.

All reserve and resource estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. Estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change.

Estimation of reserves and resources is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves and resources is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves and/or resource classifications.

Reserves and resources may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves and resources may be attributed to either conventional or unconventional petroleum accumulations under the SPE-PRMS. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale. The SPE-PRMS acknowledges unconventional petroleum accumulations as reserves and resources regardless of their in-place characteristics, the extraction method applied, or the degree of processing required.

Reserves and resources do not include quantities of petroleum being held in inventory and may be reduced for usage, processing losses and/or non-hydrocarbons that must be removed prior to sale.

SPE-PRMS

In March 2007, the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and Society of Petroleum Evaluation Engineers (SPEE) jointly approved the "Petroleum Resources Management System" (SPE-PRMS). The SPE-PRMS consolidates, builds on, and replaces guidance previously contained in the 2000 "Petroleum Resources Classification and Definitions" and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources" publications.

Reference should be made to the full SPE-PRMS for the complete definitions and guidelines as the following definitions, descriptions and explanations rely wholly or in part on excerpts from the SPE-PRMS document (passages excerpted in their entirety from the SPE-PRMS document are denoted in italics herein). For convenience, Table 1: "Recoverable Resources Classes and Sub-Classes" from the SPE-PRMS has been reproduced in full and included as an attachment to this document.

The SPE-PRMS incorporates the petroleum initially-in-place as well as the recoverable and unrecoverable petroleum quantities into a common resource classification framework. *Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase.*

The SPE-PRMS defines the major resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum. The basic classification scheme requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial (Reserves) and sub-commercial projects (Contingent Resources) in known accumulations. Under this classification scheme, estimated recoverable quantities from accumulations that have yet to be discovered are termed Prospective Resources. Further, the SPE-PRMS includes all types of petroleum whether currently considered "conventional" or "unconventional".

Figure 1 shown at the end of this document is a graphical representation of the SPE, WPC, AAPG and SPEE resources classification system. The SPE-PRMS "classifies" reserves and resources according to project maturity and increasing chance of commerciality (vertical axis) and "categorizes" reserves and resources according to the *range of uncertainty* (horizontal axis) *of the estimated quantities potentially recoverable from an accumulation by a project*. The following definitions apply to the major subdivisions within the resources classification:

RESOURCES CLASSIFICATION (SPE-PRMS)

Recoverable petroleum resources as described herein may be classified into one of three principal resource classifications: Prospective Resources, Contingent Resources, or Reserves. The distinction between Prospective and Contingent Resources depends on whether or not there exists one or more wells and other data indicating the potential for moveable hydrocarbons (e.g. the discovery status). Discovered petroleum resources may be classified as either Contingent Resources or as Reserves depending on the chance that if a project is implemented it will reach commercial producing status (e.g. chance of commerciality). The distinction between various "classifications" of Resources and Reserves relates to their discovery status and increasing chance of commerciality as described herein.

The SPE-PRMS Section 1.1 and Appendix A define the following terms:

TOTAL PETROLEUM-INITIALLY-IN-PLACE

Total Petroleum-Initially-in-Place is that quantity of petroleum which is estimated to exist originally in naturally occurring accumulations. Total Petroleum-Initially-in-Place is, therefore, that quantity of petroleum which is estimated, as of a given date, to be contained in known accumulations, plus those quantities already produced therefrom, plus those estimated quantities in accumulations yet to be discovered.

Total Petroleum-Initially-in-Place may be subdivided into Discovered Petroleum-Initially-in-Place and Undiscovered Petroleum-Initially-in-Place, with Discovered Petroleum-Initially-in-Place being limited to known accumulations.

It is recognized that not all of the Petroleum-Initially-in-Place quantities may constitute potentially recoverable resources since the estimation of the proportion which may be recoverable can be subject to significant uncertainty and will change with variations in commercial circumstances, technological developments and data availability.

Given the aforementioned constraints, a portion of the Petroleum-Initially-in-Place may need to be classified as Unrecoverable.

DISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Discovered Petroleum-Initially-in-Place is that quantity of petroleum which is estimated, as of a given date, to be contained in known accumulations prior to production.

Discovered Petroleum-Initially-in-Place may be subdivided into Commercial and Sub-commercial categories, with the estimated potentially recoverable portion being classified as Reserves and Contingent Resources respectively, as defined below.

KNOWN ACCUMULATION

The SPE-PRMS defines an accumulation as *an individual body of petroleum-in-place*. For an accumulation to be considered as "known", it must have been discovered. A discovery is defined as *one petroleum accumulation or several petroleum accumulations collectively, which have been penetrated by one or several exploratory wells which have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons*. The SPE-PRMS states in this context, *"significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating* *the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery.* Known accumulations may contain Reserves and/or Contingent Resources.

RESERVES

Reserves are defined as those quantities of petroleum which are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy the following criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied.

Reserves are categorized in *accordance with the level of certainty associated with the estimates* (horizontal axis shown in Figure 1) *and may be further sub-classified based on project maturity and/or characterized by development and production status* (Refer to Figure 2 at the end of this document). Reference should be made to the full SPE-PRMS for the complete definitions and guidelines.

ADDITIONAL TERMS USED IN RESERVES EVALUATIONS (SPE-PRMS DEFINITIONS)

The SPE-PRMS Sections 2.3, 2.3.4, 2.4 and Appendix A define the following terms as follows:

Improved recovery. *Improved Recovery is the extraction of additional petroleum, beyond Primary Recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called Enhanced Recovery.)*

Improved recovery projects must meet the same Reserves commerciality criteria as primary recovery projects. There should be an expectation that the project will be economic and that the entity has committed to implement the project in a reasonable time frame (generally within 5 years; further delays should be clearly justified). If there is significant project risk, forecast incremental recoveries may be similarly categorized but should be classified as Contingent Resources.

The judgment on commerciality is based on pilot testing within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

Similar to improved recovery projects applied to conventional reservoirs, successful pilots or operating projects in the subject reservoir or successful projects in analogous reservoirs may be required to establish a distribution of recovery efficiencies for non-conventional accumulations. Such pilot projects may evaluate both the extraction efficiency and the efficiency of unconventional processing facilities to derive sales products prior to custody transfer.

These incremental recoveries in commercial projects are categorized into Proved, Probable, and Possible Reserves based on certainty derived from engineering analysis and analogous applications in similar reservoirs.

Commercial. *When a project is commercial, this implies that the essential social, environmental and economic conditions are met, including political, legal, regulatory and contractual conditions. In addition, a project is commercial if the degree of commitment is such that the accumulation is expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.*

PROVED RESERVES (SPE-PRMS DEFINITIONS)

The SPE-PRMS Section 2.2.2 and Table 3 define proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.*

The area of the reservoir considered as Proved includes:

(1) the area delineated by drilling and defined by fluid contacts, if any, and

(2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines", Chapter 8).

Reserves in undeveloped locations may be classified as Proved provided that:

- *The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive.*

- *Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with the drilled Proved locations.*

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

UNPROVED RESERVES (SPE-PRMS DEFINITIONS)

The SPE-PRMS Section 2.2.2 and Appendix A define unproved oil and gas reserves as follows:

Unproved oil and gas reserves*. Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves or Possible Reserves. Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.*

PROBABLE RESERVES (SPE-PRMS DEFINITIONS)

The SPE-PRMS Section 2.2.2 and Table 3 define probable oil and gas reserves as follows:

Probable oil and gas reserves*. Probable Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.*

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

POSSIBLE RESERVES (SPE-PRMS DEFINITIONS)

The SPE-PRMS Section 2.2.2 and Table 3 define possible oil and gas reserves as follows:

Possible oil and gas reserves*. Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.*

Possible Reserves may be assigned to areas of a reservoir adjacent to Probable Reserves where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered *mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there is currently no viable market, or where commercial recovery is dependent on the development of new technology, or where evaluation of the accumulation is insufficient to assess commerciality.*

Contingent Resources are categorized according to the range of technical uncertainty associated with the estimates (horizontal axis shown in Figure 1) may be further sub-classified based on project maturity and/or characterized by their economic status (Refer to Figure 2 at the end of this document). Reference should be made to the full SPE-PRMS for the complete definitions and guidelines.

UNDISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Undiscovered Petroleum-Initially-in-Place is that quantity of petroleum which is estimated, as of a given date, to be contained in accumulations yet to be discovered.

The estimated potentially recoverable portion of Undiscovered Petroleum-Initially-in-Place is classified as Prospective Resources, as defined below.

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future projects. Prospective Resources have both an associated chance of discovery and a chance of development.

Prospective Resources are categorized in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be further sub-classified based on project maturity (Refer to Figure 2 at the end of this document). Reference should be made to the full SPE-PRMS for the complete definitions and guidelines.

UNRECOVERABLE

Unrecoverable is a term that refers to that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

ADDITIONAL TERMS USED IN RESOURCES CLASSIFICATION (SPE-PRMS)

CHANCE OF COMMERCIALITY

The SPE-PRMS Section 2.1, Table 1 and Appendix A define the following terms relating to commerciality:

The “Chance of Commerciality”, as denoted in the SPE-PRMS and as shown in Figure 1, *is the chance that the project will be developed and reach commercial producing status*.

The chance of commerciality is determined by the probability of a discrete event occurring. In the context of the SPE-PRMS, the discrete event is comprised of one of several conditions, as noted below, which impact the project’s commercial viability.

The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities. Commerciality is not solely determined based on the economic status of a project which refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation. Conditions as noted in the SPE-PRMS include *technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms and taxes.*

A development project *may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir. An accumulation or potential accumulation may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.*

COMMERCIALITY APPLIED TO RESERVES

Commerciality as applied to Reserves must be based upon all of the following criteria:

- *Evidence to support a reasonable timetable for development.*
- *A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.*
- *A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.*
- *Evidence that the necessary production and transportation facilities are available or can be made available.*
- *Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.*
- *High confidence in the commercial producibility of the reservoir.*

To be included in a Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming.

In general, quantities should not be classified as Reserves unless there is *evidence of firm intention that the accumulation will be developed and placed on production within a reasonable time frame.* In certain circumstances, reserves may be assigned even though development may not occur for some time. *A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project.* The SPE-PRMS recommends *five years as a benchmark, but notes that a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.*

For a project to be included in a Reserves class *there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.*

COMMERCIALITY APPLIED TO CONTINGENT RESOURCES

Estimated recoverable quantities from known accumulations that are not yet considered mature enough for commercial development as denoted by meeting all of the aforementioned conditions should be classified as Contingent Resources.

Based on assumptions regarding future conditions and their impact on economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- ***Marginal Contingent Resources** are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.*

- ***Sub-Marginal Contingent Resource**s are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonable forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.*

Those discovered in-place volumes for which a feasible development project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

RESOURCES CATEGORIZATION (SPE-PRMS)

All estimates of the quantities of petroleum potentially recoverable from an accumulation classified as having Prospective or Contingent Resources or Reserves involve uncertainty. The relative degree of uncertainty may be conveyed by placing the estimated quantities into one of several “categories” as described herein.

The SPE-PRMS Section 2.2 and Appendix A define the following terms:

RANGE OF UNCERTAINTY

The Range of Uncertainty, as denoted in the SPE-PRMS and as shown in Figure 1, reflects a range of estimated quantities potentially recoverable from an accumulation by a project. *Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods.*

DETERMINISTIC METHODS (SPE-PRMS)

RESERVES

For reserves, the range of uncertainty can be reflected as discrete incremental quantities termed Proved, Probable and Possible or expressed in cumulative terms as 1P (Proved), 2P (Proved plus Probable), and 3P (Proved plus Probable plus Possible), respectively.

CONTINGENT RESOURCES

For Contingent Resources, the range of uncertainty is generally expressed in deterministic scenario (cumulative) terms as 1C, 2C, 3C, respectively or in terms of probability using probabilistic methods. While the SPE-PRMS categorization scheme does not specifically prohibit the use of discrete incremental quantities for Contingent Resources, the SPE-PRMS does not denote the terms to be applied to these discrete incremental quantities.

PROSPECTIVE RESOURCES

For Prospective Resources, the range of uncertainty is generally expressed in deterministic scenario (cumulative) terms as low, best and high estimates or in terms of probability using probabilistic methods. As in the case of Contingent Resources, the SPE-PRMS categorization scheme does not specifically denote terms to be applied to discrete incremental quantities for Prospective Resources.

INCREMENTAL TERMS FOR CONTINGENT AND PROSPECTIVE RESOURCES (RYDER SCOTT)

Should evaluators choose to characterize the range of uncertainty for Contingent Resources or Prospective Resources in discrete incremental quantities, they should denote such quantities as such and provide sufficient detail in their report to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of the recoverable quantities. For reports prepared by Ryder Scott Company (Ryder Scott), the range of uncertainty for discrete incremental quantities of Contingent Resources shall be termed 1C Incremental (1Ci), 2C Incremental (2Ci) and 3C Incremental (3Ci) and in the case of Prospective Resources shall be termed Low Estimate Incremental (LEi), Best Estimate Incremental (BEi) and High Estimate Incremental (HEi) where (i) denotes a specific incremental quantity.

BEST ESTIMATE

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. The term "best estimate" is used here as a generic expression for the estimate considered being closest to the quantity that will actually be recovered from the accumulation between the date of the estimate and the time of abandonment. In the case of reserves, the best estimate is generally considered to represent *the sum of Proved and Probable estimates (2P). It should be noted that under the incremental (risk-based) approach for Reserves, discrete estimates are made for the quantities in each category for Proved and Probable, and they should not be aggregated without due consideration of their associated risk.* In the case of Contingent Resources and Prospective Resources, the best estimate would be represented by the 2C and Best Estimate, respectively. If probabilistic methods are used, this term would generally be a measure of central tendency of the uncertainty distribution (most likely/mode, median/P50 or mean). The terms "Low Estimate" and "High Estimate" should provide a reasonable assessment of the range of uncertainty in the Best Estimate.

PROBABILISTIC METHODS (SPE-PRMS)

If probabilistic methods are used, these estimated quantities should be based on methodologies analogous to those applicable to the definitions of Reserves, Contingent Resources and Prospective Resources; therefore, in general, the resulting probabilities should correspond to the deterministic terms as follows:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the 1P, 1C or Low Estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the 2P, 2C or Best Estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the 3P, 3C or High Estimate.

COMPARABILITY OF SIMILAR RESERVES AND RESOURCE CATEGORIES

As indicated in Figure 1, the 1C, 2C and 3C Contingent Resource estimates and the Low, Best and High Prospective Resource estimates of potentially recoverable volumes should reflect some comparability with the reserves categories of Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P), respectively. *While there may be a significant risk that sub-commercial or undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable volumes independently of such a risk.*

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves.

AGGREGATION

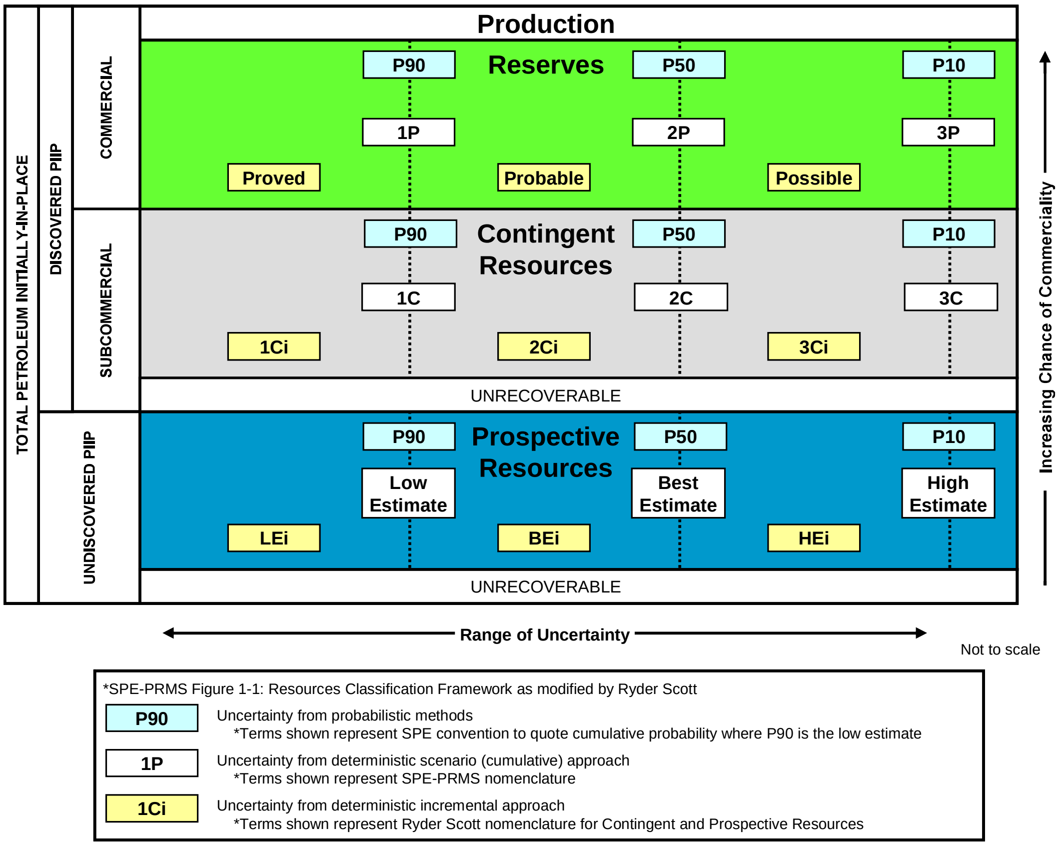
Petroleum quantities classified as Reserves, Contingent Resources or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing Contingent Resources or Prospective Resources will not achieve commercial production. Similarly, reserves and resources of different categories should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their categorization.

RESOURCES CLASSIFICATION SYSTEM (SPE-PRMS)

GRAPHICAL REPRESENTATION

Figure 1 is a graphical representation of the SPE, WPC, AAPG, SPEE resources classification system. The horizontal axis represents the “Range of Uncertainty” in the estimated potentially recoverable volume for an accumulation by a project, whereas the vertical axis represents the “Chance of Commerciality”, that is, the chance that the project will be developed and reach commercial producing status.

Figure 1
SPE, WPC, AAPG, SPEE
RESOURCES CLASSIFICATION SYSTEM*



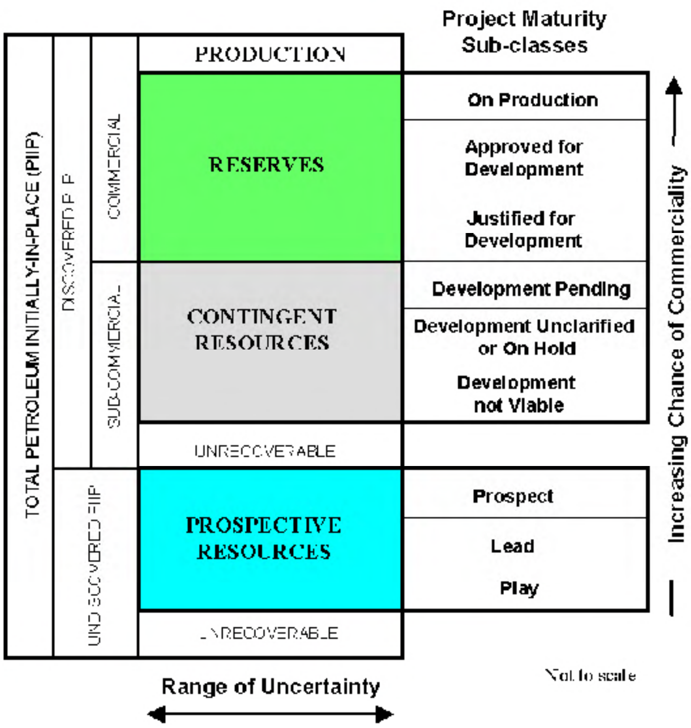
<u>INCREMENTAL TERMS FOR CONTINGENT AND PROSPECTIVE RESOURCES AS DEFINED BY RYDER SCOTT</u>

Should evaluators choose to characterize the range of uncertainty for Contingent Resources or Prospective Resources in discrete incremental quantities, they should denote such quantities as such and provide sufficient detail in their report to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of the recoverable quantities. For reports prepared by Ryder Scott Company (Ryder Scott), the range of uncertainty for discrete incremental quantities of Contingent Resources shall be termed 1C Incremental (1Ci), 2C Incremental (2Ci) and 3C Incremental (3Ci) and in the case of Prospective Resources shall be termed Low Estimate Incremental (LEi), Best Estimate Incremental (BEi) and High Estimate Incremental (HEi) where (i) denotes a specific incremental quantity.

RESOURCES CLASSIFICATION SYSTEM (SPE-PRMS)

GRAPHICAL REPRESENTATION

Figure 2
SPE, WPC, AAPG, SPEE
PROJECT MATURITY SUB-CLASSES



[1] Petroleum Resources Management System prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE); reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), March 2007.

Table 1: Recoverable Resources Classes and Sub-Classes

Class/ Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project “chance of commerciality” can be said to be 100%. The project “decision gate” is the decision to initiate commercial production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity’s current or following year’s approved budget. The project “decision gate” is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Class/ Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Class/ Sub-Class	Definition	Guidelines
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a re-classification of the project to “Not Viable” status. The project “decision gate” is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project “decision gate” is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

[1]Petroleum Resources Management System, prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE); reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), March 2007

PETROLEUM RESERVES and RESOURCES STATUS DEFINITIONS and GUIDELINES

As Adapted From:
PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE),
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

RESERVES

Reserves status categories define the development and producing status of wells and reservoirs. The SPE-PRMS Table 2 defines the reserves status categories as follows:

DEVELOPED RESERVES (SPE-PRMS DEFINITIONS)

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals which are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SPE-PRMS DEFINITIONS)

Undeveloped Reserves are quantities expected to be recovered through future investments.

Undeveloped Reserves are expected to be recovered from:

(1) new wells on undrilled acreage in known accumulations;
(2) deepening existing wells to a different (but known) reservoir;
(3) infill wells that will increase recovery; or
(4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to
  (a) recomplete an existing well; or
  (b) install production or transportation facilities for primary or improved recovery projects.

CONTINGENT RESOURCES

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent resource status categories may address the development and producing status of wells and reservoirs or may reflect the project maturity and/or be characterized by their economic status as noted in the SPE-PRMS Table 1 and Figure 2.

PROSPECTIVE RESOURCES

Prospective resources are by definition undeveloped as they are potentially recoverable from undiscovered accumulations. Prospective resource status categories reflect project maturity as noted in the SPE-PRMS Table 1 and Figure 2.

9.0 Cashflows

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018

GRAND SUMMARY - BP NORTH SEA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	23	458	335	26,257	1,377	184	136	12,196	639	68.33	38.24	6.53
12-2019	24	1,040	832	69,717	3,285	422	342	32,654	1,518	69.92	38.57	6.65
12-2020	21	905	769	67,512	3,294	371	319	31,789	1,546	71.53	39.07	6.78
12-2021	19	701	619	56,056	3,285	289	258	26,485	1,552	73.07	39.69	6.92
12-2022	16	511	444	39,706	3,285	209	185	18,736	1,556	74.44	40.67	7.07
12-2023	13	354	300	27,365	3,285	145	125	12,949	1,558	75.90	41.39	7.21
12-2024	10	229	194	18,445	3,294	94	82	8,772	1,566	77.55	41.93	7.36
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	24	4,198	3,494	305,056	21,105	1,714	1,448	143,581	9,935	72.11	39.55	6.87
REM	-	-	-	-	-	-	-	-	-			
TOTAL	24	4,198	3,494	305,056	21,105	1,714	1,448	143,581	9,935	72.11	39.55	6.87
CUMULATIVE		178,410	-	3,530,336	-				-			
ULTIMATE		182,608	3,494	3,835,391	21,105				9,935			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	12,567	5,206	79,639	-	97,412	-	-	-	-	97,412
12-2019	29,499	13,189	217,176	-	259,865	-	-	-	-	259,865
12-2020	26,550	12,459	215,568	-	254,577	-	-	-	-	254,577
12-2021	21,132	10,257	183,237	-	214,626	-	-	-	-	214,626
12-2022	15,561	7,524	132,463	-	155,549	-	-	-	-	155,549
12-2023	10,991	5,194	93,414	-	109,599	-	-	-	-	109,599
12-2024	7,297	3,428	64,521	-	75,246	-	-	-	-	75,246
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	123,597	57,259	986,018	-	1,166,873	-	-	-	-	1,166,873
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	123,597	57,259	986,018	-	1,166,873	-	-	-	-	1,166,873

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	953	29,975	-	-	-	30,928	66,484	66,484	63,390	63,390	38,034
12-2019	3,798	74,704	15,752	-	-	94,254	165,611	232,095	143,549	206,939	124,163
12-2020	3,594	73,317	-	-	-	76,911	177,666	409,760	139,998	346,937	208,162
12-2021	3,187	68,817	-	1,217	-	73,222	141,404	551,164	101,295	448,231	268,939
12-2022	2,763	62,290	-	1,227	-	66,280	89,269	640,433	58,134	506,366	303,819
12-2023	2,392	57,412	-	9,935	-	69,738	39,861	680,294	23,599	529,964	317,979
12-2024	2,106	55,625	-	9,710	-	67,441	7,805	688,098	4,201	534,165	320,499
12-2025	-	-	-	49,740	-	49,740	(49,740)	638,358	(24,337)	509,828	305,897
12-2026	-	-	-	32,621	-	32,621	(32,621)	605,737	(14,510)	495,318	297,191
12-2027	-	-	-	67,556	-	67,556	(67,556)	538,181	(27,317)	468,001	280,801
12-2028	-	-	-	84,516	-	84,516	(84,516)	453,665	(31,068)	436,933	262,160
12-2029	-	-	-	59,585	-	59,585	(59,585)	394,080	(19,912)	417,021	250,213
12-2030	-	-	-	17,442	-	17,442	(17,442)	376,639	(5,299)	411,722	247,033
12-2031	-	-	-	1,606	-	1,606	(1,606)	375,033	(443)	411,279	246,767
12-2032	-	-	-	1,123	-	1,123	(1,123)	373,910	(282)	410,997	246,598
12-2033	-	-	-	-	-	-	-	373,910	-	410,997	246,598
12-2034	-	-	-	-	-	-	-	373,910	-	410,997	246,598
12-2035	-	-	-	-	-	-	-	373,910	-	410,997	246,598
S-TOT	18,794	422,140	15,752	336,277	-	792,963	373,910		410,997		
REM	-	-	-	-	-	-	-	373,910	-	410,997	246,598
TOTAL	18,794	422,140	15,752	336,277	-	792,963	373,910		410,997		

LIFE - 7 years

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	20	272	211	6,311	336	98	76	2,272	121	67.39	43.44	7.21
12-2019	20	601	502	15,099	845	216	181	5,436	304	68.74	44.31	7.36
12-2020	17	508	448	13,557	721	183	161	4,881	259	70.11	45.19	7.52
12-2021	15	386	352	10,686	643	139	127	3,847	232	71.51	46.10	7.68
12-2022	12	294	257	7,754	621	106	92	2,791	224	72.94	47.02	7.85
12-2023	9	206	169	5,086	602	74	61	1,831	217	74.40	47.96	8.02
12-2024	6	130	104	3,130	581	47	38	1,127	209	75.89	48.92	8.19
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	20	2,397	2,044	61,624	4,349	863	736	22,185	1,565	70.71	45.60	7.60
REM	-	-	-	-	-	-	-	-	-			
TOTAL	20	2,397	2,044	61,624	4,349	863	736	22,185	1,565	70.71	45.60	7.60
CUMULATIVE		165,470	-	3,086,056	-				-			
ULTIMATE		167,867	2,044	3,147,680	4,349				1,565			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	6,604	3,305	16,380	-	26,289	-	-	-	-	26,289
12-2019	14,871	8,004	40,029	-	62,904	-	-	-	-	62,904
12-2020	12,812	7,291	36,714	-	56,816	-	-	-	-	56,816
12-2021	9,947	5,845	29,561	-	45,352	-	-	-	-	45,352
12-2022	7,726	4,343	21,908	-	33,977	-	-	-	-	33,977
12-2023	5,514	2,923	14,680	-	23,117	-	-	-	-	23,117
12-2024	3,541	1,839	9,227	-	14,607	-	-	-	-	14,607
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	61,014	33,548	168,500	-	263,062	-	-	-	-	263,062
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	61,014	33,548	168,500	-	263,062	-	-	-	-	263,062

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	181	6,561	-	-	-	6,742	19,546	19,546	18,637	18,637	11,182
12-2019	1,929	15,347	-	-	-	17,276	45,627	65,174	39,549	58,186	34,911
12-2020	1,755	13,670	-	-	-	15,425	41,392	106,565	32,616	90,802	54,481
12-2021	1,430	12,132	-	803	-	14,366	30,987	137,552	22,197	112,999	67,799
12-2022	1,111	11,346	-	803	-	13,260	20,717	158,269	13,491	126,490	75,894
12-2023	807	9,144	-	7,986	-	17,938	5,179	163,447	3,066	129,556	77,734
12-2024	569	8,444	-	7,722	-	16,736	(2,128)	161,319	(1,146)	128,411	77,046
12-2025	-	-	-	25,212	-	25,212	(25,212)	136,107	(12,336)	116,075	69,645
12-2026	-	-	-	25,713	-	25,713	(25,713)	110,395	(11,437)	104,638	62,783
12-2027	-	-	-	45,731	-	45,731	(45,731)	64,664	(18,492)	86,147	51,688
12-2028	-	-	-	65,602	-	65,602	(65,602)	(939)	(24,116)	62,031	37,219
12-2029	-	-	-	42,555	-	42,555	(42,555)	(43,494)	(14,221)	47,810	28,686
12-2030	-	-	-	-	-	-	-	(43,494)	-	47,810	28,686
12-2031	-	-	-	-	-	-	-	(43,494)	-	47,810	28,686
12-2032	-	-	-	-	-	-	-	(43,494)	-	47,810	28,686
12-2033	-	-	-	-	-	-	-	(43,494)	-	47,810	28,686
12-2034	-	-	-	-	-	-	-	(43,494)	-	47,810	28,686
12-2035	-	-	-	-	-	-	-	(43,494)	-	47,810	28,686
S-TOT	7,783	76,645	-	222,128	-	306,556	(43,494)		47,810		
REM	-	-	-	-	-	-	-	(43,494)	-	47,810	28,686
TOTAL	7,783	76,645	-	222,128	-	306,556	(43,494)		47,810		

LIFE - 7 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	2	139	111	19,625	1,023	69	55.60	9,812	511	71.30	30.70	6.36
12-2019	3	347	306	54,019	2,400	174	153	27,010	1,200	72.72	31.48	6.50
12-2020	3	330	302	53,501	2,573	165	151	26,750	1,287	74.18	32.27	6.64
12-2021	3	267	255	45,062	2,642	134	127	22,531	1,321	75.66	33.09	6.78
12-2022	3	183	179	31,744	2,664	92	90	15,872	1,332	77.17	33.92	6.93
12-2023	3	125	125	22,137	2,683	63	62	11,068	1,342	78.72	34.76	7.08
12-2024	3	85	86	15,235	2,713	43	43	7,617	1,356	80.29	35.63	7.23
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	1,476	1,364	241,323	16,698	738	682	120,661	8,349	74.94	32.77	6.73
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	1,476	1,364	241,323	16,698	738	682	120,661	8,349	74.94	32.77	6.73
CUMULATIVE		2,805	-	417,916	-				-			
ULTIMATE		4,282	1,364	659,239	16,698				8,349			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	4,946	1,707	62,455	-	69,107	-	-	-	-	69,107
12-2019	12,623	4,809	175,612	-	193,043	-	-	-	-	193,043
12-2020	12,230	4,880	177,664	-	194,774	-	-	-	-	194,774
12-2021	10,107	4,211	152,854	-	167,171	-	-	-	-	167,171
12-2022	7,063	3,039	109,985	-	120,087	-	-	-	-	120,087
12-2023	4,922	2,172	78,340	-	85,433	-	-	-	-	85,433
12-2024	3,427	1,532	55,067	-	60,026	-	-	-	-	60,026
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	55,317	22,348	811,976	-	889,642	-	-	-	-	889,642
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	55,317	22,348	811,976	-	889,642	-	-	-	-	889,642

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	669	23,060	-	-	-	23,729	45,378	45,378	43,267	43,267	25,960
12-2019	1,665	58,481	15,752	-	-	75,899	117,144	162,523	101,539	144,806	86,883
12-2020	1,686	58,939	-	-	-	60,625	134,149	296,672	105,708	250,513	150,308
12-2021	1,647	55,979	-	-	-	57,626	109,545	406,217	78,473	328,986	197,392
12-2022	1,573	50,492	-	-	-	52,066	68,021	474,238	44,297	373,283	223,970
12-2023	1,528	47,805	-	1,030	-	50,363	35,070	509,309	20,762	394,046	236,427
12-2024	1,503	46,748	-	1,051	-	49,302	10,724	520,032	5,772	399,817	239,890
12-2025	-	-	-	2,281	-	2,281	(2,281)	517,752	(1,116)	398,701	239,221
12-2026	-	-	-	2,323	-	2,323	(2,323)	515,429	(1,033)	397,668	238,601
12-2027	-	-	-	17,882	-	17,882	(17,882)	497,546	(7,231)	390,437	234,262
12-2028	-	-	-	18,479	-	18,479	(18,479)	479,068	(6,793)	383,644	230,187
12-2029	-	-	-	17,030	-	17,030	(17,030)	462,038	(5,691)	377,953	226,772
12-2030	-	-	-	17,442	-	17,442	(17,442)	444,596	(5,299)	372,655	223,593
12-2031	-	-	-	1,606	-	1,606	(1,606)	442,991	(443)	372,211	223,327
12-2032	-	-	-	1,123	-	1,123	(1,123)	441,868	(282)	371,929	223,158
12-2033	-	-	-	-	-	-	-	441,868	-	371,929	223,158
12-2034	-	-	-	-	-	-	-	441,868	-	371,929	223,158
12-2035	-	-	-	-	-	-	-	441,868	-	371,929	223,158
S-TOT	10,272	341,503	15,752	80,246	-	447,773	441,868		371,929		
REM	-	-	-	-	-	-	-	441,868	-	371,929	223,158
TOTAL	10,272	341,503	15,752	80,246	-	447,773	441,868		371,929		

LIFE - 7 years

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	1	47	13	320	18	17	4	112	6	61.52	43.44	7.21
12-2019	1	92	24	599	40	32	9	208	14	62.75	44.31	7.36
12-2020	1	68	18	454	-	24	6	158	-	64.01	45.19	7.52
12-2021	1	47	13	307	-	17	4	107	-	65.29	46.10	7.68
12-2022	1	33	9	208	-	12	3	73	-	66.59	47.02	7.85
12-2023	1	23	6	141	-	8	2	49	-	67.93	47.96	8.02
12-2024	1	14	3	79	-	5	1	28	-	69.28	48.92	8.19
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
CUMULATIVE		10,135	-	26,363	-				-			
ULTIMATE		10,460	86	28,473	59				20			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	1,017	195	804	-	2,016	-	-	-	-	2,016
12-2019	2,005	377	1,535	-	3,918	-	-	-	-	3,918
12-2020	1,508	288	1,189	-	2,986	-	-	-	-	2,986
12-2021	1,078	202	822	-	2,102	-	-	-	-	2,102
12-2022	773	142	570	-	1,485	-	-	-	-	1,485
12-2023	555	100	395	-	1,049	-	-	-	-	1,049
12-2024	328	58	227	-	613	-	-	-	-	613
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	103	354	-	-	-	457	1,559	1,559	1,487	1,487	892
12-2019	204	875	-	-	-	1,079	2,839	4,398	2,461	3,947	2,368
12-2020	153	708	-	-	-	861	2,125	6,523	1,674	5,622	3,373
12-2021	110	707	-	414	-	1,230	872	7,395	624	6,246	3,748
12-2022	79	452	-	423	-	954	531	7,926	346	6,592	3,955
12-2023	56	463	-	918	-	1,437	(388)	7,538	(230)	6,362	3,817
12-2024	33	433	-	937	-	1,404	(790)	6,747	(425)	5,937	3,562
12-2025	-	-	-	22,248	-	22,248	(22,248)	(15,501)	(10,885)	(4,948)	(2,969)
12-2026	-	-	-	4,586	-	4,586	(4,586)	(20,086)	(2,040)	(6,988)	(4,193)
12-2027	-	-	-	3,943	-	3,943	(3,943)	(24,030)	(1,595)	(8,583)	(5,150)
12-2028	-	-	-	434	-	434	(434)	(24,464)	(160)	(8,742)	(5,245)
12-2029	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2030	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2031	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2032	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2033	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2034	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2035	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
S-TOT	739	3,991	-	33,904	-	38,633	(24,464)		(8,742)		
REM	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
TOTAL	739	3,991	-	33,904	-	38,633	(24,464)		(8,742)		

LIFE - 7 years

DISCOUNT RATE @ 10%

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018

GRAND SUMMARY - BP NORTH SEA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	23	476	350	27,108	1,377	191	142	12,571	639	68.34	38.32	6.53
12-2019	26	1,241	1,034	79,657	3,285	499	418	36,863	1,518	69.87	39.23	6.68
12-2020	23	1,191	1,040	83,099	3,294	483	423	38,638	1,546	71.47	39.82	6.81
12-2021	22	961	870	73,866	3,285	394	358	34,611	1,552	73.09	40.22	6.94
12-2022	19	763	693	61,301	3,285	315	288	28,876	1,556	74.67	40.76	7.07
12-2023	16	579	532	50,287	3,285	242	224	23,873	1,558	76.34	41.11	7.21
12-2024	13	389	365	40,029	3,294	168	159	19,304	1,566	78.31	40.67	7.32
12-2025	11	283	259	32,197	3,285	125	117	15,708	1,567	80.32	40.38	7.45
12-2026	7	208	177	25,787	3,285	93	83	12,748	1,570	82.20	39.58	7.57
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	26	6,091	5,320	473,331	27,675	2,510	2,213	223,191	13,072	73.34	40.01	7.00
REM	-	-	-	-	-	-	-	-	-			
TOTAL	26	6,091	5,320	473,331	27,675	2,510	2,213	223,191	13,072	73.34	40.01	7.00
CUMULATIVE		178,410	-	3,530,336	-				-			
ULTIMATE		184,502	5,320	4,003,667	27,675				13,072			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	13,039	5,439	82,134	-	100,612	-	-	-	-	100,612
12-2019	34,867	16,414	246,231	-	297,512	-	-	-	-	297,512
12-2020	34,519	16,859	263,197	-	314,575	-	-	-	-	314,575
12-2021	28,827	14,417	240,167	-	283,411	-	-	-	-	283,411
12-2022	23,524	11,732	204,281	-	239,536	-	-	-	-	239,536
12-2023	18,473	9,211	172,030	-	199,715	-	-	-	-	199,715
12-2024	13,127	6,463	141,299	-	160,890	-	-	-	-	160,890
12-2025	10,018	4,709	116,959	-	131,687	-	-	-	-	131,687
12-2026	7,673	3,291	96,505	-	107,469	-	-	-	-	107,469
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	184,067	88,535	1,562,804	-	1,835,407	-	-	-	-	1,835,407
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	184,067	88,535	1,562,804	-	1,835,407	-	-	-	-	1,835,407

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	963	29,950	-	-	-	30,913	69,698	69,698	66,455	66,455	39,873
12-2019	4,439	76,028	15,752	-	-	96,220	201,292	270,990	174,477	240,932	144,559
12-2020	4,444	76,275	-	-	-	80,719	233,856	504,846	184,275	425,207	255,124
12-2021	3,935	72,971	-	1,217	-	78,124	205,288	710,134	147,058	572,265	343,359
12-2022	3,453	68,285	-	1,227	-	72,965	166,571	876,705	108,475	680,740	408,444
12-2023	2,998	64,386	-	9,935	-	77,318	122,396	999,101	72,462	753,202	451,921
12-2024	2,482	63,081	-	9,710	-	75,273	85,617	1,084,718	46,079	799,281	479,569
12-2025	2,186	62,665	-	49,740	-	114,591	17,097	1,101,815	8,365	807,646	484,588
12-2026	1,973	62,451	-	32,621	-	97,045	10,424	1,112,238	4,636	812,283	487,370
12-2027	-	-	-	67,556	-	67,556	(67,556)	1,044,682	(27,317)	784,966	470,979
12-2028	-	-	-	84,516	-	84,516	(84,516)	960,166	(31,068)	753,897	452,338
12-2029	-	-	-	59,585	-	59,585	(59,585)	900,582	(19,912)	733,985	440,391
12-2030	-	-	-	17,442	-	17,442	(17,442)	883,140	(5,299)	728,686	437,212
12-2031	-	-	-	1,606	-	1,606	(1,606)	881,534	(443)	728,243	436,946
12-2032	-	-	-	1,123	-	1,123	(1,123)	880,412	(282)	727,961	436,777
12-2033	-	-	-	-	-	-	-	880,412	-	727,961	436,777
12-2034	-	-	-	-	-	-	-	880,412	-	727,961	436,777
12-2035	-	-	-	-	-	-	-	880,412	-	727,961	436,777
S-TOT	26,873	576,092	15,752	336,277	-	954,995	880,412		727,961		
REM	-	-	-	-	-	-	-	880,412	-	727,961	436,777
TOTAL	26,873	576,092	15,752	336,277	-	954,995	880,412		727,961		

LIFE - 9 years

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	20	286	224	6,680	336	103	80	2,405	121	67.39	43.44	7.21
12-2019	22	769	679	20,534	845	277	244	7,392	304	68.74	44.31	7.36
12-2020	19	731	669	20,304	721	263	241	7,309	259	70.11	45.19	7.52
12-2021	18	563	534	16,251	643	203	192	5,850	232	71.51	46.10	7.68
12-2022	15	438	409	12,451	621	158	147	4,482	224	72.94	47.02	7.85
12-2023	12	314	293	8,920	602	113	106	3,211	217	74.40	47.96	8.02
12-2024	9	176	164	4,989	581	63	59	1,796	209	75.89	48.92	8.19
12-2025	8	122	94	2,793	541	44	34	1,005	195	77.41	49.90	8.36
12-2026	4	76	37	1,040	518	27	13	374	186	78.95	50.90	8.54
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	22	3,474	3,102	93,961	5,407	1,251	1,117	33,826	1,947	71.29	45.94	7.66
REM	-	-	-	-	-	-	-	-	-			
TOTAL	22	3,474	3,102	93,961	5,407	1,251	1,117	33,826	1,947	71.29	45.94	7.66
CUMULATIVE		165,470	-	3,086,056	-				-			
ULTIMATE		168,944	3,102	3,180,017	5,407				1,947			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	6,942	3,495	17,335	-	27,772	-	-	-	-	27,772
12-2019	19,017	10,826	54,439	-	84,282	-	-	-	-	84,282
12-2020	18,447	10,883	54,985	-	84,315	-	-	-	-	84,315
12-2021	14,503	8,857	44,954	-	68,314	-	-	-	-	68,314
12-2022	11,492	6,930	35,181	-	53,602	-	-	-	-	53,602
12-2023	8,417	5,065	25,744	-	39,226	-	-	-	-	39,226
12-2024	4,814	2,890	14,705	-	22,408	-	-	-	-	22,408
12-2025	3,386	1,681	8,408	-	13,476	-	-	-	-	13,476
12-2026	2,152	681	3,197	-	6,030	-	-	-	-	6,030
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	89,170	51,307	258,948	-	399,426	-	-	-	-	399,426
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	89,170	51,307	258,948	-	399,426	-	-	-	-	399,426

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	186	6,686	-	-	-	6,873	20,899	20,899	19,927	19,927	11,956
12-2019	2,533	17,927	-	-	-	20,460	63,822	84,722	55,320	75,247	45,148
12-2020	2,532	16,639	-	-	-	19,171	65,144	149,866	51,333	126,580	75,948
12-2021	2,078	14,325	-	803	-	17,207	51,108	200,974	36,611	163,191	97,915
12-2022	1,664	12,582	-	803	-	15,050	38,552	239,526	25,106	188,297	112,978
12-2023	1,260	9,635	-	7,986	-	18,881	20,345	259,871	12,045	200,342	120,205
12-2024	788	7,200	-	7,722	-	15,710	6,698	266,569	3,605	203,947	122,368
12-2025	541	3,706	-	25,212	-	29,458	(15,982)	250,587	(7,820)	196,127	117,676
12-2026	335	1,866	-	25,713	-	27,914	(21,884)	228,703	(9,734)	186,393	111,836
12-2027	-	-	-	45,731	-	45,731	(45,731)	182,973	(18,492)	167,902	100,741
12-2028	-	-	-	65,602	-	65,602	(65,602)	117,370	(24,116)	143,786	86,272
12-2029	-	-	-	42,555	-	42,555	(42,555)	74,815	(14,221)	129,565	77,739
12-2030	-	-	-	-	-	-	-	74,815	-	129,565	77,739
12-2031	-	-	-	-	-	-	-	74,815	-	129,565	77,739
12-2032	-	-	-	-	-	-	-	74,815	-	129,565	77,739
12-2033	-	-	-	-	-	-	-	74,815	-	129,565	77,739
12-2034	-	-	-	-	-	-	-	74,815	-	129,565	77,739
12-2035	-	-	-	-	-	-	-	74,815	-	129,565	77,739
S-TOT	11,917	90,566	-	222,128	-	324,611	74,815		129,565		
REM	-	-	-	-	-	-	-	74,815	-	129,565	77,739
TOTAL	11,917	90,566	-	222,128	-	324,611	74,815		129,565		

LIFE - 9 years

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	2	143	114	20,109	1,023	71	56.97	10,054	511	71.30	30.70	6.36
12-2019	3	381	331	58,524	2,400	190	166	29,262	1,200	72.72	31.48	6.50
12-2020	3	393	352	62,341	2,573	196	176	31,171	1,287	74.18	32.27	6.64
12-2021	3	350	324	57,308	2,642	175	162	28,654	1,321	75.66	33.09	6.78
12-2022	3	292	275	48,641	2,664	146	137	24,321	1,332	77.17	33.92	6.93
12-2023	3	241	233	41,225	2,683	121	116	20,613	1,342	78.72	34.76	7.08
12-2024	3	199	197	34,961	2,713	99	99	17,481	1,356	80.29	35.63	7.23
12-2025	3	162	166	29,404	2,744	81	83	14,702	1,372	81.90	36.51	7.38
12-2026	3	132	140	24,748	2,767	66	70	12,374	1,384	83.54	37.41	7.54
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	2,292	2,132	377,261	22,209	1,146	1,066	188,631	11,105	76.46	33.65	6.88
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	2,292	2,132	377,261	22,209	1,146	1,066	188,631	11,105	76.46	33.65	6.88
CUMULATIVE		2,805	-	417,916	-				-			
ULTIMATE		5,098	2,132	795,177	22,209				11,105			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	5,081	1,749	63,994	-	70,823	-	-	-	-	70,823
12-2019	13,844	5,211	190,257	-	209,312	-	-	-	-	209,312
12-2020	14,563	5,688	207,022	-	227,273	-	-	-	-	227,273
12-2021	13,245	5,358	194,392	-	212,995	-	-	-	-	212,995
12-2022	11,259	4,660	168,531	-	184,449	-	-	-	-	184,449
12-2023	9,501	4,047	145,892	-	159,440	-	-	-	-	159,440
12-2024	7,985	3,515	126,368	-	137,869	-	-	-	-	137,869
12-2025	6,632	3,028	108,551	-	118,211	-	-	-	-	118,211
12-2026	5,520	2,610	93,308	-	101,439	-	-	-	-	101,439
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	87,631	35,866	1,298,314	-	1,421,811	-	-	-	-	1,421,811
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	87,631	35,866	1,298,314	-	1,421,811	-	-	-	-	1,421,811

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	673	22,910	-	-	-	23,584	47,240	47,240	45,041	45,041	27,025
12-2019	1,703	57,226	15,752	-	-	74,681	134,631	181,871	116,696	161,737	97,042
12-2020	1,759	58,928	-	-	-	60,687	166,587	348,457	131,268	293,005	175,803
12-2021	1,747	57,939	-	-	-	59,687	153,308	501,765	109,822	402,827	241,696
12-2022	1,710	55,251	-	-	-	56,962	127,488	629,253	83,024	485,851	291,511
12-2023	1,682	54,288	-	1,030	-	57,000	102,440	731,693	60,647	546,498	327,899
12-2024	1,661	55,448	-	1,051	-	58,160	79,709	811,401	42,900	589,397	353,638
12-2025	1,645	58,959	-	2,281	-	62,885	55,327	866,728	27,070	616,467	369,880
12-2026	1,637	60,585	-	2,323	-	64,545	36,893	903,621	16,410	632,877	379,726
12-2027	-	-	-	17,882	-	17,882	(17,882)	885,739	(7,231)	625,647	375,388
12-2028	-	-	-	18,479	-	18,479	(18,479)	867,260	(6,793)	618,854	371,312
12-2029	-	-	-	17,030	-	17,030	(17,030)	850,231	(5,691)	613,163	367,898
12-2030	-	-	-	17,442	-	17,442	(17,442)	832,789	(5,299)	607,864	364,718
12-2031	-	-	-	1,606	-	1,606	(1,606)	831,183	(443)	607,420	364,452
12-2032	-	-	-	1,123	-	1,123	(1,123)	830,061	(282)	607,139	364,283
12-2033	-	-	-	-	-	-	-	830,061	-	607,139	364,283
12-2034	-	-	-	-	-	-	-	830,061	-	607,139	364,283
12-2035	-	-	-	-	-	-	-	830,061	-	607,139	364,283
S-TOT	14,217	481,535	15,752	80,246	-	591,751	830,061		607,139		
REM	-	-	-	-	-	-	-	830,061	-	607,139	364,283
TOTAL	14,217	481,535	15,752	80,246	-	591,751	830,061		607,139		

LIFE - 9 years

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	1	47	13	320	18	17	4	112	6	61.52	43.44	7.21
12-2019	1	92	24	599	40	32	9	208	14	62.75	44.31	7.36
12-2020	1	68	18	454	-	24	6	158	-	64.01	45.19	7.52
12-2021	1	47	13	307	-	17	4	107	-	65.29	46.10	7.68
12-2022	1	33	9	208	-	12	3	73	-	66.59	47.02	7.85
12-2023	1	23	6	141	-	8	2	49	-	67.93	47.96	8.02
12-2024	1	14	3	79	-	5	1	28	-	69.28	48.92	8.19
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
CUMULATIVE		10,135	-	26,363	-				-			
ULTIMATE		10,460	86	28,473	59				20			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	1,017	195	804	-	2,016	-	-	-	-	2,016
12-2019	2,005	377	1,535	-	3,918	-	-	-	-	3,918
12-2020	1,508	288	1,189	-	2,986	-	-	-	-	2,986
12-2021	1,078	202	822	-	2,102	-	-	-	-	2,102
12-2022	773	142	570	-	1,485	-	-	-	-	1,485
12-2023	555	100	395	-	1,049	-	-	-	-	1,049
12-2024	328	58	227	-	613	-	-	-	-	613
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	103	354	-	-	-	457	1,559	1,559	1,487	1,487	892
12-2019	204	875	-	-	-	1,079	2,839	4,398	2,461	3,947	2,368
12-2020	153	708	-	-	-	861	2,125	6,523	1,674	5,622	3,373
12-2021	110	707	-	414	-	1,230	872	7,395	624	6,246	3,748
12-2022	79	452	-	423	-	954	531	7,926	346	6,592	3,955
12-2023	56	463	-	918	-	1,437	(388)	7,538	(230)	6,362	3,817
12-2024	33	433	-	937	-	1,404	(790)	6,747	(425)	5,937	3,562
12-2025	-	-	-	22,248	-	22,248	(22,248)	(15,501)	(10,885)	(4,948)	(2,969)
12-2026	-	-	-	4,586	-	4,586	(4,586)	(20,086)	(2,040)	(6,988)	(4,193)
12-2027	-	-	-	3,943	-	3,943	(3,943)	(24,030)	(1,595)	(8,583)	(5,150)
12-2028	-	-	-	434	-	434	(434)	(24,464)	(160)	(8,742)	(5,245)
12-2029	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2030	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2031	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2032	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2033	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2034	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2035	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
S-TOT	739	3,991	-	33,904	-	38,633	(24,464)		(8,742)		
REM	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
TOTAL	739	3,991	-	33,904	-	38,633	(24,464)		(8,742)		

LIFE - 7 years

DISCOUNT RATE @ 10%

THESE DATA ARE PART OF A RYDER SCOTT REPORT AND ARE SUBJECT TO THE CONDITIONS IN THE TEXT OF THE REPORT
THESE DATA WERE GENERATED USING THE PALANTIRCASH PROGRAM

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018

GRAND SUMMARY - BP NORTH SEA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	23	476	350	27,108	1,377	191	142	12,571	639	68.34	38.32	6.53
12-2019	26	1,291	1,087	88,968	3,285	524	445	41,518	1,518	70.01	38.77	6.66
12-2020	23	1,254	1,109	95,329	3,294	514	458	44,753	1,546	71.63	39.25	6.79
12-2021	22	1,018	937	85,661	3,285	423	392	40,509	1,552	73.27	39.62	6.92
12-2022	19	814	755	72,284	3,285	341	319	34,367	1,556	74.86	40.10	7.05
12-2023	16	624	589	60,458	3,285	264	253	28,958	1,558	76.54	40.39	7.18
12-2024	13	428	418	49,428	3,294	187	185	24,003	1,566	78.52	39.95	7.30
12-2025	11	317	308	40,798	3,285	142	141	20,008	1,567	80.51	39.71	7.43
12-2026	7	237	221	33,653	3,285	108	105	16,681	1,570	82.38	39.12	7.56
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	26	6,459	5,773	553,687	27,675	2,694	2,439	263,369	13,072	73.61	39.47	7.00
REM	-	-	-	-	-	-	-	-	-			
TOTAL	26	6,459	5,773	553,687	27,675	2,694	2,439	263,369	13,072	73.61	39.47	7.00
CUMULATIVE		178,410	-	3,530,336	-				-			
ULTIMATE		184,870	5,773	4,084,023	27,675				13,072			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	13,039	5,439	82,134	-	100,612	-	-	-	-	100,612
12-2019	36,677	17,240	276,500	-	330,418	-	-	-	-	330,418
12-2020	36,838	17,971	303,811	-	358,621	-	-	-	-	358,621
12-2021	31,005	15,516	280,178	-	326,699	-	-	-	-	326,699
12-2022	25,493	12,780	242,335	-	280,608	-	-	-	-	280,608
12-2023	20,239	10,206	208,024	-	238,469	-	-	-	-	238,469
12-2024	14,704	7,404	175,270	-	197,379	-	-	-	-	197,379
12-2025	11,408	5,591	148,713	-	165,712	-	-	-	-	165,712
12-2026	8,892	4,117	126,161	-	139,169	-	-	-	-	139,169
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	198,295	96,265	1,843,126	-	2,137,685	-	-	-	-	2,137,685
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	198,295	96,265	1,843,126	-	2,137,685	-	-	-	-	2,137,685

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	963	29,827	-	-	-	30,790	69,821	69,821	66,572	66,572	39,943
12-2019	4,505	78,817	15,752	-	-	99,074	231,344	301,165	200,525	267,097	160,258
12-2020	4,530	80,031	-	-	-	84,561	274,060	575,225	215,955	483,052	289,831
12-2021	4,018	76,671	-	1,217	-	81,905	244,794	820,019	175,358	658,410	395,046
12-2022	3,530	71,848	-	1,227	-	76,605	204,003	1,024,021	132,852	791,263	474,758
12-2023	3,069	67,790	-	9,935	-	80,794	157,675	1,181,696	93,348	884,610	530,766
12-2024	2,547	66,264	-	9,710	-	78,522	118,857	1,300,553	63,969	948,579	569,148
12-2025	2,246	65,633	-	49,740	-	117,619	48,093	1,348,646	23,531	972,110	583,266
12-2026	2,027	65,124	-	32,621	-	99,773	39,396	1,388,042	17,523	989,634	593,780
12-2027	-	-	-	67,556	-	67,556	(67,556)	1,320,486	(27,317)	962,316	577,390
12-2028	-	-	-	84,516	-	84,516	(84,516)	1,235,970	(31,068)	931,248	558,749
12-2029	-	-	-	59,585	-	59,585	(59,585)	1,176,385	(19,912)	911,336	546,802
12-2030	-	-	-	17,442	-	17,442	(17,442)	1,158,944	(5,299)	906,037	543,622
12-2031	-	-	-	1,606	-	1,606	(1,606)	1,157,338	(443)	905,594	543,356
12-2032	-	-	-	1,123	-	1,123	(1,123)	1,156,216	(282)	905,312	543,187
12-2033	-	-	-	-	-	-	-	1,156,216	-	905,312	543,187
12-2034	-	-	-	-	-	-	-	1,156,216	-	905,312	543,187
12-2035	-	-	-	-	-	-	-	1,156,216	-	905,312	543,187
S-TOT	27,434	602,007	15,752	336,277	-	981,470	1,156,216		905,312		
REM	-	-	-	-	-	-	-	1,156,216	-	905,312	543,187
TOTAL	27,434	602,007	15,752	336,277	-	981,470	1,156,216		905,312		

LIFE - 9 years

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	20	286	224	6,680	336	103	80	2,405	121	67.39	43.44	7.21
12-2019	22	769	679	20,534	845	277	244	7,392	304	68.74	44.31	7.36
12-2020	19	731	669	20,304	721	263	241	7,309	259	70.11	45.19	7.52
12-2021	18	563	534	16,251	643	203	192	5,850	232	71.51	46.10	7.68
12-2022	15	438	409	12,451	621	158	147	4,482	224	72.94	47.02	7.85
12-2023	12	314	293	8,920	602	113	106	3,211	217	74.40	47.96	8.02
12-2024	9	176	164	4,989	581	63	59	1,796	209	75.89	48.92	8.19
12-2025	8	122	94	2,793	541	44	34	1,005	195	77.41	49.90	8.36
12-2026	4	76	37	1,040	518	27	13	374	186	78.95	50.90	8.54
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	22	3,474	3,102	93,961	5,407	1,251	1,117	33,826	1,947	71.29	45.94	7.66
REM	-	-	-	-	-	-	-	-	-			
TOTAL	22	3,474	3,102	93,961	5,407	1,251	1,117	33,826	1,947	71.29	45.94	7.66
CUMULATIVE		165,470	-	3,086,056	-				-			
ULTIMATE		168,944	3,102	3,180,017	5,407				1,947			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	6,942	3,495	17,335	-	27,772	-	-	-	-	27,772
12-2019	19,017	10,826	54,439	-	84,282	-	-	-	-	84,282
12-2020	18,447	10,883	54,985	-	84,315	-	-	-	-	84,315
12-2021	14,503	8,857	44,954	-	68,314	-	-	-	-	68,314
12-2022	11,492	6,930	35,181	-	53,602	-	-	-	-	53,602
12-2023	8,417	5,065	25,744	-	39,226	-	-	-	-	39,226
12-2024	4,814	2,890	14,705	-	22,408	-	-	-	-	22,408
12-2025	3,386	1,681	8,408	-	13,476	-	-	-	-	13,476
12-2026	2,152	681	3,197	-	6,030	-	-	-	-	6,030
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	89,170	51,307	258,948	-	399,426	-	-	-	-	399,426
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	89,170	51,307	258,948	-	399,426	-	-	-	-	399,426

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	186	6,663	-	-	-	6,850	20,923	20,923	19,949	19,949	11,969
12-2019	2,533	16,819	-	-	-	19,352	64,930	85,853	56,280	76,229	45,738
12-2020	2,532	15,382	-	-	-	17,914	66,401	152,254	52,323	128,553	77,132
12-2021	2,078	13,157	-	803	-	16,038	52,276	204,530	37,448	166,001	99,600
12-2022	1,664	11,445	-	803	-	13,912	39,690	244,220	25,847	191,848	115,109
12-2023	1,260	8,546	-	7,986	-	17,793	21,434	265,654	12,689	204,537	122,722
12-2024	788	6,326	-	7,722	-	14,836	7,572	273,226	4,076	208,612	125,167
12-2025	541	2,960	-	25,212	-	28,712	(15,236)	257,990	(7,455)	201,158	120,695
12-2026	335	1,467	-	25,713	-	27,515	(21,485)	236,504	(9,557)	191,601	114,961
12-2027	-	-	-	45,731	-	45,731	(45,731)	190,774	(18,492)	173,109	103,866
12-2028	-	-	-	65,602	-	65,602	(65,602)	125,171	(24,116)	148,994	89,396
12-2029	-	-	-	42,555	-	42,555	(42,555)	82,616	(14,221)	134,773	80,864
12-2030	-	-	-	-	-	-	-	82,616	-	134,773	80,864
12-2031	-	-	-	-	-	-	-	82,616	-	134,773	80,864
12-2032	-	-	-	-	-	-	-	82,616	-	134,773	80,864
12-2033	-	-	-	-	-	-	-	82,616	-	134,773	80,864
12-2034	-	-	-	-	-	-	-	82,616	-	134,773	80,864
12-2035	-	-	-	-	-	-	-	82,616	-	134,773	80,864
S-TOT	11,917	82,765	-	222,128	-	316,810	82,616		134,773		
REM	-	-	-	-	-	-	-	82,616	-	134,773	80,864
TOTAL	11,917	82,765	-	222,128	-	316,810	82,616		134,773		

LIFE - 9 years

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	2	143	114	20,109	1,023	71	56.97	10,054	511	71.30	30.70	6.36
12-2019	3	431	384	67,835	2,400	215	192	33,918	1,200	72.72	31.48	6.50
12-2020	3	455	421	74,572	2,573	228	211	37,286	1,287	74.18	32.27	6.64
12-2021	3	408	390	69,103	2,642	204	195	34,552	1,321	75.66	33.09	6.78
12-2022	3	343	337	59,625	2,664	171	168	29,812	1,332	77.17	33.92	6.93
12-2023	3	286	290	51,396	2,683	143	145	25,698	1,342	78.72	34.76	7.08
12-2024	3	238	250	44,359	2,713	119	125	22,180	1,356	80.29	35.63	7.23
12-2025	3	196	214	38,006	2,744	98	107	19,003	1,372	81.90	36.51	7.38
12-2026	3	161	184	32,613	2,767	81	92	16,307	1,384	83.54	37.41	7.54
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	2,660	2,584	457,617	22,209	1,330	1,292	228,809	11,105	76.57	33.74	6.90
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	2,660	2,584	457,617	22,209	1,330	1,292	228,809	11,105	76.57	33.74	6.90
CUMULATIVE		2,805	-	417,916	-				-			
ULTIMATE		5,466	2,584	875,533	22,209				11,105			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	5,081	1,749	63,994	-	70,823	-	-	-	-	70,823
12-2019	15,655	6,037	220,526	-	242,218	-	-	-	-	242,218
12-2020	16,883	6,800	247,636	-	271,319	-	-	-	-	271,319
12-2021	15,423	6,457	234,403	-	256,283	-	-	-	-	256,283
12-2022	13,228	5,709	206,585	-	225,521	-	-	-	-	225,521
12-2023	11,268	5,041	181,885	-	198,194	-	-	-	-	198,194
12-2024	9,562	4,456	160,339	-	174,357	-	-	-	-	174,357
12-2025	8,021	3,910	140,304	-	152,236	-	-	-	-	152,236
12-2026	6,740	3,436	122,964	-	133,139	-	-	-	-	133,139
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	101,859	43,595	1,578,636	-	1,724,090	-	-	-	-	1,724,090
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	101,859	43,595	1,578,636	-	1,724,090	-	-	-	-	1,724,090

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	673	22,810	-	-	-	23,484	47,339	47,339	45,136	45,136	27,082
12-2019	1,768	61,123	15,752	-	-	78,643	163,575	210,914	141,784	186,920	112,152
12-2020	1,844	63,941	-	-	-	65,786	205,534	416,448	161,957	348,878	209,327
12-2021	1,830	62,807	-	-	-	64,637	191,646	608,093	137,285	486,163	291,698
12-2022	1,787	59,952	-	-	-	61,739	163,782	771,875	106,659	592,823	355,694
12-2023	1,752	58,782	-	1,030	-	61,564	136,630	908,505	80,888	673,711	404,227
12-2024	1,726	59,505	-	1,051	-	62,283	112,075	1,020,580	60,319	734,030	440,418
12-2025	1,705	62,673	-	2,281	-	66,659	85,577	1,106,157	41,871	775,901	465,541
12-2026	1,692	63,657	-	2,323	-	67,672	65,467	1,171,624	29,120	805,021	483,012
12-2027	-	-	-	17,882	-	17,882	(17,882)	1,153,742	(7,231)	797,790	478,674
12-2028	-	-	-	18,479	-	18,479	(18,479)	1,135,263	(6,793)	790,997	474,598
12-2029	-	-	-	17,030	-	17,030	(17,030)	1,118,233	(5,691)	785,306	471,184
12-2030	-	-	-	17,442	-	17,442	(17,442)	1,100,792	(5,299)	780,007	468,004
12-2031	-	-	-	1,606	-	1,606	(1,606)	1,099,186	(443)	779,564	467,738
12-2032	-	-	-	1,123	-	1,123	(1,123)	1,098,064	(282)	779,282	467,569
12-2033	-	-	-	-	-	-	-	1,098,064	-	779,282	467,569
12-2034	-	-	-	-	-	-	-	1,098,064	-	779,282	467,569
12-2035	-	-	-	-	-	-	-	1,098,064	-	779,282	467,569
S-TOT	14,777	515,251	15,752	80,246	-	626,026	1,098,064		779,282		
REM	-	-	-	-	-	-	-	1,098,064	-	779,282	467,569
TOTAL	14,777	515,251	15,752	80,246	-	626,026	1,098,064		779,282		

LIFE - 9 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	1	47	13	320	18	17	4	112	6	61.52	43.44	7.21
12-2019	1	92	24	599	40	32	9	208	14	62.75	44.31	7.36
12-2020	1	68	18	454	-	24	6	158	-	64.01	45.19	7.52
12-2021	1	47	13	307	-	17	4	107	-	65.29	46.10	7.68
12-2022	1	33	9	208	-	12	3	73	-	66.59	47.02	7.85
12-2023	1	23	6	141	-	8	2	49	-	67.93	47.96	8.02
12-2024	1	14	3	79	-	5	1	28	-	69.28	48.92	8.19
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
CUMULATIVE		10,135	-	26,363	-				-			
ULTIMATE		10,460	86	28,473	59				20			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	1,017	195	804	-	2,016	-	-	-	-	2,016
12-2019	2,005	377	1,535	-	3,918	-	-	-	-	3,918
12-2020	1,508	288	1,189	-	2,986	-	-	-	-	2,986
12-2021	1,078	202	822	-	2,102	-	-	-	-	2,102
12-2022	773	142	570	-	1,485	-	-	-	-	1,485
12-2023	555	100	395	-	1,049	-	-	-	-	1,049
12-2024	328	58	227	-	613	-	-	-	-	613
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	103	354	-	-	-	457	1,559	1,559	1,487	1,487	892
12-2019	204	875	-	-	-	1,079	2,839	4,398	2,461	3,947	2,368
12-2020	153	708	-	-	-	861	2,125	6,523	1,674	5,622	3,373
12-2021	110	707	-	414	-	1,230	872	7,395	624	6,246	3,748
12-2022	79	452	-	423	-	954	531	7,926	346	6,592	3,955
12-2023	56	463	-	918	-	1,437	(388)	7,538	(230)	6,362	3,817
12-2024	33	433	-	937	-	1,404	(790)	6,747	(425)	5,937	3,562
12-2025	-	-	-	22,248	-	22,248	(22,248)	(15,501)	(10,885)	(4,948)	(2,969)
12-2026	-	-	-	4,586	-	4,586	(4,586)	(20,086)	(2,040)	(6,988)	(4,193)
12-2027	-	-	-	3,943	-	3,943	(3,943)	(24,030)	(1,595)	(8,583)	(5,150)
12-2028	-	-	-	434	-	434	(434)	(24,464)	(160)	(8,742)	(5,245)
12-2029	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2030	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2031	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2032	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2033	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2034	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
12-2035	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
S-TOT	739	3,991	-	33,904	-	38,633	(24,464)		(8,742)		
REM	-	-	-	-	-	-	-	(24,464)	-	(8,742)	(5,245)
TOTAL	739	3,991	-	33,904	-	38,633	(24,464)		(8,742)		

LIFE - 7 years

DISCOUNT RATE @ 10%

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - BP NORTH SEA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	23	458	335	26,257	1,377	184	136	12,196	639	68.33	38.24	6.53
12-2019	24	1,040	832	69,717	3,285	422	342	32,654	1,518	69.92	38.57	6.65
12-2020	21	905	769	67,512	3,294	371	319	31,789	1,546	71.53	39.07	6.78
12-2021	19	701	619	56,056	3,285	289	258	26,485	1,552	73.07	39.69	6.92
12-2022	16	511	444	39,706	3,285	209	185	18,736	1,556	74.44	40.67	7.07
12-2023	13	354	300	27,365	3,285	145	125	12,949	1,558	75.90	41.39	7.21
12-2024	10	229	194	18,445	3,294	94	82	8,772	1,566	77.55	41.93	7.36
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	24	4,198	3,494	305,056	21,105	1,714	1,448	143,581	9,935	72.11	39.55	6.87
REM	-	-	-	-	-	-	-	-	-			
TOTAL	24	4,198	3,494	305,056	21,105	1,714	1,448	143,581	9,935	72.11	39.55	6.87
CUMULATIVE		178,410	-	3,530,336	-				-			
ULTIMATE		182,608	3,494	3,835,391	21,105				9,935			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	12,567	5,206	79,639	-	97,412	-	-	-	-	97,412
12-2019	29,499	13,189	217,176	-	259,865	-	-	-	-	259,865
12-2020	26,550	12,459	215,568	-	254,577	-	-	-	-	254,577
12-2021	21,132	10,257	183,237	-	214,626	-	-	-	-	214,626
12-2022	15,561	7,524	132,463	-	155,549	-	-	-	-	155,549
12-2023	10,991	5,194	93,414	-	109,599	-	-	-	-	109,599
12-2024	7,297	3,428	64,521	-	75,246	-	-	-	-	75,246
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	123,597	57,259	986,018	-	1,166,873	-	-	-	-	1,166,873
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	123,597	57,259	986,018	-	1,166,873	-	-	-	-	1,166,873

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	953	29,975	-	-	-	30,928	66,484	66,484	63,390	63,390	38,034
12-2019	3,798	74,704	15,752	-	-	94,254	165,611	232,095	143,549	206,939	124,163
12-2020	3,594	73,317	-	-	-	76,911	177,666	409,760	139,998	346,937	208,162
12-2021	3,187	68,817	-	-	-	72,005	142,621	552,381	102,166	449,103	269,462
12-2022	2,763	62,290	-	-	-	65,053	90,496	642,877	58,933	508,036	304,822
12-2023	2,392	57,412	-	-	-	59,804	49,796	692,672	29,480	537,517	322,510
12-2024	2,106	55,625	-	-	-	57,731	17,515	710,188	9,427	546,943	328,166
12-2025	-	-	-	-	-	-	-	710,188	-	546,943	328,166
12-2026	-	-	-	-	-	-	-	710,188	-	546,943	328,166
12-2027	-	-	-	-	-	-	-	710,188	-	546,943	328,166
12-2028	-	-	-	-	-	-	-	710,188	-	546,943	328,166
12-2029	-	-	-	-	-	-	-	710,188	-	546,943	328,166
12-2030	-	-	-	-	-	-	-	710,188	-	546,943	328,166
12-2031	-	-	-	-	-	-	-	710,188	-	546,943	328,166
12-2032	-	-	-	-	-	-	-	710,188	-	546,943	328,166
12-2033	-	-	-	-	-	-	-	710,188	-	546,943	328,166
12-2034	-	-	-	-	-	-	-	710,188	-	546,943	328,166
12-2035	-	-	-	-	-	-	-	710,188	-	546,943	328,166
S-TOT	18,794	422,140	15,752	-	-	456,686	710,188		546,943		
REM	-	-	-	-	-	-	-	710,188	-	546,943	328,166
TOTAL	18,794	422,140	15,752	-	-	456,686	710,188		546,943		

LIFE - 7 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	20	272	211	6,311	336	98	76	2,272	121	67.39	43.44	7.21
12-2019	20	601	502	15,099	845	216	181	5,436	304	68.74	44.31	7.36
12-2020	17	508	448	13,557	721	183	161	4,881	259	70.11	45.19	7.52
12-2021	15	386	352	10,686	643	139	127	3,847	232	71.51	46.10	7.68
12-2022	12	294	257	7,754	621	106	92	2,791	224	72.94	47.02	7.85
12-2023	9	206	169	5,086	602	74	61	1,831	217	74.40	47.96	8.02
12-2024	6	130	104	3,130	581	47	38	1,127	209	75.89	48.92	8.19
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	20	2,397	2,044	61,624	4,349	863	736	22,185	1,565	70.71	45.60	7.60
REM	-	-	-	-	-	-	-	-	-			
TOTAL	20	2,397	2,044	61,624	4,349	863	736	22,185	1,565	70.71	45.60	7.60
CUMULATIVE		165,470	-	3,086,056	-				-			
ULTIMATE		167,867	2,044	3,147,680	4,349				1,565			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	6,604	3,305	16,380	-	26,289	-	-	-	-	26,289
12-2019	14,871	8,004	40,029	-	62,904	-	-	-	-	62,904
12-2020	12,812	7,291	36,714	-	56,816	-	-	-	-	56,816
12-2021	9,947	5,845	29,561	-	45,352	-	-	-	-	45,352
12-2022	7,726	4,343	21,908	-	33,977	-	-	-	-	33,977
12-2023	5,514	2,923	14,680	-	23,117	-	-	-	-	23,117
12-2024	3,541	1,839	9,227	-	14,607	-	-	-	-	14,607
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	61,014	33,548	168,500	-	263,062	-	-	-	-	263,062
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	61,014	33,548	168,500	-	263,062	-	-	-	-	263,062

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	181	6,561	-	-	-	6,742	19,546	19,546	18,637	18,637	11,182
12-2019	1,929	15,347	-	-	-	17,276	45,627	65,174	39,549	58,186	34,911
12-2020	1,755	13,670	-	-	-	15,425	41,392	106,565	32,616	90,802	54,481
12-2021	1,430	12,132	-	-	-	13,562	31,790	138,355	22,773	113,574	68,145
12-2022	1,111	11,346	-	-	-	12,457	21,520	159,875	14,015	127,589	76,553
12-2023	807	9,144	-	-	-	9,952	13,165	173,041	7,794	135,383	81,230
12-2024	569	8,444	-	-	-	9,014	5,593	178,634	3,010	138,394	83,036
12-2025	-	-	-	-	-	-	-	178,634	-	138,394	83,036
12-2026	-	-	-	-	-	-	-	178,634	-	138,394	83,036
12-2027	-	-	-	-	-	-	-	178,634	-	138,394	83,036
12-2028	-	-	-	-	-	-	-	178,634	-	138,394	83,036
12-2029	-	-	-	-	-	-	-	178,634	-	138,394	83,036
12-2030	-	-	-	-	-	-	-	178,634	-	138,394	83,036
12-2031	-	-	-	-	-	-	-	178,634	-	138,394	83,036
12-2032	-	-	-	-	-	-	-	178,634	-	138,394	83,036
12-2033	-	-	-	-	-	-	-	178,634	-	138,394	83,036
12-2034	-	-	-	-	-	-	-	178,634	-	138,394	83,036
12-2035	-	-	-	-	-	-	-	178,634	-	138,394	83,036
S-TOT	7,783	76,645	-	-	-	84,428	178,634		138,394		
REM	-	-	-	-	-	-	-	178,634	-	138,394	83,036
TOTAL	7,783	76,645	-	-	-	84,428	178,634		138,394		

LIFE - 7 years

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	2	139	111	19,625	1,023	69	55.60	9,812	511	71.30	30.70	6.36
12-2019	3	347	306	54,019	2,400	174	153	27,010	1,200	72.72	31.48	6.50
12-2020	3	330	302	53,501	2,573	165	151	26,750	1,287	74.18	32.27	6.64
12-2021	3	267	255	45,062	2,642	134	127	22,531	1,321	75.66	33.09	6.78
12-2022	3	183	179	31,744	2,664	92	90	15,872	1,332	77.17	33.92	6.93
12-2023	3	125	125	22,137	2,683	63	62	11,068	1,342	78.72	34.76	7.08
12-2024	3	85	86	15,235	2,713	43	43	7,617	1,356	80.29	35.63	7.23
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	1,476	1,364	241,323	16,698	738	682	120,661	8,349	74.94	32.77	6.73
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	1,476	1,364	241,323	16,698	738	682	120,661	8,349	74.94	32.77	6.73
CUMULATIVE		2,805	-	417,916	-				-			
ULTIMATE		4,282	1,364	659,239	16,698				8,349			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	4,946	1,707	62,455	-	69,107	-	-	-	-	69,107
12-2019	12,623	4,809	175,612	-	193,043	-	-	-	-	193,043
12-2020	12,230	4,880	177,664	-	194,774	-	-	-	-	194,774
12-2021	10,107	4,211	152,854	-	167,171	-	-	-	-	167,171
12-2022	7,063	3,039	109,985	-	120,087	-	-	-	-	120,087
12-2023	4,922	2,172	78,340	-	85,433	-	-	-	-	85,433
12-2024	3,427	1,532	55,067	-	60,026	-	-	-	-	60,026
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	55,317	22,348	811,976	-	889,642	-	-	-	-	889,642
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	55,317	22,348	811,976	-	889,642	-	-	-	-	889,642

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	669	23,060	-	-	-	23,729	45,378	45,378	43,267	43,267	25,960
12-2019	1,665	58,481	15,752	-	-	75,899	117,144	162,523	101,539	144,806	86,883
12-2020	1,686	58,939	-	-	-	60,625	134,149	296,672	105,708	250,513	150,308
12-2021	1,647	55,979	-	-	-	57,626	109,545	406,217	78,473	328,986	197,392
12-2022	1,573	50,492	-	-	-	52,066	68,021	474,238	44,297	373,283	223,970
12-2023	1,528	47,805	-	-	-	49,333	36,100	510,339	21,372	394,656	236,793
12-2024	1,503	46,748	-	-	-	48,251	11,775	522,114	6,337	400,993	240,596
12-2025	-	-	-	-	-	-	-	522,114	-	400,993	240,596
12-2026	-	-	-	-	-	-	-	522,114	-	400,993	240,596
12-2027	-	-	-	-	-	-	-	522,114	-	400,993	240,596
12-2028	-	-	-	-	-	-	-	522,114	-	400,993	240,596
12-2029	-	-	-	-	-	-	-	522,114	-	400,993	240,596
12-2030	-	-	-	-	-	-	-	522,114	-	400,993	240,596
12-2031	-	-	-	-	-	-	-	522,114	-	400,993	240,596
12-2032	-	-	-	-	-	-	-	522,114	-	400,993	240,596
12-2033	-	-	-	-	-	-	-	522,114	-	400,993	240,596
12-2034	-	-	-	-	-	-	-	522,114	-	400,993	240,596
12-2035	-	-	-	-	-	-	-	522,114	-	400,993	240,596
S-TOT	10,272	341,503	15,752	-	-	367,528	522,114		400,993		
REM	-	-	-	-	-	-	-	522,114	-	400,993	240,596
TOTAL	10,272	341,503	15,752	-	-	367,528	522,114		400,993		

LIFE - 7 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	1	47	13	320	18	17	4	112	6	61.52	43.44	7.21
12-2019	1	92	24	599	40	32	9	208	14	62.75	44.31	7.36
12-2020	1	68	18	454	-	24	6	158	-	64.01	45.19	7.52
12-2021	1	47	13	307	-	17	4	107	-	65.29	46.10	7.68
12-2022	1	33	9	208	-	12	3	73	-	66.59	47.02	7.85
12-2023	1	23	6	141	-	8	2	49	-	67.93	47.96	8.02
12-2024	1	14	3	79	-	5	1	28	-	69.28	48.92	8.19
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
CUMULATIVE		10,135	-	26,363	-				-			
ULTIMATE		10,460	86	28,473	59				20			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	1,017	195	804	-	2,016	-	-	-	-	2,016
12-2019	2,005	377	1,535	-	3,918	-	-	-	-	3,918
12-2020	1,508	288	1,189	-	2,986	-	-	-	-	2,986
12-2021	1,078	202	822	-	2,102	-	-	-	-	2,102
12-2022	773	142	570	-	1,485	-	-	-	-	1,485
12-2023	555	100	395	-	1,049	-	-	-	-	1,049
12-2024	328	58	227	-	613	-	-	-	-	613
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	103	354	-	-	-	457	1,559	1,559	1,487	1,487	892
12-2019	204	875	-	-	-	1,079	2,839	4,398	2,461	3,947	2,368
12-2020	153	708	-	-	-	861	2,125	6,523	1,674	5,622	3,373
12-2021	110	707	-	-	-	816	1,286	7,809	921	6,543	3,926
12-2022	79	452	-	-	-	530	954	8,763	621	7,164	4,299
12-2023	56	463	-	-	-	519	530	9,293	314	7,478	4,487
12-2024	33	433	-	-	-	466	147	9,440	79	7,557	4,534
12-2025	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2026	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2027	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2028	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2029	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2030	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2031	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2032	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2033	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2034	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2035	-	-	-	-	-	-	-	9,440	-	7,557	4,534
S-TOT	739	3,991	-	-	-	4,730	9,440		7,557		
REM	-	-	-	-	-	-	-	9,440	-	7,557	4,534
TOTAL	739	3,991	-	-	-	4,730	9,440		7,557		

LIFE - 7 years

DISCOUNT RATE @ 10%

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - BP NORTH SEA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	23	476	350	27,108	1,377	191	142	12,571	639	68.34	38.32	6.53
12-2019	26	1,241	1,034	79,657	3,285	499	418	36,863	1,518	69.87	39.23	6.68
12-2020	23	1,191	1,040	83,099	3,294	483	423	38,638	1,546	71.47	39.82	6.81
12-2021	22	961	870	73,866	3,285	394	358	34,611	1,552	73.09	40.22	6.94
12-2022	19	763	693	61,301	3,285	315	288	28,876	1,556	74.67	40.76	7.07
12-2023	16	579	532	50,287	3,285	242	224	23,873	1,558	76.34	41.11	7.21
12-2024	13	389	365	40,029	3,294	168	159	19,304	1,566	78.31	40.67	7.32
12-2025	11	283	259	32,197	3,285	125	117	15,708	1,567	80.32	40.38	7.45
12-2026	7	208	177	25,787	3,285	93	83	12,748	1,570	82.20	39.58	7.57
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	26	6,091	5,320	473,331	27,675	2,510	2,213	223,191	13,072	73.34	40.01	7.00
REM	-	-	-	-	-	-	-	-	-			
TOTAL	26	6,091	5,320	473,331	27,675	2,510	2,213	223,191	13,072	73.34	40.01	7.00
CUMULATIVE		178,410	-	3,530,336	-				-			
ULTIMATE		184,502	5,320	4,003,667	27,675				13,072			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	13,039	5,439	82,134	-	100,612	-	-	-	-	100,612
12-2019	34,867	16,414	246,231	-	297,512	-	-	-	-	297,512
12-2020	34,519	16,859	263,197	-	314,575	-	-	-	-	314,575
12-2021	28,827	14,417	240,167	-	283,411	-	-	-	-	283,411
12-2022	23,524	11,732	204,281	-	239,536	-	-	-	-	239,536
12-2023	18,473	9,211	172,030	-	199,715	-	-	-	-	199,715
12-2024	13,127	6,463	141,299	-	160,890	-	-	-	-	160,890
12-2025	10,018	4,709	116,959	-	131,687	-	-	-	-	131,687
12-2026	7,673	3,291	96,505	-	107,469	-	-	-	-	107,469
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	184,067	88,535	1,562,804	-	1,835,407	-	-	-	-	1,835,407
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	184,067	88,535	1,562,804	-	1,835,407	-	-	-	-	1,835,407

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	963	29,950	-	-	-	30,913	69,698	69,698	66,455	66,455	39,873
12-2019	4,439	76,028	15,752	-	-	96,220	201,292	270,990	174,477	240,932	144,559
12-2020	4,444	76,275	-	-	-	80,719	233,856	504,846	184,275	425,207	255,124
12-2021	3,935	72,971	-	-	-	76,906	206,505	711,351	147,930	573,137	343,882
12-2022	3,453	68,285	-	-	-	71,739	167,797	879,149	109,274	682,411	409,447
12-2023	2,998	64,386	-	-	-	67,384	132,331	1,011,480	78,343	760,754	456,453
12-2024	2,482	63,081	-	-	-	65,563	95,327	1,106,807	51,306	812,060	487,236
12-2025	2,186	62,665	-	-	-	64,851	66,837	1,173,644	32,702	844,762	506,857
12-2026	1,973	62,451	-	-	-	64,424	43,045	1,216,689	19,146	863,908	518,345
12-2027	-	-	-	-	-	-	-	1,216,689	-	863,908	518,345
12-2028	-	-	-	-	-	-	-	1,216,689	-	863,908	518,345
12-2029	-	-	-	-	-	-	-	1,216,689	-	863,908	518,345
12-2030	-	-	-	-	-	-	-	1,216,689	-	863,908	518,345
12-2031	-	-	-	-	-	-	-	1,216,689	-	863,908	518,345
12-2032	-	-	-	-	-	-	-	1,216,689	-	863,908	518,345
12-2033	-	-	-	-	-	-	-	1,216,689	-	863,908	518,345
12-2034	-	-	-	-	-	-	-	1,216,689	-	863,908	518,345
12-2035	-	-	-	-	-	-	-	1,216,689	-	863,908	518,345
S-TOT	26,873	576,092	15,752	-	-	618,718	1,216,689		863,908		
REM	-	-	-	-	-	-	-	1,216,689	-	863,908	518,345
TOTAL	26,873	576,092	15,752	-	-	618,718	1,216,689		863,908		

LIFE - 9 years

THESE DATA ARE PART OF A RYDER SCOTT REPORT AND ARE SUBJECT TO THE CONDITIONS IN THE TEXT OF THE REPORT
THESE DATA WERE GENERATED USING THE PALANTIRCASH PROGRAM

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	20	286	224	6,680	336	103	80	2,405	121	67.39	43.44	7.21
12-2019	22	769	679	20,534	845	277	244	7,392	304	68.74	44.31	7.36
12-2020	19	731	669	20,304	721	263	241	7,309	259	70.11	45.19	7.52
12-2021	18	563	534	16,251	643	203	192	5,850	232	71.51	46.10	7.68
12-2022	15	438	409	12,451	621	158	147	4,482	224	72.94	47.02	7.85
12-2023	12	314	293	8,920	602	113	106	3,211	217	74.40	47.96	8.02
12-2024	9	176	164	4,989	581	63	59	1,796	209	75.89	48.92	8.19
12-2025	8	122	94	2,793	541	44	34	1,005	195	77.41	49.90	8.36
12-2026	4	76	37	1,040	518	27	13	374	186	78.95	50.90	8.54
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	22	3,474	3,102	93,961	5,407	1,251	1,117	33,826	1,947	71.29	45.94	7.66
REM	-	-	-	-	-	-	-	-	-			
TOTAL	22	3,474	3,102	93,961	5,407	1,251	1,117	33,826	1,947	71.29	45.94	7.66
CUMULATIVE		165,470	-	3,086,056	-				-			
ULTIMATE		168,944	3,102	3,180,017	5,407				1,947			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	6,942	3,495	17,335	-	27,772	-	-	-	-	27,772
12-2019	19,017	10,826	54,439	-	84,282	-	-	-	-	84,282
12-2020	18,447	10,883	54,985	-	84,315	-	-	-	-	84,315
12-2021	14,503	8,857	44,954	-	68,314	-	-	-	-	68,314
12-2022	11,492	6,930	35,181	-	53,602	-	-	-	-	53,602
12-2023	8,417	5,065	25,744	-	39,226	-	-	-	-	39,226
12-2024	4,814	2,890	14,705	-	22,408	-	-	-	-	22,408
12-2025	3,386	1,681	8,408	-	13,476	-	-	-	-	13,476
12-2026	2,152	681	3,197	-	6,030	-	-	-	-	6,030
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	89,170	51,307	258,948	-	399,426	-	-	-	-	399,426
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	89,170	51,307	258,948	-	399,426	-	-	-	-	399,426

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	186	6,686	-	-	-	6,873	20,899	20,899	19,927	19,927	11,956
12-2019	2,533	17,927	-	-	-	20,460	63,822	84,722	55,320	75,247	45,148
12-2020	2,532	16,639	-	-	-	19,171	65,144	149,866	51,333	126,580	75,948
12-2021	2,078	14,325	-	-	-	16,403	51,911	201,777	37,187	163,766	98,260
12-2022	1,664	12,582	-	-	-	14,246	39,356	241,133	25,629	189,396	113,637
12-2023	1,260	9,635	-	-	-	10,895	28,331	269,464	16,773	206,169	123,701
12-2024	788	7,200	-	-	-	7,988	14,420	283,885	7,761	213,930	128,358
12-2025	541	3,706	-	-	-	4,246	9,230	293,114	4,516	218,446	131,067
12-2026	335	1,866	-	-	-	2,201	3,829	296,943	1,703	220,149	132,089
12-2027	-	-	-	-	-	-	-	296,943	-	220,149	132,089
12-2028	-	-	-	-	-	-	-	296,943	-	220,149	132,089
12-2029	-	-	-	-	-	-	-	296,943	-	220,149	132,089
12-2030	-	-	-	-	-	-	-	296,943	-	220,149	132,089
12-2031	-	-	-	-	-	-	-	296,943	-	220,149	132,089
12-2032	-	-	-	-	-	-	-	296,943	-	220,149	132,089
12-2033	-	-	-	-	-	-	-	296,943	-	220,149	132,089
12-2034	-	-	-	-	-	-	-	296,943	-	220,149	132,089
12-2035	-	-	-	-	-	-	-	296,943	-	220,149	132,089
S-TOT	11,917	90,566	-	-	-	102,483	296,943		220,149		
REM	-	-	-	-	-	-	-	296,943	-	220,149	132,089
TOTAL	11,917	90,566	-	-	-	102,483	296,943		220,149		

LIFE - 9 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	2	143	114	20,109	1,023	71	56.97	10,054	511	71.30	30.70	6.36
12-2019	3	381	331	58,524	2,400	190	166	29,262	1,200	72.72	31.48	6.50
12-2020	3	393	352	62,341	2,573	196	176	31,171	1,287	74.18	32.27	6.64
12-2021	3	350	324	57,308	2,642	175	162	28,654	1,321	75.66	33.09	6.78
12-2022	3	292	275	48,641	2,664	146	137	24,321	1,332	77.17	33.92	6.93
12-2023	3	241	233	41,225	2,683	121	116	20,613	1,342	78.72	34.76	7.08
12-2024	3	199	197	34,961	2,713	99	99	17,481	1,356	80.29	35.63	7.23
12-2025	3	162	166	29,404	2,744	81	83	14,702	1,372	81.90	36.51	7.38
12-2026	3	132	140	24,748	2,767	66	70	12,374	1,384	83.54	37.41	7.54
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	2,292	2,132	377,261	22,209	1,146	1,066	188,631	11,105	76.46	33.65	6.88
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	2,292	2,132	377,261	22,209	1,146	1,066	188,631	11,105	76.46	33.65	6.88
CUMULATIVE		2,805	-	417,916	-				-			
ULTIMATE		5,098	2,132	795,177	22,209				11,105			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	5,081	1,749	63,994	-	70,823	-	-	-	-	70,823
12-2019	13,844	5,211	190,257	-	209,312	-	-	-	-	209,312
12-2020	14,563	5,688	207,022	-	227,273	-	-	-	-	227,273
12-2021	13,245	5,358	194,392	-	212,995	-	-	-	-	212,995
12-2022	11,259	4,660	168,531	-	184,449	-	-	-	-	184,449
12-2023	9,501	4,047	145,892	-	159,440	-	-	-	-	159,440
12-2024	7,985	3,515	126,368	-	137,869	-	-	-	-	137,869
12-2025	6,632	3,028	108,551	-	118,211	-	-	-	-	118,211
12-2026	5,520	2,610	93,308	-	101,439	-	-	-	-	101,439
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	87,631	35,866	1,298,314	-	1,421,811	-	-	-	-	1,421,811
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	87,631	35,866	1,298,314	-	1,421,811	-	-	-	-	1,421,811

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	673	22,910	-	-	-	23,584	47,240	47,240	45,041	45,041	27,025
12-2019	1,703	57,226	15,752	-	-	74,681	134,631	181,871	116,696	161,737	97,042
12-2020	1,759	58,928	-	-	-	60,687	166,587	348,457	131,268	293,005	175,803
12-2021	1,747	57,939	-	-	-	59,687	153,308	501,765	109,822	402,827	241,696
12-2022	1,710	55,251	-	-	-	56,962	127,488	629,253	83,024	485,851	291,511
12-2023	1,682	54,288	-	-	-	55,970	103,470	732,723	61,257	547,108	328,265
12-2024	1,661	55,448	-	-	-	57,108	80,760	813,483	43,466	590,573	354,344
12-2025	1,645	58,959	-	-	-	60,604	57,607	871,090	28,186	618,759	371,255
12-2026	1,637	60,585	-	-	-	62,222	39,216	910,307	17,443	636,202	381,721
12-2027	-	-	-	-	-	-	-	910,307	-	636,202	381,721
12-2028	-	-	-	-	-	-	-	910,307	-	636,202	381,721
12-2029	-	-	-	-	-	-	-	910,307	-	636,202	381,721
12-2030	-	-	-	-	-	-	-	910,307	-	636,202	381,721
12-2031	-	-	-	-	-	-	-	910,307	-	636,202	381,721
12-2032	-	-	-	-	-	-	-	910,307	-	636,202	381,721
12-2033	-	-	-	-	-	-	-	910,307	-	636,202	381,721
12-2034	-	-	-	-	-	-	-	910,307	-	636,202	381,721
12-2035	-	-	-	-	-	-	-	910,307	-	636,202	381,721
S-TOT	14,217	481,535	15,752	-	-	511,505	910,307		636,202		
REM	-	-	-	-	-	-	-	910,307	-	636,202	381,721
TOTAL	14,217	481,535	15,752	-	-	511,505	910,307		636,202		

LIFE - 9 years

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	1	47	13	320	18	17	4	112	6	61.52	43.44	7.21
12-2019	1	92	24	599	40	32	9	208	14	62.75	44.31	7.36
12-2020	1	68	18	454	-	24	6	158	-	64.01	45.19	7.52
12-2021	1	47	13	307	-	17	4	107	-	65.29	46.10	7.68
12-2022	1	33	9	208	-	12	3	73	-	66.59	47.02	7.85
12-2023	1	23	6	141	-	8	2	49	-	67.93	47.96	8.02
12-2024	1	14	3	79	-	5	1	28	-	69.28	48.92	8.19
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
CUMULATIVE		10,135	-	26,363	-				-			
ULTIMATE		10,460	86	28,473	59				20			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	1,017	195	804	-	2,016	-	-	-	-	2,016
12-2019	2,005	377	1,535	-	3,918	-	-	-	-	3,918
12-2020	1,508	288	1,189	-	2,986	-	-	-	-	2,986
12-2021	1,078	202	822	-	2,102	-	-	-	-	2,102
12-2022	773	142	570	-	1,485	-	-	-	-	1,485
12-2023	555	100	395	-	1,049	-	-	-	-	1,049
12-2024	328	58	227	-	613	-	-	-	-	613
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	103	354	-	-	-	457	1,559	1,559	1,487	1,487	892
12-2019	204	875	-	-	-	1,079	2,839	4,398	2,461	3,947	2,368
12-2020	153	708	-	-	-	861	2,125	6,523	1,674	5,622	3,373
12-2021	110	707	-	-	-	816	1,286	7,809	921	6,543	3,926
12-2022	79	452	-	-	-	530	954	8,763	621	7,164	4,299
12-2023	56	463	-	-	-	519	530	9,293	314	7,478	4,487
12-2024	33	433	-	-	-	466	147	9,440	79	7,557	4,534
12-2025	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2026	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2027	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2028	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2029	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2030	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2031	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2032	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2033	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2034	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2035	-	-	-	-	-	-	-	9,440	-	7,557	4,534
S-TOT	739	3,991	-	-	-	4,730	9,440		7,557		
REM	-	-	-	-	-	-	-	9,440	-	7,557	4,534
TOTAL	739	3,991	-	-	-	4,730	9,440		7,557		

LIFE - 7 years

DISCOUNT RATE @ 10%

THESE DATA ARE PART OF A RYDER SCOTT REPORT AND ARE SUBJECT TO THE CONDITIONS IN THE TEXT OF THE REPORT
THESE DATA WERE GENERATED USING THE PALANTIRCASH PROGRAM

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - BP NORTH SEA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	23	476	350	27,108	1,377	191	142	12,571	639	68.34	38.32	6.53
12-2019	26	1,291	1,087	88,968	3,285	524	445	41,518	1,518	70.01	38.77	6.66
12-2020	23	1,254	1,109	95,329	3,294	514	458	44,753	1,546	71.63	39.25	6.79
12-2021	22	1,018	937	85,661	3,285	423	392	40,509	1,552	73.27	39.62	6.92
12-2022	19	814	755	72,284	3,285	341	319	34,367	1,556	74.86	40.10	7.05
12-2023	16	624	589	60,458	3,285	264	253	28,958	1,558	76.54	40.39	7.18
12-2024	13	428	418	49,428	3,294	187	185	24,003	1,566	78.52	39.95	7.30
12-2025	11	317	308	40,798	3,285	142	141	20,008	1,567	80.51	39.71	7.43
12-2026	7	237	221	33,653	3,285	108	105	16,681	1,570	82.38	39.12	7.56
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	26	6,459	5,773	553,687	27,675	2,694	2,439	263,369	13,072	73.61	39.47	7.00
REM	-	-	-	-	-	-	-	-	-			
TOTAL	26	6,459	5,773	553,687	27,675	2,694	2,439	263,369	13,072	73.61	39.47	7.00
CUMULATIVE		178,410	-	3,530,336	-				-			
ULTIMATE		184,870	5,773	4,084,023	27,675				13,072			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	13,039	5,439	82,134	-	100,612	-	-	-	-	100,612
12-2019	36,677	17,240	276,500	-	330,418	-	-	-	-	330,418
12-2020	36,838	17,971	303,811	-	358,621	-	-	-	-	358,621
12-2021	31,005	15,516	280,178	-	326,699	-	-	-	-	326,699
12-2022	25,493	12,780	242,335	-	280,608	-	-	-	-	280,608
12-2023	20,239	10,206	208,024	-	238,469	-	-	-	-	238,469
12-2024	14,704	7,404	175,270	-	197,379	-	-	-	-	197,379
12-2025	11,408	5,591	148,713	-	165,712	-	-	-	-	165,712
12-2026	8,892	4,117	126,161	-	139,169	-	-	-	-	139,169
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	198,295	96,265	1,843,126	-	2,137,685	-	-	-	-	2,137,685
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	198,295	96,265	1,843,126	-	2,137,685	-	-	-	-	2,137,685

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	963	29,827	-	-	-	30,790	69,821	69,821	66,572	66,572	39,943
12-2019	4,505	78,817	15,752	-	-	99,074	231,344	301,165	200,525	267,097	160,258
12-2020	4,530	80,031	-	-	-	84,561	274,060	575,225	215,955	483,052	289,831
12-2021	4,018	76,671	-	-	-	80,688	246,011	821,236	176,230	659,282	395,569
12-2022	3,530	71,848	-	-	-	75,378	205,229	1,026,465	133,651	792,933	475,760
12-2023	3,069	67,790	-	-	-	70,859	167,610	1,194,075	99,229	892,163	535,298
12-2024	2,547	66,264	-	-	-	68,812	128,567	1,322,642	69,195	961,358	576,815
12-2025	2,246	65,633	-	-	-	67,879	97,833	1,420,475	47,867	1,009,225	605,535
12-2026	2,027	65,124	-	-	-	67,152	72,018	1,492,493	32,033	1,041,259	624,755
12-2027	-	-	-	-	-	-	-	1,492,493	-	1,041,259	624,755
12-2028	-	-	-	-	-	-	-	1,492,493	-	1,041,259	624,755
12-2029	-	-	-	-	-	-	-	1,492,493	-	1,041,259	624,755
12-2030	-	-	-	-	-	-	-	1,492,493	-	1,041,259	624,755
12-2031	-	-	-	-	-	-	-	1,492,493	-	1,041,259	624,755
12-2032	-	-	-	-	-	-	-	1,492,493	-	1,041,259	624,755
12-2033	-	-	-	-	-	-	-	1,492,493	-	1,041,259	624,755
12-2034	-	-	-	-	-	-	-	1,492,493	-	1,041,259	624,755
12-2035	-	-	-	-	-	-	-	1,492,493	-	1,041,259	624,755
S-TOT	27,434	602,007	15,752	-	-	645,193	1,492,493		1,041,259		
REM	-	-	-	-	-	-	-	1,492,493	-	1,041,259	624,755
TOTAL	27,434	602,007	15,752	-	-	645,193	1,492,493		1,041,259		

LIFE - 9 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	20	286	224	6,680	336	103	80	2,405	121	67.39	43.44	7.21
12-2019	22	769	679	20,534	845	277	244	7,392	304	68.74	44.31	7.36
12-2020	19	731	669	20,304	721	263	241	7,309	259	70.11	45.19	7.52
12-2021	18	563	534	16,251	643	203	192	5,850	232	71.51	46.10	7.68
12-2022	15	438	409	12,451	621	158	147	4,482	224	72.94	47.02	7.85
12-2023	12	314	293	8,920	602	113	106	3,211	217	74.40	47.96	8.02
12-2024	9	176	164	4,989	581	63	59	1,796	209	75.89	48.92	8.19
12-2025	8	122	94	2,793	541	44	34	1,005	195	77.41	49.90	8.36
12-2026	4	76	37	1,040	518	27	13	374	186	78.95	50.90	8.54
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	22	3,474	3,102	93,961	5,407	1,251	1,117	33,826	1,947	71.29	45.94	7.66
REM	-	-	-	-	-	-	-	-	-			
TOTAL	22	3,474	3,102	93,961	5,407	1,251	1,117	33,826	1,947	71.29	45.94	7.66
CUMULATIVE		165,470	-	3,086,056	-				-			
ULTIMATE		168,944	3,102	3,180,017	5,407				1,947			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	6,942	3,495	17,335	-	27,772	-	-	-	-	27,772
12-2019	19,017	10,826	54,439	-	84,282	-	-	-	-	84,282
12-2020	18,447	10,883	54,985	-	84,315	-	-	-	-	84,315
12-2021	14,503	8,857	44,954	-	68,314	-	-	-	-	68,314
12-2022	11,492	6,930	35,181	-	53,602	-	-	-	-	53,602
12-2023	8,417	5,065	25,744	-	39,226	-	-	-	-	39,226
12-2024	4,814	2,890	14,705	-	22,408	-	-	-	-	22,408
12-2025	3,386	1,681	8,408	-	13,476	-	-	-	-	13,476
12-2026	2,152	681	3,197	-	6,030	-	-	-	-	6,030
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	89,170	51,307	258,948	-	399,426	-	-	-	-	399,426
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	89,170	51,307	258,948	-	399,426	-	-	-	-	399,426

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	186	6,663	-	-	-	6,850	20,923	20,923	19,949	19,949	11,969
12-2019	2,533	16,819	-	-	-	19,352	64,930	85,853	56,280	76,229	45,738
12-2020	2,532	15,382	-	-	-	17,914	66,401	152,254	52,323	128,553	77,132
12-2021	2,078	13,157	-	-	-	15,235	53,080	205,334	38,024	166,576	99,946
12-2022	1,664	11,445	-	-	-	13,109	40,493	245,827	26,370	192,946	115,768
12-2023	1,260	8,546	-	-	-	9,806	29,420	275,247	17,417	210,364	126,218
12-2024	788	6,326	-	-	-	7,114	15,294	290,541	8,231	218,595	131,157
12-2025	541	2,960	-	-	-	3,501	9,975	300,516	4,881	223,476	134,086
12-2026	335	1,467	-	-	-	1,803	4,227	304,744	1,880	225,356	135,214
12-2027	-	-	-	-	-	-	-	304,744	-	225,356	135,214
12-2028	-	-	-	-	-	-	-	304,744	-	225,356	135,214
12-2029	-	-	-	-	-	-	-	304,744	-	225,356	135,214
12-2030	-	-	-	-	-	-	-	304,744	-	225,356	135,214
12-2031	-	-	-	-	-	-	-	304,744	-	225,356	135,214
12-2032	-	-	-	-	-	-	-	304,744	-	225,356	135,214
12-2033	-	-	-	-	-	-	-	304,744	-	225,356	135,214
12-2034	-	-	-	-	-	-	-	304,744	-	225,356	135,214
12-2035	-	-	-	-	-	-	-	304,744	-	225,356	135,214
S-TOT	11,917	82,765	-	-	-	94,682	304,744		225,356		
REM	-	-	-	-	-	-	-	304,744	-	225,356	135,214
TOTAL	11,917	82,765	-	-	-	94,682	304,744		225,356		

LIFE - 9 years

THESE DATA ARE PART OF A RYDER SCOTT REPORT AND ARE SUBJECT TO THE CONDITIONS IN THE TEXT OF THE REPORT
THESE DATA WERE GENERATED USING THE PALANTIRCASH PROGRAM

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	2	143	114	20,109	1,023	71	56.97	10,054	511	71.30	30.70	6.36
12-2019	3	431	384	67,835	2,400	215	192	33,918	1,200	72.72	31.48	6.50
12-2020	3	455	421	74,572	2,573	228	211	37,286	1,287	74.18	32.27	6.64
12-2021	3	408	390	69,103	2,642	204	195	34,552	1,321	75.66	33.09	6.78
12-2022	3	343	337	59,625	2,664	171	168	29,812	1,332	77.17	33.92	6.93
12-2023	3	286	290	51,396	2,683	143	145	25,698	1,342	78.72	34.76	7.08
12-2024	3	238	250	44,359	2,713	119	125	22,180	1,356	80.29	35.63	7.23
12-2025	3	196	214	38,006	2,744	98	107	19,003	1,372	81.90	36.51	7.38
12-2026	3	161	184	32,613	2,767	81	92	16,307	1,384	83.54	37.41	7.54
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	2,660	2,584	457,617	22,209	1,330	1,292	228,809	11,105	76.57	33.74	6.90
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	2,660	2,584	457,617	22,209	1,330	1,292	228,809	11,105	76.57	33.74	6.90
CUMULATIVE		2,805	-	417,916	-				-			
ULTIMATE		5,466	2,584	875,533	22,209				11,105			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	5,081	1,749	63,994	-	70,823	-	-	-	-	70,823
12-2019	15,655	6,037	220,526	-	242,218	-	-	-	-	242,218
12-2020	16,883	6,800	247,636	-	271,319	-	-	-	-	271,319
12-2021	15,423	6,457	234,403	-	256,283	-	-	-	-	256,283
12-2022	13,228	5,709	206,585	-	225,521	-	-	-	-	225,521
12-2023	11,268	5,041	181,885	-	198,194	-	-	-	-	198,194
12-2024	9,562	4,456	160,339	-	174,357	-	-	-	-	174,357
12-2025	8,021	3,910	140,304	-	152,236	-	-	-	-	152,236
12-2026	6,740	3,436	122,964	-	133,139	-	-	-	-	133,139
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	101,859	43,595	1,578,636	-	1,724,090	-	-	-	-	1,724,090
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	101,859	43,595	1,578,636	-	1,724,090	-	-	-	-	1,724,090

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	673	22,810	-	-	-	23,484	47,339	47,339	45,136	45,136	27,082
12-2019	1,768	61,123	15,752	-	-	78,643	163,575	210,914	141,784	186,920	112,152
12-2020	1,844	63,941	-	-	-	65,786	205,534	416,448	161,957	348,878	209,327
12-2021	1,830	62,807	-	-	-	64,637	191,646	608,093	137,285	486,163	291,698
12-2022	1,787	59,952	-	-	-	61,739	163,782	771,875	106,659	592,823	355,694
12-2023	1,752	58,782	-	-	-	60,534	137,660	909,535	81,498	674,321	404,593
12-2024	1,726	59,505	-	-	-	61,231	113,126	1,022,661	60,885	735,206	441,124
12-2025	1,705	62,673	-	-	-	64,378	87,858	1,110,519	42,987	778,193	466,916
12-2026	1,692	63,657	-	-	-	65,349	67,790	1,178,310	30,153	808,346	485,007
12-2027	-	-	-	-	-	-	-	1,178,310	-	808,346	485,007
12-2028	-	-	-	-	-	-	-	1,178,310	-	808,346	485,007
12-2029	-	-	-	-	-	-	-	1,178,310	-	808,346	485,007
12-2030	-	-	-	-	-	-	-	1,178,310	-	808,346	485,007
12-2031	-	-	-	-	-	-	-	1,178,310	-	808,346	485,007
12-2032	-	-	-	-	-	-	-	1,178,310	-	808,346	485,007
12-2033	-	-	-	-	-	-	-	1,178,310	-	808,346	485,007
12-2034	-	-	-	-	-	-	-	1,178,310	-	808,346	485,007
12-2035	-	-	-	-	-	-	-	1,178,310	-	808,346	485,007
S-TOT	14,777	515,251	15,752	-	-	545,780	1,178,310		808,346		
REM	-	-	-	-	-	-	-	1,178,310	-	808,346	485,007
TOTAL	14,777	515,251	15,752	-	-	545,780	1,178,310		808,346		

LIFE - 9 years

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THESE DATA WERE GENERATED USING THE PALANTIRCASH PROGRAM

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF AUGUST 1, 2018
(NO DECOMMISSIONING COST)

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2018	1	47	13	320	18	17	4	112	6	61.52	43.44	7.21
12-2019	1	92	24	599	40	32	9	208	14	62.75	44.31	7.36
12-2020	1	68	18	454	-	24	6	158	-	64.01	45.19	7.52
12-2021	1	47	13	307	-	17	4	107	-	65.29	46.10	7.68
12-2022	1	33	9	208	-	12	3	73	-	66.59	47.02	7.85
12-2023	1	23	6	141	-	8	2	49	-	67.93	47.96	8.02
12-2024	1	14	3	79	-	5	1	28	-	69.28	48.92	8.19
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	325	86	2,109	59	113	30	735	20	64.25	45.33	7.54
CUMULATIVE		10,135	-	26,363	-				-			
ULTIMATE		10,460	86	28,473	59				20			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2018	1,017	195	804	-	2,016	-	-	-	-	2,016
12-2019	2,005	377	1,535	-	3,918	-	-	-	-	3,918
12-2020	1,508	288	1,189	-	2,986	-	-	-	-	2,986
12-2021	1,078	202	822	-	2,102	-	-	-	-	2,102
12-2022	773	142	570	-	1,485	-	-	-	-	1,485
12-2023	555	100	395	-	1,049	-	-	-	-	1,049
12-2024	328	58	227	-	613	-	-	-	-	613
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
12-2035	-	-	-	-	-	-	-	-	-	-
S-TOT	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	7,265	1,362	5,542	-	14,169	-	-	-	-	14,169

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2018	103	354	-	-	-	457	1,559	1,559	1,487	1,487	892
12-2019	204	875	-	-	-	1,079	2,839	4,398	2,461	3,947	2,368
12-2020	153	708	-	-	-	861	2,125	6,523	1,674	5,622	3,373
12-2021	110	707	-	-	-	816	1,286	7,809	921	6,543	3,926
12-2022	79	452	-	-	-	530	954	8,763	621	7,164	4,299
12-2023	56	463	-	-	-	519	530	9,293	314	7,478	4,487
12-2024	33	433	-	-	-	466	147	9,440	79	7,557	4,534
12-2025	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2026	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2027	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2028	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2029	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2030	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2031	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2032	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2033	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2034	-	-	-	-	-	-	-	9,440	-	7,557	4,534
12-2035	-	-	-	-	-	-	-	9,440	-	7,557	4,534
S-TOT	739	3,991	-	-	-	4,730	9,440		7,557		
REM	-	-	-	-	-	-	-	9,440	-	7,557	4,534
TOTAL	739	3,991	-	-	-	4,730	9,440		7,557		

LIFE - 7 years

DISCOUNT RATE @ 10%

PART IV – UPDATED COMPETENT PERSON'S REPORT ON SERICA'S ASSETS

ESTIMATES

of

RESERVES AND FUTURE REVENUE AND UNRISKED CONTINGENT AND PROSPECTIVE RESOURCES

to the

SERICA ENERGY PLC INTEREST

in

CERTAIN OIL AND GAS PROPERTIES

located in

IRISH WATERS IN THE ATLANTIC OCEAN

and in the

UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

as of

OCTOBER 31, 2018

BASED ON ESCALATED PRICE AND COST PARAMETERS

specified by

SERICA ENERGY PLC

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

November 16, 2018

Serica Energy plc
52 George Street
London W1U 7EA
United Kingdom

Peel Hunt LLP
120 London Wall
London EC2Y 5ET
United Kingdom

Ladies and Gentlemen:

In accordance with the request of Serica Energy plc (Serica), we have estimated the proved developed, probable, and possible reserves and future revenue, as of October 31, 2018, to the Serica interest in certain gas properties located in Erskine Field, United Kingdom (UK) Sector of the Central North Sea. Also as requested, we have estimated the unrisked contingent and prospective resources, as of October 31, 2018, to the Serica interest in certain discoveries and prospects located in Irish waters in the Atlantic Ocean and in the UK Sector of the Central North Sea. It is our understanding that Serica Energy Slyne B.V. and Serica Energy (UK) Limited own the interests in these properties and are wholly owned subsidiaries of Serica. We completed our evaluation on or about the date of this letter. For the reserves, this Competent Person's Report (report) has been prepared using escalated price and cost parameters specified by Serica, referred to as the Base Price Case, as discussed in subsequent paragraphs of this letter. Gross volumes shown in this report are 100 percent of the volumes expected to be produced from the properties.

In 2017, Serica announced that it entered into an agreement, through its wholly owned subsidiary Serica Energy (UK) Limited, to acquire interests and operatorship in Bruce, Keith, and Rhum Fields (BKR Assets) from BP Exploration Operating Company Limited (BP). We have been informed by Serica that the acquisition will constitute a reverse takeover of Serica under the AIM Rules for Companies. We have also been informed by Serica that Serica, as enlarged by the acquisition of the BKR Assets, will need to seek readmission of its shares to trading on the AIM market of the London Stock Exchange (Readmission). We understand that this report will be included in the new Admission Document in connection with Readmission.

This report has been prepared in accordance with the AIM Rules for Companies, specifically the "Note for Mining, Oil and Gas Companies - June 2009" (Note for Mining, Oil and Gas Companies) and the content requirements in Appendix 2 and the summaries set out in Appendices 1 and 3, as well as the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. Following the definitions are a list of abbreviations used in this report and the certificates of qualification for the evaluators who contributed to this report.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

As presented in the accompanying summary projections, Tables I through VII, and the revenues, taxes, and costs in Table VIII, we estimate the gross reserves and the net reserves and future net revenue to the Serica interest in Erskine Field, as of October 31, 2018, to be:

	Gross (100%) Reserves		Net Reserves			Future Net Revenue After UK Corporate Income Taxes (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	3,854.8	25,427.2	693.9	130.7	4,508.2	48,656.7	43,951.5
Proved Developed Non-Producing	301.5	2,554.9	54.3	13.1	453.0	6,582.5	6,001.4
Total Proved Developed (1P)	4,156.3	27,982.1	748.1	143.9	4,961.2	55,239.2	49,952.9
Probable	3,205.5	21,294.9	577.0	109.5	3,775.6	36,965.6	28,688.3
Proved + Probable (2P)	7,361.8	49,277.0	1,325.1	253.4	8,736.8	92,204.8	78,641.2
Possible	4,565.7	30,463.9	821.8	156.6	5,401.3	67,712.2	48,642.8
Proved + Probable + Possible (3P)	11,927.5	79,740.9	2,147.0	410.0	14,138.1	159,917.0	127,283.9

Totals may not add because of rounding.

The oil volumes shown include condensate only. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Monetary values shown in this report are expressed in United States dollars ($), thousands of United States dollars (M$), or millions of United States dollars (MM$) using the August 1, 2018, United States Federal Reserve exchange rate of $1.312 per British pound sterling.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. No study was made to determine whether proved undeveloped reserves might be established for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue for the reserves shown in this report is Serica's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Serica's share of capital costs, abandonment and reclamation costs, operating expenses, and estimates of the UK's corporate income taxes. An effective tax rate of 40 percent, composed of a 30 percent UK Ring Fence Corporation Tax and a 10 percent Supplementary Charge, was applied to future net revenue in excess of Serica's loss carry-forward pool of MM$160. The tax estimates are a simplification of current tax law and were not prepared by a tax accountant or lawyer. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

As requested, this report has been prepared using Base Price Case oil, NGL, and gas price parameters specified by Serica. Oil and NGL prices are based on Brent Crude futures prices and are adjusted for quality, transportation fees, and market differentials. Gas prices are based on National Balancing Point futures prices and are adjusted for energy content, transportation fees, and market differentials. Sensitivities using Low and High Price Cases are further detailed in the Technical Discussion section of this report. All prices for the Base Price Case, before adjustments, along with escalation parameters are shown in the following table:

	Oil/NGL	Gas Price	
Period Ending	Price ($/Barrel)	(Pence/ therm)	($/MMBTU)
12-31-2018	65.39	49.1	6.439
12-31-2019	68.15	55.5	7.277
12-31-2020	72.42	56.1	7.357
12-31-2021	71.27	52.7	6.913
12-31-2022	74.52	53.2	6.984
12-31-2023	78.02	55.7	7.312
12-31-2024	81.52	58.2	7.640

Thereafter, escalated 2.5 percent
on January 1 of each year.

Operating costs used in this report are based on operating expense records of Serica. These costs include the overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the field level. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Erskine Field produces to the Lomond Platform, and Serica's share of the operating costs for the platform are based on a cost-sharing agreement between the field's owners and other producers to the platform. Since all properties are nonoperated, headquarters general and administrative overhead expenses are not included. As requested, operating costs are escalated 2.5 percent per year throughout the lives of the properties.

Capital costs used in this report were provided by Serica and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for facilities maintenance. Based on our review of the records provided to us, we regard these estimated capital costs to be reasonable. Abandonment and reclamation costs used in this report are Serica's estimates of reclamation costs and the costs to abandon the wells, platform, and production facilities, net of any salvage value. It is our understanding that, pursuant to the sales agreement Serica entered into when it purchased its interest in Erskine Field, it is not liable for abandonment costs up to a maximum value that exceeds its current estimates of abandonment costs. As requested, capital costs are escalated 2.5 percent per year to the date of expenditure.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Serica interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Serica receiving its net revenue interest share of estimated future gross production. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report subclassified as development pending are contingent upon execution of a Production Handling Agreement (PHA) with the owners of the Shearwater Platform, which will process production from Columbus Field. The contingent resources shown in this report subclassified as development not viable are contingent upon acquisition of additional technical data that demonstrate producing rates and volumes that will be sufficient to sustain economic viability, generation and approval of a development plan, and commitment from the owners to develop the discoveries. This report does not include economic analysis for these properties. Based on analogous field developments, it appears that the best estimate development pending contingent resources in this report have a reasonable chance of being economically viable. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves. We have estimated the chance of development to account for the possibility that the contingencies are not successfully addressed.

Development Pending

The contingent resources in Columbus Field have been subclassified as development pending, which are those resources from a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. We estimate the gross and working interest unrisked development pending contingent resources to the Serica interest in Columbus Field, along with the risk factor, as of October 31, 2018, to be:

	Unrisked Development Pending Contingent Resources				
	Gross (100%)		Working Interest		Risk
Region/Area/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Factor[1] (%)
UK Sector of the Central North Sea					
Columbus Field					
Low Estimate (1C)	1,269.2	28,857.3	634.6	14,428.7	90
Best Estimate (2C)	2,793.7	63,533.2	1,396.9	31,766.6	90
High Estimate (3C)	3,636.2	82,284.1	1,818.1	41,142.1	90

(1) The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

The oil volumes shown include condensate only.

Development Not Viable

The contingent resources in the Bandon Discovery have been subclassified as development not viable, which are those resources from a discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential. There are no contingent resources in the Bandon Discovery because of the unfavorable fluid properties. We estimate the gross and working interest unrisked development not viable contingent resources to the Serica interest in the Bandon Discovery, along with the risk factor, as of October 31, 2018, to be:

Region/Area/Category	Unrisked Development Not Viable Contingent Resources				Risk Factor[1] (%)
	Gross (100%)		Working Interest		
	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	
Irish Waters in the Atlantic Ocean					
Bandon Discovery					
Low Estimate (1C)	0.0	0.0	0.0	0.0	0
Best Estimate (2C)	0.0	0.0	0.0	0.0	0
High Estimate (3C)	0.0	0.0	0.0	0.0	0

(1) The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

All Contingent Resources

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as 1C, 2C, and 3C, respectively. The estimates of contingent resources included herein have not been adjusted for development risk.

Unrisked contingent resources are estimated ranges of discovered and recoverable oil and gas volumes assuming their development and are based on estimated ranges of discovered in-place volumes. For resources, the chance of commerciality includes both the chance of geologic discovery, and, once a discovery is made, the chance of development. For contingent resources, given that a discovery has been made, the chance of commerciality is equal to the chance of development. We have estimated the chance of development to account for the possibility that the contingencies are not successfully addressed. Such risking assesses whether the project contingencies can be successfully addressed and includes assessment of the following criteria: (1) the expected timetable for development; (2) the economics of the project; (3) the marketability of the oil and gas production; (4) the availability of infrastructure and technology; (5) the political, regulatory, and environmental conditions; (6) the project maturity and definition; (7) the availability of capital; and, ultimately, (8) the expectation that the operator will undertake development. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects, as discussed in subsequent paragraphs. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable.

Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the gross and working interest unrisked prospective resources to the Serica interest in these properties, along with the risk factor, as of October 31, 2018, to be:

	Unrisked Prospective Resources(1)				
	Gross (100%)		Working Interest		Risk
Region/Prospect/Category	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Factor(2) (%)
Irish Waters in the Atlantic Ocean					
Achill					
Low Estimate (1U)	0.0	120.7	0.0	120.7	26
Best Estimate (2U)	0.0	252.7	0.0	252.7	26
High Estimate (3U)	0.0	516.5	0.0	516.5	26
Bandon South					
Low Estimate (1U)	0.0	6.7	0.0	6.7	26
Best Estimate (2U)	0.0	26.9	0.0	26.9	26
High Estimate (3U)	0.0	101.7	0.0	101.7	26
Boyne Sherwood					
Low Estimate (1U)	0.0	60.8	0.0	60.8	26
Best Estimate (2U)	0.0	180.2	0.0	180.2	26
High Estimate (3U)	0.0	528.5	0.0	528.5	26
Boyne Suisnish					
Low Estimate (1U)	5.6	1.4	5.6	1.4	20
Best Estimate (2U)	20.1	5.5	20.1	5.5	20
High Estimate (3U)	76.7	22.1	76.7	22.1	20
Liffey Sherwood					
Low Estimate (1U)	0.0	52.6	0.0	52.6	26
Best Estimate (2U)	0.0	180.4	0.0	180.4	26
High Estimate (3U)	0.0	626.7	0.0	626.7	26
Liffey Suisnish					
Low Estimate (1U)	30.3	7.6	30.3	7.6	20
Best Estimate (2U)	128.2	34.0	128.2	34.0	20
High Estimate (3U)	526.7	147.4	526.7	147.4	20
UK Sector of the Central North Sea					
Rowallan Pentland					
Low Estimate (1U)	3.5	54.4	0.5	8.2	22
Best Estimate (2U)	8.8	118.7	1.3	17.8	22
High Estimate (3U)	20.0	259.9	3.0	39.0	22

Region/Prospect/Category	Unrisked Prospective Resources(1) Gross (100%) Oil (MMBBL)	Gas (BCF)	Working Interest Oil (MMBBL)	Gas (BCF)	Risk Factor(2) (%)
UK Sector of the Central North Sea (Cont.)					
Rowallan Triassic					
Low Estimate (1U)	10.0	134.1	1.5	20.1	22
Best Estimate (2U)	33.0	422.4	4.9	63.4	22
High Estimate (3U)	113.4	1,463.9	17.0	219.6	22
Total					
Low Estimate (1U)	49.4	438.3	37.9	278.1	-
Best Estimate (2U)	190.0	1,220.9	154.6	760.8	-
High Estimate (3U)	736.9	3,666.7	623.4	2,201.5	-

Note: Totals are the arithmetic sum of multiple probability distributions and may not add because of rounding.

(1) These volumes represent only the portions of the prospects that lie within the boundaries of the respective lease and/or license areas.

(2) The risk factor for prospective resources refers to the estimated chance, or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. For the purposes of this report, the risk factor for the prospective resources refers to the PRMS term "chance of geologic discovery".

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in millions of barrels (MMBBL). Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of prospective resources are referred to as 1U, 2U, and 3U, respectively. As recommended in the 2018 PRMS, the 1U, 2U, and 3U prospective resources have been aggregated beyond the prospect level by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially recoverable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. Included in this report is a discussion of the primary geologic risk elements for each prospect.

Each prospect was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume prospects may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects. For the purposes of this report, the risk factor for the prospective resources refers to the PRMS term "chance of geologic discovery".

GENERAL INFORMATION

As shown in the Table of Contents, this report includes, for Erskine Field, summary projections of reserves and revenue by reserves category as well as a table of revenue, taxes, and costs. Also included are a technical discussion and pertinent figures for all properties in this report.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves, contingent resources, and prospective resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Serica, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves, contingent resources, and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. The contingent and prospective resources shown in this report are for undeveloped locations; such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Serica, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office and are available for examination in our offices by parties with written authorization from Serica. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

NSAI served as independent evaluator in the conduct and analyses described and in the determination of professional opinions expressed herein. NSAI is professionally qualified and a member in good standing of an appropriate, recognized professional association under the AIM Rules for Companies with at least 5 years of relevant experience in the estimation, assessment, and evaluation of oil and gas. NSAI and its management and staff are independent of Serica and have no interest in any assets or share capital of Serica or in the promotion of Serica. Neither NSAI nor its staff will receive any pecuniary or other benefits in connection with this assignment other than a normal fixed consultancy fee, and no part of the fee is linked to Readmission or the value of Serica following the acquisition of the BKR Assets.

NSAI confirms that, to the best of its knowledge, there has been no material change in the information contained in this report since October 31, 2018, being the date to which we have estimated the reserves and resources contained in the report. This report was prepared for Serica and Peel Hunt LLP (in its capacity as nominated adviser to Serica) and should not be used for purposes other than those for which it is intended without our prior written consent.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Derek F. Newton
Derek F. Newton, P.E. 97689
Senior Vice President

Date Signed: November 16, 2018

By: /s/ Edward C. Roy III
Edward C. Roy III, P.G. 2364
Vice President

Date Signed: November 16, 2018

JMM:JSM

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

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

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

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

1.1 Petroleum Resources Classification Framework

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

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

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

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

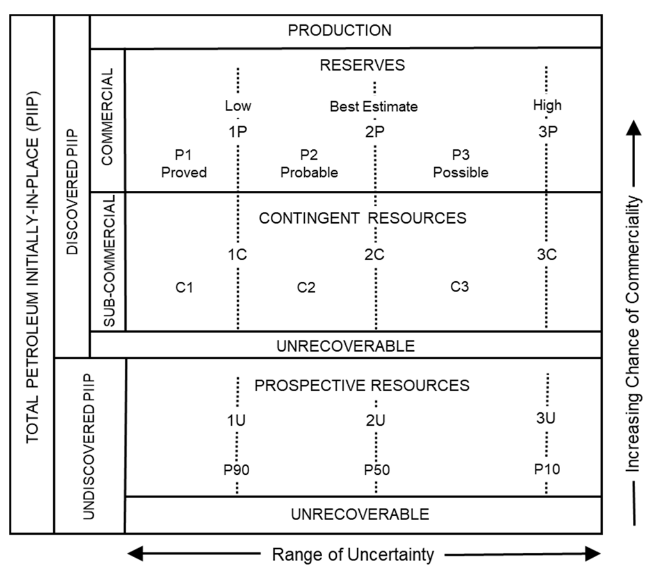

Figure 1.1—Resources classification framework

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

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

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

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

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

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

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

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

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
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1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

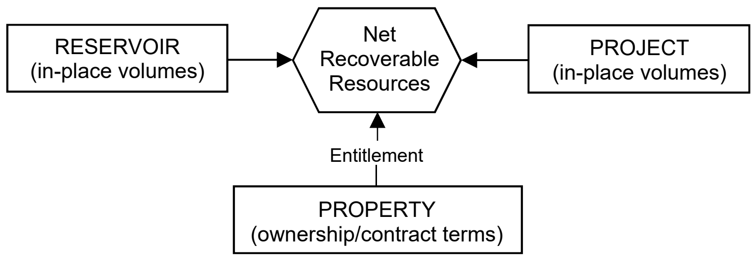

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

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1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified recoverable hydrocarbons, but is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, $CO2$) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

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2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

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Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

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

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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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

ABBREVIATIONS

$	United States dollars
°F	degrees Fahrenheit
1C	low estimate scenario of contingent resources
2C	best estimate scenario of contingent resources
3C	high estimate scenario of contingent resources
1P	proved
2P	proved plus probable
3P	proved plus probable plus possible
1U	low estimate scenario of prospective resources
2U	best estimate scenario of prospective resources
3U	high estimate scenario of prospective resources
API	American Petroleum Institute
BCF	billions of cubic feet
BKR Assets	Bruce, Keith, and Rhum Fields
BP	BP Exploration Operating Company Limited
cp	centipoise
DST	drillstem test
FEL	Frontier Exploration License
ft	feet
GDT	gas down to
GWC	gas-water contact
km	kilometers
km^2	square kilometers
m	meters
M$	thousands of United States dollars
Ma	millions of years ago
MM$	millions of United States dollars
MBBL	thousands of barrels
MDT	modular dynamics test
MMBBL	millions of barrels
MMBTU	millions of British thermal units
MMCF	millions of cubic feet
MTR	meters
NGL	natural gas liquids

ABBREVIATIONS

Note for Mining, Oil and Gas Companies	Note for Mining, Oil and Gas Companies – June 2009
NSAI	Netherland, Sewell & Associates, Inc.
OOIP	original oil-in-place
PHA	production handling agreement
P_g	chance of geologic discovery
PRMS	Petroleum Resources Management System
psia	pounds per square inch absolute
Readmission	Readmission of Serica's shares to trading on the AIM Market of the London Stock Exchange
report	Competent Person's Report
Serica	Serica Energy plc
SPE	Society of Petroleum Engineers
SPE Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE
TVDSS	true vertical depth subsea
UK	United Kingdom

NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, Derek F. Newton, Licensed Professional Engineer, 1301 McKinney Street, Suite 3200, Houston, Texas, 77010, hereby certify:

> I am an employee of Netherland, Sewell & Associates, Inc., which prepared a detailed analysis of certain oil and gas properties of Serica Energy plc (referred to herein as "Serica"). The effective date of this evaluation is October 31, 2018.
>
> I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Serica or its affiliated companies.
>
> I attended Strathclyde University in Scotland, and I graduated in 1986 with a Master of Science Degree in Petroleum Engineering; I attended University College in Cardiff, Wales, and I graduated in 1983 with a Bachelor of Science Degree in Mechanical Engineering; I am a Licensed Professional Engineer in the State of Texas, United States of America; and I have in excess of 35 years of experience in petroleum engineering studies and evaluations.
>
> 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 or records, the files from Serica, and the appropriate provincial regulatory authorities.

/s/ Derek F. Newton

By: ____________________________________

Derek F. Newton, P.E.
Senior Vice President
Texas License No. 97689

November 16, 2018
Houston, Texas

NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, Edward C. Roy III, Licensed Professional Geoscientist, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

> I am an employee of Netherland, Sewell & Associates, Inc., which prepared a detailed analysis of certain oil and gas properties of Serica Energy plc (referred to herein as "Serica"). The effective date of this evaluation is October 31, 2018.
>
> I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Serica or its affiliated companies.
>
> I attended Texas A&M University, and I graduated in 1998 with a Master of Science Degree in Geology. I attended Texas Christian University, and I graduated in 1992 with a Bachelor of Science Degree in Geology; I am a Licensed Professional Geoscientist in the State of Texas, United States of America; and I have in excess of 21 years of experience in geological and geophysical studies and evaluations.
>
> 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 or records, the files from Serica, and the appropriate provincial regulatory authorities.

/s/ Edward C. Roy III
By: ____
Edward C. Roy III, P.G.
Vice President
Texas License No. 2364

November 16, 2018
Houston, Texas

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SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

TOTAL PROVED DEVELOPED (1P) RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	372.8	0.0	2,501.4	67.1	12.9	443.5	64.79	48.85	6.241	4,347.3	628.3	2,768.1	7,743.7
12-31-2019	1,772.6	0.0	11,935.6	319.1	61.4	2,116.2	67.55	50.91	7.163	21,553.5	3,124.4	15,158.6	39,836.5
12-31-2020	1,185.6	0.0	8,029.0	213.4	41.3	1,423.5	71.82	54.10	7.251	15,327.1	2,233.4	10,322.3	27,882.9
12-31-2021	687.4	0.0	4,558.5	123.7	23.4	808.2	70.67	53.24	6.763	8,744.5	1,247.9	5,465.8	15,458.2
05-31-2022	137.9	0.0	957.7	24.8	4.9	169.8	73.92	55.67	6.841	1,834.2	274.1	1,161.6	3,270.0
SUBTOTAL	4,156.3	0.0	27,982.1	748.1	143.9	4,961.2	69.25	52.18	7.030	51,806.6	7,508.2	34,876.4	94,191.2
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,156.3	0.0	27,982.1	748.1	143.9	4,961.2	69.25	52.18	7.030	51,806.6	7,508.2	34,876.4	94,191.2
CUM PROD	63,767.2	0.0	335,345.1										
ULTIMATE	67,923.5	0.0	363,327.2										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2018	5	0.9	0.0	0.0	131.1	0.0	1,976.4	5,636.1	5,636.1	5,592.1
12-31-2019	5	0.9	0.0	0.0	790.1	0.0	11,770.8	27,275.6	32,911.7	31,311.1
12-31-2020	5	0.9	0.0	0.0	809.9	0.0	11,220.0	15,853.0	48,764.7	44,910.9
12-31-2021	5	0.9	0.0	0.0	830.1	0.0	8,910.4	5,717.7	54,482.4	49,400.3
05-31-2022	3	0.5	0.0	0.0	353.1	0.0	2,160.1	756.8	55,239.2	49,952.9
SUBTOTAL			0.0	0.0	2,914.2	0.0	36,037.7	55,239.2	55,239.2	49,952.9
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	55,239.2	49,952.9
TOTAL OF 3.6 YRS			0.0	0.0	2,914.2	0.0	36,037.7	55,239.2	55,239.2	49,952.9

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	55,239.2
5.000	52,429.4
10.000	49,952.9
15.000	47,754.7
20.000	45,791.1
25.000	44,026.8
30.000	42,433.1
35.000	40,986.6
40.000	39,667.9
50.000	37,351.4

Table I

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	342.5	0.0	2,245.1	61.7	11.5	398.1	64.79	48.85	6.241	3,994.6	563.9	2,484.4	7,043.0
12-31-2019	1,618.7	0.0	10,631.0	291.4	54.7	1,884.9	67.55	50.91	7.163	19,681.7	2,782.9	13,501.7	35,966.3
12-31-2020	1,070.1	0.0	7,050.5	192.6	36.3	1,250.1	71.82	54.10	7.251	13,834.5	1,961.3	9,064.4	24,860.1
12-31-2021	685.6	0.0	4,543.0	123.4	23.4	805.5	70.67	53.24	6.763	8,721.2	1,243.7	5,447.2	15,412.0
05-31-2022	137.9	0.0	957.7	24.8	4.9	169.8	73.92	55.67	6.841	1,834.2	274.1	1,161.6	3,270.0
SUBTOTAL	3,854.8	0.0	25,427.2	693.9	130.7	4,508.2	69.27	52.21	7.023	48,066.2	6,825.9	31,659.3	86,551.3
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	3,854.8	0.0	25,427.2	693.9	130.7	4,508.2	69.27	52.21	7.023	48,066.2	6,825.9	31,659.3	86,551.3
CUM PROD	54,807.9	0.0	278,500.8										
ULTIMATE	58,662.7	0.0	303,928.0										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	NET DEDUCTIONS/EXPENDITURES TAXES AD VALOREM M$	NET DEDUCTIONS/EXPENDITURES CAPITAL COST M$	NET DEDUCTIONS/EXPENDITURES ABDNMNT COST M$	NET DEDUCTIONS/EXPENDITURES OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED CUM M$	FUTURE NET REVENUE BEFORE INCOME TAXES DISC AT 10.000% CUM M$
12-31-2018	4	0.7	0.0	0.0	131.1	0.0	1,885.7	5,026.1	5,026.1	4,986.9
12-31-2019	4	0.7	0.0	0.0	790.1	0.0	11,266.9	23,909.3	28,935.4	27,537.8
12-31-2020	4	0.7	0.0	0.0	809.9	0.0	10,764.8	13,285.4	42,220.8	38,940.8
12-31-2021	4	0.7	0.0	0.0	830.1	0.0	8,902.9	5,679.0	47,899.9	43,398.9
05-31-2022	3	0.5	0.0	0.0	353.1	0.0	2,160.1	756.8	48,656.7	43,951.5
SUBTOTAL			0.0	0.0	2,914.2	0.0	34,980.4	48,656.7	48,656.7	43,951.5
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	48,656.7	43,951.5
TOTAL OF 3.6 YRS			0.0	0.0	2,914.2	0.0	34,980.4	48,656.7	48,656.7	43,951.5

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	48,656.7
5.000	46,153.8
10.000	43,951.5
15.000	41,999.7
20.000	40,258.6
25.000	38,696.3
30.000	37,286.7
35.000	36,008.6
40.000	34,844.7
50.000	32,802.7

Table II

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

PROVED DEVELOPED NON-PRODUCING RESERVES

SERICA ENERGY PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	30.2	0.0	256.3	5.4	1.3	45.4	64.79	48.85	6.241	352.7	64.4	283.6	700.7
12-31-2019	153.9	0.0	1,304.6	27.7	6.7	231.3	67.55	50.91	7.163	1,871.8	341.5	1,656.9	3,870.3
12-31-2020	115.5	0.0	978.5	20.8	5.0	173.5	71.82	54.10	7.251	1,492.6	272.2	1,258.0	3,022.7
01-06-2021	1.8	0.0	15.5	0.3	0.1	2.7	70.67	53.24	6.763	23.3	4.2	18.6	46.1
SUBTOTAL	301.5	0.0	2,554.9	54.3	13.1	453.0	68.93	51.94	7.102	3,740.4	682.3	3,217.1	7,639.8
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	301.5	0.0	2,554.9	54.3	13.1	453.0	68.93	51.94	7.102	3,740.4	682.3	3,217.1	7,639.8
CUM PROD	8,959.3	0.0	56,844.3										
ULTIMATE	9,260.7	0.0	59,399.2										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	NET DEDUCTIONS/EXPENDITURES TAXES AD VALOREM M$	NET DEDUCTIONS/EXPENDITURES CAPITAL COST M$	NET DEDUCTIONS/EXPENDITURES ABDNMNT COST M$	NET DEDUCTIONS/EXPENDITURES OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED CUM M$	FUTURE NET REVENUE BEFORE INCOME TAXES DISC AT 10.000% CUM M$
12-31-2018	1	0.2	0.0	0.0	0.0	0.0	90.8	610.0	610.0	605.2
12-31-2019	1	0.2	0.0	0.0	0.0	0.0	503.9	3,366.4	3,976.3	3,773.3
12-31-2020	1	0.2	0.0	0.0	0.0	0.0	455.2	2,567.5	6,543.8	5,970.1
01-06-2021	1	0.2	0.0	0.0	0.0	0.0	7.4	38.7	6,582.5	6,001.4
SUBTOTAL			0.0	0.0	0.0	0.0	1,057.3	6,582.5	6,582.5	6,001.4
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	6,582.5	6,001.4
TOTAL OF 2.2 YRS			0.0	0.0	0.0	0.0	1,057.3	6,582.5	6,582.5	6,001.4

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	6,582.5
5.000	6,275.6
10.000	6,001.4
15.000	5,755.0
20.000	5,532.5
25.000	5,330.5
30.000	5,146.5
35.000	4,978.0
40.000	4,823.2
50.000	4,548.7

Table III

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

PROBABLE RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	29.3	0.0	195.8	5.3	1.0	34.7	64.79	48.85	6.241	341.3	49.2	216.7	607.2
12-31-2019	287.7	0.0	1,911.5	51.8	9.8	338.9	67.55	50.91	7.163	3,498.2	500.4	2,427.7	6,426.3
12-31-2020	393.4	0.0	2,608.0	70.8	13.4	462.4	71.82	54.10	7.251	5,085.3	725.5	3,352.9	9,163.7
12-31-2021	506.2	0.0	3,437.6	91.1	17.7	609.5	70.67	53.24	6.763	6,439.6	941.1	4,121.9	11,502.6
12-31-2022	709.1	0.0	4,637.4	127.6	23.8	822.2	73.92	55.67	6.841	9,434.8	1,327.4	5,624.6	16,386.8
12-31-2023	600.6	0.0	4,001.5	108.1	20.6	709.5	77.42	58.28	7.202	8,369.6	1,199.2	5,109.4	14,678.2
12-31-2024	497.7	0.0	3,302.1	89.6	17.0	585.5	80.92	60.90	7.563	7,249.2	1,034.0	4,427.6	12,710.8
05-31-2025	181.5	0.0	1,200.9	32.7	6.2	212.9	82.96	62.42	7.773	2,710.8	385.4	1,654.9	4,751.2
SUBTOTAL	3,205.5	0.0	21,294.9	577.0	109.5	3,775.6	74.75	56.28	7.134	43,128.9	6,162.1	26,935.7	76,226.7
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	3,205.5	0.0	21,294.9	577.0	109.5	3,775.6	74.75	56.28	7.134	43,128.9	6,162.1	26,935.7	76,226.7
CUM PROD	0.0	0.0	0.0										
ULTIMATE	3,205.5	0.0	21,294.9										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	NET DEDUCTIONS/EXPENDITURES TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	68.0	539.1	539.1	534.8
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	792.1	5,634.2	6,173.4	5,799.4
12-31-2020	0	0.0	0.0	0.0	0.0	0.0	1,442.2	7,721.5	13,894.8	12,380.5
12-31-2021	0	0.0	0.0	0.0	0.0	0.0	2,768.3	8,734.3	22,629.1	19,159.7
12-31-2022	1	0.2	0.0	0.0	497.8	0.0	8,424.6	7,464.5	30,093.6	24,447.0
12-31-2023	3	0.5	0.0	0.0	872.1	0.0	9,736.7	4,069.4	34,163.0	27,070.0
12-31-2024	3	0.5	0.0	0.0	893.9	0.0	9,713.1	2,103.7	36,266.7	28,307.0
05-31-2025	3	0.5	0.0	0.0	380.2	0.0	3,672.1	698.9	36,965.6	28,688.3
SUBTOTAL			0.0	0.0	2,644.1	0.0	36,617.1	36,965.6	36,965.6	28,688.3
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	36,965.6	28,688.3
TOTAL OF 6.6 YRS			0.0	0.0	2,644.1	0.0	36,617.1	36,965.6	36,965.6	28,688.3

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
0.000	36,965.6
5.000	32,384.7
10.000	28,688.3
15.000	25,663.5
20.000	23,157.2
25.000	21,056.8
30.000	19,278.6
35.000	17,759.1
40.000	16,449.7
50.000	14,318.1

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Table IV

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

PROVED + PROBABLE (2P) RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2018	402.0	0.0	2,697.2	72.4	13.9	478.2	64.79	48.85	6.241	4,688.6	677.5	2,984.7	8,350.8
12-31-2019	2,060.3	0.0	13,847.1	370.9	71.2	2,455.1	67.55	50.91	7.163	25,051.7	3,624.8	17,586.3	46,262.8
12-31-2020	1,579.0	0.0	10,637.0	284.2	54.7	1,885.9	71.82	54.10	7.251	20,412.4	2,958.9	13,675.3	37,046.6
12-31-2021	1,193.7	0.0	7,996.1	214.9	41.1	1,417.7	70.67	53.24	6.763	15,184.1	2,189.0	9,587.7	26,960.7
12-31-2022	846.9	0.0	5,595.1	152.4	28.8	992.0	73.92	55.67	6.841	11,269.0	1,601.5	6,786.2	19,656.8
12-31-2023	600.6	0.0	4,001.5	108.1	20.6	709.5	77.42	58.28	7.202	8,369.6	1,199.2	5,109.4	14,678.2
12-31-2024	497.7	0.0	3,302.1	89.6	17.0	585.5	80.92	60.90	7.563	7,249.2	1,034.0	4,427.6	12,710.8
05-31-2025	181.5	0.0	1,200.9	32.7	6.2	212.9	82.96	62.42	7.773	2,710.8	385.4	1,654.9	4,751.2
SUBTOTAL	7,361.8	0.0	49,277.0	1,325.1	253.4	8,736.8	71.64	53.95	7.075	94,935.5	13,670.3	61,812.1	170,417.9
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	7,361.8	0.0	49,277.0	1,325.1	253.4	8,736.8	71.64	53.95	7.075	94,935.5	13,670.3	61,812.1	170,417.9
CUM PROD	63,767.2	0.0	335,345.1										
ULTIMATE	71,128.9	0.0	384,622.1										

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2018	5	0.9	0.0	0.0	131.1	0.0	2,044.4	6,175.2	6,175.2	6,126.8
12-31-2019	5	0.9	0.0	0.0	790.1	0.0	12,562.9	32,909.8	39,085.1	37,110.4
12-31-2020	5	0.9	0.0	0.0	809.9	0.0	12,662.3	23,574.4	62,659.5	57,291.4
12-31-2021	5	0.9	0.0	0.0	830.1	0.0	11,678.7	14,452.0	77,111.5	68,559.9
12-31-2022	4	0.7	0.0	0.0	850.9	0.0	10,584.6	8,221.3	85,332.8	74,399.9
12-31-2023	3	0.5	0.0	0.0	872.1	0.0	9,736.7	4,069.4	89,402.2	77,022.9
12-31-2024	3	0.5	0.0	0.0	893.9	0.0	9,713.1	2,103.7	91,505.9	78,259.9
05-31-2025	3	0.5	0.0	0.0	380.2	0.0	3,672.1	698.9	92,204.8	78,641.2
SUBTOTAL			0.0	0.0	5,558.3	0.0	72,654.8	92,204.8	92,204.8	78,641.2
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	92,204.8	78,641.2
TOTAL OF 6.6 YRS			0.0	0.0	5,558.3	0.0	72,654.8	92,204.8	92,204.8	78,641.2

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	92,204.8
5.000	84,814.1
10.000	78,641.2
15.000	73,418.3
20.000	68,948.3
25.000	65,083.6
30.000	61,711.7
35.000	58,745.7
40.000	56,117.5
50.000	51,669.5

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Table V

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

POSSIBLE RESERVES

SERICA ENERGY PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	53.9	0.0	360.8	9.7	1.9	64.0	64.79	48.85	6.241	628.2	90.6	399.3	1,118.1
12-31-2019	400.8	0.0	2,671.1	72.1	13.7	473.6	67.55	50.91	7.163	4,872.9	699.2	3,392.3	8,964.4
12-31-2020	474.1	0.0	3,154.8	85.3	16.2	559.4	71.82	54.10	7.251	6,128.5	877.6	4,056.0	11,062.0
12-31-2021	524.2	0.0	3,551.6	94.4	18.3	629.7	70.67	53.24	6.763	6,668.7	972.3	4,258.5	11,899.5
12-31-2022	594.9	0.0	4,100.3	107.1	21.1	727.0	73.92	55.67	6.841	7,915.5	1,173.7	4,973.2	14,062.3
12-31-2023	579.3	0.0	3,873.7	104.3	19.9	686.8	77.42	58.28	7.202	8,072.8	1,160.9	4,946.2	14,179.9
12-31-2024	441.0	0.0	2,858.7	79.4	14.7	506.9	80.92	60.90	7.563	6,423.7	895.1	3,833.1	11,151.9
12-31-2025	613.3	0.0	4,013.6	110.4	20.6	711.6	82.96	62.42	7.773	9,158.8	1,288.2	5,531.1	15,978.1
12-31-2026	556.3	0.0	3,701.5	100.1	19.0	656.3	85.05	63.98	7.988	8,516.3	1,217.7	5,242.2	14,976.3
08-31-2027	327.9	0.0	2,177.9	59.0	11.2	386.1	87.19	65.58	8.209	5,146.2	734.4	3,169.7	9,050.2
SUBTOTAL	4,565.7	0.0	30,463.9	821.8	156.6	5,401.3	77.30	58.15	7.369	63,531.6	9,109.7	39,801.6	112,442.8
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,565.7	0.0	30,463.9	821.8	156.6	5,401.3	77.30	58.15	7.369	63,531.6	9,109.7	39,801.6	112,442.8
CUM PROD	0.0	0.0	0.0										
ULTIMATE	4,565.7	0.0	30,463.9										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	116.3	1,001.8	1,001.8	993.8
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	975.0	7,989.4	8,991.3	8,477.1
12-31-2020	0	0.0	0.0	0.0	0.0	0.0	1,385.5	9,676.6	18,667.8	16,729.6
12-31-2021	0	0.0	0.0	0.0	0.0	0.0	1,905.1	9,994.4	28,662.2	24,468.0
12-31-2022	1	0.2	0.0	0.0	0.0	0.0	2,899.1	11,163.2	39,825.4	32,331.6
12-31-2023	2	0.4	0.0	0.0	0.0	0.0	3,433.0	10,746.9	50,572.4	39,248.5
12-31-2024	1	0.2	0.0	0.0	0.0	0.0	3,003.6	8,148.3	58,720.7	44,005.3
12-31-2025	1	0.2	0.0	0.0	536.1	0.0	9,086.0	6,356.0	65,076.7	47,376.4
12-31-2026	4	0.7	0.0	0.0	939.2	0.0	11,796.6	2,240.5	67,317.2	48,465.2
08-31-2027	3	0.5	0.0	0.0	639.1	0.0	8,016.1	395.0	67,712.2	48,642.8
SUBTOTAL			0.0	0.0	2,114.4	0.0	42,616.3	67,712.2	67,712.2	48,642.8
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	67,712.2	48,642.8
TOTAL OF 8.8 YRS			0.0	0.0	2,114.4	0.0	42,616.3	67,712.2	67,712.2	48,642.8

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
0.000	67,712.2
5.000	56,903.4
10.000	48,642.8
15.000	42,207.7
20.000	37,107.7
25.000	33,002.6
30.000	29,651.7
35.000	26,881.3
40.000	24,564.4
50.000	20,935.0

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Table VI

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

PROVED + PROBABLE + POSSIBLE (3P) RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	455.9	0.0	3,058.0	82.1	15.7	542.2	64.79	48.85	6.241	5,316.9	768.1	3,384.0	9,468.9
12-31-2019	2,461.1	0.0	16,518.2	443.0	84.9	2,928.7	67.55	50.91	7.163	29,924.6	4,324.0	20,978.7	55,227.3
12-31-2020	2,053.0	0.0	13,791.8	369.5	70.9	2,445.3	71.82	54.10	7.251	26,540.8	3,836.5	17,731.2	48,108.6
12-31-2021	1,717.9	0.0	11,547.7	309.2	59.4	2,047.4	70.67	53.24	6.763	21,852.8	3,161.3	13,846.2	38,860.2
12-31-2022	1,441.8	0.0	9,695.3	259.5	49.9	1,719.0	73.92	55.67	6.841	19,184.5	2,775.2	11,759.4	33,719.1
12-31-2023	1,179.9	0.0	7,875.3	212.4	40.5	1,396.3	77.42	58.28	7.202	16,442.4	2,360.1	10,055.6	28,858.1
12-31-2024	938.7	0.0	6,160.8	169.0	31.7	1,092.3	80.92	60.90	7.563	13,672.9	1,929.1	8,260.7	23,862.7
12-31-2025	794.9	0.0	5,214.5	143.1	26.8	924.5	82.96	62.42	7.773	11,869.6	1,673.6	7,186.0	20,729.3
12-31-2026	556.3	0.0	3,701.5	100.1	19.0	656.3	85.05	63.98	7.988	8,516.3	1,217.7	5,242.2	14,976.3
08-31-2027	327.9	0.0	2,177.9	59.0	11.2	386.1	87.19	65.58	8.209	5,146.2	734.4	3,169.7	9,050.2
SUBTOTAL	11,927.5	0.0	79,740.9	2,147.0	410.0	14,138.1	73.81	55.56	7.187	158,467.0	22,780.0	101,613.7	282,860.7
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	11,927.5	0.0	79,740.9	2,147.0	410.0	14,138.1	73.81	55.56	7.187	158,467.0	22,780.0	101,613.7	282,860.7
CUM PROD	63,767.2	0.0	335,345.1										
ULTIMATE	75,694.7	0.0	415,086.0										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$	PRESENT WORTH PROFILE DISC RATE %	PRESENT WORTH PROFILE CUM PW M$
12-31-2018	5	0.9	0.0	0.0	131.1	0.0	2,160.7	7,177.1	7,177.1	7,120.6	0.000	159,917.0
12-31-2019	5	0.9	0.0	0.0	790.1	0.0	13,537.9	40,899.3	48,076.3	45,587.5	5.000	141,717.5
12-31-2020	5	0.9	0.0	0.0	809.9	0.0	14,047.7	33,251.0	81,327.4	74,020.9	10.000	127,283.9
12-31-2021	5	0.9	0.0	0.0	830.1	0.0	13,583.8	24,446.4	105,773.7	93,027.9	15.000	115,625.9
12-31-2022	5	0.9	0.0	0.0	850.9	0.0	13,483.8	19,384.5	125,158.2	106,731.5	20.000	106,056.0
12-31-2023	5	0.9	0.0	0.0	872.1	0.0	13,169.6	14,816.4	139,974.6	116,271.4	25.000	98,086.2
12-31-2024	4	0.7	0.0	0.0	893.9	0.0	12,716.7	10,252.0	150,226.6	122,265.2	30.000	91,363.4
12-31-2025	4	0.7	0.0	0.0	916.3	0.0	12,758.2	7,054.9	157,281.5	126,017.6	35.000	85,627.0
12-31-2026	4	0.7	0.0	0.0	939.2	0.0	11,796.6	2,240.5	159,522.0	127,106.4	40.000	80,681.9
08-31-2027	3	0.5	0.0	0.0	639.1	0.0	8,016.1	395.0	159,917.0	127,283.9	50.000	72,604.5
SUBTOTAL			0.0	0.0	7,672.7	0.0	115,271.1	159,917.0	159,917.0	127,283.9		
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	159,917.0	127,283.9		
TOTAL OF 8.8 YRS			0.0	0.0	7,672.7	0.0	115,271.1	159,917.0	159,917.0	127,283.9		

Table VII

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

REVENUE, TAXES, AND COSTS (M$)
SERICA ENERGY PLC
ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF OCTOBER 31, 2018

BASE PRICE CASE

Category	Company Gross Revenue	Capital Costs	Abandonment and Reclamation Costs(1)	Operating Costs	Future Net Revenue Before Income Tax Discounted at 0%	Future Net Revenue Before Income Tax Discounted at 10%	United Kingdom Corporate Income Taxes(2)	Future Net Revenue After United Kingdom Corporate Income Taxes Discounted at 0%	Future Net Revenue After United Kingdom Corporate Income Taxes Discounted at 10%
Proved Developed Producing	86,551.3	2,914.2	0.0	34,980.4	48,656.7	43,951.5	0.0	48,656.7	43,951.5
Proved Developed Non-Producing	7,639.8	0.0	0.0	1,057.3	6,582.5	6,001.4	0.0	6,582.5	6,001.4
Total Proved Developed (1P)	94,191.2	2,914.2	0.0	36,037.7	55,239.2	49,952.9	0.0	55,239.2	49,952.9
Probable	76,226.7	2,644.1	0.0	36,617.1	36,965.6	28,688.3	0.0	36,965.6	28,688.3
Proved + Probable (2P)	170,417.9	5,558.3	0.0	72,654.8	92,204.8	78,641.2	0.0	92,204.8	78,641.2
Possible	112,442.8	2,114.4	0.0	42,616.3	67,712.2	48,642.8	0.0	67,712.2	48,642.8
Proved + Probable + Possible (3P)	282,860.7	7,672.7	0.0	115,271.1	159,917.0	127,283.9	0.0	159,917.0	127,283.9

(1) Serica is not liable for abandonment costs up to a maximum value that exceeds its current estimates of abandonment costs.
(2) Serica is not liable for United Kingdom corporate income taxes up to a maximum value that exceeds its current estimate of loss carry-forward costs.

TECHNICAL DISCUSSION

TECHNICAL DISCUSSION
RESERVES AND UNRISKED CONTINGENT AND PROSPECTIVE RESOURCES
IRISH WATERS IN THE ATLANTIC OCEAN AND IN THE
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF OCTOBER 31, 2018

1.0 GENERAL OVERVIEW AND SCOPE OF WORK

Netherland, Sewell & Associates, Inc. has estimated the proved developed, probable, and possible reserves and future revenue, as of October 31, 2018, to the Serica Energy plc (Serica) interest in certain gas properties located in Erskine Field, United Kingdom (UK) Sector of the Central North Sea. We have also estimated the unrisked contingent and prospective resources, as of October 31, 2018, to the Serica interest in certain discoveries and prospects located in Irish waters in the Atlantic Ocean and in the UK Sector of the Central North Sea. It is our understanding that Serica Energy Slyne B.V. and Serica Energy (UK) Limited own the interests in these properties and are wholly owned subsidiaries of Serica. Gross volumes shown in this Competent Person's Report (report) are 100 percent of the volumes expected to be produced from the properties.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves, contingent resources, and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE. We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 Petroleum Resources Management System definitions and guidelines. The contingent and prospective resources shown in this report are for undeveloped locations; such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

2.0 OVERVIEW OF BLOCK AND LICENSE AREAS

The block and license areas described herein cover approximately 439 square kilometers (km^2). Serica currently owns interests in eight blocks in Irish waters in the Atlantic Ocean and in the UK Sector of the Central North Sea. These blocks include one producing field, two discovered and undeveloped fields, and eight prospects. Serica Energy (UK) Limited operates the UK Sector of the Central North Sea and Serica Energy Slyne B.V. operates the Irish waters in the Atlantic Ocean. Location maps of the blocks in which Serica owns an interest are shown in Figures 1 through 3. The table below describes the blocks in which Serica owns an interest. A more comprehensive table showing license, operator, license expiration date, license area, working interest, status, and comments about the properties is included in Figure 4.

Region/License/Area	Operator	Serica Working Interest (%)	License Expiration Date	License Area (km^2)
Irish Waters in the Atlantic Ocean				
FEL 01/06	Serica Energy Slyne B.V.	100	12/2023	305
Achill Prospect, Block 27/9				
Bandon Discovery, Block 27/4				
Bandon South Prospect, Block 27/4				
Boyne Prospect, Blocks 27/4 and 27/5				
Liffey Prospect, Block 27/9				
UK Sector of the Central North Sea				
P 0057	Chevron North Sea Limited	18	-	4
Erskine Field, Block 23/26a				
P 0101	Serica Energy (UK) Limited	50	12/2031	9
Columbus Field, Block 23/21a				
P 0264	Chevron North Sea Limited	18	-	23
Erskine Field, Block 23/26b				
P 1314	Serica Energy (UK) Limited	50	12/2031	22
Columbus Field, Block 23/16f				
P 1620	Eni UK Limited	15	6/2035	76
Rowallan Prospect, Block 22/19c				

3.0 RESERVES

3.1 OVERVIEW

Erskine Field is a developed gas-condensate field that straddles Blocks 23/26a and 23/26b. Erskine Field was discovered following the completion of the 23/26b-4 discovery well in January 1985. The 23/26b-8 appraisal well was drilled adjacent to the discovery well in 1988. Two intervals in the Jurassic were tested at depths of 4,600 to 4,780 meters (m) true vertical depth subsea (TVDSS).

The five production wells were drilled from a single wellhead platform. The first two wells, the W1 and W2, are located in the southern and eastern areas of the field and were drilled to target the Erskine and Pentland Reservoirs. Both wells initially produced from the Pentland Reservoir. However, in May 2004, the W2 well was plugged in the Pentland Reservoir and recompleted to the overlying Erskine Reservoir. The W1 well continues to produce from the Pentland Reservoir. The third well, the W3, was drilled in the same area of the field, between the W1 and W2 wells, and specifically targets the Erskine Reservoir.

Erskine Field began producing in 1997. The W4 and W5 wells were drilled later the same year. The W4 well was drilled into the Kimmeridge Reservoir, a sandstone in the Heather Formation, and is producing in the Alpha Terrace fault block. It is the only Erskine Field development well that does so. The W5 well was drilled near the northern extent of the field in the Erskine Reservoir.

In January 2018, Erskine Field was shut in because of a blockage of the condensate export line from the Lomond Platform, which handles Erskine production. Attempts to clear the blockage were not successful. Installation of a new line to bypass the blocked segment was completed, and production came back online in October 2018. One well, the W4, had not yet been brought back online by the as-of date of this report. Therefore, this well remains classified as proved developed non-producing in this report.

3.2 GEOLOGY AND GEOPHYSICS

Erskine Field is located in the western portion of the East Central Graben in the Central North Sea and consists of three fault blocks formed during Late Jurassic rifting. These fault blocks are the Main Field Block, the Alpha Terrace, and the Beta Terrace; the latter two are downthrown from the Main Field Block. The Main Field Block is the largest fault block and contains the majority of the well penetrations. No wells are drilled into the Beta Terrace, but it is likely depleted across the fault by the main field wells.

The field contains three reservoirs of interest: Erskine, Kimmeridge, and Pentland. The Pentland Reservoir is Middle Jurassic in age and is the deepest of the three reservoirs. Overlying the Pentland Reservoir is the Erskine Reservoir, which is Late Oxfordian sandstone. The Kimmeridge Reservoir is above the Erskine Reservoir and is Late Oxfordian Heather turbidite.

The Pentland Formation comprises a heterolithic sequence of sandstones, siltstones, mudstones, and coals deposited in a fluvial to lacustrine environment. The sequence is approximately 550 m thick over the field area. The overlying Late Oxfordian Puffin Formation is known locally as the Erskine Sandstone and is between 60 and 90 m thick. This interval consists of a very fine- to fine-grained muddy sandstone deposited in an offshore transition zone setting. The depositional environment for the Pentland, Erskine, and Kimmeridge sands is consistent with the marine transgression associated with the main phase of rifting during the Late Jurassic.

The thickness of the Heather Formation above the Erskine Reservoir is controlled largely by the degree of erosion from the Base Cretaceous Unconformity. The downfaulted Alpha Terrace has a thicker section of Heather Formation than seen in the Main Field Block and the Beta Terrace. Two thin sand intervals, each approximately 10 m thick, are present within the Heather Formation in the Alpha Terrace. These Kimmeridge Reservoir sands are interpreted to be deepwater turbidite sand deposits and are produced by the W4 well. The distribution of this sandstone away from the W4 well is unknown because of the lack of a definitive seismic response from the beds.

3.3 RESERVES AND METHODOLOGY

Figures 5 and 6 present the operator and the gross and net reserves for the properties described in this section of the report. We estimate the gross reserves and the net reserves and future net revenue to the Serica interest in Erskine Field, as of October 31, 2018, to be:

	Gross (100%) Reserves		Net Reserves			Future Net Revenue After UK Corporate Income Taxes (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	3,854.8	25,427.2	693.9	130.7	4,508.2	48,656.7	43,951.5
Proved Developed Non-Producing	301.5	2,554.9	54.3	13.1	453.0	6,582.5	6,001.4
Total Proved Developed (1P)	4,156.3	27,982.1	748.1	143.9	4,961.2	55,239.2	49,952.9
Probable	3,205.5	21,294.9	577.0	109.5	3,775.6	36,965.6	28,688.3
Proved + Probable (2P)	7,361.8	49,277.0	1,325.1	253.4	8,736.8	92,204.8	78,641.2
Possible	4,565.7	30,463.9	821.8	156.6	5,401.3	67,712.2	48,642.8
Proved + Probable + Possible (3P)	11,927.5	79,740.9	2,147.0	410.0	14,138.1	159,917.0	127,283.9

Totals may not add because of rounding.

The oil volumes shown include condensate only. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Monetary values shown in this report are expressed in United States dollars ($), thousands of United States dollars (M$), or millions of United States dollars (MM$) using the August 1, 2018, United States Federal Reserve exchange rate of $1.312 per British pound sterling.

Reserves have been estimated using decline curve analysis only.

3.4 LOMOND PLATFORM COST SHARING

The Erskine Field owners' share of the operating costs for the Lomond Platform are based on a cost-sharing agreement between the Erskine Field owners and other producers to the platform. Erskine Field owners share operating costs for the Lomond Platform with other users of the platform based on the ratio of production in oil-equivalent barrels from each field flowing to the Lomond Platform. Serica's portion of shared costs shown in this report is based on our estimates of future production rates for Erskine Field and Serica's estimates of future production rates for other users of the platform.

3.5 SENSITIVITY ANALYSIS

As requested, Low and High Price Case sensitivities were prepared. Oil, NGL, and gas prices for the Low and High Price Cases are 15 percent lower and higher than the Base Price Case, respectively. Prices for the Low and High Price Cases, before adjustments, along with escalation parameters are shown in the following table:

	Low Price Case			High Price Case		
	Oil/NGL	Gas Price		Oil/NGL	Gas Price	
Period Ending	Price ($/Barrel)	(Pence/ therm)	($/MMBTU)	Price ($/Barrel)	(Pence/ therm)	($/MMBTU)
12-31-2018	55.58	41.7	5.473	75.20	56.4	7.405
12-31-2019	57.93	47.1	6.185	78.37	63.8	8.369
12-31-2020	61.56	47.7	6.253	83.28	64.5	8.461
12-31-2021	60.58	44.8	5.876	81.96	60.6	7.950
12-31-2022	63.34	45.2	5.936	85.70	61.2	8.032
12-31-2023	66.32	47.4	6.215	89.72	64.1	8.409
12-31-2024	69.29	49.5	6.494	93.75	67.0	8.786

Thereafter, escalated 2.5 percent on January 1 of each year.

Summary projections of reserves and revenue by reserves category for the Low and High Price Cases are shown in Figures 7 through 20. A table of revenue, taxes, and costs for the Low and High Price Cases is shown in Figure 21.

4.0 CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report subclassified as development pending are contingent upon execution of a Production Handling Agreement (PHA) with the owners of the Shearwater Platform. The contingent resources shown in this report subclassified as development not viable are contingent upon acquisition of additional technical data that demonstrate producing rates and volumes that will be sufficient to sustain economic viability, generation and approval of a development plan, and commitment from the owners to develop the discoveries. This report does not include economic analysis for these properties. Based on analogous field developments, it appears that the best estimate development pending contingent resources in this report have a reasonable chance of being economically viable. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed.

Figures 22 and 23 present the operator, risk factors, and gross and working interest unrisked contingent resources for the properties described in this section of the report. We estimate the unrisked contingent resources and the risk factor for these properties, as of October 31, 2018, to be:

	Unrisked Contingent Resources				
	Gross (100%)		Working Interest		Risk
Subclass/Region/Area/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Factor[1] (%)
Development Pending					
UK Sector of the Central North Sea					
Columbus Field					
Low Estimate (1C)	1,269.2	28,857.3	634.6	14,428.7	90
Best Estimate (2C)	2,793.7	63,533.2	1,396.9	31,766.6	90
High Estimate (3C)	3,636.2	82,284.1	1,818.1	41,142.1	90
Development Not Viable					
Irish Waters in the Atlantic Ocean					
Bandon Discovery					
Low Estimate (1C)	0.0	0.0	0.0	0.0	0
Best Estimate (2C)	0.0	0.0	0.0	0.0	0
High Estimate (3C)	0.0	0.0	0.0	0.0	0

(1) The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

The oil volumes shown include condensate only.

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as 1C, 2C, and 3C, respectively.

4.1 COLUMBUS FIELD

4.1.1 Overview

Columbus Field is an undeveloped gas-condensate field in the Paleocene Forties Sandstone. The field is located in Blocks 23/16f and 23/21a in the Central Graben Basin. Hydrocarbons were first encountered in the area by the 23/16a-2 well drilled by British Petroleum Exploration and Production in 1988. The main accumulation at Columbus Field was discovered by the 23/16f-11 well, which was drilled in November and

December 2006, and tested by drillstem test (DST) at a rate of 17 million cubic feet of gas per day and 1.06 MBBL of condensate per day. The field has been appraised with the 23/16f-12 and 23/16f-12z wells to the north of the discovery well, and with the 23/21-7x and 23/21-7z wells to the south. The project maturity subclass for the contingent resources in Columbus Field is development pending.

4.1.2 Geology and Geophysics

The Forties Sandstone consists of a series of amalgamated submarine fan channel sandstones deposited in a sand-rich fairway. Columbus Field lies close to the eastern margin of the Forties play fairway. A stratigraphic column for Columbus Field is shown in Figure 24.

The 23/16f-11 discovery well was drilled into an anomalous seismic amplitude in the Forties Sandstone on the western flank of the Paleocene high that was tested by the 23/16a-2 well. The 23/16a-2 well, drilled for a deeper objective, found approximately 2.5 m of possible hydrocarbon-bearing sand in the Forties Sandstone. A DST was performed on that section along with the Andrew section, but the outcome of the test is uncertain. The discovery well was drilled approximately 3.5 kilometers (km) to the southwest of the 23/16a-2 well and encountered an 80-m-thick section of Forties Sandstone with gas to the base, establishing a lowest known gas level. Log analysis shows gas is present in the formation down to a depth of 3,005 m or 9,859 feet (ft) TVDSS.

A second well, the 23/16f-12, was drilled in May 2007 into a separate anomalous amplitude approximately 3.3 km north of the 23/16f-11 well and found an 18.5-m gas column. Log analysis indicates an apparent gas-water contact (GWC) at 2,964 m (9,724 ft) TVDSS, although it is uncertain whether the wet sands below the contact are in vertical pressure communication with the gas-bearing formation. If so, this depth would be characterized as gas down to (GDT) rather than a GWC. The 23/16f-12 well was sidetracked approximately 1,450 m (4,757 ft) to the south into the same anomalous amplitude where the discovery well was drilled; the sidetrack is approximately 2.1 km northwest of the discovery well. The sidetrack well, the 23/16f-12z, found a slightly different apparent GDT at 3,010 m (9,875 ft) TVDSS, 5 m lower than the discovery well.

For the geologic evaluation, we reviewed and utilized a Petrel project originally built by Serica, which included its interpretations. In addition, Serica provided a Columbus Field Reservoir Model Report explaining the geologic model and the outcomes of that modeling and various ancillary reports that include, but are not limited to, petrophysical evaluation, petrophysical cutoffs modeling, seismic depth modeling, frequency modeling, and amplitude-versus-offset modeling. We did not perform an independent review of the seismic data.

Wells drilled by BG Group plc from Block 23/21, which is located to the south of Block 23/16f, that are in the same anomalous amplitude trend were also reviewed, interpreted, and used in the Petrel model by Serica. Similar to the 23/16f-12z well, the three closest of the BG Group plc wells, the 23/21-7, 23/21-7z, and 23/21-7x, also showed different reservoir pressures and different GDTs by log analysis. There are two interpretations that could explain the difference in apparent GDTs by log analysis. In one interpretation, the apparent GDTs could be explained by the presence of a basal seal at the F-4.2 level. Below this seal the sands are not in pressure communication with the sands above them, and the different apparent GDTs above the seal are due to changes in water saturation above a single free water level that was observed in the 23/16f-12z well. The second interpretation of the apparent GDTs is that they are actually GWCs, which would suggest the reservoir is compartmentalized by faulting or shale-outs between sand accumulations.

Initial reservoir pressure is approximately 4,687 psia at a datum depth of 10,000 ft TVDSS. Reservoir temperature is approximately 263°F. Modular dynamics test (MDT) pressure measurements also indicate that there could be different GWCs in many of the wells. However, the interpretation of the pressure data is complicated by indications that some of the wells in Block 23/21 are in communication with Lomond Field, located approximately 4 km to the southeast of Columbus Field and shown on the location map in Figure 1, and that the observed pressure and contact differences may actually be pressure differential reduction from production in Lomond Field. This conclusion is supported by the progressive apparent drawdown correlating with wellbore proximity to Lomond Field, as shown on the graph of MDT data in Figure 25.

Based on the observable data discussed above, we know that there are apparent differences in GDTs by log analysis. Therefore, in the 1C case Columbus Field has been divided into different segments with different GWCs.

Columbus Field was discovered by drilling into an amplitude anomaly in the Forties Sandstone that was defined by seismic data. Because several other fields in this part of the North Sea have been similarly located, amplitude data are very important in defining where these gas-charged Forties Sandstone channels are. Although the amplitude does diminish, the structure of Columbus Field does not close in the northern part of the field where it is affected by the Mondo salt diapir to the west. Therefore, a stratigraphic pinch-out of reservoir sandstones is required to trap hydrocarbons to the north. Because of this, in the 1C case we limited the area of gas to the anomalous amplitude areas that are shown as polygons in Figure 26.

Our 2C case employs the F-4.2 basal seal assumptions to combine the core area containing the 23/16f-12z, 23/16f-11, and 23/21-7x wells into a single, noncompartmentalized region. Our 3C case also includes volumes from the F-3 zone.

4.1.3 Development Plan

Serica's development plan includes a single subsea horizontal development well, with a planned lateral oriented to the southeast which will penetrate the 23/21-7x and 23/16f-11 areas. Serica plans to tie Columbus back to the Shearwater Platform (operated by Shell U.K. Limited) via a pipeline, which will be installed as part of the Arran Field development. Arran is located approximately 12 kilometers to the north and is also operated by Shell U.K. Limited. Production from the two fields will be commingled after metering at a subsea manifold. Transport to Shearwater, and processing there, will be covered under PHAs with the respective infrastructure owners. The Arran pipeline PHA has been executed, but the Shearwater processing PHA is still being negotiated. Start-up is expected in mid-2021, based on the riser currently used by Scoter Field becoming available in late 2020. Existing ullage at Shearwater is expected to be sufficient for Columbus to produce without significant topside modifications. Development plans for both Columbus and Arran have been approved by the UK Oil & Gas Authority.

4.2 BANDON DISCOVERY

The Bandon Discovery is located in Frontier Exploration License (FEL) 01/06 in Irish waters in the Atlantic Ocean. The discovery was made in the Suisnish Sandstone. Core samples taken over the reservoir interval contained heavy oil with an API gravity of approximately 15. The in-situ oil viscosity was measured to be between 114 and 150 centipoise (cp) in the 27/4-1 well and between 275 and 500 cp in the 27/4-1z well. There are no associated contingent resources because of the unfavorable fluid properties. The project maturity subclass for this discovery is development not viable. The viscosity characteristics mean that recovery factors for the discovery would be too low for commercial development. However, we did perform an analysis of original oil-in-place (OOIP) for the discovery. We estimate the OOIP volumes for the Bandon Discovery, as of October 31, 2018, to be:

Discovered OOIP (MMBBL)		
Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
12.7	16.4	21.1

The oil volumes shown include crude oil only. Oil volumes are expressed in millions of barrels (MMBBL).

5.0 PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for each of these prospects, as discussed in subsequent paragraphs. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable.

Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

Figures 27 and 28 present the operator, risk factors, and gross and working interest unrisked prospective resources for the properties described in this section of the report. We estimate the gross and working interest unrisked prospective resources to the Serica interest in these properties, along with the risk factor, as of October 31, 2018, to be:

	Unrisked Prospective Resources(1)				
	Gross (100%)		Working Interest		Risk
	Oil	Gas	Oil	Gas	Factor(2)
Region/Prospect/Category	(MMBBL)	(BCF)	(MMBBL)	(BCF)	(%)
Irish Waters in the Atlantic Ocean					
Achill					
Low Estimate (1U)	0.0	120.7	0.0	120.7	26
Best Estimate (2U)	0.0	252.7	0.0	252.7	26
High Estimate (3U)	0.0	516.5	0.0	516.5	26
Bandon South					
Low Estimate (1U)	0.0	6.7	0.0	6.7	26
Best Estimate (2U)	0.0	26.9	0.0	26.9	26
High Estimate (3U)	0.0	101.7	0.0	101.7	26
Boyne Sherwood					
Low Estimate (1U)	0.0	60.8	0.0	60.8	26
Best Estimate (2U)	0.0	180.2	0.0	180.2	26
High Estimate (3U)	0.0	528.5	0.0	528.5	26
Boyne Suisnish					
Low Estimate (1U)	5.6	1.4	5.6	1.4	20
Best Estimate (2U)	20.1	5.5	20.1	5.5	20
High Estimate (3U)	76.7	22.1	76.7	22.1	20
Liffey Sherwood					
Low Estimate (1U)	0.0	52.6	0.0	52.6	26
Best Estimate (2U)	0.0	180.4	0.0	180.4	26
High Estimate (3U)	0.0	626.7	0.0	626.7	26
Liffey Suisnish					
Low Estimate (1U)	30.3	7.6	30.3	7.6	20
Best Estimate (2U)	128.2	34.0	128.2	34.0	20
High Estimate (3U)	526.7	147.4	526.7	147.4	20

Region/Prospect/Category	Unrisked Prospective Resources[1] Gross (100%) Oil (MMBBL)	Gas (BCF)	Working Interest Oil (MMBBL)	Gas (BCF)	Risk Factor[2] (%)
UK Sector of the Central North Sea					
Rowallan Pentland					
Low Estimate (1U)	3.5	54.4	0.5	8.2	22
Best Estimate (2U)	8.8	118.7	1.3	17.8	22
High Estimate (3U)	20.0	259.9	3.0	39.0	22
Rowallan Triassic					
Low Estimate (1U)	10.0	134.1	1.5	20.1	22
Best Estimate (2U)	33.0	422.4	4.9	63.4	22
High Estimate (3U)	113.4	1,463.9	17.0	219.6	22
Total					
Low Estimate (1U)	49.4	438.3	37.9	278.1	-
Best Estimate (2U)	190.0	1,220.9	154.6	760.8	-
High Estimate (3U)	736.9	3,666.7	623.4	2,201.5	-

Note: Totals are the arithmetic sum of multiple probability distributions and may not add because of rounding.

[1] These volumes represent only the portions of the prospects that lie within the boundaries of the respective lease and/or license areas.

[2] The risk factor for prospective resources refers to the estimated chance, or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. For the purposes of this report, the risk factor for the prospective resources refers to the PRMS term "chance of geologic discovery".

The oil volumes shown include crude oil and condensate. Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

5.1 BLOCK 22/19C

5.1.1 Overview

License P 1620, shown on the location map on Figure 3, is located in the Central Graben Basin of Central North Sea. The basin is composed of a series of horsts and grabens that trend northwest, with the Forties-Montrose High horst block running down the center of the graben. Traps form along the upthrown sides of the faults.

The Triassic Skagerrak Sandstone is the primary target in the license and has been discovered in nearby Fiddich and Marnock Fields located to the southwest and south, respectively. The Middle Jurassic age Pentland Sandstone is a secondary target. The Kimmeridge Clay is the source rock for the fields in the Central Graben Basin. Top and lateral seals are provided by Kimmeridge Clay and Heather shales.

5.1.2 Rowallan Pentland Prospect

The Rowallan Pentland Prospect is an east-dipping, three-way closure terminating against a north-to-south-trending fault to the west and an east-to-west-trending fault to the north. The target reservoir is the Middle Jurassic age Pentland Sandstone. The Kimmeridge Clay provides top and lateral seals. Trap integrity is the primary risk, and the chance of geologic discovery (P_g) risk factor for the prospect is 22 percent.

5.1.3 Rowallan Triassic Prospect

The Rowallan Triassic Prospect is an east-dipping, three-way closure terminating against a north-to-south-trending fault to the west and an east-to-west-trending fault to the north. The target reservoir is the Triassic age Skagerrak Sandstone. The Kimmeridge Clay provides top and lateral seals. Trap integrity is the primary risk, and the P_g risk factor for the prospect is 22 percent.

5.2 FEL 01/06

5.2.1 Overview

The Slyne Basin is an elongate Mesozoic graben oriented in a north-northeast to south-southwest direction. The basin is subdivided into three asymmetric half-grabens by a series of complex transfer fault systems. The Northern Slyne Basin contains Corrib Gas Field; the Central Slyne Basin contains FEL 01/06, which is shown on the location map in Figure 2, with the 27/4-1 discovery well; and the Southern Slyne Basin is undrilled. The basin contains sediments ranging in age from Carboniferous to Tertiary.

Primary reservoirs in the Slyne Basin are the Triassic age Sherwood Sandstone and the Jurassic age Suisnish Sandstone. Both of these reservoirs were seen on the well log of the Bandon 27/4-1 discovery well. Prospective structures are half-grabens, tilted fault blocks, and hanging-wall anticlines. Regional seals are provided by the Triassic age Mercia Halite and Mudstone for the Sherwood Reservoir and by Lower Jurassic age shales for the Suisnish Reservoir. Source rocks are present in Carboniferous coals and Carboniferous and Jurassic shales. The boundaries of the prospects discussed below are also shown on the location map in Figure 2.

5.2.2 Achill Prospect

The Achill Prospect is located in the southern portion of FEL 01/06. This prospect is a west-dipping, high-side, three-way fault closure that targets the Triassic Sherwood Sandstone. The presence of the reservoir and reservoir qualities are proven in the 27/4-1 and 27/5-1 wells, but the Sherwood Sandstone is deeper in this area. The Mercia Mudstone provides the top seal, and juxtaposition against the Lower Jurassic Broadford beds provides the lateral seal across the fault. The Broadford beds are mixed carbonates and clastics and are often tight, but there is a moderate risk of lack of seal. The Jurassic Scalpa Sandstone is a secondary target for this prospect but is a downthrown trap and was not evaluated. The primary risk for this prospect is seal, and the P_g risk factor is 26 percent.

5.2.3 Bandon South Prospect

The Bandon South Prospect is located in the west-central portion of FEL 01/06. This prospect is a high-side fault closure that targets the Triassic Sherwood Sandstone. There is independent four-way closure at the top of the prospect. The Mercia Mudstone provides the top seal, and the lateral fault seal is provided by juxtaposition against the Carboniferous or Permian Zechstein Evaporite. The primary risk for this prospect is seal, and the P_g risk factor is 26 percent.

5.2.4 Boyne Sherwood Prospect

The Boyne Sherwood Prospect is located in the north-central portion of FEL 01/06. This prospect targets the Triassic Sherwood Sandstone. The structure is a west-dipping, northeast-to-southwest-trending, high-side, three-way closure at both target levels. The structure is truncated on the eastern side by a down-to-the-west fault. The vertical seal for the Sherwood Sandstone is the Mercia Mudstone, and the lateral seal is Middle Jurassic limestones, which present a seal risk. The P_g risk factor for this prospect is 26 percent.

5.2.4.1 Alternative Volumes

Based on the data we have reviewed, we consider there to be an equal likelihood of the Sherwood Sandstone in the Boyne Sherwood Prospect being oil-charged or being gas-charged. Our estimates of prospective resources in Figures 27 and 28 are based on the reservoir being gas-charged. We have estimated an alternate set of original hydrocarbons-in-place and unrisked prospective resources with the assumption that the hydrocarbon phase discovered will be oil. Since this is an alternative case to the gas reservoir presented, the undiscovered OOIP, undiscovered original gas-in-place, and prospective resources volumes estimated in this report for the Boyne Sherwood Prospect should not be considered additive and should not in any way be combined. This does not preclude the possibility of both hydrocarbon phases being present. The P_g risk factor for this alternative case is 20 percent. The oil formation volume factors for this alternative case are 1.18, 1.26, and 1.36 reservoir barrels per stock tank barrel for the low, best, and high estimates, respectively. Recovery factors for the low, best, and high estimates are 0.25, 0.35, and 0.45, respectively, and the gas-oil ratios for the low, best, and high estimates are 291, 420, and 616 standard cubic feet per barrel, respectively.

Using this alternative assumption, we estimate the undiscovered OOIP volumes and the gross and working interest unrisked prospective resources for the Sherwood Sandstone in the Boyne Sherwood Prospect, as of October 31, 2018, to be:

		Unrisked Prospective Resources			
	Undiscovered	Gross (100%)		Working Interest	
Category	OOIP (MMBBL)	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)
Low Estimate (1U)	66.1	22.7	8.9	11.3	4.5
Best Estimate (2U)	186.7	64.9	28.1	32.5	14.1
High Estimate (3U)	535.6	190.2	86.2	95.1	43.1

The oil volumes shown include crude oil only.

5.2.5 Boyne Suisnish Prospect

The Boyne Suisnish Prospect is located in the north-central portion of FEL 01/06. This prospect targets the Jurassic Suisnish Sandstone. The structure is a west-dipping, northeast-to-southwest-trending, high-side, three-way closure at both target levels. The structure is truncated on the eastern side by a down-to-the-west fault. Vertical seals for the Suisnish Sandstone are Lower and Middle Jurassic shales, and the lateral seal is Middle Jurassic limestones, which present a seal risk. The P_g risk factor for this prospect is 20 percent.

5.2.6 Liffey Sherwood Prospect

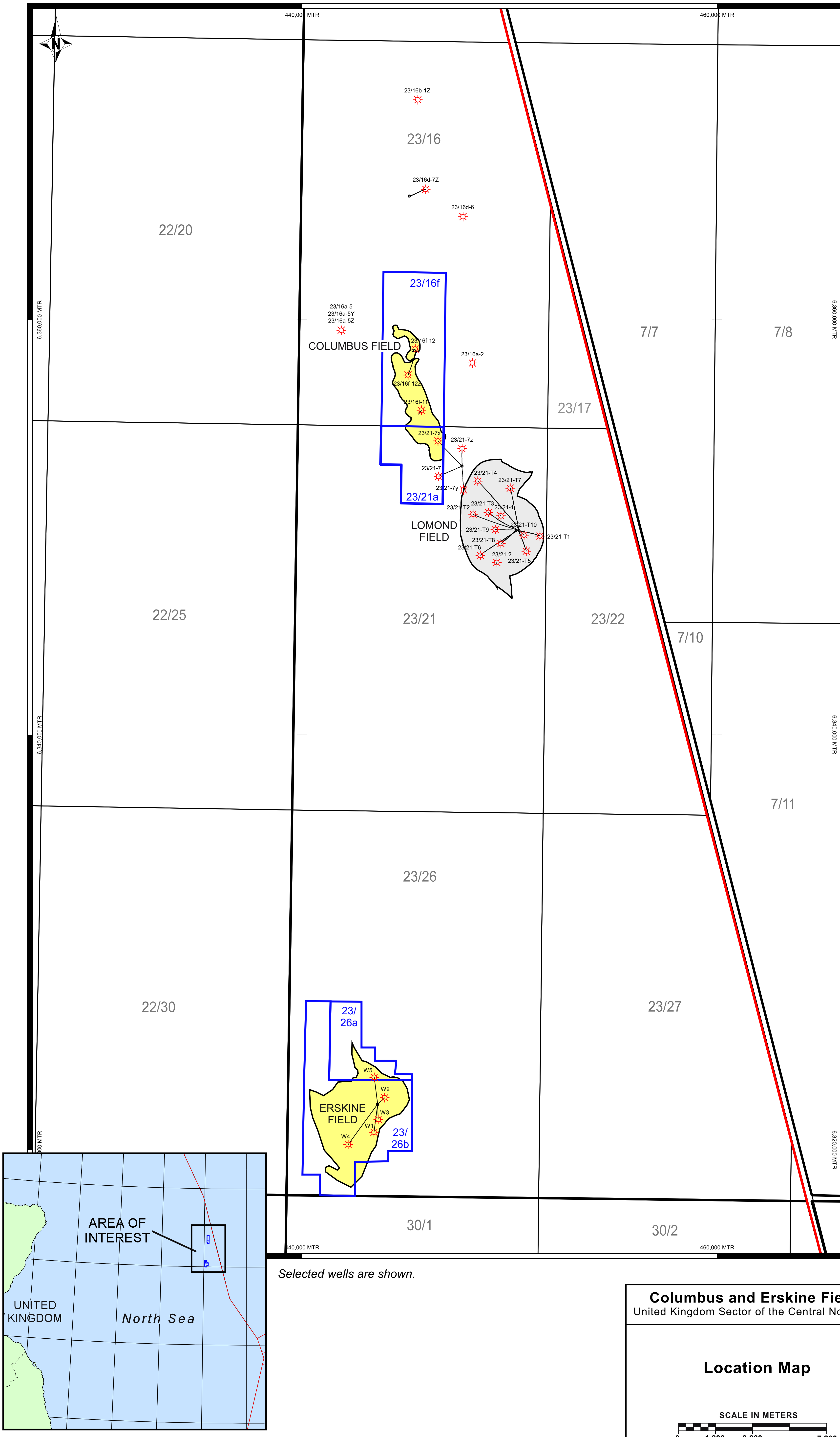
The Liffey Sherwood Prospect is located in the southeastern portion of FEL 01/06. The Triassic Sherwood Sandstone is the reservoir target for this prospect. The structure is a west-dipping, northeast-to-southwest-trending, high-side, three-way closure. The vertical seal for the Sherwood Sandstone is the Mercia Mudstone, and the lateral seal is Middle Jurassic limestones. Sealing is the primary risk, and the P_g risk factor for this prospect is 26 percent.

5.2.7 Liffey Suisnish Prospect

The Liffey Suisnish Prospect is located in the southeastern portion of FEL 01/06. The Jurassic Suisnish Sandstone is the reservoir target for this prospect. The structure is a west-dipping, northeast-to-southwest-trending, high-side, three-way closure. Vertical seals for the Suisnish Sandstone are Lower and Middle Jurassic shales, and the lateral seal is Middle Jurassic limestones. Sealing is the primary risk for this prospect, and the P_g risk factor for this prospect is 20 percent.

FIGURES

NETHERLAND, SEWELL & ASSOCIATES, INC.



Selected wells are shown.

Columbus and Erskine Fields
United Kingdom Sector of the Central North Sea

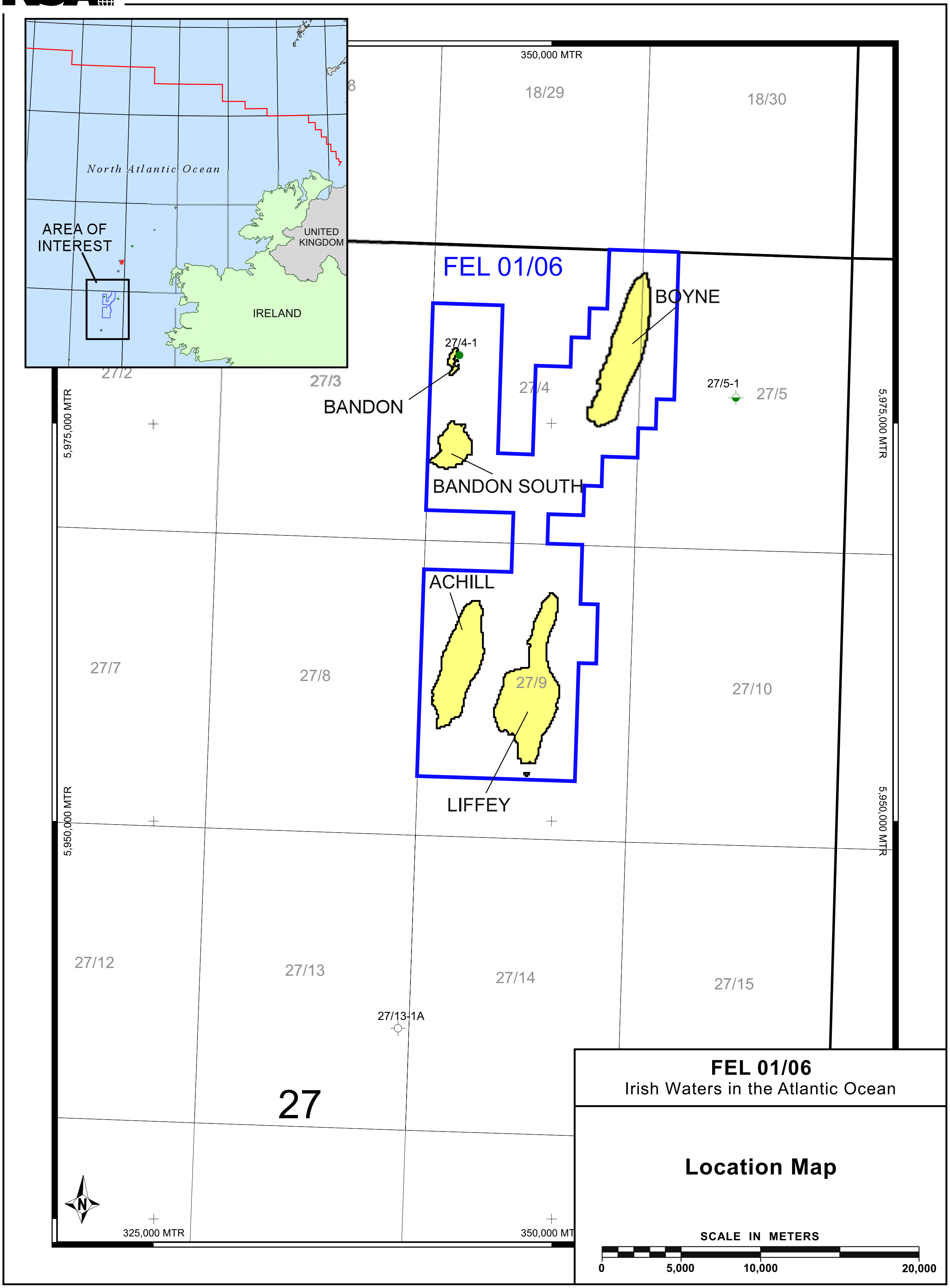
Location Map

SCALE IN METERS
0 1,800 3,600 7,200

Figure 1

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.



FEL 01/06
Irish Waters in the Atlantic Ocean

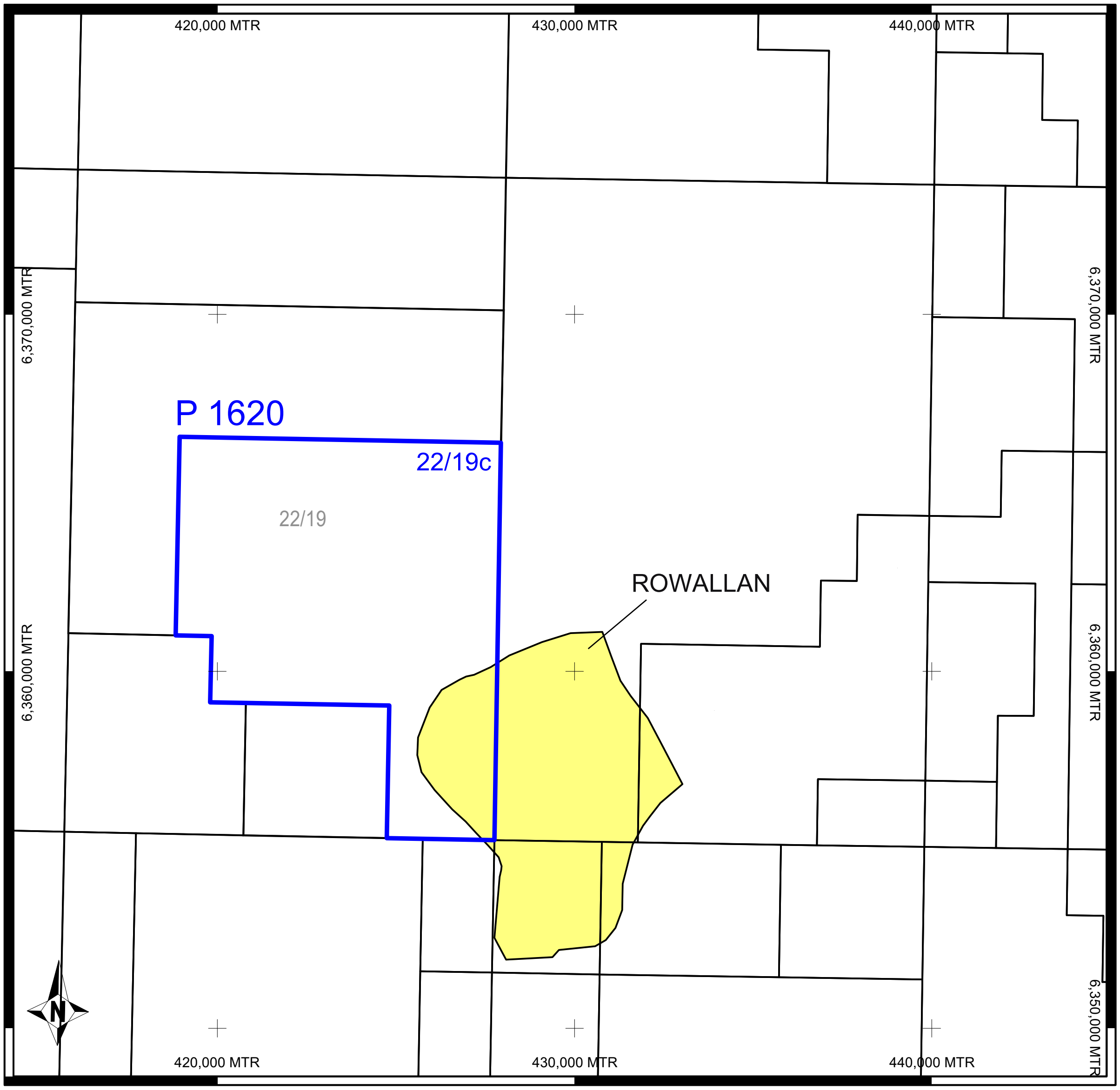
Location Map

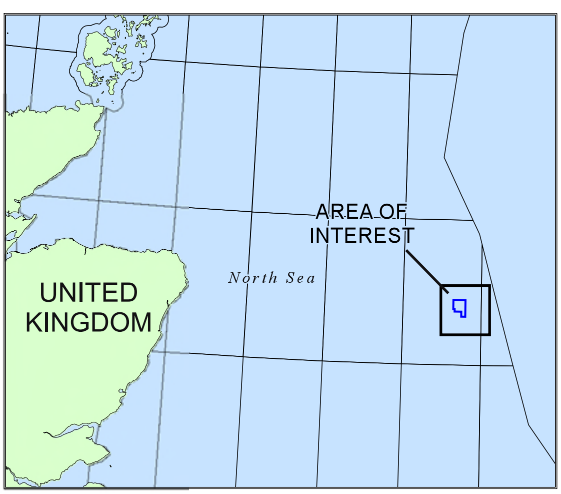
SCALE IN METERS

0 5,000 10,000 20,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions. Figure 2

NETHERLAND, SEWELL & ASSOCIATES, INC.





License P 1620

United Kingdom Sector of the Central North Sea

Location Map

SCALE IN METERS

0 2,500 5,000 10,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 3

SUMMARY OF ASSETS
SERICA ENERGY PLC INTEREST
LOCATED IN IRISH WATERS IN THE ATLANTIC OCEAN AND
IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF OCTOBER 31, 2018

Area/License/Discovery, Field, or Prospect/Block	Operator	Serica Working Interest (%)	Status	License Expiration Date	License Area (km^2)	Comments
Irish Waters in the Atlantic Ocean						
FEL 01/06	Serica Energy Slyne B.V.	100		12/2023	305	
Achill Prospect, Block 27/9			Exploration			Exploration license active since 2006
Bandon Discovery, Block 27/4			Development			No feasible development because of unfavorable fluid properties
Bandon South Prospect, Block 27/4			Exploration			Exploration license active since 2006
Boyne Prospect, Blocks 27/4 and 27/5			Exploration			Exploration license active since 2006
Liffey Prospect, Block 27/9			Exploration			Exploration license active since 2006
United Kingdom Sector of the Central North Sea						
P 0057	Chevron North Sea Limited	18		-	4	
Erskine Field, Block 23/26a			Production			Currently shut-in due to export line blockage
P 0101	Serica Energy (UK) Limited	50		12/2031	9	
Columbus Field, Block 23/21a			Development			Current development plan targets first production in 2021
P 0264	Chevron North Sea Limited	18		-	23	
Erskine Field, Block 23/26b			Production			Currently shut-in due to export line blockage
P 1314	Serica Energy (UK) Limited	50		12/2031	22	
Columbus Field, Block 23/16f			Development			Current development plan targets first production in 2021
P 1620	Eni UK Limited	15		06/2035	76	
Rowallan Prospect, Block 22/19c			Exploration			Exploration well scheduled for 2018

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 4

SUMMARY OF OIL AND LIQUIDS RESERVES
SERICA ENERGY PLC INTEREST
LOCATED IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF OCTOBER 31, 2018

		Oil and Liquids Reserves (MBBL)					
		Gross (100%)			Net		
Area/Field	Operator	Proved (1P)[1]	Proved + Probable (2P)	Proved + Probable + Possible (3P)	Proved (1P)[1]	Proved + Probable (2P)	Proved + Probable + Possible (3P)
United Kingdom Sector of the Central North Sea							
Erskine Field	Chevron North Sea Limited	4,156.3	7,361.8	11,927.5	892.0	1,578.5	2,557.0
Total		4,156.3	7,361.8	11,927.5	892.0	1,578.5	2,557.0

Note: Reserves shown are based on Base Price Case oil prices.

(1) Proved (1P) reserves are inclusive of proved developed reserves only.

Source: Netherland, Sewell & Associates, Inc.

Figure 5

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF GAS RESERVES
SERICA ENERGY PLC INTEREST
LOCATED IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF OCTOBER 31, 2018

		Gas Reserves (MMCF)					
		Gross (100%)			Net		
Area/Field	Operator	Proved (1P)[1]	Proved + Probable (2P)	Proved + Probable + Possible (3P)	Proved (1P)[1]	Proved + Probable (2P)	Proved + Probable + Possible (3P)
United Kingdom Sector of the Central North Sea							
Erskine Field	Chevron North Sea Limited	27,982.1	49,277.0	79,740.9	4,961.2	8,736.8	14,138.1
Total		27,982.1	49,277.0	79,740.9	4,961.2	8,736.8	14,138.1

Note: Reserves shown are based on Base Price Case gas prices.

[1] Proved (1P) reserves are inclusive of proved developed reserves only.

Source: Netherland, Sewell & Associates, Inc.

Figure 6

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

TOTAL PROVED DEVELOPED (1P) RESERVES

SERICA ENERGY PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	372.8	0.0	2,501.4	67.1	12.9	443.5	54.98	41.52	5.179	3,689.1	534.0	2,296.8	6,519.9
12-31-2019	1,772.6	0.0	11,935.6	319.1	61.4	2,116.2	57.33	43.27	5.962	18,292.6	2,655.9	12,616.7	33,565.1
12-31-2020	1,185.6	0.0	8,029.0	213.4	41.3	1,423.5	60.96	45.99	6.037	13,009.4	1,898.5	8,593.6	23,501.6
12-31-2021	687.4	0.0	4,558.5	123.7	23.4	808.2	59.98	45.25	5.622	7,421.7	1,060.7	4,543.9	13,026.3
03-31-2022	90.9	0.0	626.5	16.4	3.2	111.1	62.74	47.32	5.688	1,026.6	152.4	631.9	1,810.9
SUBTOTAL	4,109.3	0.0	27,651.0	739.7	142.2	4,902.5	58.73	44.32	5.851	43,439.4	6,301.6	28,682.8	78,423.8
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,109.3	0.0	27,651.0	739.7	142.2	4,902.5	58.73	44.32	5.851	43,439.4	6,301.6	28,682.8	78,423.8
CUM PROD	63,767.2	0.0	335,345.1										
ULTIMATE	67,876.5	0.0	362,996.1										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	NET DEDUCTIONS/EXPENDITURES TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2018	5	0.9	0.0	0.0	131.1	0.0	1,976.4	4,412.3	4,412.3	4,377.9
12-31-2019	5	0.9	0.0	0.0	790.1	0.0	11,770.8	21,004.2	25,416.5	24,190.6
12-31-2020	5	0.9	0.0	0.0	809.9	0.0	11,220.0	11,471.7	36,888.2	34,039.6
12-31-2021	5	0.9	0.0	0.0	830.1	0.0	8,910.4	3,285.9	40,174.0	36,633.1
03-31-2022	3	0.5	0.0	0.0	211.8	0.0	1,319.0	280.1	40,454.1	36,839.0
SUBTOTAL			0.0	0.0	2,773.0	0.0	35,196.6	40,454.1	40,454.1	36,839.0
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	40,454.1	36,839.0
TOTAL OF 3.4 YRS			0.0	0.0	2,773.0	0.0	35,196.6	40,454.1	40,454.1	36,839.0

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
0.000	40,454.1
5.000	38,537.7
10.000	36,839.0
15.000	35,323.3
20.000	33,962.9
25.000	32,735.0
30.000	31,621.4
35.000	30,606.7
40.000	29,678.3
50.000	28,039.6

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 7

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2018	342.5	0.0	2,245.1	61.7	11.5	398.1	54.98	41.52	5.179	3,389.8	479.3	2,061.5	5,930.5
12-31-2019	1,618.7	0.0	10,631.0	291.4	54.7	1,884.9	57.33	43.27	5.962	16,703.9	2,365.6	11,237.6	30,307.1
12-31-2020	1,070.1	0.0	7,050.5	192.6	36.3	1,250.1	60.96	45.99	6.037	11,742.5	1,667.2	7,546.3	20,956.0
12-31-2021	685.6	0.0	4,543.0	123.4	23.4	805.5	59.98	45.25	5.622	7,402.0	1,057.1	4,528.4	12,987.5
03-31-2022	90.9	0.0	626.5	16.4	3.2	111.1	62.74	47.32	5.688	1,026.6	152.4	631.9	1,810.9
SUBTOTAL	3,807.9	0.0	25,096.1	685.4	129.0	4,449.5	58.75	44.34	5.845	40,264.8	5,721.6	26,005.6	71,992.0
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	3,807.9	0.0	25,096.1	685.4	129.0	4,449.5	58.75	44.34	5.845	40,264.8	5,721.6	26,005.6	71,992.0
CUM PROD	54,807.9	0.0	278,500.8										
ULTIMATE	58,615.8	0.0	303,596.8										

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2018	4	0.7	0.0	0.0	131.1	0.0	1,885.7	3,913.7	3,913.7	3,883.2
12-31-2019	4	0.7	0.0	0.0	790.1	0.0	11,266.9	18,250.1	22,163.8	21,103.9
12-31-2020	4	0.7	0.0	0.0	809.9	0.0	10,764.8	9,381.3	31,545.1	29,164.3
12-31-2021	4	0.7	0.0	0.0	830.1	0.0	8,902.9	3,254.5	34,799.6	31,732.3
03-31-2022	3	0.5	0.0	0.0	211.8	0.0	1,319.0	280.1	35,079.7	31,938.2
SUBTOTAL			0.0	0.0	2,773.0	0.0	34,139.3	35,079.7	35,079.7	31,938.2
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	35,079.7	31,938.2
TOTAL OF 3.4 YRS			0.0	0.0	2,773.0	0.0	34,139.3	35,079.7	35,079.7	31,938.2

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	35,079.7
5.000	33,413.4
10.000	31,938.2
15.000	30,623.4
20.000	29,444.4
25.000	28,381.2
30.000	27,417.6
35.000	26,540.3
40.000	25,738.1
50.000	24,323.3

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 8

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

PROVED DEVELOPED NON-PRODUCING RESERVES

SERICA ENERGY PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2018	30.2	0.0	256.3	5.4	1.3	45.4	54.98	41.52	5.179	299.3	54.7	235.3	589.4
12-31-2019	153.9	0.0	1,304.6	27.7	6.7	231.3	57.33	43.27	5.962	1,588.6	290.3	1,379.1	3,258.0
12-31-2020	115.5	0.0	978.5	20.8	5.0	173.5	60.96	45.99	6.037	1,266.9	231.4	1,047.3	2,545.6
01-06-2021	1.8	0.0	15.5	0.3	0.1	2.7	59.98	45.25	5.622	19.8	3.6	15.5	38.8
SUBTOTAL	301.5	0.0	2,554.9	54.3	13.1	453.0	58.50	44.15	5.910	3,174.6	580.0	2,677.1	6,431.7
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	301.5	0.0	2,554.9	54.3	13.1	453.0	58.50	44.15	5.910	3,174.6	580.0	2,677.1	6,431.7
CUM PROD	8,959.3	0.0	56,844.3										
ULTIMATE	9,260.7	0.0	59,399.2										

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2018	1	0.2	0.0	0.0	0.0	0.0	90.8	498.6	498.6	494.7
12-31-2019	1	0.2	0.0	0.0	0.0	0.0	503.9	2,754.1	3,252.7	3,086.7
12-31-2020	1	0.2	0.0	0.0	0.0	0.0	455.2	2,090.3	5,343.0	4,875.3
01-06-2021	1	0.2	0.0	0.0	0.0	0.0	7.4	31.4	5,374.4	4,900.8
SUBTOTAL			0.0	0.0	0.0	0.0	1,057.3	5,374.4	5,374.4	4,900.8
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	5,374.4	4,900.8
TOTAL OF 2.2 YRS			0.0	0.0	0.0	0.0	1,057.3	5,374.4	5,374.4	4,900.8

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	5,374.4
5.000	5,124.3
10.000	4,900.8
15.000	4,699.9
20.000	4,518.5
25.000	4,353.8
30.000	4,203.7
35.000	4,066.4
40.000	3,940.2
50.000	3,716.3

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 9

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

PROBABLE RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2018	29.3	0.0	195.8	5.3	1.0	34.7	54.98	41.52	5.179	289.6	41.8	179.8	511.2
12-31-2019	287.7	0.0	1,911.5	51.8	9.8	338.9	57.33	43.27	5.962	2,968.9	425.3	2,020.6	5,414.9
12-31-2020	393.4	0.0	2,608.0	70.8	13.4	462.4	60.96	45.99	6.037	4,316.3	616.7	2,791.4	7,724.4
12-31-2021	506.2	0.0	3,437.6	91.1	17.7	609.5	59.98	45.25	5.622	5,465.5	799.9	3,426.6	9,692.1
12-31-2022	756.0	0.0	4,968.6	136.1	25.5	880.9	62.74	47.32	5.688	8,538.0	1,208.8	5,010.8	14,757.6
12-31-2023	600.6	0.0	4,001.5	108.1	20.6	709.5	65.72	49.54	5.995	7,104.8	1,019.4	4,253.3	12,377.4
07-31-2024	301.5	0.0	2,002.4	54.3	10.3	355.0	68.69	51.76	6.302	3,728.4	532.9	2,237.3	6,498.7
SUBTOTAL	2,874.7	0.0	19,125.4	517.5	98.3	3,390.9	62.64	47.23	5.874	32,411.6	4,644.9	19,919.8	56,976.3
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	2,874.7	0.0	19,125.4	517.5	98.3	3,390.9	62.64	47.23	5.874	32,411.6	4,644.9	19,919.8	56,976.3
CUM PROD	0.0	0.0	0.0										
ULTIMATE	2,874.7	0.0	19,125.4										

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	68.0	443.2	443.2	439.6
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	792.1	4,622.8	5,066.0	4,758.8
12-31-2020	0	0.0	0.0	0.0	0.0	0.0	1,442.2	6,282.2	11,348.2	10,113.1
12-31-2021	0	0.0	0.0	0.0	0.0	0.0	2,768.3	6,923.7	18,272.0	15,487.1
12-31-2022	1	0.2	0.0	0.0	639.0	0.0	9,265.6	4,853.0	23,124.9	18,935.8
12-31-2023	3	0.5	0.0	0.0	872.1	0.0	9,736.7	1,768.6	24,893.6	20,081.3
07-31-2024	3	0.5	0.0	0.0	519.3	0.0	5,676.6	302.8	25,196.3	20,263.1
SUBTOTAL			0.0	0.0	2,030.4	0.0	29,749.5	25,196.3	25,196.3	20,263.1
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	25,196.3	20,263.1
TOTAL OF 5.8 YRS			0.0	0.0	2,030.4	0.0	29,749.5	25,196.3	25,196.3	20,263.1

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	25,196.3
5.000	22,498.0
10.000	20,263.1
15.000	18,391.0
20.000	16,806.9
25.000	15,454.0
30.000	14,288.9
35.000	13,277.9
40.000	12,394.3
50.000	10,929.7

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 10

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

PROVED + PROBABLE (2P) RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2018	402.0	0.0	2,697.2	72.4	13.9	478.2	54.98	41.52	5.179	3,978.7	575.8	2,476.6	7,031.1
12-31-2019	2,060.3	0.0	13,847.1	370.9	71.2	2,455.1	57.33	43.27	5.962	21,261.5	3,081.2	14,637.3	38,980.0
12-31-2020	1,579.0	0.0	10,637.0	284.2	54.7	1,885.9	60.96	45.99	6.037	17,325.8	2,515.2	11,385.0	31,226.0
12-31-2021	1,193.7	0.0	7,996.1	214.9	41.1	1,417.7	59.98	45.25	5.622	12,887.3	1,860.7	7,970.5	22,718.4
12-31-2022	846.9	0.0	5,595.1	152.4	28.8	992.0	62.74	47.32	5.688	9,564.6	1,361.3	5,642.6	16,568.6
12-31-2023	600.6	0.0	4,001.5	108.1	20.6	709.5	65.72	49.54	5.995	7,104.8	1,019.4	4,253.3	12,377.4
07-31-2024	301.5	0.0	2,002.4	54.3	10.3	355.0	68.69	51.76	6.302	3,728.4	532.9	2,237.3	6,498.7
SUBTOTAL	6,984.1	0.0	46,776.4	1,257.1	240.5	8,293.4	60.34	45.51	5.860	75,851.1	10,946.4	48,602.6	135,400.1
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	6,984.1	0.0	46,776.4	1,257.1	240.5	8,293.4	60.34	45.51	5.860	75,851.1	10,946.4	48,602.6	135,400.1
CUM PROD	63,767.2	0.0	335,345.1										
ULTIMATE	70,751.3	0.0	382,121.5										

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2018	5	0.9	0.0	0.0	131.1	0.0	2,044.4	4,855.5	4,855.5	4,817.5
12-31-2019	5	0.9	0.0	0.0	790.1	0.0	12,562.9	25,627.0	30,482.5	28,949.4
12-31-2020	5	0.9	0.0	0.0	809.9	0.0	12,662.3	17,753.9	48,236.4	44,152.7
12-31-2021	5	0.9	0.0	0.0	830.1	0.0	11,678.7	10,209.6	58,446.0	52,120.1
12-31-2022	4	0.7	0.0	0.0	850.9	0.0	10,584.6	5,133.1	63,579.1	55,774.7
12-31-2023	3	0.5	0.0	0.0	872.1	0.0	9,736.7	1,768.6	65,347.7	56,920.3
07-31-2024	3	0.5	0.0	0.0	519.3	0.0	5,676.6	302.8	65,650.5	57,102.1
SUBTOTAL			0.0	0.0	4,803.5	0.0	64,946.2	65,650.5	65,650.5	57,102.1
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	65,650.5	57,102.1
TOTAL OF 5.8 YRS			0.0	0.0	4,803.5	0.0	64,946.2	65,650.5	65,650.5	57,102.1

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	65,650.5
5.000	61,035.7
10.000	57,102.1
15.000	53,714.3
20.000	50,769.7
25.000	48,189.0
30.000	45,910.3
35.000	43,884.5
40.000	42,072.6
50.000	38,969.2

Figure 11

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

POSSIBLE RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2018	53.9	0.0	360.8	9.7	1.9	64.0	54.98	41.52	5.179	533.1	77.0	331.3	941.4
12-31-2019	400.8	0.0	2,671.1	72.1	13.7	473.6	57.33	43.27	5.962	4,135.6	594.4	2,823.5	7,553.5
12-31-2020	474.1	0.0	3,154.8	85.3	16.2	559.4	60.96	45.99	6.037	5,201.8	746.0	3,376.7	9,324.5
12-31-2021	524.2	0.0	3,551.6	94.4	18.3	629.7	59.98	45.25	5.622	5,659.9	826.4	3,540.2	10,026.6
12-31-2022	594.9	0.0	4,100.3	107.1	21.1	727.0	62.74	47.32	5.688	6,718.3	997.6	4,135.1	11,851.0
12-31-2023	579.3	0.0	3,873.7	104.3	19.9	686.8	65.72	49.54	5.995	6,852.8	986.8	4,117.4	11,957.1
12-31-2024	637.2	0.0	4,158.5	114.7	21.4	737.3	68.69	51.76	6.302	7,878.0	1,106.8	4,646.4	13,631.1
12-31-2025	794.9	0.0	5,214.5	143.1	26.8	924.5	70.42	53.05	6.481	10,076.0	1,422.5	5,991.4	17,490.0
05-31-2026	243.2	0.0	1,618.4	43.8	8.3	286.9	72.20	54.38	6.664	3,160.7	452.5	1,912.0	5,525.2
SUBTOTAL	4,302.4	0.0	28,703.6	774.4	147.6	5,089.2	64.84	48.85	6.067	50,216.3	7,210.1	30,874.1	88,300.4
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,302.4	0.0	28,703.6	774.4	147.6	5,089.2	64.84	48.85	6.067	50,216.3	7,210.1	30,874.1	88,300.4
CUM PROD	0.0	0.0	0.0										
ULTIMATE	4,302.4	0.0	28,703.6										

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	116.3	825.1	825.1	818.5
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	975.0	6,578.5	7,403.6	6,980.1
12-31-2020	0	0.0	0.0	0.0	0.0	0.0	1,385.5	7,939.0	15,342.6	13,750.7
12-31-2021	0	0.0	0.0	0.0	0.0	0.0	1,905.1	8,121.5	23,464.1	20,039.1
12-31-2022	1	0.2	0.0	0.0	0.0	0.0	2,899.1	8,951.9	32,416.0	26,345.0
12-31-2023	2	0.4	0.0	0.0	0.0	0.0	3,433.0	8,524.1	40,940.1	31,831.9
12-31-2024	1	0.2	0.0	0.0	374.6	0.0	7,040.1	6,216.4	47,156.5	35,465.1
12-31-2025	4	0.7	0.0	0.0	916.3	0.0	12,758.2	3,815.6	50,972.1	37,498.7
05-31-2026	4	0.7	0.0	0.0	389.7	0.0	4,932.1	203.4	51,175.5	37,600.4
SUBTOTAL			0.0	0.0	1,680.6	0.0	35,444.3	51,175.5	51,175.5	37,600.4
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	51,175.5	37,600.4
TOTAL OF 7.6 YRS			0.0	0.0	1,680.6	0.0	35,444.3	51,175.5	51,175.5	37,600.4

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	51,175.5
5.000	43,536.4
10.000	37,600.4
15.000	32,908.3
20.000	29,142.1
25.000	26,076.6
30.000	23,549.6
35.000	21,442.3
40.000	19,666.5
50.000	16,858.7

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 12

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

PROVED + PROBABLE + POSSIBLE (3P) RESERVES

SERICA ENERGY PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2018	455.9	0.0	3,058.0	82.1	15.7	542.2	54.98	41.52	5.179	4,511.8	652.9	2,807.9	7,972.5
12-31-2019	2,461.1	0.0	16,518.2	443.0	84.9	2,928.7	57.33	43.27	5.962	25,397.1	3,675.6	17,460.8	46,533.4
12-31-2020	2,053.0	0.0	13,791.8	369.5	70.9	2,445.3	60.96	45.99	6.037	22,527.6	3,261.2	14,761.7	40,550.4
12-31-2021	1,717.9	0.0	11,547.7	309.2	59.4	2,047.4	59.98	45.25	5.622	18,547.2	2,687.1	11,510.7	32,745.0
12-31-2022	1,441.8	0.0	9,695.3	259.5	49.9	1,719.0	62.74	47.32	5.688	16,283.0	2,358.8	9,777.8	28,419.6
12-31-2023	1,179.9	0.0	7,875.3	212.4	40.5	1,396.3	65.72	49.54	5.995	13,957.6	2,006.2	8,370.7	24,334.5
12-31-2024	938.7	0.0	6,160.8	169.0	31.7	1,092.3	68.69	51.76	6.302	11,606.4	1,639.7	6,883.7	20,129.8
12-31-2025	794.9	0.0	5,214.5	143.1	26.8	924.5	70.42	53.05	6.481	10,076.0	1,422.5	5,991.4	17,490.0
05-31-2026	243.2	0.0	1,618.4	43.8	8.3	286.9	72.20	54.38	6.664	3,160.7	452.5	1,912.0	5,525.2
SUBTOTAL	11,286.5	0.0	75,480.0	2,031.6	388.1	13,382.6	62.05	46.78	5.939	126,067.3	18,156.5	79,476.6	223,700.5
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	11,286.5	0.0	75,480.0	2,031.6	388.1	13,382.6	62.05	46.78	5.939	126,067.3	18,156.5	79,476.6	223,700.5
CUM PROD	63,767.2	0.0	335,345.1										
ULTIMATE	75,053.6	0.0	410,825.1										

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2018	5	0.9	0.0	0.0	131.1	0.0	2,160.7	5,680.7	5,680.7	5,636.0
12-31-2019	5	0.9	0.0	0.0	790.1	0.0	13,537.9	32,205.4	37,886.1	35,929.5
12-31-2020	5	0.9	0.0	0.0	809.9	0.0	14,047.7	25,692.9	63,579.0	57,903.4
12-31-2021	5	0.9	0.0	0.0	830.1	0.0	13,583.8	18,331.1	81,910.1	72,159.2
12-31-2022	5	0.9	0.0	0.0	850.9	0.0	13,483.8	14,085.0	95,995.1	82,119.7
12-31-2023	5	0.9	0.0	0.0	872.1	0.0	13,169.6	10,292.7	106,287.8	88,752.1
12-31-2024	4	0.7	0.0	0.0	893.9	0.0	12,716.7	6,519.2	112,807.0	92,567.2
12-31-2025	4	0.7	0.0	0.0	916.3	0.0	12,758.2	3,815.6	116,622.5	94,600.7
05-31-2026	4	0.7	0.0	0.0	389.7	0.0	4,932.1	203.4	116,826.0	94,702.4
SUBTOTAL			0.0	0.0	6,484.1	0.0	100,390.4	116,826.0	116,826.0	94,702.4
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	116,826.0	94,702.4
TOTAL OF 7.6 YRS			0.0	0.0	6,484.1	0.0	100,390.4	116,826.0	116,826.0	94,702.4

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	116,826.0
5.000	104,572.1
10.000	94,702.4
15.000	86,622.7
20.000	79,911.8
25.000	74,265.6
30.000	69,459.8
35.000	65,326.8
40.000	61,739.1
50.000	55,827.9

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 13

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

TOTAL PROVED DEVELOPED (1P) RESERVES

SERICA ENERGY PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING M-D-Y	OIL/COND MBBL	NGL MBBL	GAS MMCF	OIL/COND MBBL	NGL MBBL	GAS MMCF	OIL/COND $/BBL	NGL $/BBL	GAS $/MCF	OIL/COND M$	NGL M$	GAS M$	TOTAL M$
12-31-2018	372.8	0.0	2,501.4	67.1	12.9	443.5	74.60	56.17	7.304	5,005.6	722.5	3,239.3	8,967.4
12-31-2019	1,772.6	0.0	11,935.6	319.1	61.4	2,116.2	77.77	58.54	8.364	24,814.5	3,592.9	17,700.6	46,108.0
12-31-2020	1,185.6	0.0	8,029.0	213.4	41.3	1,423.5	82.68	62.21	8.466	17,644.7	2,568.4	12,051.1	32,264.1
12-31-2021	687.4	0.0	4,558.5	123.7	23.4	808.2	81.36	61.22	7.904	10,067.2	1,435.1	6,387.7	17,890.0
06-30-2022	155.9	0.0	1,087.5	28.1	5.6	192.8	85.10	64.02	7.994	2,388.3	358.0	1,541.3	4,287.6
SUBTOTAL	4,174.4	0.0	28,112.0	751.4	144.6	4,984.2	79.75	60.03	8.210	59,920.2	8,676.9	40,920.0	109,517.2
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,174.4	0.0	28,112.0	751.4	144.6	4,984.2	79.75	60.03	8.210	59,920.2	8,676.9	40,920.0	109,517.2
CUM PROD	63,767.2	0.0	335,345.1										
ULTIMATE	67,941.5	0.0	363,457.1										

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING M-D-Y	GROSS	NET	PRODUCTION M$	AD VALOREM M$	COST M$	COST M$	EXPENSE M$	PERIOD M$	CUM M$	CUM M$
12-31-2018	5	0.9	0.0	0.0	131.1	0.0	1,976.4	6,859.9	6,859.9	6,806.2
12-31-2019	5	0.9	0.0	0.0	790.1	0.0	11,770.8	33,547.1	40,406.9	38,431.6
12-31-2020	5	0.9	0.0	0.0	809.9	0.0	11,220.0	20,234.3	60,641.2	55,782.2
12-31-2021	5	0.9	0.0	0.0	830.1	0.0	8,910.4	8,149.6	68,790.7	62,167.5
06-30-2022	3	0.5	0.0	0.0	423.7	0.0	2,562.8	1,301.1	70,091.9	63,114.9
SUBTOTAL			0.0	0.0	2,984.9	0.0	36,440.4	70,091.9	70,091.9	63,114.9
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	70,091.9	63,114.9
TOTAL OF 3.7 YRS			0.0	0.0	2,984.9	0.0	36,440.4	70,091.9	70,091.9	63,114.9

PRESENT WORTH PROFILE	
DISC RATE %	CUM PW M$
0.000	70,091.9
5.000	66,377.8
10.000	63,114.9
15.000	60,227.2
20.000	57,654.7
25.000	55,349.1
30.000	53,271.4
35.000	51,389.8
40.000	49,677.9
50.000	46,679.2

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

Figure 14

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	342.5	0.0	2,245.1	61.7	11.5	398.1	74.60	56.17	7.304	4,599.4	648.5	2,907.4	8,155.4
12-31-2019	1,618.7	0.0	10,631.0	291.4	54.7	1,884.9	77.77	58.54	8.364	22,659.4	3,200.2	15,765.8	41,625.5
12-31-2020	1,070.1	0.0	7,050.5	192.6	36.3	1,250.1	82.68	62.21	8.466	15,926.4	2,255.4	10,582.5	28,764.2
12-31-2021	685.6	0.0	4,543.0	123.4	23.4	805.5	81.36	61.22	7.904	10,040.4	1,430.2	6,366.0	17,836.6
06-30-2022	155.9	0.0	1,087.5	28.1	5.6	192.8	85.10	64.02	7.994	2,388.3	358.0	1,541.3	4,287.6
SUBTOTAL	3,872.9	0.0	25,557.0	697.1	131.4	4,531.3	79.78	60.06	8.201	55,613.9	7,892.3	37,163.0	100,669.2
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	3,872.9	0.0	25,557.0	697.1	131.4	4,531.3	79.78	60.06	8.201	55,613.9	7,892.3	37,163.0	100,669.2
CUM PROD	54,807.9	0.0	278,500.8										
ULTIMATE	58,680.8	0.0	304,057.8										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	NET DEDUCTIONS/EXPENDITURES TAXES AD VALOREM M$	NET DEDUCTIONS/EXPENDITURES CAPITAL COST M$	NET DEDUCTIONS/EXPENDITURES ABDNMNT COST M$	NET DEDUCTIONS/EXPENDITURES OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED CUM M$	FUTURE NET REVENUE BEFORE INCOME TAXES DISC AT 10.000% CUM M$
12-31-2018	4	0.7	0.0	0.0	131.1	0.0	1,885.7	6,138.5	6,138.5	6,090.6
12-31-2019	4	0.7	0.0	0.0	790.1	0.0	11,266.9	29,568.4	35,707.0	33,971.7
12-31-2020	4	0.7	0.0	0.0	809.9	0.0	10,764.8	17,189.5	52,896.5	48,717.4
12-31-2021	4	0.7	0.0	0.0	830.1	0.0	8,902.9	8,103.6	61,000.1	55,065.4
06-30-2022	3	0.5	0.0	0.0	423.7	0.0	2,562.8	1,301.1	62,301.2	56,012.8
SUBTOTAL			0.0	0.0	2,984.9	0.0	35,383.1	62,301.2	62,301.2	56,012.8
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	62,301.2	56,012.8
TOTAL OF 3.7 YRS			0.0	0.0	2,984.9	0.0	35,383.1	62,301.2	62,301.2	56,012.8

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	62,301.2
5.000	58,950.9
10.000	56,012.8
15.000	53,417.1
20.000	51,108.1
25.000	49,041.8
30.000	47,182.2
35.000	45,500.2
40.000	43,971.6
50.000	41,298.1

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 15

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

PROVED DEVELOPED NON-PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	30.2	0.0	256.3	5.4	1.3	45.4	74.60	56.17	7.304	406.1	74.0	331.9	812.1
12-31-2019	153.9	0.0	1,304.6	27.7	6.7	231.3	77.77	58.54	8.364	2,155.0	392.7	1,934.8	4,482.5
12-31-2020	115.5	0.0	978.5	20.8	5.0	173.5	82.68	62.21	8.466	1,718.3	313.0	1,468.6	3,499.9
01-06-2021	1.8	0.0	15.5	0.3	0.1	2.7	81.36	61.22	7.904	26.8	4.9	21.7	53.4
SUBTOTAL	301.5	0.0	2,554.9	54.3	13.1	453.0	79.35	59.73	8.294	4,306.2	784.6	3,757.0	8,847.9
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	301.5	0.0	2,554.9	54.3	13.1	453.0	79.35	59.73	8.294	4,306.2	784.6	3,757.0	8,847.9
CUM PROD	8,959.3	0.0	56,844.3										
ULTIMATE	9,260.7	0.0	59,399.2										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2018	1	0.2	0.0	0.0	0.0	0.0	90.8	721.3	721.3	715.7
12-31-2019	1	0.2	0.0	0.0	0.0	0.0	503.9	3,978.6	4,699.9	4,459.8
12-31-2020	1	0.2	0.0	0.0	0.0	0.0	455.2	3,044.7	7,744.7	7,064.8
01-06-2021	1	0.2	0.0	0.0	0.0	0.0	7.4	46.0	7,790.6	7,102.1
SUBTOTAL			0.0	0.0	0.0	0.0	1,057.3	7,790.6	7,790.6	7,102.1
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	7,790.6	7,102.1
TOTAL OF 2.2 YRS			0.0	0.0	0.0	0.0	1,057.3	7,790.6	7,790.6	7,102.1

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	7,790.6
5.000	7,426.9
10.000	7,102.1
15.000	6,810.2
20.000	6,546.5
25.000	6,307.3
30.000	6,089.2
35.000	5,889.6
40.000	5,706.3
50.000	5,381.1

Figure 16

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

PROBABLE RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	29.3	0.0	195.8	5.3	1.0	34.7	74.60	56.17	7.304	393.0	56.6	253.5	703.1
12-31-2019	287.7	0.0	1,911.5	51.8	9.8	338.9	77.77	58.54	8.364	4,027.4	575.4	2,834.8	7,437.7
12-31-2020	393.4	0.0	2,608.0	70.8	13.4	462.4	82.68	62.21	8.466	5,854.3	834.3	3,914.5	10,603.0
12-31-2021	506.2	0.0	3,437.6	91.1	17.7	609.5	81.36	61.22	7.904	7,413.7	1,082.2	4,817.1	13,313.1
12-31-2022	691.0	0.0	4,507.6	124.4	23.2	799.2	85.10	64.02	7.994	10,585.1	1,483.8	6,388.5	18,457.4
12-31-2023	600.6	0.0	4,001.5	108.1	20.6	709.5	89.12	67.02	8.408	9,634.5	1,379.0	5,965.5	16,979.0
12-31-2024	497.7	0.0	3,302.1	89.6	17.0	585.5	93.15	70.03	8.823	8,344.8	1,189.1	5,165.6	14,699.5
06-30-2025	207.9	0.0	1,367.0	37.4	7.0	242.4	95.49	71.78	9.065	3,573.3	504.6	2,196.9	6,274.8
SUBTOTAL	3,213.8	0.0	21,331.1	578.5	109.7	3,782.0	86.13	64.78	8.339	49,826.2	7,105.0	31,536.5	88,467.7
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	3,213.8	0.0	21,331.1	578.5	109.7	3,782.0	86.13	64.78	8.339	49,826.2	7,105.0	31,536.5	88,467.7
CUM PROD	0.0	0.0	0.0										
ULTIMATE	3,213.8	0.0	21,331.1										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	NET DEDUCTIONS/EXPENDITURES TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	68.0	635.1	635.1	629.9
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	792.1	6,645.6	7,280.7	6,839.9
12-31-2020	0	0.0	0.0	0.0	0.0	0.0	1,442.2	9,160.8	16,441.5	14,647.9
12-31-2021	0	0.0	0.0	0.0	0.0	0.0	2,768.3	10,544.8	26,986.2	22,832.3
12-31-2022	1	0.2	0.0	0.0	427.2	0.0	8,021.8	10,008.4	36,994.6	29,910.2
12-31-2023	3	0.5	0.0	0.0	872.1	0.0	9,736.7	6,370.2	43,364.9	34,010.7
12-31-2024	3	0.5	0.0	0.0	893.9	0.0	9,713.1	4,092.5	47,457.4	36,408.7
06-30-2025	3	0.5	0.0	0.0	456.2	0.0	4,366.5	1,452.1	48,909.4	37,200.2
SUBTOTAL			0.0	0.0	2,649.5	0.0	36,908.8	48,909.4	48,909.4	37,200.2
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	48,909.4	37,200.2
TOTAL OF 6.7 YRS			0.0	0.0	2,649.5	0.0	36,908.8	48,909.4	48,909.4	37,200.2

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
0.000	48,909.4
5.000	42,394.1
10.000	37,200.2
15.000	32,997.6
20.000	29,551.2
25.000	26,690.6
30.000	24,290.0
35.000	22,255.4
40.000	20,515.3
50.000	17,710.6

Figure 17

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

PROVED + PROBABLE (2P) RESERVES

SERICA ENERGY PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2018	402.0	0.0	2,697.2	72.4	13.9	478.2	74.60	56.17	7.304	5,398.6	779.1	3,492.9	9,670.5
12-31-2019	2,060.3	0.0	13,847.1	370.9	71.2	2,455.1	77.77	58.54	8.364	28,841.9	4,168.4	20,535.4	53,545.7
12-31-2020	1,579.0	0.0	10,637.0	284.2	54.7	1,885.9	82.68	62.21	8.466	23,499.0	3,402.6	15,965.5	42,867.1
12-31-2021	1,193.7	0.0	7,996.1	214.9	41.1	1,417.7	81.36	61.22	7.904	17,480.9	2,517.3	11,204.8	31,203.1
12-31-2022	846.9	0.0	5,595.1	152.4	28.8	992.0	85.10	64.02	7.994	12,973.4	1,841.8	7,929.8	22,745.0
12-31-2023	600.6	0.0	4,001.5	108.1	20.6	709.5	89.12	67.02	8.408	9,634.5	1,379.0	5,965.5	16,979.0
12-31-2024	497.7	0.0	3,302.1	89.6	17.0	585.5	93.15	70.03	8.823	8,344.8	1,189.1	5,165.6	14,699.5
06-30-2025	207.9	0.0	1,367.0	37.4	7.0	242.4	95.49	71.78	9.065	3,573.3	504.6	2,196.9	6,274.8
SUBTOTAL	7,388.1	0.0	49,443.1	1,329.9	254.2	8,766.3	82.52	62.08	8.265	109,746.4	15,781.9	72,456.6	197,984.8
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	7,388.1	0.0	49,443.1	1,329.9	254.2	8,766.3	82.52	62.08	8.265	109,746.4	15,781.9	72,456.6	197,984.8
CUM PROD	63,767.2	0.0	335,345.1										
ULTIMATE	71,155.3	0.0	384,788.2										

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2018	5	0.9	0.0	0.0	131.1	0.0	2,044.4	7,495.0	7,495.0	7,436.1
12-31-2019	5	0.9	0.0	0.0	790.1	0.0	12,562.9	40,192.7	47,687.6	45,271.4
12-31-2020	5	0.9	0.0	0.0	809.9	0.0	12,662.3	29,395.0	77,082.7	70,430.0
12-31-2021	5	0.9	0.0	0.0	830.1	0.0	11,678.7	18,694.3	95,777.0	84,999.8
12-31-2022	4	0.7	0.0	0.0	850.9	0.0	10,584.6	11,309.5	107,086.5	93,025.1
12-31-2023	3	0.5	0.0	0.0	872.1	0.0	9,736.7	6,370.2	113,456.7	97,125.6
12-31-2024	3	0.5	0.0	0.0	893.9	0.0	9,713.1	4,092.5	117,549.3	99,523.6
06-30-2025	3	0.5	0.0	0.0	456.2	0.0	4,366.5	1,452.1	119,001.3	100,315.1
SUBTOTAL			0.0	0.0	5,634.3	0.0	73,349.2	119,001.3	119,001.3	100,315.1
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	119,001.3	100,315.1
TOTAL OF 6.7 YRS			0.0	0.0	5,634.3	0.0	73,349.2	119,001.3	119,001.3	100,315.1

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	119,001.3
5.000	108,771.9
10.000	100,315.1
15.000	93,224.8
20.000	87,205.8
25.000	82,039.6
30.000	77,561.4
35.000	73,645.2
40.000	70,193.1
50.000	64,389.8

Figure 18

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

POSSIBLE RESERVES

SERICA ENERGY PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	53.9	0.0	360.8	9.7	1.9	64.0	74.60	56.17	7.304	723.4	104.2	467.2	1,294.8
12-31-2019	400.8	0.0	2,671.1	72.1	13.7	473.6	77.77	58.54	8.364	5,610.1	804.1	3,961.2	10,375.4
12-31-2020	474.1	0.0	3,154.8	85.3	16.2	559.4	82.68	62.21	8.466	7,055.1	1,009.2	4,735.3	12,799.6
12-31-2021	524.2	0.0	3,551.6	94.4	18.3	629.7	81.36	61.22	7.904	7,677.4	1,118.1	4,976.8	13,772.3
12-31-2022	594.9	0.0	4,100.3	107.1	21.1	727.0	85.10	64.02	7.994	9,112.7	1,349.7	5,811.2	16,273.6
12-31-2023	579.3	0.0	3,873.7	104.3	19.9	686.8	89.12	67.02	8.408	9,292.8	1,335.0	5,775.0	16,402.8
12-31-2024	441.0	0.0	2,858.7	79.4	14.7	506.9	93.15	70.03	8.823	7,394.6	1,029.4	4,472.0	12,896.0
12-31-2025	587.0	0.0	3,847.6	105.7	19.8	682.2	95.49	71.78	9.065	10,089.9	1,420.2	6,183.7	17,693.8
12-31-2026	556.3	0.0	3,701.5	100.1	19.0	656.3	97.90	73.58	9.312	9,803.0	1,400.4	6,111.4	17,314.8
12-31-2027	480.8	0.0	3,191.8	86.5	16.4	565.9	100.36	75.42	9.566	8,685.3	1,237.8	5,413.6	15,336.7
08-31-2028	285.3	0.0	1,890.0	51.4	9.7	335.1	102.88	77.30	9.826	5,284.2	751.2	3,292.8	9,328.2
SUBTOTAL	4,977.6	0.0	33,201.8	896.0	170.7	5,886.7	90.10	67.71	8.698	80,728.5	11,559.3	51,200.3	143,488.1
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,977.6	0.0	33,201.8	896.0	170.7	5,886.7	90.10	67.71	8.698	80,728.5	11,559.3	51,200.3	143,488.1
CUM PROD	0.0	0.0	0.0										
ULTIMATE	4,977.6	0.0	33,201.8										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	116.3	1,178.5	1,178.5	1,169.1
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	975.0	9,400.4	10,578.9	9,974.1
12-31-2020	0	0.0	0.0	0.0	0.0	0.0	1,385.5	11,414.1	21,993.1	19,708.5
12-31-2021	0	0.0	0.0	0.0	0.0	0.0	1,905.1	11,867.3	33,860.3	28,896.9
12-31-2022	1	0.2	0.0	0.0	0.0	0.0	2,899.1	13,374.5	47,234.8	38,318.2
12-31-2023	2	0.4	0.0	0.0	0.0	0.0	3,433.0	12,969.8	60,204.6	46,665.0
12-31-2024	1	0.2	0.0	0.0	0.0	0.0	3,003.6	9,892.4	70,097.1	52,439.7
12-31-2025	1	0.2	0.0	0.0	460.0	0.0	8,391.6	8,842.1	78,939.2	57,119.4
12-31-2026	4	0.7	0.0	0.0	939.2	0.0	11,796.6	4,579.0	83,518.2	59,336.3
12-31-2027	3	0.5	0.0	0.0	962.7	0.0	12,017.7	2,356.3	85,874.5	60,375.6
08-31-2028	3	0.5	0.0	0.0	655.1	0.0	7,661.5	1,011.6	86,886.1	60,786.4
SUBTOTAL			0.0	0.0	3,017.0	0.0	53,585.0	86,886.1	86,886.1	60,786.4
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	86,886.1	60,786.4
TOTAL OF 9.8 YRS			0.0	0.0	3,017.0	0.0	53,585.0	86,886.1	86,886.1	60,786.4

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
0.000	86,886.1
5.000	71,958.0
10.000	60,786.4
15.000	52,238.3
20.000	45,566.7
25.000	40,266.4
30.000	35,988.0
35.000	32,484.6
40.000	29,578.6
50.000	25,071.5

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 19

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF OCTOBER 31, 2018

SERICA ENERGY PLC INTEREST

PROVED + PROBABLE + POSSIBLE (3P) RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UK SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2018	455.9	0.0	3,058.0	82.1	15.7	542.2	74.60	56.17	7.304	6,121.9	883.3	3,960.1	10,965.3
12-31-2019	2,461.1	0.0	16,518.2	443.0	84.9	2,928.7	77.77	58.54	8.364	34,452.0	4,972.4	24,496.6	63,921.1
12-31-2020	2,053.0	0.0	13,791.8	369.5	70.9	2,445.3	82.68	62.21	8.466	30,554.1	4,411.8	20,700.8	55,666.7
12-31-2021	1,717.9	0.0	11,547.7	309.2	59.4	2,047.4	81.36	61.22	7.904	25,158.4	3,635.4	16,181.7	44,975.4
12-31-2022	1,441.8	0.0	9,695.3	259.5	49.9	1,719.0	85.10	64.02	7.994	22,086.1	3,191.6	13,741.1	39,018.7
12-31-2023	1,179.9	0.0	7,875.3	212.4	40.5	1,396.3	89.12	67.02	8.408	18,927.3	2,714.0	11,740.5	33,381.8
12-31-2024	938.7	0.0	6,160.8	169.0	31.7	1,092.3	93.15	70.03	8.823	15,739.4	2,218.6	9,637.6	27,595.6
12-31-2025	794.9	0.0	5,214.5	143.1	26.8	924.5	95.49	71.78	9.065	13,663.3	1,924.7	8,380.6	23,968.6
12-31-2026	556.3	0.0	3,701.5	100.1	19.0	656.3	97.90	73.58	9.312	9,803.0	1,400.4	6,111.4	17,314.8
12-31-2027	480.8	0.0	3,191.8	86.5	16.4	565.9	100.36	75.42	9.566	8,685.3	1,237.8	5,413.6	15,336.7
08-31-2028	285.3	0.0	1,890.0	51.4	9.7	335.1	102.88	77.30	9.826	5,284.2	751.2	3,292.8	9,328.2
SUBTOTAL	12,365.7	0.0	82,644.9	2,225.8	425.0	14,652.9	85.57	64.34	8.439	190,474.9	27,341.2	123,656.8	341,472.9
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	12,365.7	0.0	82,644.9	2,225.8	425.0	14,652.9	85.57	64.34	8.439	190,474.9	27,341.2	123,656.8	341,472.9
CUM PROD	63,767.2	0.0	335,345.1										
ULTIMATE	76,132.9	0.0	417,990.0										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2018	5	0.9	0.0	0.0	131.1	0.0	2,160.7	8,673.5	8,673.5	8,605.2
12-31-2019	5	0.9	0.0	0.0	790.1	0.0	13,537.9	49,593.1	58,266.6	55,245.5
12-31-2020	5	0.9	0.0	0.0	809.9	0.0	14,047.7	40,809.2	99,075.7	90,138.5
12-31-2021	5	0.9	0.0	0.0	830.1	0.0	13,583.8	30,561.6	129,637.3	113,896.7
12-31-2022	5	0.9	0.0	0.0	850.9	0.0	13,483.8	24,684.1	154,321.4	131,343.3
12-31-2023	5	0.9	0.0	0.0	872.1	0.0	13,169.6	19,340.0	173,661.4	143,790.6
12-31-2024	4	0.7	0.0	0.0	893.9	0.0	12,716.7	13,984.9	187,646.3	151,963.3
12-31-2025	4	0.7	0.0	0.0	916.3	0.0	12,758.2	10,294.2	197,940.5	157,434.5
12-31-2026	4	0.7	0.0	0.0	939.2	0.0	11,796.6	4,579.0	202,519.5	159,651.4
12-31-2027	3	0.5	0.0	0.0	962.7	0.0	12,017.7	2,356.3	204,875.8	160,690.7
08-31-2028	3	0.5	0.0	0.0	655.1	0.0	7,661.5	1,011.6	205,887.4	161,101.5
SUBTOTAL			0.0	0.0	8,651.3	0.0	126,934.2	205,887.4	205,887.4	161,101.5
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	205,887.4	161,101.5
TOTAL OF 9.8 YRS			0.0	0.0	8,651.3	0.0	126,934.2	205,887.4	205,887.4	161,101.5

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	205,887.4
5.000	180,729.9
10.000	161,101.5
15.000	145,463.1
20.000	132,772.5
25.000	122,306.0
30.000	113,549.4
35.000	106,129.8
40.000	99,771.8
50.000	89,461.3

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 20

LOW AND HIGH PRICE CASE SENSITIVITIES

Case/Category	Company Gross Revenue	Capital Costs	Abandonment and Reclamation Costs[1]	Operating Costs	Future Net Revenue Before Income Tax Discounted at 0%	Future Net Revenue Before Income Tax Discounted at 10%	United Kingdom Corporate Income Taxes	Future Net Revenue After United Kingdom Corporate Income Taxes Discounted at 0%	Future Net Revenue After United Kingdom Corporate Income Taxes Discounted at 10%
LOW PRICE CASE									
Proved Developed Producing	71,992.0	2,773.0	0.0	34,139.3	35,079.7	31,938.2	0.0	35,079.7	31,938.2
Proved Developed Non-Producing	6,431.7	0.0	0.0	1,057.3	5,374.4	4,900.8	0.0	5,374.4	4,900.8
Total Proved Developed (1P)	78,423.8	2,773.0	0.0	35,196.6	40,454.1	36,839.0	0.0	40,454.1	36,839.0
Probable	56,976.3	2,030.4	0.0	29,749.5	25,196.3	20,263.1	0.0	25,196.3	20,263.1
Proved + Probable (2P)	135,400.1	4,803.5	0.0	64,946.2	65,650.5	57,102.1	0.0	65,650.5	57,102.1
Possible	88,300.4	1,680.6	0.0	35,444.3	51,175.5	37,600.4	0.0	51,175.5	37,600.4
Proved + Probable + Possible (3P)	223,700.5	6,484.1	0.0	100,390.4	116,826.0	94,702.4	0.0	116,826.0	94,702.4
HIGH PRICE CASE									
Proved Developed Producing	100,669.2	2,984.9	0.0	35,383.1	62,301.2	56,012.8	0.0	62,301.2	56,012.8
Proved Developed Non-Producing	8,847.9	0.0	0.0	1,057.3	7,790.6	7,102.1	0.0	7,790.6	7,102.1
Total Proved Developed (1P)	109,517.2	2,984.9	0.0	36,440.4	70,091.9	63,114.9	0.0	70,091.9	63,114.9
Probable	88,467.7	2,649.5	0.0	36,908.8	48,909.4	37,200.2	0.0	48,909.4	37,200.2
Proved + Probable (2P)	197,984.8	5,634.3	0.0	73,349.2	119,001.3	100,315.1	0.0	119,001.3	100,315.1
Possible	143,488.1	3,017.0	0.0	53,585.0	86,886.1	60,786.4	18,355.0	68,531.1	50,876.0
Proved + Probable + Possible (3P)	341,472.9	8,651.3	0.0	126,934.2	205,887.4	161,101.5	18,355.0	187,532.4	151,191.1

Totals may not add because of rounding.

(1) Serica is not liable for abandonment costs up to a maximum value that exceeds its current estimates of abandonment costs.

Figure 21

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

SUMMARY OF UNRISKED CONTINGENT OIL RESOURCES[1]
SERICA ENERGY PLC INTEREST
LOCATED IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA AND IN IRISH WATERS IN THE ATLANTIC OCEAN
AS OF OCTOBER 31, 2018

			Unrisked Contingent Oil Resources (MBBL)					
			Gross (100%)			Working Interest		
Subclass/Area/Field or Discovery	Operator	Risk Factor[2] (%)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Development Pending								
United Kingdom Sector of the Central North Sea								
Columbus Field	Serica Energy (UK) Limited	90	1,269.2	2,793.7	3,636.2	634.6	1,396.9	1,818.1
Development Not Viable								
Irish Waters in the Atlantic Ocean								
Bandon Discovery	Serica Energy Slyne B.V.	0	0.0	0.0	0.0	0.0	0.0	0.0
Total			1,269.2	2,793.7	3,636.2	634.6	1,396.9	1,818.1

(1) These volumes represent only the portions of the reservoirs that lie within the boundaries of the respective lease areas.
(2) The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

Source: Netherland, Sewell & Associates, Inc.

Figure 22

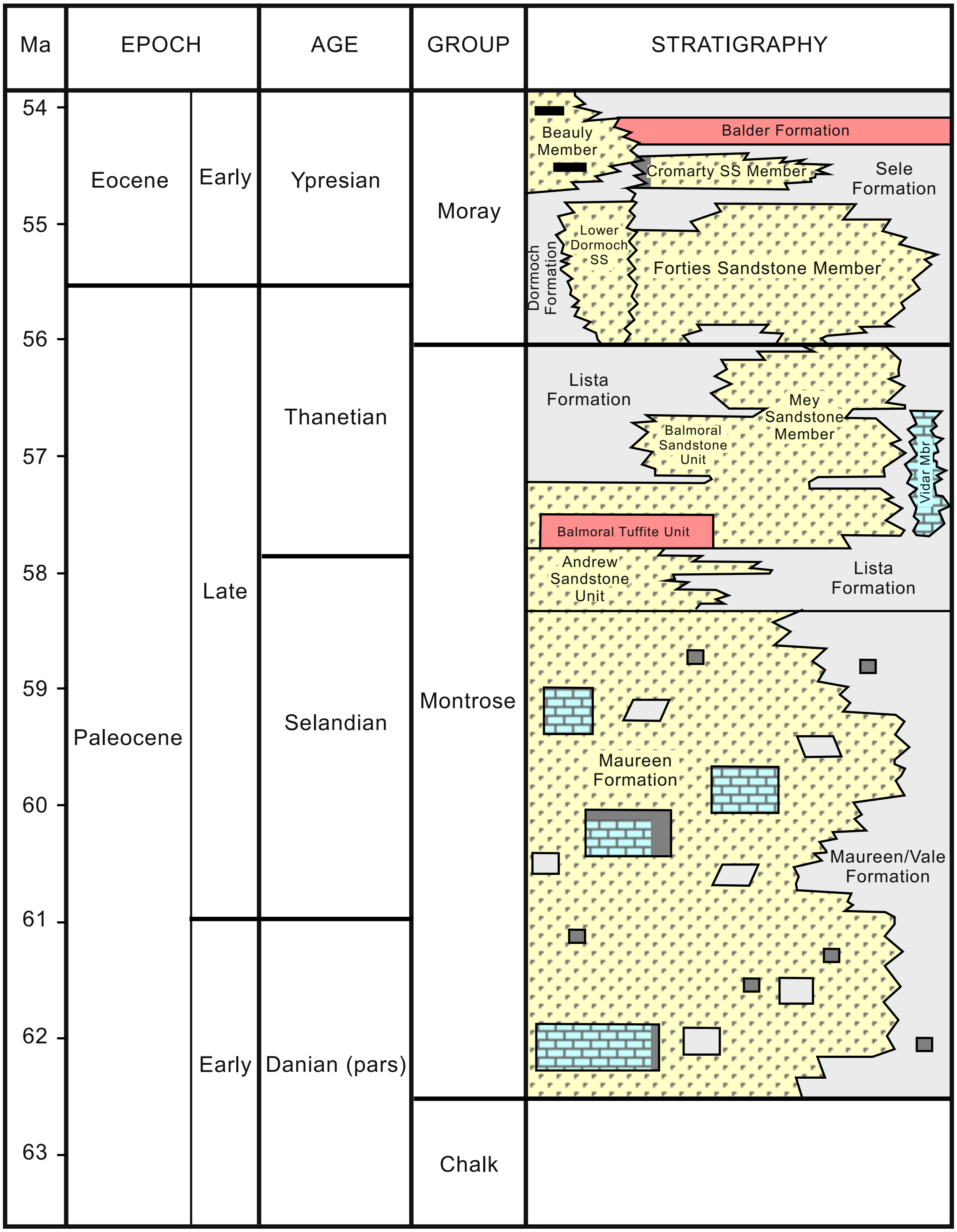
SUMMARY OF UNRISKED CONTINGENT GAS RESOURCES[1]
SERICA ENERGY PLC INTEREST
LOCATED IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA AND IN IRISH WATERS OF THE ATLANTIC OCEAN
AS OF OCTOBER 31, 2018

			Unrisked Contingent Gas Resources (MMCF)					
			Gross (100%)			Working Interest		
Subclass/Area/Field or Discovery	Operator	Risk Factor[2] (%)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Development Pending								
United Kingdom Sector of the Central North Sea								
Columbus Field	Serica Energy (UK) Limited	90	28,857.3	63,533.2	82,284.1	14,428.7	31,766.6	41,142.1
Development Not Viable								
Irish Waters in the Atlantic Ocean								
Bandon Discovery	Serica Energy Slyne B.V.	0	0.0	0.0	0.0	0.0	0.0	0.0
Total			28,857.3	63,533.2	82,284.1	14,428.7	31,766.6	41,142.1

(1) These volumes represent only the portions of the reservoirs that lie within the boundaries of the respective lease areas.
(2) The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

Source: Netherland, Sewell & Associates, Inc.

Stratigraphic Column
Columbus Field
United Kingdom Sector of the Central North Sea



Adapted from "The Millennium Atlas, Fig. 14.2" by Ahmadi et al., 2003.

MODULAR DYNAMICS TEST RESULTS BY WELL
COLUMBUS FIELD, UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF OCTOBER 31, 2018

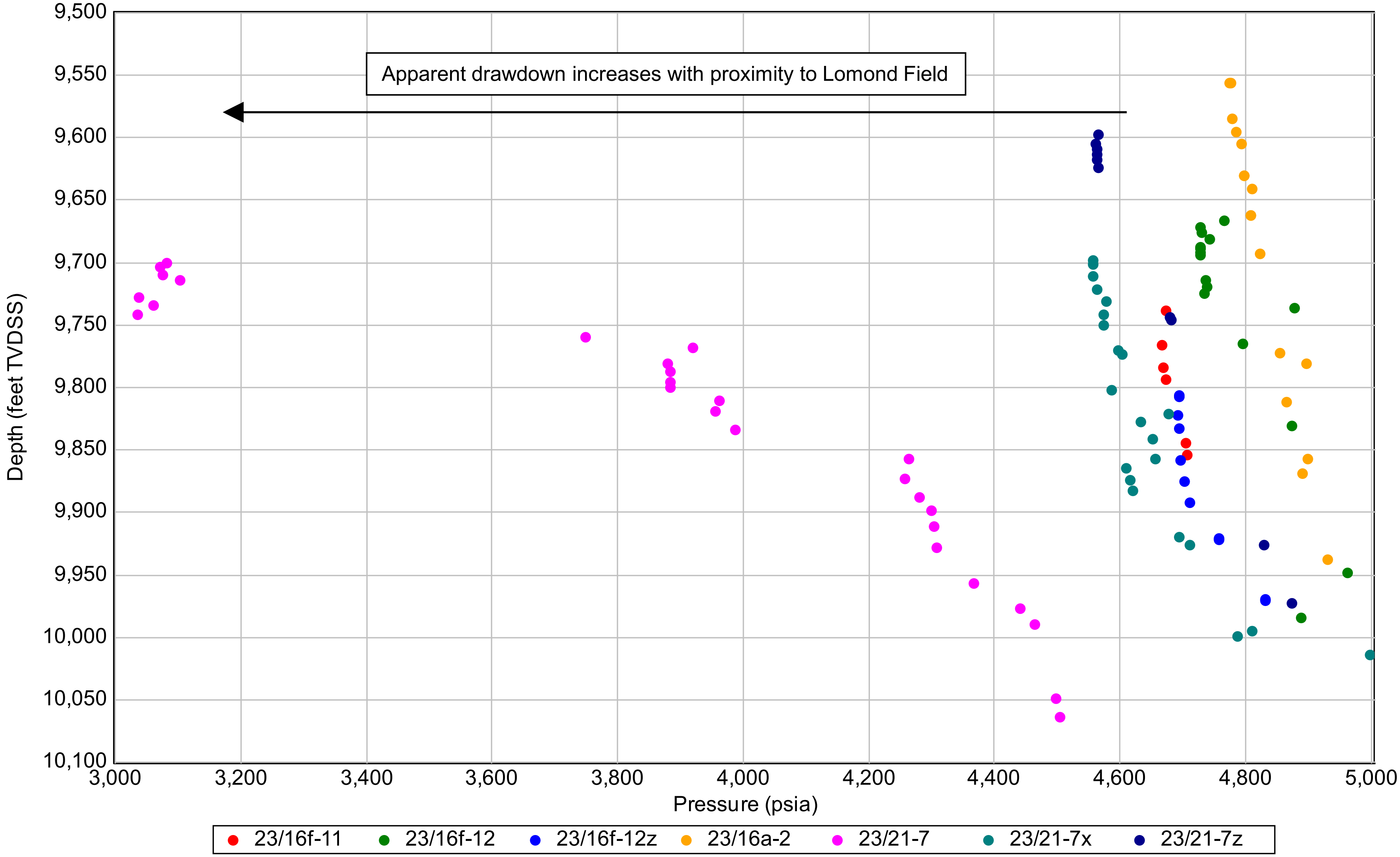
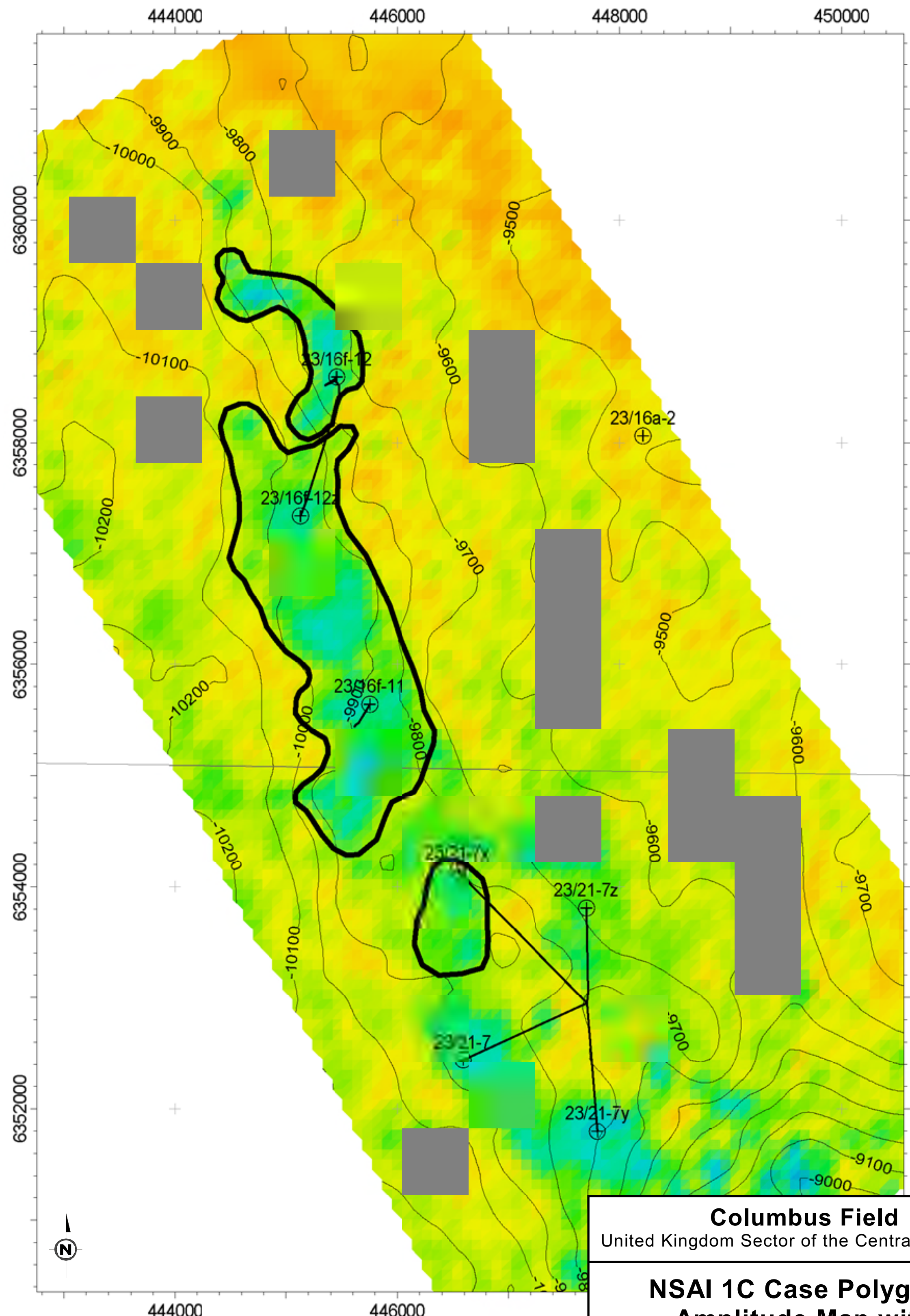


Figure 25



Columbus Field
United Kingdom Sector of the Central North Sea

NSAI 1C Case Polygons
Amplitude Map with
Depth Structure (Top F-4 Zone)

Contour Interval: 100 feet

SCALE IN METERS

0 500 1,000 2,000

SUMMARY OF UNRISKED PROSPECTIVE OIL RESOURCES[1]
SERICA ENERGY PLC INTEREST
LOCATED IN IRISH WATERS IN THE ATLANTIC OCEAN AND IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF OCTOBER 31, 2018

			Unrisked Prospective Oil Resources (MMBBL)					
			Gross (100%)			Working Interest		
Area/Prospect	Operator	Risk Factor[2] (%)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)
Irish Waters in the Atlantic Ocean								
Achill	Serica Energy Slyne B.V.	26	0.0	0.0	0.0	0.0	0.0	0.0
Bandon South	Serica Energy Slyne B.V.	26	0.0	0.0	0.0	0.0	0.0	0.0
Boyne Sherwood	Serica Energy Slyne B.V.	26	0.0	0.0	0.0	0.0	0.0	0.0
Boyne Suisnish	Serica Energy Slyne B.V.	20	5.6	20.1	76.7	5.6	20.1	76.7
Liffey Sherwood	Serica Energy Slyne B.V.	26	0.0	0.0	0.0	0.0	0.0	0.0
Liffey Suisnish	Serica Energy Slyne B.V.	20	30.3	128.2	526.7	30.3	128.2	526.7
United Kingdom Sector of the Central North Sea								
Rowallan Pentland	Eni (UK) Ltd	22	3.5	8.8	20.0	0.5	1.3	3.0
Rowallan Triassic	Eni (UK) Ltd	22	10.0	33.0	113.4	1.5	4.9	17.0
Total			49.4	190.0	736.9	37.9	154.6	623.4

Note: Totals are the arithmetic sum of multiple probability distributions and may not add because of rounding. Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

(1) These volumes represent only the portions of the prospects that lie within the boundaries of the respective lease and/or license areas.

(2) The risk factor for prospective resources refers to the estimated chance, or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. For the purposes of this report, the risk factor for the prospective resources refers to the PRMS term "chance of geologic discovery".

Source: Netherland, Sewell & Associates, Inc.

Figure 27

SUMMARY OF UNRISKED PROSPECTIVE GAS RESOURCES[1]
SERICA ENERGY PLC INTEREST
LOCATED IN IRISH WATERS IN THE ATLANTIC OCEAN AND IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF OCTOBER 31, 2018

			Unrisked Prospective Gas Resources (BCF)					
			Gross (100%)			Working Interest		
Area/Prospect	Operator	Risk Factor[2] (%)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)
Irish Waters in the Atlantic Ocean								
Achill	Serica Energy Slyne B.V.	26	120.7	252.7	516.5	120.7	252.7	516.5
Bandon South	Serica Energy Slyne B.V.	26	6.7	26.9	101.7	6.7	26.9	101.7
Boyne Sherwood	Serica Energy Slyne B.V.	26	60.8	180.2	528.5	60.8	180.2	528.5
Boyne Suisnish	Serica Energy Slyne B.V.	20	1.4	5.5	22.1	1.4	5.5	22.1
Liffey Sherwood	Serica Energy Slyne B.V.	26	52.6	180.4	626.7	52.6	180.4	626.7
Liffey Suisnish	Serica Energy Slyne B.V.	20	7.6	34.0	147.4	7.6	34.0	147.4
United Kingdom Sector of the Central North Sea								
Rowallan Pentland	Eni (UK) Ltd	22	54.4	118.7	259.9	8.2	17.8	39.0
Rowallan Triassic	Eni (UK) Ltd	22	134.1	422.4	1,463.9	20.1	63.4	219.6
Total			438.3	1,220.9	3,666.7	278.1	760.8	2,201.5

Note: Totals are the arithmetic sum of multiple probability distributions and may not add because of rounding. Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

(1) These volumes represent only the portions of the prospects that lie within the boundaries of the respective lease and/or license areas.

(2) The risk factor for prospective resources refers to the estimated chance, or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. For the purposes of this report, the risk factor for the prospective resources refers to the PRMS term "chance of geologic discovery".

Source: Netherland, Sewell & Associates, Inc.

Figure 28

PART V – FURTHER UNAUDITED HISTORICAL FINANCIAL INFORMATION ON THE BKR ASSETS

	Six months ended 30 June 2018 (Unaudited)	Year ended 31 December 2017 (Unaudited)
	US$'000	***US$'000***
Revenue	**114,430**	**228,974**
Production expenditure	(33,636)	(43,070)
Other Government take	(719)	(887)
Other operating costs	(15,320)	(5,318)
Change in pipeline inventory	6,305	–
Oil/NGL under/overlift	(8,234)	–
Transportation costs	(27,682)	(61,466)
Insurance costs	(3,088)	(5,472)
FX gain	345	834
Operating expenditure	**(82,029)**	**(115,379)**
EBITDA	**32,401**	**113,595**
Impairment	–	30,898
Depreciation	(21,326)	(53,348)
Decommissioning accretion	(671)	(1,241)
Profit Before Tax	**10,404**	**89,903**

EBITDA in respect of the BKR Assets for the year ended 31 December 2017 comprised a strong first half performance followed by a lower second half performance, due largely to a decline in oil and gas production in both the Rhum field and the Bruce and Keith fields. This was driven by a maintenance outage in the Forties pipeline system in August 2017, by a further outage in the Forties pipeline system in December 2017 following the discovery of cracks on the onshore section of the pipeline and by Rhum R2 well workover work in the third quarter of the year ended 31 December 2017. The impact of lower production was offset to some degree by an increase in the average realised oil and gas prices driven by increases in market spot prices in the period.

EBITDA in the six month period ended 30 June 2018 was proportionately lower than the full year 2017. Revenues were consistent with 2017 with variations in realised oil and gas sales prices and production volumes netting out. An increase in production expenditure was largely attributable to special projects carried out in the first half of 2018 related to the annual maintenance programme during June 2018 and conductor work on the Rhum field relating to the conductor pipes that connect the individual wells on the seabed to the production facilities on the platform. An increase in other operating costs related to a US$12.5 million write-off by BP of cost-share receivable from IOC. The write-off of the cost-share receivable was as a result of the resolution of an ongoing dispute with IOC regarding the move from tariffs to a cost-share arrangement for the use of the Bruce facilities and related to periods prior to the effective date of the BKR Acquisition (1 January 2018).

The unaudited historical financial information on the BKR Assets presented in this document has been compiled on the following basis:

Revenue

Revenue predominantly represents the sale of produced oil, gas and NGLs from the Bruce, Keith and Rhum fields in each respective period. Product revenue is recognised on an entitlement basis and not on a lifting basis. Therefore, oil and NGL revenue is calculated as actual liftings revenue adjusted for the change in the underlift or overlift balance during the period to derive the entitlement revenue for the period. Gas is accounted for on a sales basis. Also included in reported revenue is the net income which the Bruce field receives in the form of cost share (previously tariff) from the Rhum field.

A breakdown of the revenue by aggregated product across the BKR Assets can be found within Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document.

Operating expenditure

This is comprised of production expenditure covering onshore manpower and overheads, offshore manpower, repairs and maintenance, engineering services and subsea works/drilling and logistics and platform services. The government take relates principally to the costs associated with licence fees. Other operating expenditure covers the associated upstream technology and research and development costs allocated to the BKR Assets. Transportation costs represent Frigg and Forties pipeline costs and tariffs as well as blending costs. The operating expenditure also covers insurance costs allocated to the BKR Assets as well as any FX gains/losses associated with operations experienced in the periods.

Impairment, Depreciation and Decommissioning accretion

Non-cash items of impairment, depreciation and accretion of decommissioning provisions have also been included as part of the BKR Assets unaudited historic financial information.

Basis of preparation

Audited financial statements are not prepared at the BKR Asset or field level by BP and therefore individual field level financial information has been extracted from BP's SAP system and has been aggregated to form the above unaudited historical financial information table. Pro forma and consolidation adjustments have been overlaid as part of the aggregation, but a full pro forma and consolidation analysis has not been undertaken and the profit and loss information is not part of a full set of financial statements. It should be noted that neither the aggregated profit and loss information, nor the field level profit and loss information, has been audited.

PART VI – UNAUDITED HISTORICAL FINANCIAL INFORMATION ON THE BK ASSETS

Section A: Unaudited Historical Financial Information on the Total E&P Assets

	Six months ended 30 June 2018[(1)] (Unaudited)	Year ended 31 December 2017[(2)] (Unaudited)
	US$'000	***US$'000***
Revenue	**41,183**	**74,008**
Production expenditure	(20,473)	(32,813)
Transportation costs	(2,767)	(7,399)
Other operating costs	(7)	(26)
Operating expenditure	**(23,247)**	**(40,238)**
EBITDA	**17,936**	**33,770**
Impairment	0	0
Depreciation	(469)	(2,438)
Decommissioning accretion	(2,979)	(30,033)
Profit Before Tax	**14,488**	**1,299**

Notes:

(1) Reported by Total E&P in pounds sterling, converted at an exchange rate of £1: US$1.3762, which was the average exchange rate prevailing over the six months ended 30 June 2018.

(2) Reported by Total E&P in pounds sterling, converted at an exchange rate of £1: US$1.2884, which was the average exchange rate prevailing over the year ended 31 December 2017.

The unaudited historic financial information on the Total E&P Assets presented in this Supplementary Admission Document has been compiled on the following basis:

Revenue

Revenue predominantly represents the sale of produced oil, gas and NGLs from the Bruce and Keith fields in each respective period. Product revenue is recognised on an entitlement basis after adjustment for oil and NGL over/underlift volumes.

A breakdown of the revenue by aggregated product across the Total E&P Assets can be found within Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document.

Operating expenditure

This comprises production expenditure, transportation costs and other operating costs.

Production expenditure comprises onshore and offshore manpower and overheads, repairs and maintenance, engineering services, subsea works/drilling, logistics and platform services. Transportation costs comprise pipeline costs and tariffs. Other operating costs covers further costs allocated to the Total E&P Assets.

Impairment, Depreciation and Decommissioning accretion

Non-cash items of impairment, depreciation and decommissioning have also been included as part of the Total E&P Assets unaudited historic financial information.

Basis of preparation

Audited financial statements are not prepared at the Total E&P Asset or field level by Total E&P and therefore individual field level financial information has been extracted from Total E&P's accounting system and has been aggregated to form the above unaudited historical financial information table. Neither the aggregated profit and loss nor the individual field profit and loss accounts are subject to separate external audit and they have not been prepared in accordance with IFRS.

Section B: Unaudited Historical Financial Information on the BHP Assets

	Six months ended 30 June 2018 (Unaudited)	Year ended 31 December 2017 (Unaudited)
	US$'000	*US$'000*
Revenue	**14,010**	**30,054**
Production expenditure	(5,107)	(12,188)
Transportation costs	(921)	(2,974)
Other operating costs	(97)	(210)
Operating expenditure	**(6,125)**	**(15,372)**
EBITDA	**7,885**	**14,682**
Impairment	4,855	(3,667)
Depreciation	0	(259)
Decommissioning accretion	(2,560)	(4,562)
Profit Before Tax	**10,180**	**6,194**

The unaudited historic financial information on the BHP Assets presented in this Supplementary Admission Document has been compiled on the following basis:

Revenue

Revenue predominantly represents the sale of produced oil, gas and NGLs from the Bruce and Keith fields in each respective period. Product revenue is recognised on an entitlement basis after adjustment for oil and NGL over/underlift volumes.

A breakdown of the revenue by aggregated product across the BHP Assets can be found within Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document.

Operating expenditure

This comprises production expenditure, transportation costs and other operating costs.

Production expenditure comprises onshore and offshore manpower and overheads, repairs and maintenance, engineering services, subsea works/drilling, logistics and platform services. Transportation costs comprise inter-field and pipeline costs and tariffs. Other operating costs covers further costs allocated to the BHP Assets.

Impairment, Depreciation and Decommissioning accretion

Non-cash items of impairment, depreciation and decommissioning have also been included as part of the BHP Assets unaudited historic financial information.

Basis of preparation

Audited financial statements are not prepared at the BHP Asset or field level by BHP and therefore individual field level financial information has been extracted from BHP's accounting system and has been aggregated to form the above unaudited historical financial information table. Neither the aggregated profit and loss nor the individual field profit and loss accounts are subject to separate external audit and they have not been prepared in accordance with IFRS.

Section C: Unaudited Historical Financial Information on the Marubeni Assets

	Six months ended 30 June 2018 (Unaudited)	**Year ended 31 December 2017 (Unaudited)**
	US$'000	***US$'000***
Revenue	**4,340**	**8,345**
Production expenditure	(1,467)	(3,774)
Transportation costs	(239)	(924)
Operating expenditure	**(1,706)**	**(4,698)**
EBITDA	**2,634**	**3,647**
Impairment	0	0
Depreciation	(41)	(211)
Decommissioning accretion	(576)	(4,623)
Profit/(loss) Before Tax	**2,017**	**(1,187)**

The unaudited historic financial information on the Marubeni Assets presented in this Supplementary Admission Document has been compiled on the following basis:

Revenue

Revenue predominantly represents the sale of produced oil, gas and NGLs from the Bruce and Keith fields in each respective period. Product revenue is recognised on an entitlement basis after adjustment for oil and NGL over/underlift volumes.

A breakdown of the revenue by aggregated product across the Marubeni Assets can be found within Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document.

Operating expenditure

This comprises production expenditure, transportation costs and other operating costs.

Production expenditure comprises onshore and offshore manpower and overheads, repairs and maintenance, engineering services, subsea works/drilling, logistics and platform services. Transportation costs comprise inter-field and pipeline costs and tariffs.

Impairment, Depreciation and Decommissioning accretion

Non-cash items of impairment, depreciation and decommissioning have also been included as part of the Marubeni Assets unaudited historic financial information.

Basis of preparation

Audited financial statements are not prepared at the Marubeni Asset or field level by Marubeni and therefore individual field level financial information has been extracted from Marubeni's accounting system and has been aggregated to form the above unaudited historical financial information table. Neither the aggregated profit and loss nor the individual field profit and loss accounts are subject to separate external audit and they have not been prepared in accordance with IFRS.

PART VII – FURTHER HISTORICAL FINANCIAL INFORMATION ON SERICA

1. Background

The consolidated financial statements of the Serica Group for the year ended 31 December 2017, as set out in the annual report and accounts of the Serica Group for 2017, and the unaudited consolidated interim financial statements of the Serica Group for the six months ended 30 June 2018, as set out in the interim report of the Serica Group for the six months ended 30 June 2018, are incorporated by reference into this document. The audit report for the financial year ended 31 December 2017 was unqualified. The consolidated financial statements for the financial year ended 31 December 2017 and for the six months ended 30 June 2018 (unaudited) were prepared in accordance with IFRS.

2. Cross reference list

The following list is intended to enable investors to identify easily specific items of information which have been incorporated by reference into this document. A copy of each of these documents incorporated by reference into this document can be accessed on the Company's website at http://www.serica-energy.com/.

2.1 IFRS financial statements for the financial year ended 31 December 2017 and the audit report thereon

The page numbers below refer to the relevant pages of the annual report and accounts of the Serica Group for the financial year ended 31 December 2017:

Section	Page number(s)
Independent Auditor's Report	32 to 38
Group Income Statement	39
Group Statement of Comprehensive Income	39
Balance Sheet	40
Statement of Changes in Equity	41
Cash Flow Statement	42
Notes to the Financial Statements	43 to 76

2.2 Unaudited IFRS financial statements for the six months ended 30 June 2018

The page numbers below refer to the relevant pages of the interim report and accounts of the Serica Group for the six months ended 30 June 2018:

Section	Page number(s)
Group Income Statement	17
Group Statement of Comprehensive Income	17
Group Balance Sheet	18
Group Statement of Changes in Equity	19
Group Cash Flow Statement	20
Notes to the Unaudited Consolidated Financial Statements	21 to 32

PART VIII – UPDATED UNAUDITED PRO FORMA FINANCIAL INFORMATION OF THE ENLARGED GROUP

The unaudited *pro forma* statement of net assets set out below has been prepared for the purpose of illustrating the effect of the BKR Acquisition and the BK Transactions on the net asset position of the Company as at 30 June 2018 as if they had taken place on that date. The unaudited pro forma statement of net assets has been prepared for illustrative purposes only and, by its nature, addresses a hypothetical situation and, does not, therefore, represent the Company's or the Enlarged Group's actual financial position or results. The unaudited *pro forma* statement of net assets has been prepared on the basis set out in the notes below and in accordance with Schedule Two of the AIM Rules for Companies.

The unaudited *pro forma* statement of net assets does not constitute financial statements within the meaning of Section 434 of the Companies Act.

Unaudited Pro Forma Statement of Net Assets

As at 30 June 2018

		Adjustments			
	Serica net assets as at 30 June 2018 (Note 1) ***US$'000***	**Prepayment Facility drawing for Initial Consideration at BKR Completion (Note 2)** ***US$'000***	**BKR Acquisition and BK Transactions (Note 3)** ***US$'000***	**Deferred Taxation (Note 4)** ***US$'000***	**Enlarged Group *pro forma* as at 30 June 2018** ***US$'000***
Non-current assets					
Property, plant and equipment	9,534	-	346,023	-	355,557
Exploration & evaluation assets	54,407	-	-	-	54,407
Deferred tax assets	18,719	-	-	-	18,719
Total non-current assets	82,660	-	346,023	-	428,683
Current assets					
Inventory	416	-	-	-	416
Trade and other receivables	5,778	-	2,979	-	8,757
Derivative financial asset	511	-	-	-	511
Cash and cash equivalents	18,374	16,640	30,618	-	65,632
Term deposits	2,641	-	-	-	2,641
Total current assets	27,720	16,640	33,597	-	77,957
Total Assets	**110,380**	**16,640**	**379,620**	**-**	**506,640**
Current liabilities					
Trade and other payables	(9,504)	-	-	-	(9,504)
Provisions	(2,690)	-	-	-	(2,690)
Total current liabilities	(12,194)	-	-	-	(12,194)
Non-current liabilities					
Deferred income tax	-	-	-	(31,448)	(31,448)
Contingent/deferred consideration payable	-	-	(309,319)	-	(309,319)
Other financial liabilities	(3,908)	(16,640)	-	-	(20,548)
Decommissioning provisions	-	-	(30,683)	-	(30,683)
Total non-current liabilities	(3,908)	(16,640)	(340,002)	(31,448)	(391,998)
Total liabilities	(16,102)	(16,640)	(340,002)	(31,448)	(404,192)
Net assets	**94,278**	**-**	**39,618**	**(31,448)**	**102,448**

Notes:

The unaudited *pro forma* statement of net assets of the Enlarged Group as at 30 June 2018 (the **"Pro Forma"**) has been prepared on the basis that the acquisition of the BKR Assets and the BK Assets by Serica will be treated as an acquisition in accordance with IFRS 3 – Business Combinations. The calculation of the actual consideration to be reflected in the first set of consolidated financial statements prepared by Serica after the transactions have completed will be based on available information at the date of BKR Completion, Total E&P Completion, BHP Completion and Marubeni Completion. This may be materially different from the Pro Forma. The Pro Forma has been prepared for illustrative purposes only, to illustrate the effect on assets and liabilities of the Enlarged Group as at 30 June 2018 as if the BKR Acquisition and the BK Transactions had taken place on that date.

A foreign exchange rate of £1 = US$1.30 has been used in the Pro Forma.

1. The net assets of Serica as at 30 June 2018 have been extracted without material adjustment from the unaudited consolidated interim financial statements of Serica for the six months ended 30 June 2018, as incorporated by reference in Part VII (*Further Historical Financial Information on Serica*) of this Supplementary Admission Document.

   The adjustments arising as a result of the acquisition of the BKR Assets and the BK Assets are set out below.

2. As set out in paragraph 11.1(d) of Part XII (*Additional Information*) of the Admission Document, Serica UK entered into a Prepayment Facility dated 21 November 2017 with BP Gas to provide for drawings to cover the Initial Consideration of £12.8 million (US$16.6 million) and the cost of premiums payable for gas price puts which have been purchased by Serica UK in conjunction with signing the BP SPA. This adjustment reflects a drawing to cover the Initial Consideration at BKR Completion.

3. The acquisition accounting adjustments relate to the fair value measurement of the acquired assets and liabilities of the BKR Assets and BK Assets on the basis that the transactions will be treated as acquisitions in accordance with IFRS 3 – Business Combinations. The adjustments in respect of plant, property and equipment relate to the assessment of the fair value of interests in the acquired oil and gas assets. These have been based on economic models prepared in respect of those assets using information currently available which includes forecast data including oil and gas production, production sales contracts, future capital expenditure and operating expenditure. The calculation of contingent/deferred consideration is also based on the same economic models prepared in respect of those assets using information currently available which includes forecast data including oil and gas production, production sales contracts, future capital expenditure, operating and other expenditure relevant to the calculation. Discount rates have been applied to both the fair value measurement and contingent/deferred consideration calculations reflecting specific risks associated with the transactions. The adjustment also reflects the interim adjustment payable to Serica for the period from the economic effective date of the BKR Acquisition, 1 January 2018, to the assumed dates of BKR Completion, Total E&P Completion, BHP Completion and Marubeni Completion, on 30 November 2018.

   The adjustment to decommissioning provisions of US$30.7 million is in respect of the Marubeni Transaction where Serica will assume liability for all the costs of decommissioning facilities and wells relating to the Marubeni Assets.

   Transaction costs expected to be incurred by Serica after 30 June 2018 are approximately £1.0 million (US$1.3 million) and have been recognised as an operating expense and deducted from cash and cash equivalents in the Pro Forma.

4. A deferred income tax liability of US$31.4 million has been recognised, calculated by applying the prevailing combined corporate and supplementary charge tax rate of 40% in respect of the difference between the fair value of the property, plant and equipment and decommissioning provisions recognised, and the tax carrying value associated with the tax deductible elements of the estimated contingent/deferred consideration and decommissioning payments.

   The adjustment does not reflect any potential impact of the BKR Acquisition and BK Transactions on the amount of deferred tax asset that might be recognised going forward by Serica post completion of the BKR acquisition and BK transactions in respect of Serica UK's pool of carried forward UK tax allowances which stood at approximately US$146.5 million at 1 January 2018.

PART IX – SUMMARY OF NEW KEY LICENCES AND AGREEMENTS SINCE THE DATE OF THE ADMISSION DOCUMENT

1. **BKR Assets**

Licence P.209 (relating to the Bruce and Keith fields) was amended pursuant to a deed of amendment dated 9 March 2018 (effective 11 March 2018). This extends the term of Licence P.209 beyond its original expiry date of 15 March 2018, and Licence P.209 will now remain extant until it terminates in accordance with its (amended) terms being, generally, after a period of 12 consecutive months of either production below an agreed level or zero production. Further details on Licence P.209 is set out in paragraph 1.1 of Part XI (*Summary of Key Licences and Agreements*) of the Admission Document.

Licence P.198 (relating to the Rhum field) was amended pursuant to a deed of amendment dated 9 March 2018 (effective 11 March 2018). This extends the term of Licence P.198 beyond its original expiry date of 15 March 2018, and Licence P.198 will now remain extant until it terminates in accordance with its (amended) terms being, generally, after a period of 12 consecutive months of either production below an agreed level or zero production. This licence extension contained conditions that were required to be satisfied in relation to the potential impact of sanctions against Iran on the continued production of the Rhum field. These conditions have now been satisfied. Further details on Licence P.198 is set out in paragraph 1.3 of Part XI (*Summary of Key Licences and Agreements*) of the Admission Document.

2. **Serica Assets**

2.1 **30th Offshore Licensing Round**

The Company has been awarded three new exploration licence areas (four licences) on the UK Continental Shelf in the UK's 30th Offshore Licensing Round and licences have been granted in respect of each of the licence areas:

- Rowallan South – Blocks 22/24g and 22/25f – Licence P.2385. Serica UK has a 20% working interest and the operator is ENI UK Limited. These blocks lie directly to the south of the Rowallan Prospect, in which Serica UK holds a 15% interest and which is due to be drilled later this year. The blocks are offered on condition of making a 'drill or drop' decision to enter the next phase;

- Columbus West – Block 23/21b – Licence P. 2388. Serica UK has a 50% working interest and the operator is Summit Exploration and Production. The block lies immediately to the west of Serica UK's Columbus field which received FDP approval on 30 October 2018. The proposed work programme contains further seismic reprocessing and a 'drill or drop' decision to enter the next phase; and

- Skerryvore – Blocks 30/12c, 30/13c, 30/17h and 30/18c – Licence P.2400 and Ruuval – Block 30/19c – Licence P.2402. Serica UK has a 20% working interest and the operator is Parkmead (E&P) Limited. The Skerryvore prospect lies in the Central North Sea, 60 kilometres south of Serica UK's Erskine field. The proposed work programme includes purchasing 3D seismic data and a contingent well decision.

(a) *Licence P. 2385*

Licence P.2385 in the seaward area comprising Blocks 22/24g and 22/25f was executed on 20 September 2018 and had an effective date of 1 October 2018. The parties to the licence are Serica UK (20% working interest), ENI UK Limited (53.33% working interest) and Mitsui E&P UK Limited (30% working interest). The licence administrator is ENI UK Limited. The initial term of the licence is five years ending on 30 September 2023, with a second four year term ending on 30 September 2027. In order to continue the licence into the second term, the licensees must notify the OGA, not later than one month before the expiry of the final phase of the initial term, of their desire to continue the licence. The anticipated licence end date is 30 September 2045.

Under the terms of the licence, the licensees are required to:

- complete post drill studies of the Rowallan well results to constrain the extension of the Rowallan prospect into Blocks 22/24g and 22/25f; and
- drill a well on the Rowallan Prospect Extension to 4,200 metres or the Pentland/Skagerrak target, whichever is the shallower, or determine the licence before the end of the initial term.

(b) *Licence P.2388*

Licence P.2388 in the seaward area comprising Block 23/21b was executed on 20 September 2018 and had an effective date of 1 October 2018. The parties to the licence are Serica UK and Summit Exploration and Production Limited. They each hold an equal 50% working interest in the licence and the licence administrator is Summit Exploration and Production Limited. The initial term of the licence is four years ending on 30 September 2022, with a second four year term ending on 30 September 2026. In order to continue the licence into the second term, the licensees must notify the OGA, not later than one month before the expiry of the final phase of the initial term, of their desire to continue the licence. The anticipated licence end date is 30 September 2044.

Under the terms of the licence, the licensees are required to:

- reprocess 100 square kilometres of 3D seismic data;
- carry out additional rock physics and petrophysical studies on six additional wells;
- commission a hydro-dynamic study;
- complete a development study including dynamic reservoir modelling; and
- drill a well to 3,170 metres TVDSS to evaluate the Forties Member, or determine the licence before the end of the initial term.

(c) *Licence P.2400*

Licence P.2400 in the seaward area comprising Block(s) 30/12c, 30/13c, 30/17h and 30/18c was executed on 8 October 2018 and had an effective date of 1 October 2018. The parties to the licence are Serica UK (20% working interest), Calenergy Gas Limited (20% working interest), Parkmead (E&P) Limited (30% working interest) and Zennor North Sea Limited (30% working interest). The licence administrator is Parkmead (E&P) Limited. The initial term of the licence is six years ending on 30 September 2024, with a second four year term ending on 30 September 2028. In order to continue the licence into the second term, the licensees must notify the OGA, not later than one month before the expiry of the final phase of the initial term, of their desire to continue the licence. The anticipated licence end date is 30 September 2046.

Under the terms of the licence, the licensees are required to:

- purchase 507 square kilometres of broadband processed seismic data and reprocess 507 square kilometres seismic data to inversion;
- complete a rock physics study to include fluid substitution and forward modelling studies; and
- drill a contingent well on the Skerryvore Prospect to 3,500 metres TVDSS or 200 metres into the Chalk Group, whichever is the shallower.

(d) *Licence P.2402*

Licence P.2402 in the seaward area comprising Block 30/19c was executed on 8 October 2018 and had an effective date of 1 October 2018. The parties to the licence are Serica UK (20% working interest), Calenergy Gas Limited (20% working interest), Parkmead (E&P) Limited (30% working interest) and Zennor North Sea Limited (30% working interest). The licence administrator is Parkmead (E&P) Limited. The initial term of the licence is six years ending on 30 September 2024, with a second four year term ending on 30 September 2028. In order to continue the licence into the second term, the licensees must notify the OGA, not later than one month before the expiry of the final phase of the initial term, of their desire to continue the licence. The anticipated licence end date is 30 September 2046.

Under the terms of the licence, the licensees are required to:

- complete a rock physics study to include fluid substitution and forward modelling studies; and
- drill a well to 3,500 metres TVDSS or 200 metres below Top Chalk, whichever is shallower, or determine the licence before the end of the initial term.

2.2 **Luderitz Basin**

As disclosed in the Admission Document, Serica has progressed to the first renewal exploration period of the licence in relation to the Luderitz Basin in Namibia, which runs until the end of 2018. Since the date of the Admission Document, the Company applied for, and has been granted by the Ministry of Mines and Energy in Namibia, a one-year extension to the first renewal exploration period of the licence to 18 December 2019.

2.3 **Rockall Basin Licence 1/09**

As at the date of the Admission Document and as disclosed in the Admission Document, the first phase of the Group's Irish licence (FEL 1/09) relating to the Rockall Basin had expired and while confirmation had been received that the first phase of the licence will be extended for an 18-month period, the extension had not been formalised. Since the date of the Admission Document, formal consent was granted on 21 March 2018 by the Minister of State at the Department of Communications, Climate Action and Environment, by way of an addendum dated 21 March 2018 to the licence, to an extension of the first phase of Licence 1/09 to 20 January 2019, subject to completion of the programme of work over the relevant licensed area during the period from the execution of the addendum to the end of the first phase, being 20 January 2019.

PART X – FURTHER ADDITIONAL INFORMATION

1. **Responsibility**

1.1 The Company, the Directors (whose names and functions appear in paragraph 12 of Part I (*Letter from the Chairman of Serica*) of the Admission Document) and the Proposed Directors (whose names and functions appear in paragraph 9 of Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document) accept responsibility for the information contained in this document and for compliance with the AIM Rules for Companies. To the best of the knowledge of the Company, the Directors and the Proposed Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and contains no omission likely to affect its import.

1.2 Ryder Scott Company, L.P., whose address is 1100 Louisiana, Suite 4600, Houston, Texas 77010 USA, accepts responsibility for the information set out in Part III (U*pdated Competent Person's Report on the BKR Assets*) of this Supplementary Admission Document. To the best of the knowledge of Ryder Scott Company, L.P. (who has taken all reasonable care to ensure that such is the case), the information contained in Part III (*Updated Competent Person's Report on the BKR Assets*) of this Supplementary Admission Document and otherwise included in this document from the Updated BKR CPR is in accordance with the facts and contains no omission likely to affect the import of such information.

1.3 Netherland, Sewell & Associates, Inc., whose address is Fulbright Tower, 1301 McKinney Street, Suite 3200, Houston, Texas 77010 USA, accepts responsibility for the information set out in Part IV (*Updated Competent Person's Report on Serica's Assets*) of this Supplementary Admission Document. To the best of the knowledge of Netherland, Sewell & Associates, Inc. (who has taken all reasonable care to ensure that such is the case), the information contained in Part IV (*Updated Competent Person's Report on Serica's Assets*) of this Supplementary Admission Document and otherwise included in this document from the Updated Serica CPR is in accordance with the facts and contains no omission likely to affect the import of such information.

2. **The Company and its subsidiaries**

Since the date of the Admission Document, the following indirect subsidiary undertakings of the Company, which were dormant entities, have been liquidated with effect from 23 October 2018:

- Serica Walvis Namibia BV; and
- Serica Foum Draa BV.

3. **Share capital**

3.1 As at 23 November 2018 (being the latest practicable date prior to the date of this document), the issued share capital of the Company comprises one A Share of £50,000 (paid up to one quarter of the nominal value) and 264,757,819 Ordinary Shares of US$0.10 each (all of which are fully paid). As at 23 November 2018 (being the latest practicable date prior to the date of this document), the Company holds no treasury shares.

3.2 Pursuant to an ordinary resolution of the Company passed at the 2018 Annual General Meeting, the Directors are generally and unconditionally authorised for the purposes of section 551 of the Companies Act to exercise all of the powers of the Company to allot shares and grant rights to subscribe for, or convert any security into, shares in the Company (a) up to an aggregate nominal amount of US$8,799,427; and (b) up to a further aggregate nominal amount of US$8,799,427 in connection with a rights issue to (i) holders of ordinary shares in proportion (as nearly as practicable) to the respective number of Ordinary Shares held by them on the relevant record date; and (ii) holders of other classes of equity securities as required or permitted by the rights of those securities, but subject to such exclusions or other arrangements as the Directors may consider necessary or appropriate to deal with fractional entitlements, treasury shares, record dates or legal, regulatory or practical difficulties which may arise under the laws of, or the requirements of any regulatory body or stock exchange in any territory or any other matter whatsoever. Such authorities expire on 30 June 2019, or if earlier, the date of the next annual general meeting of the Company, save that the Company may before such expiry make any offer or agreement which would or might require shares to be allotted or rights to be granted, after such expiry and the Directors may allot shares, or grant rights to subscribe for or to convert any security into shares, in pursuance of any such offer or agreement as if the authorities conferred by such resolution had not expired.

3.3 Pursuant to a special resolution of the Company passed at the 2018 Annual General Meeting, the Directors are empowered pursuant to sections 570(1) and 573 of the Companies Act to (i) allot equity securities of the Company (as defined in section 560 of the Companies Act) for cash pursuant to the authority conferred by the resolution detailed at paragraph 3.2 above; and (ii) sell ordinary shares (as defined in section 560(1) of the Companies Act) held by the Company as treasury shares for cash, as if section 561 of the Companies Act did not apply to such allotment or sale. Such power is limited to the allotment of equity securities and sale of treasury shares for cash:

(a) in connection with or pursuant to an offer of or invitation to acquire equity securities (but in the case of the authority granted under the resolution described at paragraph 3.2 above, by way of a rights issue only) in favour of holders of ordinary shares in proportion (as nearly as practicable) to the respective number of ordinary shares held by them on the record date for such allotment (and holders of any other class of equity securities entitled to participate therein or if the directors consider it necessary, as permitted by the rights of those securities) but subject to such exclusions or other arrangements as the Directors may consider necessary or expedient to deal with fractional entitlements, record dates or legal or practical difficulties which may arise; and

(b) in the case of an allotment otherwise than pursuant to paragraph 3.2 above, up to an aggregate nominal amount of US$2,639,828.

Such powers expire on the expiry of the general authority conferred by the resolution in respect of paragraph 3.2 above, save that the Company may before such expiry make any offer or agreement that would or might require equity securities to be allotted, or treasury shares to be sold, after such expiry, and the Directors may allot equity securities or sell treasury shares in pursuance of any such offer or agreement as if the power conferred by such resolution had not expired.

4. **Outstanding options and awards under share schemes**

4.1 **Directors**

As disclosed in paragraph 4 of Part XII (*Additional Information*) of the Admission Document, it was proposed to grant to the Company's executive Directors certain awards under the newly adopted Serica Energy plc 2017 Long Term Incentive Plan.

On 25 May 2018, the Company announced that it has formally granted the following Performance Share Awards and the Deferred Bonus Awards to the Company's executive Directors:

Director	**Total number of shares subject to Deferred Bonus Share Awards**	**Exercise Price**
Antony Craven Walker	225,000	Nil
Mitchell Flegg	225,000	Nil

Director	**Total number of shares subject to Performance Share Awards**	**Exercise Price**
Antony Craven Walker	1,500,000	Nil
Mitchell Flegg	1,500,000	Nil

These Performance Share Awards and Deferred Bonus Awards, also known as Admission Awards, are made in relation to the financial year of the Company ended 31 December 2017 and are awarded under the Serica Energy plc 2017 Long Term Incentive Plan.

As disclosed in the Admission Document, vesting of the Deferred Share Bonus Awards is conditional on BKR Completion and have a long stop date of 31 January 2019, subject to the Board's discretion. The Performance Share Awards are subject to performance conditions based on average share price targets to be measured by reference to dealing days in the period of 90 days ending immediately prior to the expiry of a three-year performance period starting on 30 November 2017.

The Admission Awards will not count towards the individual limits applying to any further awards that may be granted to the Directors in relation to the current financial year ending 31 December 2018.

4.2 **Total outstanding options and awards**

Details of the total number of options and awards under the Company's share schemes as at 23 November 2018 (being the latest practicable date prior to the date of this document) are set out in the following tables:

(a) *Serica Energy plc Long Term Incentive Plan*

Director/Employees	**Number of shares deemed granted subject to Deferred Bonus Share Awards**
Antony Craven Walker	225,000
Mitch Flegg	225,000
Employees below Board level (in aggregate)	575,000
Total	**1,025,000**

Director/Employees	**Number of shares deemed granted subject to Performance Share Awards**
Antony Craven Walker	1,500,000
Mitch Flegg	1,500,000
Employees below Board level (in aggregate)	2,250,000
Total	**5,250,000**

(b) *Serica Energy plc Share Option Plan 2005*

Director/Employees	**Number of shares under option**
Antony Craven Walker	2,500,000
Employees below Board level (in aggregate)	3,965,550
Total	**6,465,550**

(c) *Serica Share Incentive Plan*

There are a total of 1,156,658 Ordinary Shares outstanding under the Serica Share Incentive Plan. These comprise of 210,668 Partnership Shares, 421,336 Matching Shares and 524,654 Free Shares (as defined under paragraph 8.6 of Part XII (*Additional Information*) of the Admission Document).

5. **Directors', Proposed Directors' and other interests**

5.1 **Directors and Proposed Directors**

None of the Directors or Proposed Directors or any person connected with them (within the meaning of section 252 of the Act) is interested in any related financial product referenced to the Ordinary Shares (being a financial product whose value is, in whole or in part, determined directly or indirectly by reference to the price of the Ordinary Shares including a contract for difference or a fixed odds bet).

Further information relating to the Proposed Directors is set out in paragraph 9 of Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document.

5.2 **Major Shareholders**

Save as disclosed in this paragraph 5.2, as at 23 November 2018 (being the latest practicable date prior to the date of this document), none of the Directors or the Proposed Directors are aware of any interest which represents 3% or more of the issued share capital of the Company or of any persons who, directly or indirectly, jointly or severally, exercise or could exercise control over the Company:

	As at 23 November 2018	
Shareholder	**Number of Ordinary Shares**	**Percentage of existing issued ordinary share capital**
GRG UK Oil LLC	46,090,576	17.41%
Mr D.R and Mrs D.A Hardy	29,583,000	11.17%
Canaccord Genuity (formerly Hargreave Hale)	20,109,633	7.60%
AXA Investment Managers	17,541,337	6.63%
BP Exploration Operating Company	13,500,000	5.10%
Hargreaves Lansdown Asset Management(1)	10,435,184	3.94%
Interactive Investor Trading(1)	8,576,755	3.24%
Serica Energy plc director and related holdings(2)	8,315,074	3.14%

Notes:

(1) Private client holdings.

(2) A breakdown of the Directors' interests in the issued share capital of the Company is set out in paragraph 6.1 of Part XII (*Additional Information*) of the Admission Document.

None of the major shareholders of the Company set out above has different voting rights from any other holder of Ordinary Shares in respect of any Ordinary Share held by them. The Directors and the Proposed Directors are not aware of any arrangements, the operation of which may at a subsequent date result in a change of control of the Company.

5.3 **Other Interests**

Excluding professional advisers otherwise named in this document and trade suppliers and save as disclosed in this paragraph 5.3 of this Part X (*Further Additional Information*) and in paragraph 6.10 of Part XII (*Additional Information*) of the Admission Document, no person has at any time within the 12 months preceding the date of this document received, directly or indirectly, from the Company or entered into any contractual arrangement to receive, directly or indirectly, from the Company on or after Admission any fees totalling £10,000 or more or securities in the Company with a value of £10,000 or more or any other benefit with a value of £10,000 or more.

A summary of payments made since the date of the Admission Document aggregating over £10,000 which have been made to any government or regulatory authority or similar body by the Enlarged Group or on behalf of it, with regard to the acquisition of, or maintenance of, its assets as at the date of this document, is set out in the table below:

(a) *Serica*

Government Authority	Description	Amount (US$)
Namibia Licence		
Ministry of Mines and Energy (Namibia)	Licence Fee	119,379(1)
Petrofund	Petrofund Training and Education Fund	25,000
Columbus		
Oil and Gas Authority Trust	Licence Fees (Licence P.1314)	109,549(2)(3)
Slyne		
Department of Communications, Climate Action and Environment (Ireland)	Licence fee (Licence FEL 1/06)	43,584(4)
Department of Communications, Climate Action and Environment (Ireland)	Expanded Offshore Support Group (EOSG) (Ireland) (Licence FEL 1/06)	20,617(4)
Petroleum Infrastructure Programme (PIPCO RSG Limited)	Irish Shelf Petroleum Study Group (ISPSG) (Ireland) (Licence FEL 1/06)	103,086(4)
Rockall		
Department of Communications, Climate Action and Environment (Ireland)	Licence Fee (Licence FEL4/13)	31,655(4)
Department of Communications, Climate Action and Environment (Ireland)	Petroleum Exploration and Production Promotion and Support (Licence 4/13)	20,617(4)
Petroleum Infrastructure Programme (PIPCO RSG Limited)	Irish Shelf Petroleum Study Group (ISPSG) (Ireland) (Licence FEL 4/13)	103,086(4)
Department of Communications, Climate Action and Environment (Ireland)	Licence Fee (Licence FEL 1/09)	13,347(4)
Petroleum Infrastructure Programme (PIPCO RSG Limited)	Irish Shelf Petroleum Study Group (ISPSG) (Ireland) (Licence FEL 1/09)	103,086(4)

Notes:

(1) Paid in Namibia Dollars, converted at an exchange rate of US$1 = NS$13.11

(2) Net to Serica (50%)

(3) Paid in pounds sterling, converted at an exchange rate of £1 = US$1.31

(4) Paid in Euro, converted at an exchange rate of EUR1 = US$1.18.

(b) *Bruce Field*

Government Authority	Description	Amount (£)
Department for Business, Energy and Industrial Strategy (UK)	Yearly licence fee (Licence 276)	166,800
OGA	OGA levy yearly charge (Licence 276)	74,991
Health & Safety Executive	Bruce Offshore Inspection & Prep	78,643
Health & Safety Executive	Bruce Offshore Inspection & Prep	12,170
Health & Safety Executive	Bruce Offshore Diving Inspection	31,920
Health & Safety Executive	Bruce Onshore Inspection	44,981

(c) *Keith Field*

Government Authority	Description	Amount (£)
Department for Business, Energy and Industrial Strategy (UK)	Yearly licence fee (Licence 209)	22,500
OGA	OGA levy yearly charge (Licence 209)	74,991

(d) *Rhum Field*

Government Authority	Description	Amount (£)
Department for Business, Energy and Industrial Strategy (UK)	Yearly licence fee (Licence 198)	24,080
OGA	OGA levy yearly charge (Licence 198)	74,991

(e) *Rhum Field (Non-Unit)*

Government Authority	Description	Amount (£)
Department for Business, Energy and Industrial Strategy (UK)	Yearly licence fee (Licence 975)	121,260
OGA	OGA levy yearly charge (Licence 975)	74,991
Department for Business, Energy and Industrial Strategy (UK)	Yearly licence fee (Licence 566)	124,200
OGA	OGA levy yearly charge (Licence 566)	74,991

6. Proposed Directors' letters of appointment

Each of the Proposed Directors will be appointed to the Board as a non-executive director of the Company with effect from BKR Completion. It is expected that the Proposed Directors will enter into letters of appointment on terms similar to those of the existing non-executive directors, further details of which are summarised in paragraph 7.1 of Part XII (*Additional Information*) of the Admission Document.

7. Employee Incentive Plans

7.1 Serica Energy 2018 Sharesave Plan

The Board approved and adopted the Sharesave Plan on 6 September 2018. Further details of the Sharesave Plan, including a summary of the key terms of the plan, are set out in paragraph 8.7 of Part XII (*Additional Information*) of the Admission Document.

7.2 Serica Energy plc Employee Benefit Trust

On 6 September 2018, the Company approved the establishment of the EBT, which is a discretionary employee benefit trust. The EBT will primarily be used in conjunction with the Serica Energy plc Long Term Incentive Plan; although it may also be used to satisfy options under the Serica Energy plc 2017 Company Share Option Plan, Serica Energy plc Share Option Plan 2005 and the Sharesave Plan. The trustee of the EBT has the power to subscribe for new shares (at a price determined by the Board, provided it is not less than the nominal value of a share) or acquire shares in the market or from treasury.

The class of beneficiaries of the EBT includes the employees and former employees of the Company and its subsidiaries, any holding company of the Company or any subsidiaries of that holding company, and certain classes of their dependants.

The trustee of the EBT has wide powers of investment and is permitted to borrow money. However, it is intended that, in practice, the EBT will be funded by loans and/or gifts from the Company or any of its subsidiaries and will only invest in shares for use with the Company's employees' share plans or otherwise for allocation to beneficiaries.

The trustee of the EBT is independent of the Company and is based offshore. The Company has the power to appoint new or additional trustees and remove any trustee. A professional trustee may charge fees in the normal course of business for acting as a trustee of the Trust.

8. United Kingdom Taxation

The following is a general guide to certain limited aspects of the UK tax treatment of holding and disposing of the Ordinary Shares and does not purport to be a complete analysis of all the potential UK tax considerations thereof. The comments set out below do not constitute tax advice and are based on current United Kingdom tax law as applied in England and Wales and HM Revenue & Customs' published practice (which may not be binding on HM Revenue & Customs) as at the date of this document, both of which are subject to change, possibly with retrospective effect.

The information provided below applies only to shareholders (a) who are resident (and, in the case of individuals, domiciled) for UK tax purposes in the UK; (b) who hold their shares as investments (other than in an individual savings account); and (c) who are the absolute beneficial owners thereof.

The discussion does not address all possible tax consequences relating to an investment in any relevant shares. Certain categories of investors, including those carrying on certain financial activities, (including market makers, brokers, dealers, intermediaries and persons connected with depository arrangements or clearance services), those subject to specific tax regimes or benefiting from certain reliefs and exemptions and those for whom the shares are employment-related securities may be subject to special rules and this summary does not apply to such investors. Such investors should consult their professional advisors without delay.

Shareholders or prospective shareholders who are resident or otherwise subject to taxation in a jurisdiction outside the United Kingdom, or who are in any doubt about their tax position, are also advised to consult their own professional advisers immediately.

8.1 Dividends on the Ordinary Shares

(a) *UK tax resident individual shareholders*

All dividends received by a shareholder who is an individual in respect of the Ordinary Shares will form part of that shareholder's total income for income tax purposes and will constitute the top slice of that income. A nil rate of income tax will apply to the first £2,000 of taxable dividend income received by that shareholder in a tax year.

Where the dividend income is above the dividend allowance, an individual shareholder will not be subject to tax on dividend income above the allowance to the extent that, treating that income as the top slice of the shareholder's income, that income would be within that individual's personal allowance. Any amount in excess of the nil rate and the personal allowance (if applicable) will be taxed at the relevant rate. The rates are 7.5% to the extent that the excess amount falls within the basic rate tax band, 32.5% to the extent that the excess amount falls within the higher rate tax band and 38.1% to the extent that the excess amount falls within the additional rate tax band.

(b) *UK tax resident corporate shareholders*

Dividends paid to shareholders who are subject to UK corporation tax are likely to fall within one or more of the classes of dividend qualifying for exemption from corporation tax, although the exemptions are not comprehensive and are also subject to anti-avoidance rules. Such shareholders should consult their own professional advisers.

8.2 **Disposals of Ordinary Shares**

A disposal or deemed disposal of Ordinary Shares by a shareholder who is resident in the UK for tax purposes may give rise to a liability to UK tax on capital gains (in the case of shareholders who are individuals) or UK corporation tax on chargeable gains (in the case of shareholders within the charge to UK corporation tax) depending upon the shareholder's circumstances and subject to any available exemption or relief.

(a) *UK tax resident individual shareholder*

For an individual shareholder within the charge to UK capital gains tax, a disposal (or deemed disposal) of the Ordinary Shares may give rise to a chargeable gain or an allowable loss for the purposes of capital gains tax. The rate of capital gains tax on the disposal of shares is 10% (for the tax year 2018/2019) for basic rate taxpayers and 20% (for the tax year 2018/2019) for higher or additional rate taxpayers. An individual shareholder is entitled to realise an annual exempt amount of gains (£11,700 for the 2018/19 tax year) without being liable to tax.

(b) *UK tax resident corporate shareholders*

For a corporate shareholder within the charge to UK corporation tax, a disposal (or deemed disposal) of the Ordinary Shares may give rise to a chargeable gain or allowable loss for the purposes of UK corporation tax, depending on the circumstances and subject to any available exemption or relief. Indexation allowance may reduce the amount of any chargeable gain for these purposes, but will not create or increase any allowable loss. The rate of UK corporation tax is 19% for the financial years commencing 1 April 2018 and 1 April 2019. Legislation has been enacted which reduces the rate of UK corporation tax to 17% for the financial year commencing 1 April 2020.

8.3 **Stamp Duty and Stamp Duty Reserve Tax**

The statements below are intended as a general guide to the current position. They do not apply to certain intermediaries who are not liable to stamp duty or stamp duty reserve tax or (except where stated otherwise) to persons connected with depositary arrangements or clearance services who may be liable at a higher rate.

No stamp duty or stamp duty reserve tax should generally be payable on the issue of Ordinary Shares. Nor should any UK stamp duty or stamp duty reserve tax arise on transfers of Ordinary Shares on AIM (including instruments transferring Shares and agreements to transfer Ordinary Shares) for so long as:

(a) the Ordinary Shares are admitted to trading on AIM, but are not listed on any market (with the term "listed" being construed in accordance with section 99A of the Finance Act 1986), and this has been certified to Euroclear; and

(b) AIM continues to be accepted as a "recognised growth market" as construed in accordance with section 99A of the Finance Act 1986.

In the event that either of the above assumptions does not apply, stamp duty or stamp duty reserve tax may apply to transfers of Ordinary Shares in certain circumstances.

9. **Material contracts**

The following further contracts since the date of the Admission Document have been entered into by members of the Group (a) in the two years immediately preceding the date of this document and are, or may be material, or (b) were entered into outside the two years immediately preceding the publication of this document and contain provisions under which a member of the Group has an obligation or entitlement which is material to the Group as at the date of this document.

9.1 **Serica**

(a) *Total E&P Transaction*

(i) Total E&P SPA

Pursuant to the Total E&P SPA, Serica UK will acquire a 42.25% interest in the Bruce field (Total E&P is retaining 1%) and Total E&P's entire 25% interest in the Keith field. In addition to the BK Assets, Total E&P is also transferring to Serica UK its interests in certain blocks in neighbouring non-producing areas adjacent to the Bruce and Keith fields, but which do not themselves form part of the fields. Operatorship of Licence P.090 will also transfer to Serica UK.

The effective date of the Total E&P Transaction is 1 January 2018, so Serica UK will be entitled to a share of the net cash flows from the BK Assets between the effective date of the Total E&P Transaction to the date of Total E&P Completion. Subject to the conditions to the Total E&P SPA being satisfied, completion of the assignments for all the licence interests in the BK Assets will occur at the same time. Subject to satisfaction of the conditions to the Total E&P SPA, Total E&P Completion will take place immediately following BKR Completion.

The consideration payable by Serica UK to Total E&P is as follows:

- an initial cash consideration of US$5 million payable on Total E&P Completion. This amount will be adjusted for net post-tax cash flows from the BK Assets between the effective date (1 January 2018) and the date of Total E&P Completion. The Directors anticipate that the net cash flow to which Serica UK is entitled between the effective date and the date of Total E&P Completion will be more than the amount of the Total E&P Initial Consideration resulting in a net payment to Serica UK from Total E&P on Total E&P Completion.

- subject to continued production from the Rhum field, up to a further US$15 million in aggregate is payable in three equal instalments approximately 8, 16 and 24 months following Total E&P Completion and, should Rhum production be interrupted due to the application of US sanctions limiting Rhum operations, the relevant instalments will be deferred.

- Total E&P will also receive a share of net pre-tax cash flows from the Total E&P Assets of 60% in 2018 following Total E&P Completion, 50% in 2019 and 40% in each of 2020 and 2021. The net cash flow shares are calculated on a monthly basis. No amounts are payable by Serica UK unless this cash flow is positive and amounts are repayable to Serica UK in the event of negative cash flow, up to the amount Serica UK has already paid to Total E&P in the same year. Net negative cash flow during the year can be carried forward to be offset against positive cash flow in subsequent years. The arrangements in relation to Serica UK and Total E&P sharing net cash flows from the BK Assets are set out in the Total E&P Net Cash Flow Sharing Deed.

- Serica UK will pay additional consideration equal to 30% of Total E&P's retained share of decommissioning costs when due, reduced by the tax relief that Total E&P

receives on those costs. This element of consideration is capped by the amount of net cash flow received by Serica UK as a result of the Total E&P Transaction.

- Serica UK will also pay deferred consideration equal to 90% of its share (net to the Total E&P Assets) of the realised value of oil in the Bruce pipeline at the end of field life.

Total E&P Completion is conditional upon *inter alia* the following conditions:

- Serica UK confirming that the BP SPA is capable of completion;

- the OGA's consent to the assignment of the BK Assets to Serica UK and the transfer of operatorship of Licence P.090 to Serica UK;

- the approval of Total E&P's partners in the Total E&P Assets to the assignment of the Total E&P Assets and the transfer of operatorship of Licence P.090 to Serica UK (the requirement for such approval is customary for transactions of this nature);

- clearance being sought by Serica UK and received from HMRC that the tax treatment of the sharing of the net cash flows from the Total E&P Assets pursuant to the Total E&P Net Cash Flow Sharing Deed will be applied as intended; and

- the amendment of certain decommissioning security agreements and operating agreements in relation to the BK Assets to give effect to the retention by Total E&P of its liability for decommissioning and voting rights on decommissioning matters pursuant to the Total E&P Transaction.

Subject to satisfaction of the conditions, completion of the Total E&P SPA will take place immediately following completion of the BP SPA, which is expected to occur on 30 November 2018.

In addition to the conditions under the Total E&P SPA, Serica UK has the right to terminate the Total E&P SPA prior to Total E&P Completion in the event of catastrophic damage to the whole or a material element of facilities relating to the Bruce field and/or the Keith field.

Total E&P will retain liability for all the costs of decommissioning facilities and wells existing at Total E&P Completion relating to the BK Assets. Serica UK will pay for the costs of decommissioning new facilities.

Further, the parties have agreed that Total E&P shall control the voting rights of Serica UK in relation to decommissioning matters that concern existing facilities.

Each of Total E&P and Serica UK has given warranties and indemnities each to the other under the Total E&P SPA which are customary for a transaction of this nature.

The Total E&P SPA places obligations on Total E&P to consult with Serica UK on all material matters arising in relation to the BK Assets during the period between the date of the Total E&P SPA and Total E&P Completion. Serica UK's approval is required for Total E&P to vote in favour of new budgets and work programmes and for unbudgeted expenditures above a certain level during this interim period. Under the Total E&P SPA, Serica UK requires the approval of Total E&P to sell interests in the BK Assets.

(ii) Product Sales Agreements

Serica UK's share of natural gas production from the Bruce, Keith and Rhum fields will be delivered at St Fergus via the Frigg UK pipeline and sold under a life of field gas sales agreement between BP Gas and BP which will be novated to Serica UK on BKR Completion. Serica UK's additional share of natural gas from the Bruce and Keith fields acquired as a result of, and after, Total E&P Completion will also be delivered and sold in the same way. The combined gas volumes will be sold at daily spot prices determined as the Heren Day Ahead Mid-Point Price for natural gas at the National Balancing Point (**"NBP"**). This is subject to normal deductions comprising marketing fees, transportation charges to the NBP, entry capacity charges and imbalance charges. There may also be price adjustments related to potential over and under deliveries.

Serica UK's share of oil production from the Bruce, Keith and Rhum fields, which is exported via Forties Pipeline System, will be sold to BP Oil under an oil sales agreement between BP Oil and BP which will be novated to Serica UK on BKR Completion. Serica UK's additional share of oil production from the Bruce and Keith fields acquired as a result of, and after, Total E&P Completion will also be delivered and sold in the same way. The combined oil volumes will be sold at daily spot prices for Forties Blend Crude Oil published in the Platts Crude Oil Market Wire subject to adjustment for sulphur content and deductions for demurrage costs.

Serica UK's uncontracted share of NGL production from the Bruce field will be sold to BP Oil under NGL sales agreements between BP and BP Oil which will be novated to Serica UK on BKR Completion. Serica UK's additional share of NGL production from the Bruce field acquired as a result of, and after, Total E&P Completion will also be delivered and sold in the same way. The combined NGL volumes will be sold at the following prices:

- for Butane, at the fixed price for metric tonne(s) FOB Grangemouth as shall be posted under the heading ANSI (Argus North Sea Index) as published in Argus International LPG Report and effective for the month of bill of lading minus a typical market discount;
- for Naphtha, at the fixed price per metric tonne(s) in tank in situ Grangemouth as shall be the arithmetic average of the mean quotes for Naphtha under the heading CARGOES CIF NORTH WEST EUROPE as published in Platts European Marketscan minus a typical market discount; and
- for Propane, at the fixed price per metric tonne(s) FOB Grangemouth as shall be the posted quote for Propane under the heading ANSI (Argus North Sea Index) as published in Argus International LPG Report and effective for the month of bill of lading minus a typical market discount.

Small quantities of other hydrocarbon products arise from processing at the delivery terminals for the Frigg UK and Forties Pipeline System. Certain of the existing agreements for the sales of these products (being the Total E&P net volumes) are expected to be transferred from Total E&P to Serica UK on Total E&P Completion.

(iii) Total E&P Net Cash Flow Sharing Deed

The Total E&P Net Cash Flow Sharing Deed which will be entered into on Total E&P Completion between Total E&P and Serica UK (and which is an agreed form document pursuant to the Total E&P SPA), sets out the methodology for calculating Total E&P's share of future net cash flows from the BK Assets according to the percentages described in the description of the Total E&P SPA at paragraph 9.1(a)(i) of this Part X (*Further Additional Information*) of this Supplementary Admission Document.

Net cash flow is defined as all field revenues less operating and transportation costs less capital expenditure on Bruce field facilities the parties agree is necessary to achieve a specified level of Bruce production.

Serica UK has sought and received confirmation from HMRC that the cash flow payments payable to Total E&P under the Total E&P Net Cash Flow Sharing Deed will qualify for ring fence tax deductions for Serica. As stated above, such confirmation from HMRC is a condition to Total E&P Completion.

(iv) Parent Company Guarantee

Serica has provided a guarantee to Total E&P in respect of Serica UK's obligations under the Total E&P SPA.

(v) Transfer of Operatorship Agreement

A transfer of operatorship agreement will be entered into in respect of Licence P.090 at Total E&P Completion. This agreement is short-form and on industry standard terms.

(b) *BHP Transaction*

(i) BHP SPA

Pursuant to the BHP SPA, Serica UK will acquire BHP's entire 16% interest in the Bruce field and 31.83% interest in the Keith field. In addition to the Bruce and Keith field interests, BHP is also transferring to Serica UK its interests in certain blocks in neighbouring non-producing areas adjacent to the Bruce and Keith fields, but which do not themselves form part of the fields.

The effective date of the BHP Transaction is 1 January 2018, so Serica UK will be entitled to a share of the net cash flows from the BHP Assets between the effective date of the BHP Transaction to the date of BHP Completion. Subject to the conditions to the BHP SPA being satisfied, completion of the assignments for all the licence interests in the BHP Assets will occur at the same time. Subject to satisfaction of the conditions to the BHP SPA, BHP Completion will take place immediately following BKR Completion and Total E&P Completion.

The consideration payable by Serica UK to BHP is as follows:

- an initial consideration of £1 million in cash payable on BHP Completion. This amount will be adjusted for working capital and 40% of post-tax cash flows from the effective date of 1 January 2018. The Directors anticipate that the net cash flow to which Serica UK is entitled between the effective date and the date of BHP Completion will be more than the amount of the BHP Initial Consideration resulting in a net payment to Serica UK from BHP on BHP Completion.

- BHP will also receive a share of net pre-tax cash flows from the BHP Assets of 60% in 2018 following BHP Completion, 50% in 2019 and 40% in each of 2020 and 2021. The net cash flow shares are calculated on a monthly basis. No amounts are payable by Serica UK unless this cash flow is positive and amounts are repayable to Serica UK in the event of negative cash flow, up to the amount Serica UK has already paid to BHP in the same year. Net negative cash flow during the year can be carried forward to be offset against positive cash flow in subsequent years. The arrangements in relation to Serica UK and BHP sharing net cash flows from the BHP Assets are set out in the BHP Net Cash Flow Sharing Deed.

- Serica UK will pay additional consideration equal to 30% of BHP's retained share of decommissioning costs when due, reduced by the tax relief that BHP receives on those costs. This element of consideration is capped by the amount of net cash flow received by Serica UK as a result of the BHP Transaction.

- Serica UK will also pay deferred consideration equal to 90% of its share (net to the BHP Assets) of the realised value of oil in the Bruce pipeline at the end of field life.

BHP's right to receivables pursuant to the BHP SPA (including the BHP Net Cash Flow Sharing Deed) has been assigned to BHP BK Limited.

BHP Completion is conditional upon *inter alia* the following conditions:

- Serica UK confirming that the BP SPA is capable of completion;

- the OGA's consent to the assignment of the BHP Assets to Serica UK;

- the approval of BHP's partners in the BHP Assets to the assignment of the BHP Assets to Serica UK (the requirement for such approval is customary for transactions of this nature);

- clearance being sought by Serica UK and received from HMRC that the tax treatment of the sharing of the net cash flows from the BHP Assets pursuant to the BHP Net Cash Flow Sharing Deed will be applied as intended; and
- the amendment of certain decommissioning security agreements and operating agreements in relation to the BHP Assets to give effect to the retention by BHP of its liability for decommissioning and voting rights on decommissioning matters pursuant to the BHP Transaction.

Subject to satisfaction of the conditions, completion of the BHP SPA will take place immediately following completion of the BP SPA and the Total E&P SPA, which is expected to occur on 30 November 2018.

In addition to the conditions under the BHP SPA, Serica UK has the right to terminate the BHP SPA prior to BHP Completion in the event of catastrophic damage to the whole or a material element of facilities relating to the Bruce field and/or the Keith field.

BHP will retain liability for all the costs of decommissioning facilities and wells existing at BHP Completion relating to the BHP Assets. Serica UK will pay for the costs of decommissioning new facilities.

Further, the parties have agreed that BHP shall control the voting rights of Serica UK in relation to decommissioning matters that concern existing facilities.

Each of BHP and Serica UK has given warranties and indemnities each to the other under the BHP SPA which are customary for a transaction of this nature. The BHP SPA places obligations on BHP to consult with Serica UK on all material matters arising in relation to the BHP Assets during the period between the date of the BHP SPA and BHP Completion. Serica UK's approval is required for BHP to vote in favour of new budgets and work programmes and for unbudgeted expenditures above a certain level during this interim period. Under the BHP SPA, Serica UK requires the approval of BHP to sell interests in the BHP Assets.

(ii) Product Sales Agreements

Pursuant to the Product Sales Agreements, Serica UK will sell its incremental share of natural gas and, where applicable, oil and NGLs from the BHP Assets to BP entities. The amount sold will be in addition to those volumes acquired as a result of completion of the BKR Acquisition and the Total E&P Transaction. The Product Sales Agreements provide for sales prices based on standard spot pricing, subject to deductions for marketing fees and normal system charges.

(iii) BHP Net Cash Flow Sharing Deed

The BHP Net Cash Flow Sharing Deed which will be entered into on BHP Completion (and which is an agreed form document pursuant to the BHP SPA), sets out the methodology for calculating BHP's share of future net cash flows from the BHP Assets according to the percentages described in the description of the BHP SPA at paragraph 9.1(b)(i) of this Part X (*Further Additional Information*) of this Supplementary Admission Document.

Net cash flow is defined as all field revenues less operating and transportation costs less capital expenditure on Bruce field facilities the parties agree is necessary to achieve a specified level of Bruce production.

Serica UK has sought and received confirmation from HMRC that the cash flow payments payable to BHP under the BHP Net Cash Flow Sharing Deed will qualify for ring fence tax deductions for Serica. As stated above, such confirmation from HMRC is a condition to BHP Completion.

(iv) Parent Company Guarantee

Serica has provided a guarantee to BHP BK Limited (as a result of the assignment by BHP of its right to receivables arising pursuant to the BHP SPA) in respect of Serica UK's obligations under the BHP SPA.

(c) *Marubeni Transaction*

(i) Marubeni SPA

Pursuant to the Marubeni SPA, Serica UK will acquire Marubeni's entire 3.75% interest in the Bruce field and 8.33% interest in the Keith field. In addition to the Bruce and Keith field interests, Marubeni is also transferring to Serica UK its interests in certain blocks in neighbouring non-producing areas adjacent to the Bruce and Keith fields, but which do not themselves form part of the fields.

The effective date of the Marubeni Transaction is 1 January 2018, so Serica UK will be entitled to the net cash flows from the Marubeni Assets between the effective date of the Marubeni Transaction to the date of Marubeni Completion. Subject to the conditions to the Marubeni SPA being satisfied, completion of the assignments for all the licence interests in the Marubeni Assets will occur at the same time. Subject to satisfaction of the conditions to the Marubeni SPA, Marubeni Completion will take place immediately following BKR Completion, Total E&P Completion and BHP Completion.

The reverse consideration payable by Marubeni to Serica UK is a US$1 million cash payment, payable at Marubeni Completion adjusted for working capital and post-tax net cash flows from the effective date.

Marubeni Completion is conditional upon inter alia the following conditions:

- Serica UK confirming that the BP SPA is capable of completion;
- the OGA's consent to the assignment of the Marubeni Assets to Serica UK; and
- the approval of Marubeni's partners in the Marubeni Assets to the assignment of the Marubeni Assets to Serica UK (the requirement for such approval is customary for transactions of this nature).

Subject to satisfaction of the conditions, completion of the Marubeni SPA will take place immediately following completion of the BP SPA, the Total E&P SPA and the BHP SPA, which is expected to occur on 30 November 2018.

In addition to the conditions under the Marubeni SPA, Serica UK has the right to terminate the Marubeni SPA prior to Marubeni Completion in the event of catastrophic damage to the whole or a material element of facilities relating to the Bruce field and/or the Keith field.

Unlike with the BKR Acquisition, the Total E&P Transaction and the BHP Transaction, Serica UK will at Marubeni Completion assume liability for all the costs of decommissioning facilities and wells relating to the Marubeni Assets.

Each of Marubeni and Serica UK has given warranties and indemnities each to the other under the Marubeni SPA which are customary for a transaction of this nature.

The Marubeni SPA places obligations on Marubeni to consult with Serica UK on all material matters arising in relation to the Marubeni Assets during the period between the date of the Marubeni SPA and Marubeni Completion. Serica UK's approval is required for Marubeni to vote in favour of new budgets and work programmes and for unbudgeted expenditures above a certain level during this interim period.

(ii) Product Sales Agreements

Pursuant to the Product Sales Agreements, Serica UK will sell its incremental share of natural gas, oil and, where applicable, NGLs from the Marubeni Assets to BP entities. The amount sold will be in addition to those volumes acquired as a result of completion of the BKR Acquisition, the Total E&P Transaction and the BHP Transaction. The Product Sales Agreements provide for sales prices based on standard spot pricing, subject to deductions for marketing fees and normal system charges.

(iii) Decommissioning Security

It is expected that BP and Serica will, prior to Marubeni Completion, enter into an agreement whereby BP would provide security required under the decommissioning security agreements in respect of the Bruce and Keith fields for a period up to 31 December 2019 for the share of security due to be provided by Serica in respect of the share of Bruce and Keith interests to be acquired from Marubeni.

(d) *Introduction Agreement*

On 26 November 2018, the Company, the Executive Directors and Peel Hunt entered into an amendment agreement to the Introduction Agreement dated 30 November 2017, pursuant to which further warranties in relation to the BK Assets and certain other matters were given by the Company and the Executive Directors in favour of Peel Hunt.

Further information on the Introduction Agreement dated 30 November 2017 is set out in paragraph 11.1(a) of Part XII (*Additional Information*) of the Admission Document.

9.2 **BKR Assets**

Matters arising in respect of key licences relating to the BKR Assets are summarised in Part IX (*Summary of New Key Licences and Agreements Since the Date of the Admission Document*) of this Supplementary Admission Document.

10. **Litigation**

10.1 **Serica**

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) covering at least the 12 months preceding the date of this document which may have, or have had, a significant effect on the financial position or profitability of the Company and/or the Group.

10.2 **BKR Assets and BK Assets**

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) covering at least the 12 months preceding the date of this document which may have, or have had, a significant effect on the financial position or profitability of the BKR Assets or BK Assets for which the Company may be liable after BKR Completion and completion of the BK Transactions respectively.

10.3 **No significant change**

Save as disclosed in this Supplementary Admission Document there has been no material new factor, mistake or inaccuracy relating to the information included in the Admission Document which is capable of affecting the assessment of the Company, the BKR Assets, the BK Assets or the admission of the Ordinary Shares to trading on AIM.

(a) *Serica*

There has been no significant change in the financial or trading position of the Group since 30 June 2018, the date to which the last unaudited interim financial statements were prepared.

(b) *BKR Assets and BK Assets*

There has been no significant change in the financial or trading position of the BKR Assets and the BK Assets since 30 June 2018, the date to which the financial information on the BKR Assets and the BK Assets set out in Part V (*Further Unaudited Historical Financial Information on the BKR Assets*) and Part VI (*Unaudited Historical Financial Information on the BK Assets*) of this Supplementary Admission Document was prepared.

11. **Related party transactions**

Save as disclosed in the Group's audited consolidated historical financial information for the year ended 31 December 2017, incorporated by reference in Part VII (*Further Historical Financial Information on Serica*) of this Supplementary Admission Document there are no related party transactions entered into by the Company during the financial year ended 31 December 2017, the six months ended 30 June 2018 or during the period from and including 1 July 2018 to and including 23 November 2018 (being the latest practicable date prior to the date of this document).

12. **Working Capital**

In the opinion of the Directors and the Proposed Directors, having made due and careful enquiry, the working capital available to the Enlarged Group will be sufficient for its present requirements, that is, for at least the next 12 months from the date of Admission.

13. **Premises**

In addition to the premises disclosed in the Admission Document, the Serica Group occupies the following property:

Property Location	**Current use**	**Owned/leased**	**Lease end**
1st Floor, Suite 1, H1, The Hill of Rubislaw, Aberdeen AB15 6BL	Office	Leased	7 years from 18 July 2018

14. **Employees**

14.1 **Serica**

As at 23 November 2018 (being the latest practicable date prior to the date of this document), the Serica Group had 23 employees. The table below sets out the average number of people employed by the Serica Group in the year ended 31 December 2017:

	Year ended 31 December 2017
Management	4
Technical	1
Finance and administration	1
Total	6

14.2 **BKR Assets and BK Assets**

As at 23 November 2018 (being the latest practicable date prior to the date of this document), the BKR Assets employed 111 employees who are expected to transfer across to the Group as part of the BKR Acquisition. No employees are expected to transfer across to the Group as part of the Total E&P Transaction, the BHP Transaction or the Marubeni Transaction. In addition, Serica is recruiting 21 employees for the Enlarged Group.

15. **Consents**

15.1 Peel Hunt LLP has given and has not withdrawn its written consent to the issue of this document with the inclusion herein of references to its name in the form and context in which it appears.

15.2 Ryder Scott Company, L.P. has given and has not withdrawn its written consent to the inclusion of its report set out in Part III (*Updated Competent Person's Report on the BKR Assets*) of this Supplementary Admission Document, and the references thereto and to its name, in the form and context in which they appear and has authorised the contents of those parts of this document. The Updated BKR CPR was prepared at the request of the Company. Ryder Scott Company, L.P. has no interest in the share capital of the Serica Group.

15.3 Netherland, Sewell & Associates, Inc. has given and has not withdrawn its written consent to the inclusion of its report set out in Part IV (*Updated Competent Person's Report on Serica's Assets*) of this Supplementary Admission Document, and the references thereto and to its name, in the form and context in which they appear and has authorised the contents of those parts of this document. The Updated Serica CPR was prepared at the request of the Company. Netherland, Sewell & Associates, Inc. has no interest in the share capital of the Serica Group.

16. **Miscellaneous**

16.1 The total costs and expenses payable by the Company in connection with or incidental to the Proposals and the BK Transactions, including London Stock Exchange fees, professional fees, consulting and investor relation services and the costs of printing and distribution, are estimated to amount to approximately £2.75 million (excluding VAT).

16.2 The financial information contained in this document does not constitute statutory accounts within the meaning of section 434 of the Act.

16.3 No public takeover bids have been made by third parties in respect of the Company's issued share capital in the current financial year nor in the last financial year.

16.4 Save as disclosed in the Admission Document and in this Supplementary Admission Document, the Directors and Proposed Directors are not aware of any trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Group's prospects or the BKR Assets or the BK Assets for the current financial year.

16.5 Save as disclosed in the Admission Document and in this Supplementary Admission Document, the Company had no principal investments for each financial year covered by the historical financial information and there are no principal investments in progress and there are no principal future investments on which the Board has made a firm commitment.

16.6 Information sourced from third parties has been accurately reproduced and so far as the Company is aware, and able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

16.7 Save as disclosed in the Admission Document and in this Supplementary Admission Document, the Directors and Proposed Directors are not aware of any exceptional factors which have influenced the activities of the Serica Group, the BKR Assets or the BK Assets.

16.8 Save as disclosed in the Admission Document and in this Supplementary Admission Document, there are no patents or other intellectual property rights, licences or particular industrial, commercial or financial contracts or new manufacturing processes which are of fundamental importance to the Enlarged Group's business or profitability.

16.9 Save as disclosed in Part IV (*Risk Factors*) of the Admission Document and Part II (*Further Risk Factors*) of this Supplementary Admission Document, the Directors and Proposed Directors are not aware of any material environmental issues or risks affecting the utilisation of the Enlarged Group's tangible fixed assets or its operations.

16.10 Save as disclosed in the Admission Document and in this Supplementary Admission Document, there are no outstanding convertible securities, exchangeable securities or securities with warrants issued by the Company.

17. **Documents available for inspection**

In addition to the documents set out at paragraph 21 of Part XII (*Additional Information*) of the Admission Document, copies of the following documents will be available for inspection during normal business hours on any weekday (except Saturdays, Sundays and public holidays) at the offices of Serica Energy PLC, 52 George Street, London W1U 7EA from the date of this document until the date which is one month from the date of Admission and will be available for viewing on the Company's website at www.serica-energy.com:

(a) the Updated BKR CPR;

(b) the Updated Serica CPR;

(c) the audited consolidated accounts for the Serica Group for the financial year ended 31 December 2017;

(d) the unaudited consolidated interim financial statements for the Serica Group for the six months ended 30 June 2018;

(e) the consent letters referred to in paragraph 15 of this Part X (*Further Additional Information*) of this Supplementary Admission Document; and

(f) this document.

18. **Documents incorporated by reference**

The information incorporated by reference and set out in Part VII (*Further Historical Financial Information on Serica*) of this Supplementary Admission Document is available free of charge in electronic format on the Company's website at www.serica-energy.com.

Any statement contained in a document which is deemed to be incorporated by reference herein shall be deemed to be modified or superseded for the purpose of this document to the extent that a statement contained herein (or in a later document which is incorporated by reference herein) modifies or supersedes such earlier statement (whether expressly, by implication or otherwise). Any statement so modified or superseded for the purpose of this document shall be deemed, except as so modified or superseded, to constitute a part of this document.

Dated: 26 November 2018

PART XI – DEFINITIONS

Save as provided in this Supplementary Admission Document, or unless the context otherwise requires, the definitions used in the Admission Document also apply in this Supplementary Admission Document. In addition, the following definitions apply throughout this document unless the context requires otherwise:

"Admission Document"	the admission document of the Company issued in connection with the Proposals dated 30 November 2017;
"BHP"	BHP Billiton Petroleum Great Britain Limited;
"BHP Transaction"	the proposed acquisition by Serica UK of the BHP Assets on the terms of the BHP SPA as described in Part I (*Matters Arising Since the Publication of the Admission Document*) of this Supplementary Admission Document;
"BHP Assets"	BHP's interests in the Bruce and Keith fields in the North Sea and as more specifically set out in the BHP SPA and described in this Supplementary Admission Document;
"BHP Completion"	completion of the acquisition by Serica UK of the BHP Assets in accordance with the terms of the BHP SPA;
"BHP Initial Consideration"	the initial consideration of £1 million payable for the BHP Assets pursuant to the BHP SPA;
"BHP Net Cash Flow Sharing Deed"	a deed between BHP and Serica UK to be entered into on BHP Completion which sets out the methodology for calculating BHP's share of future net cash flows from the BHP Assets, as described in paragraph 9.1(b)(iii) of Part X (*Further Additional Information*) of this Supplementary Admission Document;
"BHP SPA"	the conditional agreement between Serica UK and BHP dated 2 November 2018 in relation to the acquisition of the BHP Assets described at paragraph 9.1(b)(i) of Part X (*Further Additional Information*) of this Supplementary Admission Document;
"BK Assets"	the BHP Assets, the Marubeni Assets and the Total E&P Assets;
"BK SPAs"	the Total E&P SPA, the BHP SPA and the Marubeni SPA;
"BK Transactions"	the BHP Transaction, the Marubeni Transaction and the Total E&P Transaction;
"BKR Acquisition"	the proposed acquisition by Serica UK of the BKR Assets on the terms of the BP SPA;
"BKR Completion"	completion of the BKR Acquisition in accordance with the terms of the BP SPA;
"BP SPA"	the conditional agreement between Serica UK and BP dated 21 November 2017 in relation to the acquisition of the BKR Assets, described at paragraph 11.1(b) of Part XII (*Additional Information*) of the Admission Document;
"Columbus"	the Columbus gas condensate field in the North Sea in which Serica holds a 50% interest;

"EBT"	the Serica Energy plc Employee Benefit Trust established by the Company on 6 September 2018;
"Enlarged Group"	the Company and its subsidiaries following BKR Completion, and where the context requires, following completion of the BK Transactions;
"IOC's Rhum Licence Interest"	the 50% interest held by IOC in the Rhum gas field;
"Marubeni"	Marubeni Oil & Gas (U.K.) Limited;
"Marubeni Transaction"	the proposed acquisition by Serica UK of the Marubeni Assets on the terms of the Marubeni SPA;
"Marubeni Assets"	Marubeni's interests in the Bruce and Keith fields in the North Sea and as more specifically set out in the Marubeni SPA and described in this Supplementary Admission Document;
"Marubeni Completion"	completion of the acquisition by Serica UK of Marubeni Assets in accordance with the terms of the Marubeni SPA;
"Marubeni Consideration"	the reverse cash consideration of US$1 million payable by Marubeni in respect of the acquisition by Serica UK of the Marubeni Assets pursuant to the Marubeni SPA;
"Marubeni SPA"	the conditional agreement between Serica UK and Marubeni dated 5 November 2018 in relation to the acquisition of the Marubeni Assets described at paragraph 9.1(c)(i) of Part X (*Further Additional Information*) of this Supplementary Admission Document;
"NICO"	Naftiran Intertrade Co. (NICO) Limited;
"Proposed Directors"	Trevor Garlick and Malcolm Webb, the proposed new non-executive directors of the Company who will be appointed to the Board following BKR Completion;
"QCA Code"	the Quoted Company Alliance Corporate Governance Code 2018;
"Rhum JOA"	the joint operating agreement in respect of the Rhum field;
"Sharesave Plan"	the Serica Energy 2018 Sharesave Plan;
"Supplementary Admission Document"	this document;
"Total E&P"	Total E&P UK Limited;
"Total E&P Transaction"	the proposed acquisition by Serica UK of the Total E&P Assets on the terms of the Total E&P SPA;
"Total E&P Assets"	Total E&P's interests in the Bruce and Keith fields in the North Sea (save for a 1% interest in the Bruce field which is being retained by Total E&P) and as more specifically set out in the Total E&P SPA and described in this Supplementary Admission Document;
"Total E&P Completion"	completion of the acquisition by Serica UK of the Total E&P Assets in accordance with the terms of the Total E&P SPA;

"Total E&P Initial Consideration"	the initial consideration of US$5 million payable for the Total E&P Assets pursuant to the Total E&P SPA;
"Total E&P Net Cash Flow Sharing Deed"	a deed between Total E&P and Serica UK to be entered into on Total E&P Completion which sets out the methodology for calculating Total E&P's share of future net cash flows from the Total E&P Assets, as described in paragraph 9.1(a)(iii) of Part X (*Further Additional Information*) of this Supplementary Admission Document;
"Total E&P SPA"	the conditional agreement between Serica UK and Total E&P dated 2 August 2018 in relation to the acquisition of the Total E&P Assets described at paragraph 9.1(a)(i) of Part X (*Further Additional Information*) of this Supplementary Admission Document;
"**Updated BKR CPR**"	the independent technical report of Ryder Scott Company L.P. dated 10 October 2018 which is reproduced in its entirety in Part III (*Updated Competent Person's Report on the BKR Assets*) of this Supplementary Admission Document; and
"Updated Serica CPR"	the independent technical report of Netherland, Sewell & Associates, Inc., dated 16 November 2018, which is reproduced in its entirety in Part IV (*Updated Competent Person's Report on Serica's Assets*) of this Supplementary Admission Document.

PART XII – GLOSSARY OF TECHNICAL TERMS

Save as provided in this Supplementary Admission Document, or unless the context otherwise requires, the glossary of technical terms used in the Admission Document also apply in this Supplementary Admission Document. In addition, the following glossary of technical terms applies throughout this document unless the context requires otherwise:

Term	Meaning
"drill or drop"	a clause in a licence that allows the licence holder to either relinquish the licence at the end of a defined period or commit to drilling a well in the next defined period;
"FDP"	Field Development Plan, a document submitted to the government for approval to develop a field;
"gas hydrates"	ice-like crystals of water and gas formed under certain temperatures and pressures;
"NBP"	National Balancing Point;
"pigging"	a process of cleaning or inspecting a pipeline by sending a solid device known as a pig down the line;
"TVDSS"	true vertical depth subsea; and
"Workover"	work performed to repair an existing well, often to change the production tubing (completion).