THIS 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) who specialises in advising on the acquisition of shares and other securities if you are resident in the UK or, if you are not resident in the UK, from another appropriately authorised independent financial adviser in your own jurisdiction.

This document, which comprises an AIM admission document, has been drawn up in accordance with the AIM Rules for Companies and has been issued in connection with the application for admission to trading of the entire issued and to be issued ordinary share capital of the Company to trading on AIM. This document contains no offer of transferable securities to the public within the meaning of section 102B of the FSMA, the Companies Act or otherwise.

In accordance with section 85 and Schedule 11A of FSMA, this document is not, and is not required to be, a prospectus for the purposes of the Prospectus Rules published by the FCA and has not been approved by the FCA or any other authority or regulatory body.

Application has been made for the Existing Issued Ordinary Share Capital, together with the New Ordinary Shares, to be admitted to trading on AIM. It is expected that Admission will become effective and that unconditional dealings will commence in the Ordinary Shares at 8.00 a.m. on 11 June 2018. The New Ordinary Shares to be issued will, on Admission, rank *pari passu* in all respects with the Existing Ordinary Shares, and will rank in full for all dividends and other distributions declared, made or paid on Ordinary Shares after Admission.

It is expected that Admission will become effective and dealings will commence in the Ordinary Shares on 8.00 a.m. on 11 June 2018.

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 United Kingdom 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. 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 the Ordinary Shares to the Official List. The Ordinary Shares are not dealt on any regulated market and no application has been or is being made for the Ordinary Shares to be admitted to listing or trading on any other exchange.

Block Energy PLC

(Incorporated in England and Wales with Registered Number 05356303)

PLACING OF, AND SUBSCRIPTION FOR, 125,000,000 ORDINARY SHARES AT A PRICE OF 4 PENCE PER ORDINARY SHARE

ADMISSION TO TRADING ON AIM

Nominated Adviser	*Joint Brokers*	
SPARK Advisory Partners Limited	*Baden Hill, a trading name of Northland Capital Partners Limited*	*Novum Securities Limited*
Authorised and regulated by the Financial Conduct Authority	Authorised and regulated by the Financial Conduct Authority	Authorised and regulated by the Financial Conduct Authority

Issued ordinary share capital immediately following Admission

	Number	**Amount**
Ordinary Shares of £0.0025 each	258,547,601	£646,369

The Company and the Directors of the Company, whose names appear on page 6 of this document, accept responsibility, collectively and individually, for the information contained in this document and compliance with the AIM Rules for Companies. To the best of the knowledge of the Company and the Directors (having taken all reasonable care to ensure such is the case) the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information. Prospective investors should read this document in its entirety. An investment in the Company includes a significant degree of risk and prospective investors should consider carefully the risk factors set out in Part II of this document. This document does not constitute an offer to sell, or a solicitation to buy Ordinary Shares in any jurisdiction in which such offer or solicitation is unlawful.

SPARK Advisory Partners Limited, which is authorised and regulated in the United Kingdom by the FCA, is acting as nominated adviser to the Company in connection with the matters disclosed herein and is not acting for any other person (including a recipient of this document) or otherwise responsible to any person for providing the protections afforded to clients of SPARK Advisory Partners Limited or for advising any other person in respect of the Placing and Subscription, and Admission or any transaction, matter or arrangement referred to in this document. SPARK Advisory Partners Limited's responsibilities as the Company's nominated adviser under the AIM Rules for Nominated Advisers are owed solely to London Stock Exchange and are not owed to the Company or to any Director or to any other person in respect of their decision to acquire shares in the Company in reliance on any part of this document. No representation or warranty, express or implied, is made by SPARK Advisory Partners Limited, for the accuracy of any information or opinions contained in this document or for the omission of any material information, for which it is not responsible. Apart from the responsibilities and liabilities, if any, which may be imposed on SPARK Advisory Partners Limited by the FSMA or the regulatory regime established thereunder, SPARK Advisory Partners Limited does not accept any responsibility whatsoever for the contents of this document, including its accuracy, completeness or verification or for any other statement made or purported to be made by it, or on its behalf, in connection with the Company, the Ordinary Shares, the Placing and Subscription, or Admission. SPARK Advisory Partners Limited accordingly disclaims all and any liability whether arising in tort, contract or otherwise (save as referred to above) in respect of this document or any such statement.

Baden Hill, which is authorised and regulated in the United Kingdom by the FCA, is acting as joint broker to the Company in connection with the matters disclosed herein and is not acting for any other person (including a recipient of this document) or otherwise responsible to any person for providing the protections afforded to clients of Baden Hill or for advising any other person in respect of the proposed Placing and Subscription, and Admission or any transaction, matter or arrangement referred to in this document. No representation or warranty, express or implied, is made by Baden Hill, for the accuracy of any information or opinions contained in this document or for the omission of any material information, for which it is not responsible.

Novum, which is authorised and regulated in the United Kingdom by the FCA, is acting as joint broker to the Company in connection with the matters disclosed herein and is not acting for any other person (including a recipient of this document) or otherwise responsible to any person for providing the protections afforded to clients of Novum or for advising any other person in respect of the Placing and Subscription, and Admission or any transaction, matter or arrangement referred to in this document. No representation or warranty, express or implied, is made by Novum, for the accuracy of any information or opinions contained in this document or for the omission of any material information, for which it is not responsible.

A copy of this document is available, subject to certain restrictions relating to persons resident in any Restricted Jurisdiction, at the Company's website www.blockenergy.co.uk. Neither the content of the Company's website nor any website accessible by hyperlinks to the Company's website is incorporated in, or forms part of, this document. Nothing in this document shall be effective to limit or exclude any liability for fraud or which, by law or regulation, cannot be so limited or excluded.

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'', ''estimates'', ''plans'', ''projects'', ''anticipates'', ''expects'', ''intends'', ''may'', ''will'' 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 all matters that are not historical facts. They appear in a number of places throughout this document and include, but are not limited to, statements regarding the intentions, beliefs or current expectations of the Company, or the Board, concerning, among other things, the Company's results of operations, financial position, liquidity, prospects, strategy and the Group's markets.

By their nature, forward-looking statements involve risk and uncertainty because they relate to future events and circumstances. Forward-looking statements are not guarantees of future performance and the development of the markets may differ materially from those described in, or suggested by, the forward-looking statements contained in this document. In addition, even if the development of those markets is consistent with the forward-looking statements contained in this document, those developments may not be indicative of developments in subsequent periods. A number of factors could cause developments to differ materially from those expressed or implied by the forward-looking statements including, without limitation, general economic and business conditions, industry trends, competition, commodity prices, changes in law or regulation, currency fluctuations, political and economic uncertainty and other factors discussed in the sections Part I ''**Information relating to the Group**'', Part II ''**Risk factors**'', Part IV ''**Financial Information**'' and Part V ''**Additional Information**'' of this document.

Any forward-looking statements in this document reflect the Company's 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 Company's strategy. Investors should specifically consider the factors identified in this document which could cause results to differ before making an investment decision. These forward-looking statements speak only as at the date of this document. Subject to any applicable obligations, the Company undertakes no obligation to update or review any forward-looking statement, whether as a result of new information, future developments or otherwise. All subsequent written and oral forward-looking statements attributable to the Company or individuals acting on behalf of the Company are expressly qualified in their entirety by this paragraph. Prospective investors should specifically consider the factors identified in this document (including the Risk Factors set out in Part II) of this document which could cause actual results to differ before making an investment decision. Investors should note that the contents of these paragraphs relating to forward-looking statements are not intended to qualify the statement made as to sufficiency of working capital in paragraph 17 of Part V of this document.

NOTICE TO OVERSEAS PERSONS

The distribution of this 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 restrictions. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction. The Ordinary Shares have not been, nor will they be, registered under the United States Securities Act of 1933, as amended, (the ''US Securities Act'') and may not be offered, sold or delivered in, into or from the United States except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act. Subject to certain exemptions, this document does not constitute an offer of Ordinary Shares to any person with a registered address, or who is resident in, the United States. There will be no public offer in the United States. Outside of the United States, the Placing Shares and Subscription Shares are being offered in reliance on Regulation S under the US Securities Act. The Ordinary Shares will not qualify for distribution under the relevant securities laws of Australia, Canada, the Republic of Ireland, the Republic of South Africa or Japan, nor has any prospectus in relation to the Ordinary Shares been lodged with, or registered by, the Australian Securities and Investments Commission or the Japanese Ministry of Finance. Accordingly, subject to certain exemptions, the Ordinary Shares may not be offered, sold, taken up, delivered or transferred in, into or from the United States, Australia, Canada, the Republic of Ireland, the Republic of South

Africa, Japan or any other jurisdiction where to do so would constitute a breach of local securities laws or regulations (each a ''Restricted Jurisdiction'') or to or for the account or benefit of any national, resident or citizen of a Restricted Jurisdiction. This document does not constitute an offer to issue or sell, or the solicitation of an offer to subscribe for or purchase, any Ordinary Shares to any person in a Restricted Jurisdiction and is not for distribution in, into or from a Restricted Jurisdiction. The Ordinary Shares have not been approved or disapproved by the US Securities and Exchange Commission, or any other securities commission or regulatory authority of the United States, nor have any of the foregoing authorities passed upon or endorsed the merits of the offering of the Placing Shares or Subscription Shares nor have they approved this document or confirmed the accuracy or adequacy of the information contained in this document. Any representation to the contrary is a criminal offence in the US.

CONTENTS

KEY STATISTICS

Issue Price	4 pence
Number of Ordinary Shares in issue immediately prior to the Placing and Subscription	97,968,209
Number of Placing Shares being placed on behalf of the Company	116,075,000
Number of Subscription Shares being placed on behalf of the Company	8,925,000
Number of other New Ordinary Shares being issued	35,579,392
Percentage of Enlarged Issued Ordinary Share Capital being placed pursuant to the Placing and Subscription	48.4%
Number of Ordinary Shares in issue immediately following Admission	258,547,601
Market capitalisation of the Company following Admission	£10.3 million
Estimated net proceeds of the Placing and Subscription receivable by the Company	£4.27 million
Number of Ordinary Shares the subject of Options and Warrants following Admission	16,617,116
% of Enlarged Issued Ordinary Share Capital the subject of Options and Warrants	6.4%
EPIC/TIDM	BLOE
ISIN Number	GB00BF3TBT48
SEDOL number	BF3TBT4
Legal Entity Identifier (LEI)	213800E2J8QAIJ6KN415

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

	2018
Publication of this document	4 June
Admission and commencement of dealings in the Ordinary Shares on AIM	8.00 a.m. on 11 June
CREST accounts credited	11 June
Despatch of definitive share certificates (where applicable)	18 June

Notes:
All references to times in this timetable are to London times and each of the times and dates are indicative only and may be subject to change. Any such change will be notified by an announcement on a regulatory information service.

DIRECTORS, SECRETARY AND ADVISERS

Directors on Admission	Philip Dimmock	*Chairman*†*
	Paul Haywood	*Chief Executive Officer*
	Serina Bierer ACA	*Financial Director*†
	Niall Tomlinson	*Executive Director*
	Timothy Parson	*Director**
	Roger McMechan	*Technical Director*†
		** non-executive*
		† to be appointed on Admission

Company Secretary	Ben Harber
Registered and Head Office	60 Gracechurch Street London EC3V 0HR
Nominated Adviser	SPARK Advisory Partners Limited 5 St John's Lane London EC1M 4BH
Joint Brokers and Bookrunners	Novum Securities Limited 8-10 Grosvenor Gardens London SW1W 0DH
	Baden Hill (a trading name of Northland Capital Partners Limited) 40 Gracechurch Street London EC3V 0BT
Placing Agent and Adviser	Gneiss Energy Limited 69 Old Broad Street, London EC2M 1QS
Competent Person	Gustavson Associates, LLC 5757 Central Avenue Suite D Boulder, Colorado 80301 United States of America
Reporting Accountants and Statutory Auditor	PKF Littlejohn LLP 1 Westferry Circus Canary Wharf London E14 4HD
Solicitors to Block Energy (as to English Law)	Hill Dickinson LLP The Broadgate Tower 20 Primrose Street London EC2A 2EW
Solicitors to Block Energy (as to Georgian Law)	BLC Law Office 129a, D. Agmashenebeli Ave. Tbilisi, 0102 Georgia
Solicitors to the Nominated Adviser and Broker	DAC Beachcroft LLP 100 Fetter Lane London EC4A 1BN
Registrars	Share Registrars Limited Suite E, First Floor 9 Lion and Lamb Yard Farnham, Surrey GU9 7LL
Website	www.blockenergy.co.uk

DEFINITIONS

The following words and expressions apply throughout this document unless the context requires otherwise:

"**£**", "**pound sterling**", "**p**" and "**pence**"	lawful currency for the time being of the United Kingdom;
"**$**", or "**dollar**"	lawful currency for the time being of the United States of America;
"**Admission**"	admission of the Enlarged Issued Ordinary Share Capital to trading on AIM becoming effective in accordance with Rule 6 of the AIM Rules for Companies, which is expected to occur on 11 June 2018;
"**Agency**"	LEPL State Oil And Gas Agency, which is the representative of the State in the PSAs;
"**AIM**"	AIM, a market of that name operated by the London Stock Exchange;
"**AIM Rules**"	together the AIM Rules for Companies and the AIM Rules for Nomads;
"**AIM Rules for Companies**"	the "AIM Rules for Companies" published by the London Stock Exchange, as amended from time to time (including, without limitation, all applicable guidance notes) which govern the rules and responsibilities of companies whose shares are admitted to trading on AIM;
"**AIM Rules for Nomads**"	the "AIM Rules for Nominated Advisers" issued by the London Stock Exchange, as amended from time to time, setting out the eligibility, ongoing obligations and certain disciplinary matters in relation to nominated advisers;
"**Antubia SPA**"	the share purchase agreement between (1) Ensign Resources Limited and (2) Star Goldfields Limited dated 7 September 2017 for the sale of the entire issued share capital of Antubia Resources Limited;
"**Articles**"	the articles of association of the Company at the date of this document;
"**Audit Committee**"	the audit and risk committee of the Company from Admission;
"**Baden Hill**"	Baden Hill, a trading name of Northland Capital Partners Limited, the Company's joint broker;
"**Board**" or "**Directors**"	the directors (including, where applicable, the Proposed Directors) of the Company as set out on page 6;
"**Certificated**" or "**in certificated form**"	where an Ordinary Share is not in uncertificated form (i.e. not in CREST);
"**Companies Act**"	the Companies Act 2006 (as amended);
"**Company**" or "**Block Energy**"	Block Energy plc, a company incorporated in England and Wales with registered number 05356303;
"**Connected Person**"	so far as could be known from reasonable investigation, a person connected with an individual or company within the meaning of sections 252 to 255 of the Companies Act;
"**Convertible Loan Notes**" or "**CLN**"	together (i) the £210,000 of convertible loan notes, issued in June 2017 to Mayan Energy Limited, details of which are set out in paragraph 13 xviii of Part V of this document, and (ii) the £150,000 of convertible loan notes, issued in December 2017 to various private investors, details of which are set out in paragraph 13 xix of Part V of this document;

"**CREST**"	the relevant system (as defined in the CREST Regulations) in respect of which Euroclear is the Operator (as defined in the CREST Regulations);
"**CREST Regulations**"	the Uncertificated Securities Regulations 2001 (SI 2001/3755), as amended, and any applicable rules made under those regulations;
"**Deferred Shares**"	deferred shares of £0.00049 (0.049 pence) each in the capital of the Company;
"**Disclosure Guidance and Transparency Rules**" or "**DTR**"	the Disclosure Guidance and Transparency Rules, being the rules and regulations made by the FCA in its capacity as the UKLA under Part V of FSMA, as amended and contained in the UKLA publication of the same name;
"**Disclosure Committee**"	the disclosure committee of the Company from Admission;
"**EMI Schemes**"	the proposed Enterprise Management Incentive Schemes which the Company proposes to establish;
"**Enlarged Issued Ordinary Share Capital**"	the issued ordinary share capital of the Company as enlarged by the issue of the New Ordinary Shares;
"**Ensign SPA**"	the share purchase agreement between (1) the Company and (2) Safi Minerals Ltd dated 15 November 2017 for the sale of the entire issued share capital of Ensign Resources Limited;
"**EU**"	the European Union;
"**Euroclear**"	Euroclear UK & Ireland Limited, the Operator of CREST;
"**Existing Issued Ordinary Share Capital**" or "**Existing Ordinary Shares**"	the 97,968,209 Ordinary Shares in issue at the date of this document;
"**FCA**"	the Financial Conduct Authority;
"**FSMA**"	the Financial Services and Markets Act 2000 (as amended);
"**Georgia**"	Republic of Georgia;
"**Georgian Oil**"	the National Oil and Gas Corporation of Georgia – JSC Georgian Oil and Gas Corporation;
"**Georgia Oil and Gas Ltd**" or "**GOG**"	a company incorporated on April 2 2008 and existing under the laws of the British Virgin Islands;
"**GOG Norioskhevi**"	GOG Norioskhevi Ltd, a company incorporated and existing under the laws of the British Virgin Islands with the registered address at Trident Chambers, P O Box 146, Road Town, Tortola, British Virgin Islands, Registration No 1849997; GOG Norioskhevi is a subsidiary of the Company and is owner of a 100% working interest in the Norio PSA;
"**GNV**"	Georgia New Ventures Inc, a company incorporated and existing under the laws of the Bahamas with the registered address at Winterbotham Place, Marlborough & Queen, Streets, Nassau, Bahamas, Registration No 167542; GNV is a subsidiary of the Company and is owner of a 5% working interest in the West Rustavi PSA;
"**GNV SPA**" or "**GNV Share Purchase Agreement**"	the share purchase agreement between (1) the Company and (2) GOG entered into on 21 June 2017 for the purchase of the entire issued share capital of GNV, further details of which are set out in paragraph 13 viii of Part V of this document;
"**Group**"	the Company and its subsidiaries from time to time and "**Group Company**" should be interpreted accordingly;
"**HMRC**"	Her Majesty's Revenue and Customs;

"**Issue Price**" or "**Placing Price**"	4p, being the price at which each Placing Share and Subscription Share is to be issued;
"**Lock-in Deeds**"	the conditional lock-in deeds dated 4 June 2018, further details of which are contained in paragraph 13 xxiv of Part V of this document;
"**Locked-in Persons**"	the Directors, the Proposed Directors and Iskander Energy Corporation;
"**London Stock Exchange**"	London Stock Exchange plc;
"**MAR**"	the Market Abuse Regulation (Regulation 596/2014);
"**New Ordinary Shares**"	the new Ordinary Shares to be issued by the Company pursuant to the Placing, the Subscription, the conversion of the Convertible Loan Notes and other shares to be issued as set out in paragraph 11 of Part I of this document;
"**NOC**"	LLC Norio Operating Company, an affiliate of GOG and operator under the Norio PSA and the Satskhenisi PSA;
"**Nominations Committee**"	the nominations committee of the Company from Admission;
"**Norio Block**"	the area covered by the Norio PSA;
"**Norio PSA**" or "**Norioskhevi PSA**"	the Production Sharing Agreement between (1) GOG Norioskhevi and GOG, and (2) the State Agency for Regulation of Oil and Gas Resources in Georgia and the National Oil Company of Georgia – Georgian Oil, for the distribution of hydrocarbons amongst the parties from production in Norio Block of the Republic of Georgia further details of which are set out in paragraph 13 vi of Part V of this document;
"**Norio SPA**"	the share purchase agreement between (1) the Company and (2) GOG entered into on 7 April 2017 for the purchase of the entire issued share capital of GOG Norioskhevi further details of which are set out in paragraph 13 iv of Part V of this document;
"**Northland**"	Northland Capital Partners Limited;
"**Novum**"	Novum Securities Limited, the Company's joint broker;
"**Official List**"	the Official List of the UK Listing Authority;
"**Options**"	share options to subscribe for Ordinary Shares following Admission;
"**Ordinary Shares**"	ordinary shares of £0.0025 (0.25 pence) each in the capital of the Company;
"**Placing**"	the conditional Placing of the Placing Shares carried out by Novum and Baden Hill as agents for and on behalf of the Company pursuant to the terms of the Placing Agreement;
"**Placing Agreement**"	the agreement dated 4 June 2018 between (1) the Company, (2) the Directors, (3) SPARK, (4) Novum and (5) Baden Hill relating to the Placing, further details of which are set out in paragraph 13 xvi of Part V of this document;
"**Placing Shares**"	the 116,075,000 new Ordinary Shares which are the subject of the Placing;
"**Proposed Directors**"	Serina Bierer, Philip Dimmock and Roger McMechan;
"**PSA**" or "**Production Sharing Agreement**"	Production Sharing Agreement entered into between (1) a contractor party or parties and (2) the State Agency for Regulation of Oil and Gas Resources in Georgia and Georgian Oil, for the distribution of hydrocarbons amongst the parties;
"**QCA**"	Quoted Companies Alliance;
"**QCA Code**"	the Corporate Governance Code for Small and Mid-Sized Quoted Companies issued by the QCA from time to time;

"**Registrars**"	Share Registrars Limited, the Company's registrars;
"**Remuneration Committee**"	the remuneration committee of the Company from Admission;
"**Restricted Jurisdiction**"	the United States, Canada, Australia, the Republic of South Africa, the Republic of Ireland, Japan or any other country outside of the United Kingdom where the distribution of this document may lead to a breach of any applicable legal or regulatory requirements;
"**Satskhenisi Block**"	the area covered by the Satskhenisi PSA;
"**Satskhenisi Ltd**"	Satskhenisi Ltd, a company incorporated under the existing laws of the Marshall Islands with the registered address Ajeltake Road, Ajeltake Island, Majuro, Marshall Islands with company number 91733; Satskhenisi Ltd is a subsidiary of the Company and is owner of a 90% working interest in the Satskhenisi PSA;
"**Satskhenisi Operator Letter**"	the letter from Satskhenisi and GOG to NOC, pursuant to which NOC acts as operator under the Satskhenisi PSA;
"**Satskhenisi PSA**" or "**Satskhenisi Production Sharing Agreement**"	the Production Sharing Agreement between (1) Satskhenisi Ltd and GOG, and (2) the State Agency for Regulation of Oil and Gas Resources in Georgia and the National Oil Company – Georgian Oil, for the distribution of hydrocarbons amongst the parties from production in Satskhenisi Block of the Republic of Georgia, further details of which are set out in paragraph 13 ii of Part V of this document;
"**Satskhenisi SPA**" or "**Satskhenisi Share Purchase Agreement**"	the share purchase agreement between (1) the Company and (2) Iskander Energy Corporation entered into on 25 July 2017 for the purchase of the entire issued share capital of Satskhenisi Ltd, further details of which are set out in paragraph 13 i of Part V of this document;
"**Shareholders**"	holders of issued Ordinary Shares;
"**SPARK**" or "**SPARK Advisory Partners**"	SPARK Advisory Partners Limited, the Company's nominated adviser;
"**State**"	the State of Georgia;
"**Subscription Shares**"	the 8,925,000 New Ordinary Shares which are the subject of the Subscription;
"**Subscription**"	the subscription by certain investors to subscribe for 8,925,000 New Ordinary Shares at the Issue Price;
"**Substantial Shareholder**"	as defined in the AIM Rules for Companies, any person who holds any legal or beneficial interest directly or indirectly in 10% or more of any class of AIM security (excluding treasury shares) or 10% or more of the voting rights (excluding treasury shares) of an AIM company;
"**Taoudini SPA**"	the share purchase agreement between (1) the Company and (2) Safi Minerals Ltd dated 8 November 2017 for the sale of the entire issued share capital of Taoudini Resources SARL;
"**TRL SPA**"	the share purchase agreement between (1) the Company and (2) Hot Rocks Investments plc and others entered into on 18 January 2016 for the purchase of the entire issued share capital of Taoudini Resources Limited;
"**uncertificated**" or "**in uncertificated form**"	recorded on the relevant register of Ordinary Shares as being held in uncertificated form in CREST, and title to which, by virtue of the CREST Regulations, may be transferred by means of CREST;
"**UK**" or "**United Kingdom**"	United Kingdom of Great Britain and Northern Ireland;

"**UK Corporate Governance Code**"	the UK Corporate Governance Code published by the Financial Reporting Council from time to time;
"**UKLA**" or "**UK Listing Authority**"	the Financial Conduct Authority acting in its capacity as the competent authority for the purposes of Part V of the Financial Services and Markets Act 2000;
"**US**", "**USA**" or "**United States**"	the United States of America, each state thereof, its territories and possessions and the District of Columbia and all other areas subject to its jurisdiction;
"**VAT**"	UK value added tax;
"**Warrants**"	warrants to subscribe for Ordinary Shares following Admission;
"**West Rustavi Block**"	the area covered by the West Rustavi PSA;
"**West Rustavi PSA**"	the Production Sharing Agreement dated 28 March 2018 between (1) GOG and GNV and (2) the State Agency for Regulation of Oil and Gas Resources in Georgia and the National Oil Company – Georgian Oil, for the distribution of hydrocarbons amongst the parties from production in the West Rustavi Block (Permit XI (f)) of the Republic of Georgia, further details of which are set out in paragraph 13 ix of Part V of this document.

GLOSSARY

The following meanings and interpretations of terms applying to the oil & gas industry shall apply throughout this Document unless the context requires otherwise

"**BOPD**" or "**bopd**"	barrels of oil per day;
"**BCF**" or "**Bcf**"	billion standard cubic feet;
"**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;
"**Cost Oil**"	a portion of produced oil that the operator applies on an annual basis to recover defined costs specified by a production sharing contract;
"**E&P**"	oil & gas exploration and production;
"**formations**"	geological subsurface strata;
"**horizontal drilling**"	method used to improve the outcome of a well, for example to reach targets beneath adjacent lands, reduce the footprint of gas field development, intersect natural fractures and fissures or increase the length of the pay zone;
"**hydrocarbons**"	naturally occurring organic compounds comprising hydrogen and carbon such as natural gas, oil and coal;
"**MBbl**"	thousand barrels;
"**MMBbl**"	million barrels;
"**MBOPD**"	thousand barrels of oil per day;
"**mmcf**"	million cubic feet;
"**mmcfd**"	million cubic feet per day;
"**OOIP**"	original oil in-place;
"**OPEC**"	Organisation of the Petroleum Exporting Countries;
"**probable reserves**"	reserves which, based on the available evidence and taking into account technical and economic factors, have at least a 50 per cent. chance of being produced;
"**Profit Oil**"	the amount of production, after deducting Cost Oil production allocated to costs and expenses, that will be divided between the participating parties and the host government under the production sharing contract;
"**prospective resources**"	those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations;
"**proved reserves**"	reserves which, based on the available evidence and taking into account technical and economic factors, have at least a 90 per cent. chance of being produced;
"**re-completion**"	after the initial completion of a well, the action and techniques of re-entering the well and redoing or repairing the original completion to restore the well's productivity;
"**recovery**"	the fraction of hydrocarbons that can or has been produced from a well, reservoir or field;
"**reserves**"	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, reference should be made to the full Petroleum Reserves Management System ("PRMS") definitions for the complete definitions and guidelines;

"**reservoir**"	an underground porous and permeable formation where oil and gas has accumulated;
"**resources**"	contingent and prospective resources, unless otherwise specified;
"**shale**"	a fine grained, fissile, detrital sedimentary rock that can include relatively large amounts of organic material and thus has potential to become a rich hydrocarbon source rock;
"**side-track**"	drilling of a secondary wellbore away from an original wellbore. Side-tracks might bypass an unusable section of the original wellbore or explore a geologic feature nearby. In the bypass case, the secondary wellbore is usually drilled substantially parallel to the original well, which may be inaccessible due to junk in the hole, or a collapsed wellbore; when exploring new nearby geologic features, the secondary wellbore may be deviated at an angle away from the original wellbore or drilled horizontally away from the original vertical wellbore;
"**wellbore**"	the drilled hole of borehole, including the openhole or uncased portion of the well;
"**workover**"	the process of performing major maintenance or remedial treatments on an oil or gas well.

PART I

INFORMATION RELATING TO THE GROUP

1. Introduction and background

The Company was until April 2017 a gold and copper focussed exploration company with interests in projects primarily in Ghana and Mauritania, and carried the name Goldcrest Resources plc. In April 2017 the Company amended its strategy to focus on oil and gas projects with an emphasis on investment opportunities in the Republic of Georgia. It changed its name to Block Energy plc in May 2017, and is now an owner of three oil and gas assets in the Republic of Georgia, two of which have existing oil production. These are the Norio PSA, in which the Company has a 100% working interest, and the Satskhenisi PSA, in which it has a 90% working interest. In addition, the Company's subsidiary GNV has a 5% interest in the West Rustavi PSA, with the option to increase its working interest to 75% (although the West Rustavi PSA is yet to come into effect pending the satisfaction of routine conditions). The owner of the balance of the working interests in the Satskhenisi PSA and the West Rustavi PSA, GOG, is an established operator and drilling service provider in Georgia. GOG is an established operator, and is one of the Company's service providers.

All three licence blocks are located east of the Black Sea in the Kartli Basin (also referred to as the Kura Basin), an oil and gas province located in the eastern part of Georgia. Map 1 and Map 2 show the location of the licence blocks within Georgia. Within the Kartli Basin, approximately 15 oil and gas fields have been discovered over the years, amongst which the 236 MMBbl Samgori-Patardzeuli and the 58 MMBbl Ninotsminda fields are the best known. The Kartli Basin is coincident with the Kura River valley and is a tectonically complex area situated to the south of the Greater Caucasus.

Modified from Frontera Resources Corporation

Map 1: Index Map of the Republic of Georgia and the Area of Interest

Map 2: Map of Georgia Licence Blocks with Block Energy Licence Areas

2 Key Strengths

The Directors believe that the key strengths of the Company include:

- Operating in a proven yet relatively under-developed hydrocarbon region, specifically the Kura basin which at its peak produced ~70,000 bopd from one single field in Georgia;
- Ownership of interests in three Production Sharing Agreements ("PSAs"): a 100% working interest in the Norio PSA, a 90% working interest in the Satskhenisi PSA, and a 5% interest in the West Rustavi PSA, with an option to increase to 75% (subject to satisfaction of conditions as set out in paragraph 13 ix of Part V of this document);
- Existing production – the Company already operates and is producing oil, albeit small quantities currently, in Norio and Satskhenisi at a commercial level;
- Proven reserves – the areas covered by Norio and Satskhenisi PSAs hold gross (2P) oil reserves of 1.6 MMBbl, which have been assigned an NPV10 of $29.73m, and 35MMBbls of gross unrisked (2C) contingent oil resources;
- The area covered by the West Rustavi PSA holds gross (2P) oil reserves of 0.92MMBbls, which have been assigned an NPV10 of $9.6m, and 37.9MMBbl of gross unrisked (2C) contingent oil resources, together with 608Bcf of gross unrisked (2C) contingent gas resources. West Rustavi area is contiguous with the licence owned by Schlumberger;
- A three phase development strategy is in place to exploit the Group's current and prospective Georgian interests;
- Phase I over the next 12 months – and funded by Placing and Subscription proceeds and revenues – involves scaling up existing oil production via a programme of low cost, low risk workovers re-completions and side-tracks of existing wells at Norio, Satskhenisi and West Rustavi;
- A management team with significant collective experience of operating in the oil and gas industry, and specifically within the Republic of Georgia;
- Close working relationship with GOG, a well established Georgian operator which produces from and explores in licences adjoining those of the Company. GOG is a joint venture partner in two of the Company's licences, is a shareholder in Block Energy and acts as its operator under the Satskhenisi PSA and Norio PSA; and

- Company's current PSAs located in areas close to significant oil and gas infrastructure and transportation links.

3. Current Oil and Gas Assets

Norio

Location

The Norio Block area is approximately 5,570 acres (22.54 km^2) and is located 22 miles (35 km) north of Tbilisi.

Ownership

The Company, via its subsidiary GOG Norioskhevi, has a 100% working interest in the Norio PSA. Details of the acquisition of GOG Norioskhevi are set out in paragraph 13iv of Part V of this document.

The Norio PSA Block

The Norio Block contains the Norio field, which was discovered in 1938. To date, a total of 55 oil wells have been drilled on the block. Out of the 55 wells, 31 produced oil from the Miocene age Chokrak formation. This reservoir is a fractured, volcanic-sourced arkosic sandstone formation that has been subjected to complex thrust faulting that has created compartments of oil accumulation. Production from the field commenced in 1939 with an estimated cumulative production of 1.8MMBbl and continues producing today from three wells at a total rate of around 12bopd as of November 2017. The Company has access to extensive existing data relating to the Norio field, including 400km of seismic data.

Georgian Legal Opinion

In the opinion of BLC Law Office, the Company's Georgian counsel, GOG Norioskhevi Limited is the legal and beneficial owner of a 100% interest in the Norio PSA, whose licence has been validly issued on behalf of the Georgian State by the Oil and Gas Agency pursuant to the law on Oil and Gas and is in good standing, and which interest has been validly acquired by and registered in the name of GOG Norioskhevi; and the obligations of the parties to the Norio PSA constitute legal, valid, binding and enforceable obligations.

Reserves

The current reserves position of the Norio Block is as set out in the table below, which is directly extracted from page 50 in Part III (Competent Person's Report) of this document:

Reserves and Future Cash Flow Projections, Norio

	Oil Reserves, MBbl											
	Gross			Net			Net Cash Flow, MM$			Net Present Value Discounted at 10%, MM$		
Reserve Classification	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)
Producing	28.1	32.7	37.2	16.7	21.7	28.5	0.2	0.2	0.4	0.1	0.2	0.3
Developed Non-Producing	65.8	93.0	167.5	61.6	80.9	133.5	1.0	2.3	5.7	0.6	1.5	3.8
Undeveloped	805.2	1,505.3	2,328.6	603.5	1,005.2	1,334.9	20.0	43.1	61.3	10.9	27.8	41.0
Total	**899.2**	**1,630.9**	**2,533.3**	**681.8**	**1,107.8**	**1,496.9**	**21.2**	**45.6**	**67.4**	**11.6**	**29.5**	**45.1**

For 100% Working Interest. Net is net of government share.
(MBbl = thousand barrels of oil; MM$ = millions of US$)

Norio Production Sharing Agreement

The Norio PSA has a 25 year initial term running to April 2026. In April 2017, Block Energy purchased an initial 38% interest in the Norio PSA from GOG, increasing to 69% in July 2017 and 100% in September 2017.

Block Energy's subsidiary, GOG Norioskhevi, is now the contractor of the Norio Block and is responsible for providing all financial and technical requirements relating to the exploration and exploitation of petroleum in that area. Prior to the Company acquiring its interests in Norio, the operator under the Norio PSA was NOC, a company owned by GOG. For the time being, NOC shall continue to act as operator under the Norio PSA, pursuant to which the Company shall pay to NOC a fee of US$12,500 per calendar month. These costs are included in the economics; however, they are allocated differently between the Norio and Satskhenisi licenses. In addition, GOG Norioskhevi has established a branch office in Georgia which shall be the operator under the Norio PSA and shall be responsible for performing petroleum operations in the Norio Block post Admission once it has the resource and capability to do so.

The parties to the Norio PSA are compensated for their services by receipt of their share in the petroleum produced in the Norio permit. Firstly, operation expenses (including production, processing, transportation, training and administration expenses) are recovered from all available petroleum (''Available Oil''). Secondly, capital expenditure (including drilling costs and development expenditures and exploration expenditures) and all historical capital costs not yet recovered shall be recovered from a maximum of 50% of remaining petroleum (''Cost Oil'') following the recovery of operation expenses. Such capital expenditure is recoverable according to the date it was incurred, earliest first. Thirdly, following the recovery of operation expenses and capital expenditure, the remaining petroleum (''Profit Oil'') shall be allocated between Georgian Oil and GOG Norioskhevi as to 50% each (if such split occurs prior to the date on which the proceeds from the sale of all petroleum produced are equal to GOG Norioskhevi's costs and expenses.) Fourthly, following the date on which the proceeds from the sale of oil and gas produced are equal to GOG Norioskhevi's costs and expenses, then the proceeds shall be allocated between Georgian Oil and GOG Norioskhevi as to 60% to Georgian Oil and 40% to GOG Norioskhevi. If outstanding recoverable operation expenses and capital expenditure exceed Cost Petroleum in any calendar year, the excess shall be carried forward year on year up until the termination of the Norio PSA (following which no such costs and expenses will be recoverable). The Georgian government pays all taxes from its share of the profit.

Further details of the Norio PSA are set out in paragraph 13 vi of Part V of this document.

Satskhenisi

Location

The Satskhenisi Block is approximately 6,024 acres (24.38 km^2) and is located 20 miles (32 km) north of Tbilisi.

Ownership

Block Energy, via its subsidiary Satskhenisi Ltd, has a 90% working interest in the Satskhenisi Block. The remaining 10% is owned by GOG. Details of the acquisition of Satskhenisi Ltd are set out in paragraph 13 i of Part V of this document.

Satskhenisi Block

The Satskhenisi Block contains the Satskhenisi field, which was discovered in 1956. To date, a total of 64 oil wells have been drilled on the block. Out of the 64 wells, 14 wells produced oil from the Lower Miocene age Maikop formation. This reservoir is a fractured, volcanic-sourced arkosic sandstone formation that has been subjected to complex thrust faulting that has created compartments of oil accumulation similar to Norio. Production from the field commenced in 1956 with an estimated cumulative production of 326.5 MBbl and continues producing today from four wells at a total rate of 5 bopd with very little water.

Georgian Legal Opinion

In the opinion of BLC Law Office, the Company's Georgian counsel, Satskhenisi Ltd is the legal and beneficial owner of a 90% interest in the Satskhenisi PSA, whose licence has been validly issued by the on behalf of the Georgian State by the Oil and Gas Agency pursuant to the law on Oil & Gas, and is in good standing, and which interest has been validly acquired by and registered in the name of ''Satskhenisi Georgia''; and the obligations of the parties to the Satskhenisi PSA constitute legal, valid, binding and enforceable obligations.

Reserves

The current reserves position of the Satskhenisi Block is as set out in the table below, which is directly extracted from page 50 Part III (Competent Person's Report) of this document.

Reserves and Future Cash Flow Projections, Satskhenisi

	Oil Reserves, MBbl											
	Gross			Net			Net Cash Flow, MM$			Net Present Value Discounted at 10%, MM$		
Reserve Classification	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)
Producing	4.4	4.4	4.4	2.3	2.3	2.4	0.03	0.03	0.03	0.03	0.03	0.03
Developed Non-Producing	7.2	9.4	12.9	5.6	7.3	10.3	0.19	0.26	0.39	0.16	0.20	0.29
Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00
Total	**11.6**	**13.8**	**17.3**	**7.9**	**9.6**	**12.7**	**0.22**	**0.29**	**0.42**	**0.18**	**0.23**	**0.32**

For 90% Working Interest. Net is net of government share and partner's interests.
(MBbl = thousand barrels of oil; MM$ = millions of US$)

Satskhenisi Production Sharing Agreement

In July 2017, the Company acquired the 90% interest in the Satskhenisi PSA by virtue of the acquisition of Satskhenisi Ltd from Iskander Energy Corp. GOG owns the remaining 10% interest in the Satskhenisi PSA.

The Satskhenisi PSA has a 25 year initial term and is effective until April 2026 with an optional five-year renewal. There are no outstanding work obligations related to the permit. The provisions of the agreement are identical to the terms for the Norio permit set out on page 16 above.

Prior to the Company acquiring its interests in Satskhenisi, the operator under the Satskhenisi PSA was NOC, a company owned by GOG. For the time being, NOC shall continue to act as operator under the Satskhenisi PSA, pursuant to which NOC shall be entitled to a fee of US$5,555 per calendar month, $5,000 of which shall be payable by Satskhenisi Ltd. These costs are included in the economics; however, they are allocated differently between the Norio and Satskhenisi licenses.

The parties to the Satskhenisi PSA are compensated for their services by receipt of their share in the petroleum produced in the Satskhenisi permit in the same manner as the parties to the Norio PSA.

Further details of the Satskhenisi PSA are set out in paragraph 13 ii of Part V of this document.

West Rustavi (Permit XIf)

Location

The West Rustavi Block area is approximately 9,328 acres (37.75 km2) and is located 6 miles (10 km) south-east of Tbilisi and approximately 14 miles (23 km) south of the Norio Field.

Ownership

Block Energy owns 100% of GNV, which it acquired in June 2017 from GOG. GNV holds a 5% interest in the West Rustavi PSA; and the remaining 95% is presently held by GOG.

The Company can increase its interest in the West Rustavi PSA to up to 75% by exercising an option granted to it by GOG pursuant to the GNV SPA, details of which are set out below:

The option is subject to the Company's shares being admitted to AIM before the date falling 3 months after the date on which the West Rustavi PSA was entered into (being 28 March 2018). The option is exercisable in the following 3 stages:-

Stage 1 – (to be exercised and fulfilled within 10 days of the Company being admitted to AIM) GNV may acquire an additional 20% participating interest in the West Rustavi PSA from GOG in consideration for which either the Company or GNV shall pay to GOG either (i) US$1,500,000 or (ii) US$500,000 and shares in the Company equalling a price of US$1,000,000;

Stage 2 – (to be exercised and fulfilled within 3 months of the Company being admitted to AIM) GNV may acquire an additional 25% participating interest in the West Rustavi PSA from GOG if by such time (i) GNV has conducted work overs or prepared wells for side-tracks in Block XIF, and (ii) paid an amount of US$ 1,000,000 to LLC Norio Operating Company to fund these works for the benefit of GNV, such amounts to be paid in 3 tranches prior to exercise of stage 2 of the West Rustavi Option; and

Stage 3 – (to be exercised and fulfilled within 6 months of the Company being admitted to AIM). GNV may acquire an additional 25% participating interest in the West Rustavi PSA from GOG in consideration for which either the Company or GNV shall (i) perform a side-track in each of two wells and for these purposes transfer to LLC Norio Operating Company no less than US$ 3,000,000 in aggregate (ii) purchase production facilities up to a maximum amount of US$ 1,000,000 for use in connection with the West Rustavi PSA. If these obligations of GNV are only partially satisfied, the additional interest in the West Rustavi PSA shall be increased by a proportionate amount to which the obligations have been satisfied.

Further consideration may be payable in the event that daily average production reaches pre-determined levels over specified periods, as more fully detailed in the West Rustavi SPA which is described in paragraph 13 viii of Part V of this document.

The West Rustavi Block (Permit XIf)

Permit XIf contains the West Rustavi Field, which was discovered in 1988 by well 16a. A total of 13 wells have been drilled on the block. The field has produced 41 MBbl and 41 MMcf from two wells completed in the Middle Eocene horizon and is currently not producing.

The West Rustavi area has multiple vertical wells that have tested oil and gas from multiple geological formations including the lower, middle and upper Eocene and Upper Cretaceous from depths of approximately 2000-4000m. One well in the field has produced over 40,000 Bbls and another well on just outside the Permit border produced 440,000 Bbl of light sweet oil from the middle Eocene reservoir.

Georgian Legal Opinion

In the opinion of BLC Law Office, the Company's Georgian counsel, Georgian New Ventures Inc is the legal and beneficial owner of a 5% interest in the West Rustavi PSA, whose licence has been validly issued by the on behalf of the Georgian State by the Oil and Gas Agency pursuant to the law on Oil & Gas, and is in good standing, and which interest has been validly acquired by and registered in the name of "Georgian New Ventures Inc"; and the obligations of the parties to the West Rustavi PSA constitute legal, valid, binding and enforceable obligations. However, the West Rustavi PSA is not yet effective and operational pending the satisfaction of the conditions precedent contained in the West Rustavi PSA. Satisfying these conditions precedent is a routine procedure which is usually satisfied without any impediments provided that the applicant complies with the relevant requirements of Georgian law. Until the West Rustavi PSA becomes effective, GNV will not be able to realise any value from the West Rustavi PSA.

Reserves

The current reserves position of West Rustavi (based on a 75% working interest, being the maximum Block Energy can obtain) is as set out in the table below, which is directly extracted from page 50 in Part III (Competent Person's Report) of this document:

Reserves and Future Cash Flow Projections, West Rustavi

	Oil Reserves, MBbl											
	Gross			Net			Net Cash Flow, MM$			Net Present Value Discounted at 10%, MM$		
Reserve Classification	**P_{90} (1P)**	**P_{50} (2P)**	**P_{10} (3P)**	**P_{90} (1P)**	**P_{50} (2P)**	**P_{10} (3P)**	**P_{90} (1P)**	**P_{50} (2P)**	**P_{10} (3P)**	**P_{90} (1P)**	**P_{50} (2P)**	**P_{10} (3P)**
Producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Developed Non-Producing	470.8	906.8	1,606.2	210.7	347.8	565.2	6.1	13.6	25.6	4.1	9.6	18.4
Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00
Total	**470.8**	**906.8**	1,606.2	**210.7**	**347.8**	**565.2**	**6.1**	**13.6**	**25.6**	**4.1**	**9.6**	**18.4**

For 75% Working Interest. Net is net of government share and partner's interest.
(MBbl = thousand barrels of oil; MM$ = millions of US$)

Note: the figures for West Rustavi show a 75% working interest. Block Energy has a 5% interest in the West Rustavi PSA at present, and the Company has an option to increase its interest to 75% as described in paragraph 13 ix of Part V of this document.

West Rustavi Production Sharing Agreement

The West Rustavi PSA provides access to increased production potential in a field which directly neighbours the largest discovery in Georgia – Block XIb (in which Schlumberger has a 100% working interest).

The West Rustavi PSA shall have an initial term of 25 years from its effective date (following the satisfaction of conditions precedent) with an optional five-year renewal. The provisions of the agreement would include that cost recovery of both capital and operating costs is limited to 50% of the revenue from sales of hydrocarbons before sharing with the government. The government would pay all taxes from its share of Profit Oil. Profit Oil is to be split 50/50 until payout, defined as the time when all cumulative revenues from Cost Recovery and Profit Oil exceed cumulative capital expenditure, including the historic cost recovery pool. After payout, the Profit Oil split would be 60% for the Government and 40% for the Contractor.

Further details of the West Rustavi PSA are set out in paragraph 13 ix of Part V of this document.

Contingent Resources

The contingent resources within the Norio Block, Satskhenisi Block and West Rustavi Block are as follows, which are directly extracted from page 56 in Part III (Competent Person's Report) of this document.

Gross Unrisked Contingent Resource Estimates by Area

	Contingent Oil/Condensate Resources, MMBbl			Contingent Associated/Free Gas Resources, Bcf			
Block	**Low Estimate (1C)**	**Best Estimate (2C)**	**High Estimate (3C)**	**Low Estimate (1C)**	**Best Estimate (2C)**	**High Estimate (3C)**	**Risk Factor**
Norio	3.1	7.2	13.9	0.8	1.9	3.7	75%
Satskhenisi	16.4	27.8	43.7	9.3	16.4	26.5	75%
Sub-total	**19.5**	**35.0**	**57.6**	**10.1**	**18.3**	**30.2**	
West Rustavi*	18.6	37.9	69.3	314	608	1,000	75%
TOTAL	**38.1**	**72.9**	**126.9**	**324**	**626**	**1,030**	

(MBBbl = million barrels of oil; BCF = billion cubic feet)

***Note: Block Energy has a 5% interest in the West Rustavi PSA at present, and the Company has an option to increase its interest to 75% as described in paragraph 13 ix of Part V of this document.**

Block Energy WI Share Unrisked Contingent Resource Estimates by Area

	Contingent Oil/Condensate Resources, MMBbl			Contingent Associated/Free Gas Resources, Bcf			
Block	**Low Estimate (1C)**	**Best Estimate (2C)**	**High Estimate (3C)**	**Low Estimate (1C)**	**Best Estimate (2C)**	**High Estimate (3C)**	**Risk Factor**
Norio	3.1	7.2	13.9	0.8	1.9	3.7	75%
Satskhenisi	14.7	25.0	39.3	8.4	14.7	23.9	75%
Sub-total	**17.8**	**32.2**	**53.2**	**9.2**	**16.6**	**27.6**	
West Rustavi*	13.9	28.4	52.0	235	456	750	75%
TOTAL	**31.8**	**60.6**	**105.2**	**244**	**473**	**778**	

(MBBbl = million barrels of oil; BCF = billion cubic feet)

*** Note : the figures for West Rustavi show a 75% working interest. Block Energy has a 5% interest in the West Rustavi PSA at present, and the Company has an option to increase its interest to 75% as described in paragraph 13 ix of Part V of this document.**

Prospective Resources

The prospective resources within the Norio Block, the Satskhenisi Block and the West Rustavi Block are as set out in the table below, which is directly extracted from page 56 in Part III (Competent Person's Report) of this document.

Gross Unrisked Prospective Resource Estimates by Area

	Prospective Oil/Condensate Resources, MMBbl			Prospective Associated/Free Gas Resources, Bcf			
Block	**Low Estimate**	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**	**Risk Factor**
Norio	1.4	3.1	5.2	1.0	2.2	3.7	60%
Satskhenisi	0.0	0.0	0.0	0.0	0.0	0.0	—
Sub-total	**1.4**	**3.1**	**5.2**	**1.0**	**2.2**	**3.7**	
West Rustavi	0.0	0.0	0.0	0.0	0.0	0.0	—
TOTAL	**1.4**	**3.1**	**5.2**	**1.0**	**2.2**	**3.7**	

(MBBbl = million barrels of oil; BCF = billion cubic feet)

4 Information on Georgia

Georgia lies at the cross roads of Western Asia and Eastern Europe, between Turkey and Russia. It also shares boundaries with the Black Sea to the west and Armenia and Azerbaijan to the south. The country covers a land area of approximately 69,700 km^2 and has a total coast line of 310 km^2. The population of Georgia is approximately 4.9 million, of which 1.5 million reside in the capital and largest city, Tbilisi.

Oil & Gas in Georgia – History

Numerous surface oil seeps have been known and utilised in Georgia (Nibladze and Janiashvili, 2014). Exploration in the country began in the late 19th century with shallow drilling beneath surface seeps. By 1866, more than 100 shallow wells (less than 100 meters (328 feet)) had been drilled in eastern Georgia. As oil production grew, two oil refineries were built.

Modern exploration began in 1928 with a oil well drilled to 540 meters. This oil discovery opened the Mirzaani field located in southeast Georgia. Total production is reported at 7.9 MMBbl (Nibladze and Janiashvili, 2014).

After World War II, drilling targets were anticlines identified on seismic. More than 1,300 wells were drilled during the Soviet Era and small discoveries were made.

The state company GruzNeft was the only licence holder in the country between 1930 and 1994, during which time 197 MMBbl were produced. Peak production was achieved in 1981 with rates around 70 MBoPD. Also during this time, seventeen oil fields were discovered, 5 of which were commercially successful.

Only two large discoveries were made in the Kura Basin, the Samgori-Patardzeuli-South Dome (Samgori) Field and its eastward extension, the Ninotsminda Field. The Samgori Field was discovered in 1974. It has a cumulative production of 210 MMBbl and is still producing. Initial flow rates in the field were as high as 5,000 bopd per well. The Ninotsminda Field is significant as the field is a direct analogue to West Rustavi XIf and has produced 12 MMBbl of oil and 8.5 BCF of gas to date and is still being developed. Well flow at rates around 1,200-1,500 bopd have been achieved. Performance in both these fields is dependent on fractures and has been from the thick middle Eocene section. Ninotsminda is significant as 5 horizontal side-track re-entries were drilled in the mid/late '90's by Canargo. According to GOG, these horizontal wells intersected multiple natural fractures and in excess of 1.5 MMBbl was produced from these five wells. The program was terminated by Canargo due to the very low oil prices being realized during this period.

Approximately fifteen companies have held PSA's in Georgia since 1994, with nine companies doing so at present. Between 1994 and 2012, 10.7 MMBbl of oil was produced from existing fields, but no new commercial discoveries have been made.

Many of the discoveries in Georgia have been in the foreland basins and fold and thrust belts. To date, five oil fields have been discovered and eighteen additional discoveries have been made, fifteen of which are in Georgia's portion of the Kura Basin.

Currently, the Georgian oil and gas industry is mainly in the exploration and redevelopment stage, and by applying modern technologies, the Directors believe that there is real potential to increase cumulative production dramatically in the short to mid-term.

Political Landscape – Overview

Georgia's geostrategic location and political stability defines the country's role as a dynamic transportation corridor for oil and gas, evidenced by BP's (and co-venturers') recent $2 billion pipeline project. Approximately one per cent. of the world's hydrocarbons pass through Georgia every day.

Since regaining its independence, Georgia has focused on improving its democratic governance and becoming integrated with Euro-Atlantic institutions. This began in 2003 when Georgia's new government actively engaged itself in rooting out endemic corruption in public administration. The efforts resulted in Georgia's success in becoming a regional leader in implementing anti-corruption reforms and eradicating lower/mid-level corruption; it now ranks better than Italy and is close to Spain on Transparency International's corruption perceptions index.

Following the 2012 Parliamentary elections, Georgia began its path of European integration, signing the Association Agreement with the European Union ("EU"), including the Deep and Comprehensive Free Trade Agreement, with the EU in June 2014.

After the 2013 Presidential elections, won by President Giorgi Margvelashvili, Georgia began its transition from a presidential to a parliamentary system. President Margvelashvili is aligned with the Georgian Dream movement supported by its founder and former Prime Minister Bidzina Ivanishvili. As of 2016 the Prime Minister is Giorgi Kvirikashvili who represents the Georgian Dream party and is also supported by Bidzina Ivanishvili.

Oil and Gas in Georgia – Legal Framework

The main statutes, governing the Oil and Gas related issues within jurisdiction of Georgia are the (a) Law N1892 of Georgia on Oil and Gas, adopted on 16 April 1999 (as amended) (hereinafter – the "LOG"), along with (b) the National Rules Regulating Carrying Out of Oil and Gas Operations, as adopted by the National Agency of Oil and Gas on 9 April 2002 (as amended) on the basis of the above law. The General Licence to Utilize Oil and Gas Resources ((the "General Licence") is granted under the LOG and the Law N1775 of Georgia on Licences and Permits, adopted on 24 June 2005 (as amended). The LOG states, that along with creation of a unified legal framework for the development of oil and gas resources and oil refining, gas processing or transportation activities, one of its main aims is to promote investments in the field of oil and gas and protect legitimate interests of the entities involved in oil and gas operations in Georgia. Hence, the Oil and Gas legislation of Georgia can reasonably be described as being investor-friendly.

The oil and gas resources existing in the subsoil within the territory of Georgia are recognized as property of the State. Private persons are granted a right to explore and extract oil and gas resources under the General Licence. The General Licence, along with respective licence block (a piece of land within borders determined by the Agency based on its geological characteristics) is publicly tendered out by the State. Terms and conditions of the tender process are determined by the Agency and the tender itself is registered by the Ministry of Justice a month prior to it being opened. The winning bidder receives the right to perform oil and gas operations on a respective licence block based on a negotiation of respective agreement with the State (usually a PSA) and the respective licence (terms of which are identical to those expressed in the PSA). The licence is automatically issued within 30 days after the respective PSA has been signed. Issues to be included in the PSA are regulated by LOG.

Key regulators of the sector are the Ministry of Economy and Sustainable Development of Georgia on a more general level, and the Agency as the executing body charged with day to day regulation of oil and gas operations in Georgia. The latter organizes public tenders of licence blocks, conducts negotiations of PSAs and issues respective licences. Furthermore, the Agency exercises control over compliance of the licence holder (the "Holder") with the terms of the PSA and the respective licence. Should the Holder be found to be in breach, the Agency is entitled to issue a warning or, if the circumstances justify, terminate the respective licence. Aside from the above regulators, an important player in the relevant field is Georgian Oil, which is actively involved in tendering, PSA negotiation and performance process and, among other, acts as a commercial partner on behalf of Georgia when performing under PSA (by participating in coordination committees, etc.).

To enable the Holder to properly carry out the oil and gas operations as set forth in relevant agreement and licence, the State, within its competence and provided that the Holder is not in breach of the applicable law, shall have the obligation to use its best efforts to assist the Holder to secure all additional approvals or permits needed to conduct such oil and gas operations in a timely manner, e.g. land access rights (with expropriation, if required and applicable), water use rights, etc.

The maximum statutory term of a General Licence is 25 years which may be extended at the initiative of the Holder for a period necessary and sufficient to economically and rationally extract, use and protect oil and gas. If the extension is necessary before the 25-year period expires, the term may be extended temporarily, but for not more than five years.

Due to the fact that the oil and gas resources existing in the subsoil within the territory of Georgia are recognized as property of the State, the latter has a share in any oil and gas extracted by the Holder within the licence block. The amount of the State's share shall be determined in the respective PSA.

The Agency, in the event that the respective Holder is in breach of the licence and/or PSA requirements, has the right to issue warning in the form of the sanction. Aside from issuance of warnings, the Agency is also authorized to reach a decision on termination of the licence, in the case of which the Holder shall be obliged to release the licence block and quit all oil and gas activity in relation thereto. Certain additional penalties may be envisaged in the respective agreement.

In the terms of assignment of the General Licence to a third party, two options are envisaged in the LOG, namely (a) transfer to an affiliate and (b) transfer to a third party. Transfer to an affiliate is relatively simple and requires only a 30 day prior notification sent to the Agency. No formal consent is required and no additional fees are payable. As for the transfer of the General Licence to a non-related third party, the Holder has to first relinquish its right to the respective licence and follow such relinquishment application with the seeker's application to the same licence block. The licence that has been transferred to a third person shall be effective for the remaining validity term of the previous licence and requires no payment of additional fee.

5 Group strategy for growth

The Company's strategy is focused on becoming one of the largest independent oil and gas companies in Georgia. Supported by one of its major shareholders, GOG, (see section 6 below) the Company plans to build a portfolio of low cost/high impact development assets in a proven region of Georgia and to scale up existing production and reserves via the implementation of low cost work programmes.

The Company currently owns a 5% working interest (GOG 95%) in the West Rustavi PSA and intends to seek to further exercise its option to acquire an additional 70% working interest by executing a defined development programme, which dove-tails into the Company's overall work programme.

The Directors intend that the proceeds of the Placing and Subscription, together with the cashflow from production from the workovers/re-completions, will be used to fund these developments. Once fully completed, the work programmes conducted during Phase I will satisfy the minimum work requirements set out under the Norio PSA and the West Rustavi PSA. Completion of Phase I would see the Company exercise its option over West Rustavi PSA up to the maximum 75% working interest.

The Company may in future consider farm-in agreements with third parties at project level, as a means of funding its capital and operational expenditure. At the present time, no such agreements are in contemplation.

Phase I (next 12 months)

Phase I involves scaling up existing oil production via a low cost, high impact workover, re-completion and side-track programme of existing wells as follows:

Norio and Satskhenisi

The Board plans to undertake five re-completions/workovers of existing wells and one side-track at Norio. This will involve cleaning up existing producing wells (cleaning/changing of pumps) and re-completing further existing wells utilising modern jetting technologies and re-perforations. One horizontal side-track from an existing well is planned. Given the shallow depths of the targets (1,000 to 1,500m) and proximity of the field to drilling equipment and transport facilities for oil sales, the Board expects its development plan to be efficiently rolled out rapidly to achieve an increase in field production. The Company has planned re-activations and re-completions of three historic wells at the Satskhenisi Block. In aggregate, the Company aims to increase production to 250 bopd within 12 months of the work programme commencing.

West Rustavi

The Directors proposal for the West Rustavi Block is to undertake workovers of up to five existing wells (moving the Block working interest in the West Rustavi PSA to 50%) following which the Company then intends to complete up to two horizontal or highly deviated side-tracks from existing wells targeting the Middle Eocene reservoir that has produced approximately 200 MMbbls within 20km of the West Rustavi permit. Drilling these wells will fulfil the Company's agreed expenditure under the West Rustavi SPA and thereby increase its working interest to 75%. Block Energy's proposed development plan follows a traditional step-by-step development and appraisal programme.

The first step is to re-enter up to 5 wells and to clean the wells of any debris or downhole "junk" left from former operators. The wells will also be logged to review previous oil and gas discovery intervals and affirm casing integrity and primary cement in each wellbore. In addition, this logging program will provide further geological information on the oil and gas productive intervals of each wellbore thereby optimizing perforating and testing programs. Following logging, it is intended the best two candidates will be selected to re-perforate proven oil zones and then be fitted with production equipment including bottom hole pumps and placed on production to evaluate the vertical well performance.

Following the well workovers to clean and log the wells, up to four wells will be selected for re-entry and horizontal well side-tracking operations. The Company aims to side-track two of the four wells, completing its farm-in to West Rustavi; and increase production up to 650 bopd within 12 months of the work programme commencing.

In the offset permit of Ninotsminda, horizontal side-tracks have been successful at converting wells near the end of their productive lives to productive wells producing an average of approximately 270 MBbls of light, sweet oil at first year average production rates of almost 400bopd. The Company believes that Schlumberger, the owner of the permit immediately to the north of West Rustavi, will be pursuing a similar re-entry and side-track type program in the same geological formation.

The gas potential of the Lower Eocene and Upper Cretaceous are key assets for the Company. The independent CPR reserves and resource study estimates that there are 2C resources of 456bcf net (608bcf gross) to Block Energy, assuming the Company completes the full earn-in program. Current gas prices in Georgia are over $5/mcf providing the Company with the commercial incentive to aggressively pursue a gas development strategy. As part of Phase I well re-entry program described above, the Company plans to re-enter two wells to re-perforate and test the Lower Eocene gas reservoir. This testing program will be designed to obtain critical reservoir data regarding reserve size, productivity and optimal completion design for future wells.

Phase II

Assuming modestly successful results from the two re-entries in the Lower Eocene gas reservoir in early 2018 (as Part of Phase I), the Company plans to move forward with contract discussions with the Georgian government and local industrial gas consumers, and intends to commission the acquisition of a 3D seismic survey that will delineate the gas and oil potential of the West Rustavi permit and provide critical information for future drilling locations.

Once the 3D seismic survey has been interpreted and analysed, it is intended that new horizontal wells will be planned and drilled to further delineate the Middle Eocene oil and Lower Eocene/ Upper Cretaceous gas reservoirs with the ambition of increasing the permit's gross oil production to over 2,000 bopd and providing sufficient evidence of gas reserves which will dove-tail into the Company's intention of securing a gas sales contract with already identified off-takers

Timing of this work will be scheduled behind the work of Schlumberger, which the Directors understand will be drilling two wells in Q2 2018, targeting the same play and gas bearing horizons as the Company. Collaborating on this work, thus enabling both parties to share knowledge and data, is a priority for the Company, prior to moving this stage of the work programme forward in West Rustavi.

Phase III

On the assumption that gas reserves and off-taker contracts described in Phase II above are entered into, and assuming significant oil production from the Middle Eocene reservoir, providing continuous and material cash flow, the Company intends to build the first module of a gas processing and sales facility. The intention would then be for additional gas production wells to be drilled to supply the local market. Oil production will be enhanced through further drilling of the Middle Eocene light oil reservoir leading into further field development and drilling of the Upper Eocene conventional/unconventional light over-pressured oil reservoir, which has estimated 2C gross contingent resources of over 12MMbbls light oil and 3.9bcf sweet gas (Source: Part III: CPR Table 7.5 on page 147 of this document).

The Directors intend that the proceeds of the Placing and Subscription, together with the cashflow from production from the workovers/re-completions, will be used to fund these developments. Once fully completed, the work programmes conducted during Phase I satisfy the minimum work requirements set out under the Norio PSA and the West Rustavi PSA. Completion of Phase I would see the Company exercise its option over West Rustavi PSA up to the maximum 75% working interest.

6 Relationship with GOG

GOG is an established owner of oil and gas assets in Georgia, having working interests in a number of PSAs, and is also owner of NOC, which, prior to Schlumberger's acquisition of participating interests in Blocks IX, X and XI(b) in May 2017, was one of the few service companies available in Georgia.

Consequent to Block Energy's acquisition of respective working interests in the Norio PSA and the West Rustavi PSA, GOG has acquired an equity interest in Block Energy of c12.7 per cent. of the Enlarged Issued Ordinary Share Capital. The Directors believe GOG is consequently aligned with the rest of the Company's shareholders.

GOG has agreed that, should its shareholding in the Company exceed 20% of the Enlarged Issued Ordinary Share Capital, it will enter into an appropriate relationship agreement with the Company.

7 Sale/Marketing of Oil & Gas

At present Block Energy is producing a small volume of oil from five wells at Norio and Satskhenisi. The Company's oil is gathered in at existing storage facilities at either Norio or a tank terminal in the nearby town of Lilo. Currently, oil is sold to local refineries for a price based on the Brent Crude Oil price less a local marketing/transportation discount of \$9-\$10/bbl. Oil sales have been occurring regularly for both Satskhenisi and Norio on a quarterly basis depending on local demand. As the Company's production increases, the Directors anticipate that moving oil to the Black Sea port and selling it on the open market will provide a better net price to the Company.

Minimum obligations under Share Purchase Agreements

Each of the Norio SPA and the GNV SPA contain minimum work requirements relating to workovers and / or side-tracking of existing wells to be undertaken by the Company within stipulated time frames. The Company intends to meet at least these minimum obligations, the funding for which will be provided by the proceeds of the Placing and Subscription together with expected revenue generated from the Company's producing wells (as enhanced by the workovers and side-tracks). In the event that these minimum work requirements are not undertaken on a timely basis, the Company's interest in Norio would be reduced (further details of which are set out in paragraph 13 iv of Part V of this document) and financial penalties shall be payable in respect of West Rustavi. There is no minimum work requirement in relation to the Satskhenisi SPA.

Other prospective investments

Pursuant to the Norio SPA, the Company was granted an option (with current 100% owner GOG) to acquire a 70% working interest in Block VIII. The option expired on 31 May 2017. However the Directors believes the opportunity remains available for the Company to resurrect this opportunity, although there are no current plans to do so.

8 Details of the Group's Prospects

The Directors believe that Block's Norio and Satskhenisi licences and interest in the West Rustavi licence provide an attractive combination of existing production and proven reserves. These reserves and resources, together with an experienced management team and established local partners, and with funding from the Placing and Subscription, provide an opportunity for the Company to embark on a multi-well programme to scale up production over the coming 12 months.

9 Summary financial information

Pro forma financial information on the Group for the period 1 July 2014 to 31 December 2017 is set out in Part IV (B) and (C) of this document. An unaudited *pro forma* statement of net assets is set out in Part IV (E) of this document.

10 Directors

Brief biographies of the current and proposed Directors are set out below. Paragraph 5 of Part V of this document contains further details of current and past directorships and certain other important information about the Directors.

Philip (Phil) Dimmock, Non-Executive Chairman (aged 71)

Philip spent a significant part of his career at BP in a wide variety of senior positions including manager of the Forties oil field, and UK Director of Ranger Oil Limited where he also held the post of vice president of the international division, and served as chairman. Philip was a non-executive director of Nautical Petroleum plc until its acquisition by Cairn Energy in 2012 and presently serves as a senior independent non-executive director of Gulf Keystone Petroleum plc. Philip graduated from Oxford with an MA in Physics. Philip will join the Board on Admission.

Paul Haywood, Chief Executive Officer (aged 36)

Paul has over 15 years' experience in operational and investment management for a range of private, corporate & institutional companies throughout Europe, Asia and the Middle East and has been instrumental in creating what is Block Energy today. Having spent more than 8 years in the Georgian oil and gas industry, Paul has a significant understanding of the entire commercial E&P process including project identification, acquisition, asset management and divestment, both as a contractor on behalf of private and public companies and as an advisor, where Paul worked as a consultant to PWC.

Paul is also a non-executive director of AIM quoted Oilex Petroleum Plc and a director of resource-focused advisory firm, Plutus Strategies Limited.

Niall Tomlinson, Executive Director (aged 36)

Niall Tomlinson is an experienced geologist with over ten years' experience across a number of commodities. Previously he was a director of Taoudeni Resources Ltd, which was acquired by the Company in 2016, Technical Manager for Alecto Minerals plc and a senior geologist with consultants SRK Exploration and geologist with mining major Rio Tinto. More recently, he has spent over 3 years assessing natural resource projects in Georgia. Niall holds an MSc in Metals & Energy Finance from Imperial College London, an MSc in Mining Geology from Camborne School of Mines and is a Chartered Geologist of the Geological Society of London. He is also a director of Plutus Strategies Limited.

Serina Bierer, Financial Director (aged 37)

Serina gained her MSci in Geological Sciences from the Royal School of Mines, Imperial College London in 2003. She qualified as a Chartered Accountant with BDO LLP, subsequently working in the Natural Resources team. Her client portfolio covered both oil and gas, and mining companies, with the latter years concentrated on Middle Eastern due diligence projects.

Serina has specialised in the AIM and ASX upstream oil and gas industry for over 10 years, with a proven track record of successfully delivering board strategy through financial management, planning, financial modelling, system integration, treasury management, joint interest partner ventures and structured finance activities. In addition, Serina has worked closely with overseas government and financial regulatory bodies, negotiating a range of applicable tax and financial reporting policies. Serina will join the Board on Admission.

Roger McMechan, Technical Director (aged 59)

Roger has over 30 years' experience managing domestic and international operations with senior managerial/executive roles at companies including Petro Canada, Burlington Resources, Winstar Resources (Algeria, Hungary, Romania and Tunisia) and Iskander Energy Corp. (Georgia, Ukraine, Bulgaria and Poland). He has extensive experience in new field development, mature field optimization, oil and gas well completions and stimulation as well as oil/gas opportunity evaluations. He has five years' experience of working in Georgia, including operations, crude marketing, new well drilling, old well workovers & recompletions. Roger has a BSc, Engineering. from the University of Waterloo, Canada and is a Professional Engineer registered in Alberta, Canada. Roger will join the Board on Admission.

Timothy (Tim) Parson, Non-Executive Director (aged 60)

Tim Parson is a Petroleum Engineer with almost 40 years global experience on and offshore from deep water operations in the Far East to onshore multi-rig operations in the Middle East, Amazon and Europe. Roles include Superintendent role at Schlumberger and Executive at Occidental Petroleum. Tim has degrees in Petroleum Engineering from the University of New South Wales and Business Management from Curtin University.

11 Reasons for the Placing and Subscription and use of proceeds

Block Energy is seeking Admission to trading on AIM in conjunction with a Placing and Subscription to raise £5 million (net of expenses of £730,000). These funds will be used to satisfy the Company's obligations under the West Rustavi SPA and the Norio SPA, and otherwise to contribute towards the funding of the Company's operating and capital expenditure requirements.

Upon Admission the outstanding £360,000 of Convertible Loan Notes (together with accrued interest) will be converted into 10,759,132 New Ordinary Shares at an issue price of 3.6 pence per share in line with the respective CLN Instrument summarised in paragraphs 13 xviii and xix of Part V.

In addition, the following New Ordinary Shares will be issued, subject to Admission:

4,695,717 New Ordinary Shares to GOG (to the value of $250,000) pursuant to the terms of the Norio SPA;

18,782,870 New Ordinary Shares to GOG (to the value of $1,000,000) pursuant to the terms of the GNV SPA;

637,500 New Ordinary Shares to Philip Dimmock (312,500 shares) and Timothy Parson (325,000 shares) to fulfil outstanding obligations under their respective letters of appointment;

420,000 New Ordinary Shares to Serina Bierer to fulfil outstanding obligations under a consultancy agreement between the Company and Bierer Resources Limited;

72,120 New Ordinary Shares in aggregate to Ryan Long, Charles Vaughan and Brian Rowbotham pursuant to the terms of the TRL SPA; and

212,053 New Ordinary Shares to suppliers.

The Directors believe that Admission will be beneficial to the Group for the following reasons:

- to enhance liquidity for the Company's shareholders and provide more direct access to the London capital markets;
- to enable the Company to access a wider range of potential investors and broaden its investor base;
- to improve the Company's ability to access further funding from international capital markets and to finance the future growth of the business consistent with its current strategy; and
- to enhance the Company's reputation and financial standing with its partners in Georgia.

12 Competent Person's Report

A technical report prepared in accordance with the 2011 Petroleum Resources Management System (as defined by the Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and the Society of Petroleum Evaluation Engineers), and the "AIM Note for Mining and Oil & Gas Companies" as published in June 2009 by the London Stock

Exchange that is effective 1 January 2018 (the "Competent Person's Report") prepared by Gustavson Associates is available in this document, and on the Company's website.

The Competent Person, whose name and address is set out at page 6 of this Admission Document, accepts responsibility for the information contained in the Competent Person's Report and has reviewed and approved the technical information contained in this Admission Document. To the best of the knowledge and belief of the Competent Person (who has taken all reasonable care to ensure that such is the case) the information contained in the Competent Person's Report is in accordance with the facts, and does not omit anything likely to affect the import of such information.

A competent person's report had been prepared by the Company with an effective date of 15 September 2017 which has not been used in this document because it is no longer in date as required by the AIM note for oil and gas companies. The Competent Person's Report used is an updated version of the 15 September 2017 report and reaches the same conclusions included therein.

13 Admission to AIM and dealings

Application has been made to the London Stock Exchange for the Enlarged Issued Ordinary Share Capital to be admitted to trading on AIM. It is expected that Admission will become effective, and dealings in the Ordinary Shares on AIM will commence, at 8.00 a.m. on 11 June 2018.

The New Ordinary Shares, when issued, will rank *pari passu* in all respects with the Existing Ordinary Shares including the right to receive all dividends and other distributions declared, paid or made after the date of issue. The Placing and Subscription are conditional, *inter alia*, upon Admission becoming effective.

No temporary documents of title will be issued. All documents sent by or to a placee, or at his direction, will be sent through the post at the placee's risk. Pending the despatch of definitive share certificates, instruments of transfer will be certified against the register of members of the Company.

The Company's Existing Ordinary Shares are admitted to CREST and it is expected that the New Ordinary Shares will be so admitted and accordingly enabled for settlement in CREST on the date of Admission. Accordingly, settlement of transactions in Ordinary Shares following Admission may take place within the CREST system if any individual Shareholder so wishes provided such person is a "system member" (as defined in the CREST Regulations) in relation to CREST.

CREST is a paperless settlement procedure enabling securities to be evidenced otherwise than by a certificate and transferred otherwise than by a written instrument in accordance with the CREST Regulations. The Articles permit the holding and transfer of Ordinary Shares to be evidenced in uncertificated form in accordance with the CREST Regulations. CREST is a voluntary system and holders of Ordinary Shares who wish to receive and retain share certificates will be able to do so.

14 Lock-in and orderly market arrangements

In compliance with the AIM Rules for Companies, the Directors and the Locked-in Persons have agreed not to, and to procure that their related parties will not, dispose of any interests in Ordinary Shares held by them for 12 months following Admission. For the following 12 month period, the Directors and the Locked-in Persons have agreed not to, and to procure that their related parties will not, dispose of any interest in Ordinary Shares held by them unless such disposals are effected through the Company's broker so as to ensure an orderly market in the Ordinary Shares.

The restrictions on the disposal of Ordinary Shares contained in the Lock-in Deeds do not apply in certain limited circumstances, including transfers to Connected Persons or disposals by way of acceptance of a recommended takeover offer for the entire issued share capital of the Company. Further details of the Lock-in Deeds can be found in paragraph 13 xxiv of Part V of this document.

15 Corporate Governance

The Directors recognise the value and importance of sound corporate governance. The Company intends, following Admission, so far as is practicable for a company of its size, to follow the QCA Code.

The Board will meet regularly to consider strategy, performance and the framework of internal controls. To enable the Board to discharge its duties, all directors will receive appropriate and timely information. Briefing papers will be distributed to all directors in advance of Board meetings. All Directors will have access to the advice and services of the Company Secretary, who will be responsible for ensuring that the Board procedures are followed and that applicable rules and regulations are complied with. In addition, procedures will be in place to enable the Directors to obtain independent professional advice in the furtherance of their duties, if necessary, at the Company's expense. On Admission, the Company will have in place an audit committee, a remuneration committee, a nomination committee and a disclosure committee with formally delegated rules and responsibilities.

a. Audit Committee

The Audit Committee will have the primary responsibility of monitoring the quality of internal controls and ensuring that the financial performance of the Group is properly measured and reported on. It will receive and review reports from the Group's management and external auditors relating to the interim and annual accounts and the accounting and internal control systems in use throughout the Group. The Audit Committee will meet not less than twice in each financial year and will have unrestricted access to the Group's external auditors. At Admission, the Audit Committee will comprise Philip Dimmock, Niall Tomlinson and Timothy Parson. Philip Dimmock will chair the committee.

b. Remuneration Committee and Nominations Committee

The Remuneration Committee will review the performance of the executive directors and make recommendations to the Board on matters relating to their remuneration and terms of service. The Remuneration Committee will also make recommendations to the Board on proposals for the granting of share options and other equity incentives pursuant to any employee share option scheme or equity incentive plans in operation from time to time.

The Nominations Committee will meet as and when necessary to consider appointments to the Board and senior management positions. In exercising this role, the Directors shall have regard to the recommendations put forward in the QCA Code and, where appropriate, the UK Corporate Governance Code. On Admission, each of the Remuneration Committee and the Nominations Committee will comprise Philip Dimmock and Timothy Parson. Timothy Parson will chair each committee.

c. Disclosure Committee

The Disclosure Committee will have the primary responsibility and authority to make decisions on disclosure delay for the purposes of MAR. On Admission, the Disclosure Committee will comprise Philip Dimmock as Chairman, Paul Haywood and Serina Bierer.

d. Share dealing code

The Board has adopted a share dealing code consistent with Rule 21 of the AIM Rules for Companies and MAR to regulate dealings in the Ordinary Shares by Directors and any other applicable employees (as defined by the AIM Rules for Companies). The Directors consider that this share dealing code is appropriate for a company whose shares are admitted on AIM.

The Company will take proper steps to ensure compliance by the Directors and applicable employees with the terms of the share dealing code and the relevant provisions of the AIM Rules for Companies (including Rule 21) and MAR.

16 Details of the Placing, the Subscription and Admission

The Company, the Directors, SPARK, Novum and Baden Hill have entered into the Placing Agreement in relation to the Placing, pursuant to which Novum and Baden Hill have conditionally agreed to use their reasonable endeavours to procure subscribers for the Placing Shares. The Placing is not underwritten or guaranteed.

Further details of the Placing Agreement are set out in paragraph 13 xvi of Part V of this document.

The Placing and the Subscription are conditional, amongst other things, upon Admission having become effective by no later than 8.00 a.m. on 11 June 2018 or such later time being no later than 8.00 a.m. on 30 June 2018, as the Company, SPARK, Novum and Baden Hill may agree.

In addition, a subscription for 8,925,000 Subscription Shares has been made directly with the Company.

17 Dividend policy

As the Company has not been profitable in the past, Block Energy currently has a distributable reserves deficit which means that legally it is not able to pay a dividend. The Directors intend, if the Group achieves profitability, to undertake a reduction of share premium account to remove this deficit which will allow the Directors to declare dividends, should they deem it appropriate to do so. Whilst the Directors do not expect to be in a position to declare a dividend in the short term, the Board wish to be in a position to do so once the Company becomes profitable and cash flow positive.

18 Share options and warrants

As at the date of Admission, the Company will have outstanding options and warrants to subscribe for an aggregate of 16,617,116 Ordinary Shares.

The Company is in the process of establishing two Enterprise Management Incentive (EMI) share option schemes – one specifically for the issue of options (over 4,400,000 new Ordinary Shares) which it is intended will be awarded to Paul Haywood at an exercise price of 2.5p subject only to the establishment of the scheme; and the other scheme will be for the issue of options to Directors and employees.

It is intended that a maximum of around 10 per cent of the Enlarged Issued Ordinary Share Capital will be subject to option grants under the latter scheme. The Remuneration Committee shall be responsible for determining the awarding of options and the performance conditions and vesting period attached thereto. It is anticipated that options will be granted over up to 25,800,000 Ordinary Shares at an exercise price of 4 pence (being the Issue Price) under the EMI Scheme(s) shortly after Admission, once clearance from HMRC has been received.

In addition, unapproved options over 1,200,000 new Ordinary Shares are being issued to Roger McMechan at an exercise price of 2.5p per share.

On 4 June 2018, and conditional upon Admission, the Company has granted warrants over 1,875,000 Ordinary Shares to Novum which are exercisable at 4p per Ordinary Share at any time up to 11 December 2019.

On 4 June 2018, and conditional upon Admission, the Company has granted warrants over 3,775,000 Ordinary Shares to Northland which are exercisable at 4p per Ordinary Share at any time up until 11 December 2019.

On 4 June 2018, and conditional upon Admission, the Company has granted warrants over 1,837,500 Ordinary Shares to Gneiss Energy Limited which are exercisable at 4p per Ordinary Share at any time up until 11 December 2019.

On 4 June 2018, and conditional upon Admission, the Company has granted warrants over 1,250,000 Ordinary Shares to SPARK which are exercisable at 4p per Ordinary Share at any time during the five years from Admission.

19 United Kingdom Taxation

Your attention is drawn to the UK taxation section contained in paragraph 10 of Part V of this document. These details are, however, intended only as a general guide to the current tax position under UK taxation law. If you are in any doubt as to your tax position, or are subject to tax in jurisdictions other than the UK, you are strongly advised to consult your own independent financial adviser immediately.

EIS and VCT status

VCT

The Company anticipates subscription by VCTs in Ordinary Shares should be regarded as a subscription in eligible shares and form a qualifying holding under the relevant legislation, however HMRC has informed the Company that it no longer considers speculative advance assurance applications.

EIS

Advance assurance has been obtained from HMRC that it is able to authorise the Company to issue certificates under section 204 of the Income Tax Act 2007 in respect of Ordinary Shares issued to individuals, following receipt from the Company of a properly completed compliance statement (EIS1 form) within the prescribed time limit stipulated in section 205(4) of the Income

Tax Act 2007. The status of the Ordinary Shares as qualifying for EIS purposes will be conditional on the qualifying conditions being satisfied throughout the relevant period of ownership. Neither the Company nor the Directors give any warranty, representation or undertaking that any investment in the Company by way of EIS shares will remain a qualifying investment for EIS purposes. EIS eligibility is also dependent on a Shareholder's own position and not just that of the Company. Accordingly, prospective investors should take their own advice in this regard.

The Directors and Proposed Directors consider that the Company or its subsidiaries will not have received, in the 12 months immediately prior to the Placing and Subscription, any investments (including under the SEIS, EIS and from VCTs) pursuant to a measure approved by the European Commission as compatible with Article 107 of the Treaty on the Functioning of the European Union in accordance with the principles laid down in the current Community Guidelines on State Aid to promote Risk Capital Investments in Small and Medium-sized Enterprises. Accordingly, the Placing and Subscription will be limited to funds not exceeding £5 million from EIS investors and VCTs in order to not exceed the maximum amount that can be raised annually through risk capital schemes.

20 Risk factors and further information

Your attention is drawn to the risk factors set out in Part II of this document. Prospective investors should, in addition to all other information set out in this document, carefully consider the risks described in those sections before making a decision to invest in the Company.

Your attention is also drawn to Part V of this document which provide additional information on the Company and the matters described in this Part I.

PART II

RISK FACTORS

AN INVESTMENT IN THE COMPANY IS SPECULATIVE AND INVOLVES A HIGH DEGREE OF RISK.

An investment in the Ordinary Shares involves a high degree of risk. Accordingly, prospective investors should carefully consider the specific risks set out below in addition to all of the other information set out in this document before investing in Ordinary Shares. The investment offered in this document may not be suitable for all of its recipients. Potential investors are accordingly advised to consult a professional adviser duly authorised under FSMA who specialises in advising on the acquisition of shares and other securities before making any investment decision. A prospective investor should consider carefully whether an investment in the Company is suitable in the light of their personal circumstances and the financial resources available to them.

In addition, it may be more difficult for an investor to realise his or her investment on AIM than it is to realise an investment in a company whose shares or other securities are quoted on the Official List. The AIM Rules for Companies are less demanding than the Listing Rules. Therefore, an investment in a share which is traded on AIM is likely to carry a higher risk than an investment in the same share if it were quoted on the Official List. The market for Ordinary Shares may be highly volatile and subject to wide fluctuations in response to a variety of factors, which could lead to losses for Shareholders. These factors include, amongst others, the following: changes in tax regime; additions or departures of key personnel at the Company; and adverse press, newspaper and other media reports.

The Directors believe the following risks to be the most significant for potential investors. However, the risks listed do not necessarily comprise all those associated with an investment in the Company and are not set out in any particular order of priority. Additional risks and uncertainties not currently known to the Directors, or which the Directors currently deem immaterial, may also have an adverse effect on the Company and the information set out below does not purport to be an exhaustive summary of the risks affecting the Company. In particular, the Company's performance may be affected by changes in market or economic conditions and in legal, regulatory and tax requirements. If any of the following risks were to materialise, the Company's business, financial condition, results or future operations could be materially adversely affected. In such cases, the market price of the Ordinary Shares could decline and an investor may lose part or all of his or her investment.

SPECIFIC RISKS RELATING TO AN INVESTMENT IN THE GROUP AND THE ORDINARY SHARES

Dependence on key executives and personnel, employee retention and recruitment

Block Energy has a comparatively small number of current and proposed employees. The future success of the Group depends partially on the expertise of the Directors. The loss of key personnel, and in particular Paul Haywood, Niall Tomlinson and Roger McMechan, and the inability to recruit further key personnel could have a material adverse effect on the Group's future by impairing the day to day running of the Group and its ability to exploit the opportunities open to it. An inability to attract or retain additional key personnel could have a material adverse effect on the Group's business and trading results. In addition, the loss of the services of the executive directors or other key employees could damage the Group's business.

Early stage of operations

Block Energy has only conducted operations in Georgia since 2017, having now disposed of its previous activities in Ghana and Mauritania. As such the Group itself has only a limited track record in the geography in which all its future operations will be managed.

Dependence on key relationships including, inter alia, the State, Georgian Oil and GOG

The success of the business of the Group and the effective operation of the Group's interests in Georgia is dependent in part on good relationships and co-operation with these parties. The State and Georgian Oil are counterparties to the Satskhenisi PSA and the West Rustavi PSA whereas GOG is a co-contractor to Block Energy in Satskhenisi, and also will be in West Rustavi. Accordingly if the State, the Agency and/or GOG are not able to co-operate with each other or the Company, it could have an adverse impact on the business, operations and prospects of the Group.

Foreign location of assets

All of Block Energy's operating assets are located in Georgia, whose laws differ materially from those in the UK, which may impede or adversely affect the ability of Block Energy and its Directors to manage its operations and protect its assets.

Main statutes, governing the Oil and Gas related issues within jurisdiction of Georgia are the (a) Law N1892 of Georgia on Oil and Gas, adopted on 16 April 1999 (as amended), along with (b) the National Rules Regulating Carrying Out of Oil and Gas Operations, as adopted by the National Agency of Oil and Gas on 9 April 2002 (as amended) on the basis of the above law.

The General Licence to Utilize Oil and Gas Resources ((the "General Licence") is granted under the LOG and the Law N1775 of Georgia on Licences and Permits, adopted on 24 June 2005 (as amended). The LOG states, that along with creation of a unified legal framework for the development of oil and gas resources and oil refining, gas processing or transportation activities, one of its main aims is to promote the attraction of investments in the field of oil and gas and protect legitimate interests of the entities involved in oil and gas operations in Georgia. Hence, the Oil and Gas legislation of Georgia can reasonably be described as being investor-friendly.

The LOG differentiates between the right of ownership on land, which can be held by any person, whether physical or legal (with a certain exceptions pertaining to agricultural land) and the right to oil and gas resources located beneath it. The oil and gas resources existing in the subsoil within the territory of Georgia are recognised as property of the State. Private persons are granted a right to explore and extract oil and gas resources under the General Licence, covering with two types of special sub-licences: a) a special licence to explore Oil and Gas Resources and b) a special licence to Extract Oil and Gas Resources. The General Licence, along with respective licence block (a piece of land within borders determined by the Agency based on its geological characteristics) is publicly tendered out by the State. Terms and conditions of the tender process are determined by the Agency and the tender itself is registered by the Ministry of Justice a month prior to it being opened. The winning bidder is determined on the basis of being able to satisfy all tender requirements and providing of the most commercially attractive offer. As a result, the winner receives the right to perform oil and gas operations on a respective licence block based on a negotiation of respective agreement with the State (usually a PSA) and the respective licence (terms of which are identical to those expressed in the PSA). The licence is automatically issued within 30 days after the respective PSA has been signed. Issues to be included in the PSA are regulated by LOG and include minimal volume of the pre-agreed work (seismic surveys, well drilling, etc.) to be performed on the licenced block, and the amount to be spent, the rights of ownership of the extracted oil and gas, etc.

Key regulators of the sector are the Ministry of Economy and Sustainable Development of Georgia on a more general, and the Agency as the executing body charged with day to day regulation of oil and gas operations in Georgia. The latter organises public tenders of licence blocks, conducts negotiations of PSAs and issues respective licences. Furthermore, the Agency exercises control over compliance of the licence holder (the "Holder") with the terms of the PSA and the respective licence. Should the Holder be found to be in breach, the Agency is entitled to issue a warning or, if the circumstances justify, terminate the respective licence.

Aside from the above regulators, an important player in the relevant field is Georgian Oil, which is actively involved in tendering, PSA negotiation and performance process and, among other, acts as a commercial partner on behalf of Georgia when performing under PSA (by participating in coordination committees, etc.).

The General Licence allows the Holder to perform oil and gas operations, namely prospecting and exploration and extraction activities in the subsoil of the relevant licence block, as well as activities directly related to these operations (collection, preparation, measurement and storage of the extracted oil and gas).

To enable the Holder to properly carry out the oil and gas operations as set forth in relevant agreement and licence, the State, within its competence and provided that the Holder is not in breach of the applicable law, shall have the obligation to use its best efforts to assist the Holder to secure all additional approvals or permits needed to conduct such oil and gas operations in a timely manner, e.g. land access rights (with expropriation, if required and applicable), water use rights, etc.

The right of exploration and exploitation of oil and gas resources granted under a General Licence is exclusive. The General Licence includes the right to both conduct exploration activities and extract the resources discovered. Third parties generally have no right to object to issuance of the General Licence to the Holder, as the licences are tendered out in public tenders and the winner is selected on the basis of objective criteria. Unless the third party challenging a particular General Licence is able to demonstrate that the tender process was carried out and/or completed in an unfair manner, the licence shall stay with its winning Holder until the expiration/termination thereof.

The maximum statutory term of a General Licence is 25 years which may be extended at the initiative of the Holder for a period necessary and sufficient to economically and rationally extract, use and protect oil and gas. If the extension is necessary before the 25-year period expires, the term may be extended temporarily, but for not more than five years. The procedure and conditions for extension of the validity of the term of a contract shall be determined by agreement of the parties to the PSA.

Citizens, legal persons or a combination – (consortium) – of legal persons of Georgia or foreign states that are involved in oil and gas prospecting and exploration and extraction and are using private, borrowed or raised funds for this purpose may become Holders of General Licence with no restrictions.

The cost of General Licence is payable by the winning bidder in a lump sum of 22,000 (twenty two thousand) GEL upon the issuance of the respective licence. The tender conditions may envisage provision of certain performance security in the form of bank guarantee or other.

Due to the fact that the oil and gas resources existing in the subsoil within the territory of Georgia are recognized as property of the State, the latter has a share in any oil and gas extracted by the Holder within the licence block. The amount of State's share shall be determined in the respective PSA.

The Agency, in the event that the respective Holder is in breach of the licence and/or PSA requirements, has the right to issue warning in the form of the sanction. Aside from issuance of warnings, the Agency is also authorized to reach a decision on termination of the licence, in the case of which the Holder shall be obliged to release the licence block and quit all oil and gas activity in relation thereto. Certain additional penalties may be envisaged in the respective Agreement.

In the terms of assignment of the General Licence to a third party, two options are envisaged in the LOG, namely (a) transfer to an affiliate and (b) transfer to a third party. Transfer to an affiliate is relatively simple and requires only a 30 day prior notification sent to the Agency. No formal consent is required and no additional fees are payable. As for the transfer of the General Licence to a non-related third party, the Holder has to first relinquish its right to the respective licence and follow such relinquishment application with the seeker's application to the same licence block. The Agency shall review the documentation and make a decision to issue a licence if it concludes that the seeker has sufficient financial and technical resources and relevant experience (qualifications) to carry out the activity under a business licence and perform duties delegated to it and an investment programme presented by an applicant is sufficient to conduct activities under the previous licence, taking account of the changed conditions, including prices, market demand, supply capacity for raw materials or oil and gas products or other relevant economic factors. The licence that has been transferred to a third person shall be effective for the remaining validity term of the previous licence and requires no payment of additional fee.

The Directors have experience of international business, with a strong focus on Georgia. It has a mature oil & gas industry stretching back over 25+ years and is a major transporter of oil from east to west. The Directors also believe that other international oil & gas operators in the region have positive experiences of operating in a stable and cooperative environment with authorities in Georgia. Further, declining production from the largest producing fields and governmental focus on energy security has further encouraged Georgian authorities to attract foreign investment to develop new assets and maintain or increase the country's production. PSAs in Georgia are within the bounds of accepted industry standards and, in many respects, are more favourable than many found in other jurisdictions around the world.

Asset concentration

Generally, risk is reduced through diversification. Diversification for an oil and gas exploration and production company can be achieved by operating in a number of countries and drilling a large number of wells over a large area of prospects having different geological characteristics. The Group will, for the time being, continue to focus its activities in the Kura Basin in Georgia. Although successfully identifying and prioritising specific prospects is an important aspect of an effective development strategy, the drilling and development programme will have only a relatively limited amount of diversification with a correspondingly higher degree of financial risk for investors.

West Rustavi PSA does not become effective

At the date of this document, the West Rustavi PSA, albeit signed and having been approved by certain governmental departments, has not become effective pending the satisfaction of certain conditions precedents, although this is anticipated shortly. However, failure to satisfy the conditions precedent will mean that the Company (which has a 5% working interest) and GOG (95% working interest) will not be able to realise any value from the West Rustavi PSA. Satisfying the conditions precedent contained in the West Rustavi is considered to be a routine procedure which is usually satisfied without any impediments provided that the applicant complies with the relevant requirements of Georgian law.

Substantial capital requirements and access to funding

The Company will use the Placing and Subscription proceeds, together with cash generated from operations, to fulfil at least the minimum requirements stipulated by the Share Purchase Agreements entered into by the Company in relation to its Georgian assets, and to execute its planned strategy. The Company's development strategy will require significant expenditure to fully exploit its potential. The Company will need to generate free cash flow from its operations, or to raise debt or equity funding during that period, to be able to finance these costs.

If the Company's revenues or reserves decline, it may have limited ability to expend the capital necessary to undertake or complete future drilling programs and may require additional financing to do so. If Block Energy is unable to raise funding to support ongoing operations and to fund capital expenditures it may limit the Company's growth or may have a material adverse effect upon the Company's financial condition, results of operations or prospects. The ability of Block Energy to arrange financing in the future will depend in part upon the prevailing capital market conditions, risk associated with Georgia, as well as the business performance of the Company. Fluctuations in oil and gas prices may affect lending policies for potential future lenders. This in turn could limit growth prospects in the short-term or may even require Block Energy to dedicate existing cash balances or cash flows, dispose of assets or raise new equity to continue operations under circumstances of declining energy prices, disappointing drilling results, or economic or political dislocation in Georgia.

There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. This may be further complicated by the limited market liquidity for shares of smaller companies, restricting access to some institutional investors. If additional financing is raised by the issuance of shares from treasury of Block Energy, control of the Company may change and shareholders may suffer additional dilution. The Company cannot predict the size of future issuances of equity or the issuance of debt or the effect, if any, that future issuances and sales of the Company's securities will have on the market price of the Company's shares.

Economic and market cycles and volatility

The Group's business may be affected by the general risks associated with all companies operating in the same markets. The markets in which the Group operates depend on numerous factors, many of which are beyond the Group's control and the exact effect of which cannot be accurately predicted. Such factors include general economic and political activities, including the extent of any governmental regulation and taxation. The Group could be affected adversely by changes in economic, political, administrative, taxation or other regulatory factors, whether under Georgian law or in any other jurisdictions in which the Group is subject to regulation.

Permits, licences and leases

Significant parts of the Company's operations require permits, licences and leases from various governmental authorities in Georgia. There can be no assurance that the Company will be able to obtain all necessary permits, licences and leases that may be required to carry out future exploration and development at our projects. If the present permits, licences and leases are terminated or withdrawn, such event could have an adverse negative effect of the Company's operations.

The Directors believe that the Group has the benefit of all material licences and permits which are necessary to carry on the activities required under applicable laws and regulations. The Directors believe that the Group is complying in all material respects with the terms of the licences and permits granted to it in order to undertake its activities in Georgia. Furthermore, the PSAs contain provisions obliging the government of Georgia to co-operate fully with the Group in obtaining all necessary consents and permits. Nevertheless, the Group's ability to obtain, sustain or renew such licences and permits on acceptable terms are subject to change in regulations and policies and to the discretion of the applicable regulatory authorities and governments.

Corruption

The Company's operations are governed by the laws of a number of jurisdictions, which generally prohibit bribery and other forms of corruption. The Company has policies in place to prevent corruption or bribery, which includes enforcement of policies against giving or accepting money or gifts in certain circumstances and an annual certification from each employee confirming that each employee has received and understood the Company's anticorruption policies. It is possible that the Company, some of its subsidiaries, or some of the Company or its subsidiaries' employees or contractors, could be charged with bribery or corruption as a result of the unauthorized actions of employees or contractors. If the Company is found guilty of such a violation, which could include a failure to take effective steps to prevent or address corruption by its employees or contractors, the Company could be subject to onerous penalties and reputational damage. A mere investigation itself could lead to significant corporate disruption, high legal costs and forced settlements (such as the imposition of an internal monitor). In addition, bribery allegations or bribery or corruption convictions could impair the Company's ability to work with governments or non-governmental organizations. Such convictions or allegations could result in the formal exclusion of the Company from a country or area, national or international lawsuits, government sanctions or fines, project suspension or delays, reduced market capitalisation and increased investor concern. Further, from time to time the Company may acquire a company that subsequently is subject to bribery or corruption charge, whereby the Company could assume onerous penalties and/or suffer reputational damage as a result of activities in which the Company has no part.

Obligations under exploration and production agreements

The current exploration and production licences, lease operatorship agreements and joint operating agreements with respect to Block Energy's properties contain significant obligations on the part of the Company or its subsidiaries including minimum work commitments on blocks held in Georgia which, upon a continuing default, could give rise to the termination or reduction of the Company's participating interest therein. There are no assurances that all of these commitments will be fulfilled within the time frames allowed. As such, Block Energy may lose certain exploration and production rights on the blocks affected and may be subject to certain financial penalties.

The Company's proposed development plans are subject to several operational risks

Both the drilling and workover programmes proposed to be carried out by the Group involve potentially complicated and difficult technical operations with which there are inherent risks. These include human error by the drilling operator, equipment failure, mistakes in the planning of the operations and the encountering of unforeseen difficulties within field operations. While these risks cannot be eliminated, they are to an extent mitigated because the geology and geophysics of Block Energy's assets are well known, in particular because of the number of wells previously drilled each of the licences. Block Energy has an experienced technical team who have worked in Georgia for many years. In addition, GOG has overseen the drilling of a number of wells in Georgia.

Block Energy's proposed work programme may yield no or low production

There is a risk that any new wells drilled in the licence areas in future will not produce oil in significant quantities or will fail to find any oil or gas reserves at all. Failure of the new drilling can be mitigated by re-perforating existing wells from which production already exists which is Block Energy's initial plan, however production from such workovers may not produce at the levels expected. The Company's current business plan is predicated on successfully achieving production in its licences, at least. Any failure to achieve such production at the predicted levels could have a material adverse effect on the Company's financial performance and prospects.

The Directors' estimates of capital required to fund drilling may be incorrect

The Directors have taken technical advice and received indicative cost estimates from contractors capable of carrying out the planned work on its licences. However, there can be no guarantee that when the work programme proceeds, forecast costs will match actuals. Further, during the work, costs can increase for a number of unexpected technical reasons. While the Directors have made allowances for contingencies in their planning, any material increase in costs would have an adverse effect on the cashflows of the Company in the short term and potentially its ability to complete all of the planned work using the capital raised during the Placing and Subscription.

Independent contractors and equipment may delay operations

Block Energy does not itself have the capability to carry out the planned work in the licences and, in common with most other operators, will engage specialist contractors to carry out most activities. Block Energy expects that GOG and Schlumberger (which owns the licence to the adjacent block to West Rustavi) will be engaged to provide the majority of the equipment pertaining to the initial work programme, so the Directors have as good a grip on this risk as possible, however there is a risk that suitable contractors and equipment will not be available at the times required to carry out the planned work programme, leading to delays in completion.

Independent contractors perform various operational tasks, including carrying out drilling activities and delivering required consumables.

When commodity prices are high, demand for independent contractors may exceed supply resulting in increased costs or lack of availability of key contractors. Interruptions in operations or higher costs also can occur as a result of disputes with contractors or a shortage of contractors. Moreover, because the Company will not have the same control over independent contractors as it does over its employees, there is a risk that such contractors will not operate in accordance with the Company's safety standards or other policies. Any of the foregoing conditions may lead to a delay in increasing production and revenues, with a consequent adverse effect on the Company's cashflows.

Block Energy may be unable to access necessary infrastructure services, including transportation and utilities, which may adversely affect the Group's operations.

Inadequate supply of the critical infrastructure elements for drilling activity could result in reduced production or sales volumes, which could have a negative effect on the Company's financial performance. Supply interruptions of essential utility services, such as electricity and water, may extend beyond current capabilities for independent power generation and therefore suspend the Group's production for the duration of the disruption and, when unexpected, may cause loss of life or damage to its drilling or mining equipment or facilities, which may in turn affect its capacity to restart operations on a timely basis. Adequate transportation services, are critical to distributing products, and disruptions to such services may affect the Group's operations. Block Energy may be dependent on third-party providers of utility and transportation services. As such, third-party provision of services, maintenance of networks and expansion and contingency plans may be outside the control of the Group. In addition, in the event that the Group's proposed drilling programme produces a much higher production volume than the Directors have forecast, production may exceed the amount that existing traders can absorb. In such circumstances, the Company may need to negotiate access to the export facility pipeline to transport to market these higher levels of production. Whilst the Directors consider that obtaining pipeline access will be possible, to the extent that it is not (or is delayed) this would curtail the benefit of such higher production.

Block Energy will be reliant on several customers for all of the oil currently produced and to be produced at its sites

For the foreseeable future and in the absence of any other offtaker, Block Energy will be entirely reliant on the ability of a number of customers to continue buying the oil produced in Georgia. Any material diminution in the offtakers' own liquidity or ability to buy such production would have a material adverse effect on the Company's financial position and future prospects.

Currency exchange rate fluctuations may negatively affect Block Energy

The Group's consolidated financial statements are stated in British pounds sterling and certain ongoing management costs will be denominated in British pounds sterling. However, the markets for the commodities produced are typically listed in US dollars and so Block Energy expects that the majority of its future revenues and operating expenses will be in US dollars, British pounds sterling and Georgian Laris. Consequently, Block Energy will be exposed to ongoing currency risk. Block Energy may also have operating expenses denominated in another currency. Consequently, changes in the exchange rates of these currencies may negatively affect the Group's cash flows, operating results or financial condition to a material extent.

Block Energy does not intend to hedge its cash resources against risks associated with disadvantageous movements in the currency exchange rates for the time being. Therefore, currency exchange rate fluctuations may negatively affect the Group.

The Company's cash flows and results of operations may be adversely affected by inflation and other cost increases

The Company will be unable to control the market prices of any commodities produced in its operations and may be unable to pass increased production costs to customers. Therefore, significant inflation or other production cost in Georgia could increase operational costs without a corresponding increase in the sales price of the commodities Block Energy may produce. Moreover, an increase in input costs relative to decreasing commodity prices will have a similar negative impact on the Group's operations. Any such costs may negatively affect the Group's profitability, cash flows and results of operations. Historical trends have shown that, at times of high oil prices, the costs of using oil service providers has also typically increased. Whilst the primary oil price risk to Block Energy remains the situation of prolonged weak or falling prices, Shareholders should note that it is reasonable to expect Block Energy's cost base to increase should oil prices rise substantially from their current levels.

Inherent risks in the oil and gas sector

Activities in the oil & gas sectors can be dangerous and may be subject to interruption. The Group's operations are subject to the significant hazards and risks inherent in the oil & gas sector in which it operates. These hazards and risks include:

- explosions and fires;
- blowouts and other operational disruptions in relation to the Group's upstream exploration;
- disruption to production operations;
- spills, release of gas or soil contamination from site operations and storage;
- natural disasters;
- ruptures and spills from crude and product carriers or storage tanks;
- equipment break-downs and other mechanical or system failures;
- improper installation or operation of equipment;
- transportation accidents or disruption of deliveries of crude oil, fuel, equipment and other supplies;
- disruption of electricity, water and other utility services;
- acts of political unrest, war or terrorism;
- labour disputes; and
- community opposition activities.

In addition, the Group's future operations will be subject to all of the risks normally associated with drilling of oil wells and the operation and development of oil properties, including encountering unexpected formations or pressures, differential sticking of drilling assemblages, premature declines of reservoirs, equipment failures and other accidents (including vehicle accidents during equipment and rig moves), sour-gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, diseases impacting the health of personnel, pollution and other environmental risks. If any of these events were to occur, they could result in environmental damage, injury to persons and/or loss of life, and a failure to produce oil or gas in commercial quantities. They could also result in significant delays to drilling programmes, a partial or total shutdown of operations, significant damage to the Group's equipment and equipment owned by third parties, and personal injury or wrongful death claims being brought against the Group. These events could also put at risk some or all of the Group's licences, which enable it to explore and develop, and could result in Block Energy incurring significant civil liability claims, significant fines or penalties, as well as criminal sanctions potentially being enforced against Block Energy and/or its officers. In addition, the Group's operations, as well as the transport and other logistics on which Block Energy is dependent, may be adversely affected and severely disrupted by climatic conditions. Natural disasters or adverse conditions may occur in those geographical areas in which Block Energy operates, including severe weather, earthquakes, cyclones, excessive rainfall, tropical storms, floods, bridge or road washouts, droughts or epidemic and disease.

Litigation

All industries are subject to legal claims, with and without merit. Block Energy may become involved in legal disputes in the future. Defence and settlement costs can be substantial, even with respect to claims that have no merit. Due to the inherent uncertainty in the litigation process, there can be no assurance that the resolution of any particular legal proceeding will not have a material effect on the Group's financial position or results of operations.

Dividends

There can be no assurance as to the level of future dividends. Subject to compliance with the Act and the Articles, the declaration, payment and amount of any future dividends are subject to the discretion of the Directors, and will depend on, *inter alia*, future oil production, the Company's earnings, financial position, cash requirements, availability of profits and the Company's ability to access, and repatriate within the Group, cash flow and profits generated outside the UK. There is no guarantee that a dividend will ever be paid. In forming their dividend policy, the Directors have taken into account, *inter alia*, the workover and development plan, budgets for the following financial year, the current taxation regime of Georgia and current capital requirements of the Group. Any material change or combination of changes to these factors may require a revision of this policy.

ECONOMIC, SOCIAL AND POLITICAL EXPOSURE RELATED TO GEORGIA

Regional tensions could have an adverse effect on the local economy and our business

Georgia shares borders with Russia, Azerbaijan, Armenia and Turkey and could be adversely affected by political unrest within its borders and in surrounding countries. In particular, Georgia has had ongoing disputes in the breakaway regions of Abkhazia and the Tskhinvali Region/South Ossetia, and with Russia, since Georgian independence in 1991. These disputes have led to sporadic violence and breaches of peacekeeping operations. In August 2008, the conflict in the Tskhinvali Region/South Ossetia escalated as Georgian troops engaged with local militias and Russian forces that crossed the international border, and Georgia declared a state of war. Although Georgia and Russia signed a French-brokered ceasefire that called for the withdrawal of Russian forces later that month, Russia recognised the independence of the breakaway regions and tensions persist as Russian troops continue to occupy Abkhazia and the Tskhinvali Region/South Ossetia. For example, in summer 2013 Russian border guards erected fences along portions of the demarcation line between Georgia and South Ossetia and similar future actions could further increase tensions. Russia is also opposed to the eastward enlargement of NATO, potentially including former Soviet republics such as Georgia. The Georgian government has taken certain steps towards improving relations with Russia, but these have not currently resulted in any formal or legal changes in the relationship between the two countries.

Relations between Azerbaijan and Armenia remain tense, and there are sporadic instances of violence between these two countries.

Geopolitical tensions between Ukraine and Russia may also have an adverse impact on the Georgian economy. The crisis in Ukraine began in late 2013 and is still ongoing. The United States and EU have imposed trade sanctions on various Russian and Crimean officials and against Russia, including several Russian banks and companies. The ongoing political instability, civil disturbances and military conflict in Ukraine, any prolongation or further escalation of the geopolitical conflict between Russia and Ukraine, any further decline in the Russian economy due to the impact of the trade sanctions, falling oil prices or currency depreciation, increasing levels of uncertainty, increasing levels of regional, political and economic instability and any future deterioration of Georgia's relationship with Russia, may have a negative effect on the political or economic stability of Georgia.

Accordingly, the political and economic stability of Georgia may be affected by any of the following:

- deterioration of Georgia's relationship with Russia, including in relation to border and territorial disputes;

- changes in Georgia's importance as a transit country for energy supplies;
- changes in the amount of aid granted to Georgia or the ability of Georgian manufacturers to access world export markets; or
- significant deterioration in relations between Azerbaijan and Armenia.

Political and governmental instability in Georgia could have a material adverse effect on the local economy and Block Energy's business.

Since its independence from the former USSR in 1991, Georgia has experienced an ongoing and substantial political transformation from a constituent republic in a federal socialist state to an independent sovereign democracy.

Georgia faces several challenges, one of which is the need to implement further economic and political reforms. However, business and investor friendly reforms may not continue or may be reversed or such reforms and economic growth may be hindered as a result of any changes affecting the continuity or stability of the Georgian Dream coalition government or as a result of a rejection of reform policies by the president, the parliament or others.

In October 2010, the parliament of Georgia approved certain amendments to the constitution of Georgia that were intended to enhance the primary governing authority of the parliament, to increase the powers of the prime minister of Georgia and to limit the scope of functions of the president of Georgia. Although the parliament unanimously adopted certain constitutional amendments further limiting the powers of the president of Georgia in March 2013, any further changes to Georgian parliamentary, presidential or prime ministerial powers might create political disruption or political instability or otherwise negatively affect the political climate in Georgia.

Although political conditions in Georgia are generally stable, changes may occur in its political, fiscal and legal systems, which might affect the ownership or operation of the Company's interests including, *inter alia*, changes in exchange rates, exchange control regulations, expropriation of oil and gas rights, changes in government and in legislative, fiscal and regulatory regimes.

Because Block Energy operates solely within Georgia, the Company will be affected by changes in Georgian economic conditions.

Block Energy's operations are located in, and all of its revenue is sourced from, Georgia. Results of operations are, and are expected to continue to be, significantly affected by financial and economic developments in or affecting Georgia and, in particular, by the level of economic activity in Georgia. Factors such as gross domestic product (GDP), inflation, interest and currency exchange rates, as well as unemployment, personal income and the financial situation of companies, have a material impact on customer demand for Block Energy's products.

Georgia faces significant risks to its growth prospects, including risks associated with the exchange rate, financial stability, inflation, budget and capital flight. Market turmoil and economic deterioration in Georgia may cause consumer spending to decline and have a material adverse effect on the liquidity and financial condition of our customers in Georgia.

Georgian Tax

As noted above, pursuant to the terms of the PSAs entered into all taxation from the Group's current and planned operations is paid for on Block Energy's behalf by the State, with certain limited exceptions. Tax laws have not been in force in Georgia for significant periods of time compared to more developed market economies. This creates challenges in complying with the laws, to the extent that the tax laws are unclear or subject to differing interpretations, and subjects companies to the risk that their attempted compliance could be challenged by the authorities.

Moreover, such tax laws are subject to changes and amendments, which can result in unusual complexities for Block Energy and our business. A new tax code came into effect on 1 January 2011. Differing opinions regarding the interpretation of various provisions exist both among and within governmental ministries and organisations, including the tax authorities, creating uncertainties, inconsistencies and areas at conflict. There is a risk that some provisions this tax code may not be consistent with the provisions of the PSAs and that the relevant government bodies may interpret those provisions in the PSAs differently and apply conflicting tax code provisions. The resulting effect on the tax liability of the Group could have a material adverse effect on the financial position of the Group. However, the tax code does provide for the Georgian tax authorities to give advance tax rulings on tax issues raised by taxpayers.

In addition, tax laws and government tax policies may be subject to change in the future, including changes resulting from a change of government (see –*"Political and governmental instability in Georgia could have a material adverse effect on the local economy and Block Energy's business'*). Such changes could include the introduction of new taxes or an increase in the tax rates applicable to Block Energy or its customers, and this may have a material adverse effect on our business.

There are additional risks associated with investing in emerging markets such as Georgia.

Emerging markets may have higher volatility, more limited liquidity and a narrower export base than more mature markets and are subject to more frequent changes in the political, economic, social, legal and regulatory environment. They are subject to rapid change and are particularly vulnerable to market conditions and economic downturns elsewhere in the world.

In addition, international investors may react to events, disfavouring an entire region or class of investment, a phenomenon known as the "contagion effect". If such a contagion effect occurs, Georgia could be adversely affected by negative economic or financial developments in other emerging market countries. Georgia has been adversely affected by contagion effects in the past, including following the 1998 Russian financial crisis and the more recent global financial crisis and may be affected by similar events in the future.

Financial or political instability in emerging markets also tends to have a material adverse effect on capital markets and the wider economy as investors generally move their money to more developed markets, which they may consider to be more stable. These risks may be compounded by incomplete, unreliable, unavailable or untimely economic and statistical data on Georgia, which may include information in this document.

The uncertainties of the judicial system in Georgia, or any arbitrary or inconsistent state action taken in Georgia in the future, may have a material adverse effect on the local economy, which could, in turn, have an adverse effect on our business.

Georgia is still developing an adequate legal framework required for the proper functioning of a market economy. Several fundamental civil, criminal, tax, administrative and commercial laws have only recently become effective. The recent introduction of this legislation and the rapid evolution of the Georgian legal system have given rise to doubts as to the quality and the enforceability of laws, and have resulted in ambiguities and inconsistencies in their application. In addition, the court system in Georgia is understaffed and has been undergoing significant reform. Judges and courts in Georgia are generally less experienced in commercial and corporate law than in certain other countries, particularly in Europe and the United States. The uncertainties of the Georgian judicial system could have a negative effect on the Georgian economy, which could, in turn, have a material adverse effect on our business, financial condition and results of operations.

GENERAL EXPLORATION, DEVELOPMENT AND PRODUCTION RISKS

General risks relating to the Company and to the hydrocarbon exploration and production industry

The exploration for, and production of, hydrocarbons is a highly speculative activity which can involve a high degree of risk. Notwithstanding the Group has 2P reserves of 2.6 MMBbl, and that a number of wells at the Norio and Satskhenisi fields which are currently producing low volumes of oil, the Company's programme of workovers and re-completions of existing wells may not generate the flow improvements required to be commercially viable. Accordingly, the Ordinary Shares should be regarded as a highly speculative investment and an investment in the Company should only be made by those investors with the necessary expertise to evaluate the investment fully and who can sustain the total loss of their investment.

Commodity prices, markets and marketing

Numerous factors beyond the Company's control do and will continue to affect the marketability and price of oil and natural gas acquired or discovered by the Company. Accordingly, commodity prices are one of the Company's most significant financial risks. The Company's ability to market its oil and natural gas may depend upon its ability to transport hydrocarbons or acquire space on pipelines that deliver oil and natural gas to commercial markets. Deliverability uncertainties are present related to the distance the Company's reserves are to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil, and natural gas. Many other aspects of the oil and natural gas business may also affect the Company. At present, the Company's crude oil sales in Georgia are generally benchmarked at a $9-10 discount against Brent Oil reference prices.

The price that the Company receives for its oil is subject to negotiation between the Company and local buyer and the discount against Brent can vary to the benefit or detriment of the Company's net sales price

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, and a variety of additional factors beyond the control of the Company. These factors include economic conditions in the United States, Canada, Europe and China, the actions of Organization of Petroleum Exporting Countries ("OPEC"), governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports, and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, and OPEC's decisions pertaining to oil production management of OPEC member countries, among other factors. A material decline in prices could result in a reduction of the Company's net production revenue and cash flows from operations. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Company's reserves. The Company may also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Company's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of the Company's reserves, borrowing capacity, revenues, profitability and cash flows from operations, and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

General conditions relating to oil exploration, development, production and commercial viability

The Company's operations are subject to all the risks normally incident to the exploration for and production of oil including geological risks, operating risks, political risks, development risks, marketing risks, decommissioning risk and logistical risks of operating in Georgia. Future oil exploration may involve unprofitable efforts, not only from dry wells but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure commercial viability or profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include: delays in obtaining or the requirement for additional governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration and development activities are dependent on the availability of seismic, drilling, completions and other specialized equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities.

Other factors affecting the exploration, development, production and sale of oil and natural gas that could result in decreases in profitability include: (i) expiration or termination of the leases, licences, permits, lease operating agreements, farmout agreements, joint operation or venture agreements and marketing agreements, as applicable, or sales price redeterminations or suspension of deliveries; (ii) future litigation; (iii) the timing and amount of insurance recoveries; (iv) work stoppages or other labour difficulties; (v) changes in the market and general economic conditions; and (vi) hazards typically associated with oil and gas operations, including fire, explosion, blow-outs, cratering, and spills, or adverse geological conditions, each of which could result in substantial damage to oil wells, production facilities, other property and the environment or in personal injury.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. A future increase in the Company's reserves will depend on both the ability of the Company to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects.

Block Energy's operations will be subject to all the risks normally associated with the exploration, development and operation of oil and natural gas properties and the drilling of oil and natural gas wells. In accordance with customary industry practice, Block Energy will maintain insurance coverage but will not be fully insured against all risks nor are all such risks insurable. In either event, the Company could incur significant costs.

Project operating costs

The operating costs associated with Block Energy's drilling and well recompletion program could be incorrectly estimated due to unforeseen issues arising in the course of a project, such as delays. This could lead Block Energy to experience adverse variances to budget with respect to capital expenditures. The Company could therefore require additional funding in the future to fulfil its stated objectives, and there can be no assurance that such funding will be available to Block Energy on favourable terms, or at all. The Company's future oil and gas projects may involve unprofitable efforts, due either to dry wells or to wells that are productive but do not produce sufficient net revenues to return a profit after development, operating and other costs. Furthermore, completion of a well does not guarantee a profit on the investment or recovery of the costs associated with that well. In addition, drilling hazards or environmental damage could significantly affect operating costs, and production from successful wells may be adversely affected by conditions including delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity, or adverse geological conditions. Production delays and declines, whether or not as a result of the foregoing conditions, may result in lower revenue or cash flows from operating activities until such time, if at all, that the delay or decline is cured or arrested. In the event that such cash flows are reduced in the future, the Company may be forced to scale back or delay capital expenditure, resulting in delays to, or the postponement of, the Company's planned production and development activities which could have a material adverse effect on its financial condition, business, prospects and results of operations.

Recovery, reserve and resource estimates may prove inaccurate and reporting standards in the United Kingdom may differ from the standards of other jurisdictions

There are numerous uncertainties that Block Energy faces that are inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Group. Estimation of underground accumulations of hydrocarbons (which cannot be measured in an exact manner) is a subjective process aimed at understanding the statistical probabilities of recovery. The interpretation and estimates of the amounts of oil reserves and resources are subjective and the results of drilling, testing and production subsequent to the date of any particular estimate may result in substantial revisions to the original interpretation and estimates. Moreover, different reservoir engineers may make different estimates of reserves, resources and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves and resources will vary from estimates, and the variances may be material.

In general, estimates of economically recoverable oil reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil, oil quality (including, without limitation, API gravity and sulphur content), royalty rates, assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. All such estimates are, to some degree, speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom that have been prepared by different engineers, or by the same engineers at different times, may vary. The Group's actual production, revenues, and development and operating expenditures with respect to its reserves will vary from estimates thereof, and such variations could be material. Estimates of proved and probable reserves that may be developed and produced in the future are often based upon volumetric estimates without the benefit of actual production history.

Estimates based solely on volumetric methods are, in some cases, more uncertain than estimates also supported by actual production history. The estimates used assume that the Group's forecasts as to its capital expenditure and operating costs are accurate and that the capital expenditure strategy of Block Energy is successfully implemented. There can be no assurance that actual capital expenditures will not vary significantly from current estimates or that Block Energy will be able to implement its capital expenditure strategy or on the timetable currently envisaged. Furthermore, there are numerous uncertainties in estimating the timing and quantity of development expenditures and associated production projections. The production profiles and development plans in this Document are based on a number of assumptions which, together with the estimates, may prove to be materially incorrect. As a result, investors should not place undue reliance on the forward-looking statements contained in this Admission Document concerning the Group's resources, production profiles and development plans. In addition, nothing in this document should be interpreted as assurances of the Group's reserves or resources, the production profiles of the Group's assets or the development plans of the Group. Special uncertainties exist with respect to the estimation of prospective resources in addition to those set out above that apply to reserves. Prospective resources are defined as 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 a chance of discovery and of development. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty of commercial production from the resources. If the actual reserves or resources of Block Energy are less than the current estimates or of lesser quality than expected, Block Energy may be unable to recover and produce the estimated levels or quality of oil or gas and, as a result, Block Energy may not recover its initial outlay of capital expenditures and operating costs of any such operation, and there may be a material adverse effect on the financial condition, business, prospects and results of operations of the Group.

Reserve replacement

Block Energy's oil and natural gas reserves and production, and its cash flows and earnings derived therefrom are highly dependent upon the Company developing and increasing its current reserve base. Without the addition of reserves through exploration, acquisition or development activities, Block Energy's reserves and production will decline over time as reserves are depleted. To the extent that cash flow or net revenue from operations is insufficient and external sources of capital become limited or unavailable, Block Energy's ability to make the necessary capital investments to maintain and expand its oil and natural gas reserves will be impaired. There can be no assurance that Block will be able to find and develop or acquire additional reserves to replace production at commercially feasible costs.

Safety, health and environmental exposures and related regulations may expose the Company to increased litigation, compliance costs, interruptions to operations, unforeseen environmental remediation expenses and loss of reputation

The oil and gas sector involves extractive enterprises. These endeavours can often make the sector a hazardous industry. The industry is highly regulated by health, safety and environmental laws. The Group's operations may be subject to these kinds of governmental regulations in any region in which it operates. Operations are subject to general and specific regulations and restrictions governing drilling and production, mining and processing, land tenure and use, environmental requirements (including site-specific environmental licences, permits and remediation requirements), workplace health and safety, social impacts and other laws. The Group's operations may create environmental risks including dust, noise or leakage of polluting substances from its operations. Failing to adequately manage environmental risks or to provide safe working environments could cause harm to the Group's employees or the environment surrounding the operations site. Facilities are subject to closure by governmental authorities and the Company may be subject to fines and penalties, liability to employees and third parties for injury, statutory liability for environmental remediation and other financial consequences, which may be significant. The Company may also suffer impairment of reputation, industrial action or difficulty in recruiting and retaining skilled employees. Subsequent changes in regulations, laws or community expectations that govern the Group's operations could result in increased compliance and remediation costs. Any of the foregoing developments could have a materially adverse effect on the Group's results of operations, cash flows or financial condition.

Ability to market

Block Energy's ability to market its oil and natural gas depends upon numerous factors beyond its control.

These factors include:

- the availability of economic processing capacity;
- the availability and proximity of economic pipeline capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of extreme weather conditions; and
- regulation of oil and natural gas marketing.

Because of these factors, Block Energy could be unable to market all of the oil or natural gas it produces. In addition, Block Energy may be unable to obtain competitive prices for the oil and natural gas it produces.

Gathering and processing facilities and pipeline system

The Company delivers its products through trucking and railway systems which it does not own. The amount of oil and natural gas that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems could result in the Company's inability to realise the full economic potential of its production or in a reduction of the price offered for the Company's production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, the Company's financial condition, results of operations and cash flows.

All of the Company's production is delivered for shipment on facilities owned by third parties and over which the Company does not have control. From time to time, these facilities may discontinue or decrease operations, either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Company's ability to process its production and to deliver the same for sale. Unexpected shut downs or curtailment of capacity of facilities, rail lines and pipelines (in relation to gas) for maintenance or integrity work or because of actions taken by regulators could also affect the Company's production, operations and financial results.

Availability of drilling equipment and reliance on third party operators

Oil exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent that the Company's subsidiaries are not the operator of any oil properties, the Company will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

The Group's insurance and indemnities, if and when put in place, may not adequately cover all risks or expenses

Block Energy expects to maintain insurance with respect to its operations in accordance with international oilfield practice, including third-party liability insurance up to specified limits. However, Block Energy will be unable to insure against all risks and may be exposed under certain circumstances to uninsurable hazards and risks, which may result in financial liability, property damage, personal injury or other hazards and/or liability for the acts or omissions of sub-contractors, operators and joint venture partners. Although indemnities may in the future be provided by sub-contractors, operators and joint venture partners, such indemnities may be difficult to enforce given the financial positions of those giving the indemnities or due to the jurisdiction in which Block Energy may seek to enforce the indemnities, potentially leaving Block Energy exposed to claims by third parties.

There is also no guarantee that Block Energy will be able to maintain adequate insurance in the future at rates that Block Energy considers reasonable. Accordingly, Block Energy could incur substantial losses if an event which is not fully covered by insurance occurs, which would have a material adverse effect on the Group's business, cash-flows, results of operations and financial condition.

Environmental liabilities could impose significant liabilities on Block Energy for damages, clean-up costs or penalties in the event of certain discharges into the environment, environmental damage caused by previous owners of properties purchased or used by the Group, acts of sabotage by third parties or non-compliance with environmental laws or regulations by the Group. Such liabilities could have a material adverse effect on the Group. While the current legislation to which Block Energy is subject is not extensive, it is expected that additional environmental protection laws will be implemented in the future. It is not possible to predict what future environmental regulations will provide; however, these laws could impose additional obligations on Block Energy which may, for example, result in Block Energy incurring significant expenditures for the installation and operation of pollution control systems, as well as equipment for remedial measures and a penalty regime in the event of a breach of those laws, which could adversely affect the Group's business, financial condition and results of operations. It is also not possible to predict how environmental regulations will be applied or enforced in the future. Furthermore, no assurance can be given that changes to environmental laws and regulations outside the Group's control will not result in a curtailment of production, a material increase in the cost of production, development and/or exploration activities, or increased compliance and remediation costs, or otherwise adversely affect the Group's financial condition, business, prospects and results of operations.

Natural disasters may affect drilling operations and have a material impact on the productivity of the operations and may not be covered by insurance

Natural disasters, including earthquakes, drought, floods, fire, tropical storms and the physical effects of climate change, all of which are outside the Company's control, may adversely affect the Group's operations. Operating difficulties, such as unexpected geological variations that could result in significant failure, could affect the costs and feasibility of its operations for indeterminate periods. Damage to or breakdown of a physical asset, including as a result of fire, explosion or natural catastrophe, can result in a loss of assets and financial losses. Insurance (if arranged by the Group) may provide protection from some, but not all, of the costs that may arise from unforeseen events but the occurrence of a significant adverse event not fully covered by insurance could have a material adverse effect on the Group's business, results of operations, financial condition and prospects.

Labour disruptions could adversely affect the Company's results of operations, cash flows and financial condition

Strikes and the potential of conflict with employees may occur at the Group's operations or in the regions in which Block Energy operates. Labour interruptions may be employed to support labour, political or social goals. Labour interruptions have the potential to increase operational costs and decrease revenues by suspending the business activities or increasing the cost of substitute labour, which may not be available. If such disruptions are material, they may adversely affect the Company's results of operations, cash flows and financial condition.

Shortages and disruptions in lead times to deliver certain key inputs may adversely affect the Group's operations The Group's inability to make timely purchases of strategic consumables, raw materials, drilling and processing equipment could have an adverse impact on any results of operations and financial condition. Periods of high demand for supplies can arise when availability of supplies is limited. This can cause costs to increase above normal inflation rates. Interruption to supplies or increase in costs could adversely affect the operating results and cash flows of the Company.

The Group's future growth potential could be adversely affected if it fails to manage relationships with local communities, government and non-government organisations

The public is increasingly concerned about the perceived negative effects of globalisation. Consequently, businesses often face increasing public scrutiny of their operations. Communities may perceive the Group's operations as disadvantageous to their environmental, economic or social circumstances. Negative community reaction to such operations could have a materially adverse impact on the cost, profitability, ability to finance or even viability of an operation. Such events could also lead to disputes with national or local governments and/or with local communities and give rise to material reputational damage. Moreover, Block Energy may choose to operate in regions where ownership of rights with respect to land and resources is uncertain and where disputes in relation to ownership or other community matters may arise. The inherent unpredictability of these disputes may cause disruption to projects or operations. Natural resources operations can also have an impact on local communities, including the need, from time to time, to relocate communities or infrastructure networks such as railways and utility services. Failure to manage relationships with local communities, government and/or non-governmental organisations may adversely affect the Company's reputation, as well as its ability to commence production projects, which could in turn affect the Group's revenues, results of operations and cash flows.

GENERAL RISKS RELATING TO AN INVESTMENT IN ORDINARY SHARES

General market and investment risks relating to AIM traded securities

A prospective investor should consider with care whether an investment in the Company is suitable for them in light of their personal circumstances and the financial resources available to them. An investment in the Company is only suitable for investors capable of evaluating the risks and merits of such investment and who have sufficient resources to bear any loss which may result from the investment. Prospective investors should therefore consult an independent financial adviser authorised under the FSMA before investing if you are in the United Kingdom or, if not, another appropriately authorised independent adviser who specialises in advising on the acquisition of shares and other securities.

Investment in the Company should not be regarded as short-term in nature. There can be no guarantee that any appreciation in the value of the Company's assets or investments will occur or that the investment objectives of the Company will be achieved. Investors may not get back the full amount initially invested. The value of the Ordinary Shares and the income derived from them can go down as well as up. Past performance is not necessarily a guide to the future. There is also the possibility that the market value of an investment in the Company may not reflect the true underlying value of the Company.

Changes in economic conditions including, for example, interest rates, rates of inflation, industry conditions, competition, political and diplomatic events and trends, tax laws and other factors can substantially and adversely affect investments and the Company's prospects.

Notwithstanding the fact that an application will be made for the Ordinary Shares to be admitted to trading on AIM, this should not be taken as implying that there will be a "liquid" market in the Ordinary Shares. The market for shares in smaller public companies is less liquid than for larger public companies. Therefore, an investment in the Company may be difficult to realise.

The price for the Ordinary Shares may be volatile and influenced by many factors, some of which are beyond the control of the Company. For example, the performance of the overall share market, other Shareholders buying or selling large numbers of Ordinary Shares, changes in legislation or regulations and general economic conditions.

Possible volatility in the price of Ordinary Shares

The market price of the Ordinary Shares could be volatile and subject to significant fluctuations due to a variety of factors, including changes in market sentiment regarding Ordinary Shares (or securities similar to them), any regulatory changes affecting the Company's operations, variations in its operating results, developments in the industry or its competitors, the operating and share price performance of other companies in the financial services and markets sector, or speculation about the Company's business in the press, media or investment communities. Specifically, Block Energy's licences in Georgia neighbour high profile operations by Schlumberger and Frontera. Failures in either of the neighbouring oil fields could result in negative market sentiment towards Block Energy and negatively impact the Company's market value. The Company's operating results and prospects from time to time, may be below the expectations of market analysts and investors. Any of these events could result in a decline in the market price of the Ordinary Shares.

Risks relating to taxation

Taxation risk

Any change in the Group's tax status or the tax applicable to holding Ordinary Shares or in taxation legislation or its interpretation, could affect the value of the Ordinary Shares or the investments held by the Group, affect the Company's ability to provide returns to Shareholders and/or alter the post-tax returns to Shareholders. Statements in this document concerning the taxation of the Company and its investors are based upon tax law and HMRC practice at the date of this document, which is subject to change.

Taxation of returns from assets located outside the UK may reduce any net return to investors

It is possible that any return that the Company receives from its Georgian operations may be reduced by irrecoverable foreign withholding or other local taxes and this may reduce any net return derived by investors from a shareholding in the Company. At present, Georgia has a taxation system that the Directors consider favourable to foreign investment. All material currently applicable taxes have been included in the business models developed and analysed by the Directors in deciding to recommend the Acquisition. However, there can be no guarantee that the Government will not make changes to the tax regime in the future in a manner that adversely affects the Company.

Future changes in tax legislation applicable to the Company's entities may reduce net returns to Shareholders

The tax treatment of Block Energy entities is subject to changes in tax legislation or practices in territories in which Group entities are resident for tax purposes. Such changes may include (but are not limited to) the taxation of operating income, investment income, dividends received or (in the specific context of withholding tax) dividends paid. Any changes to tax legislation or practices in countries in which Block Energy entities are resident for tax purposes may have a material adverse effect on the financial position of the Company and/or Block Energy entities, potentially reducing net returns to Shareholders. In many jurisdictions, the resources sector is subject to particular taxation regimes that sometimes impose a comparatively heavy burden on activities within the sector.

There can be no assurance that the Company will be able to make returns to Shareholders in a tax-efficient manner

It is intended that the Directors will structure Block Energy to maximise returns for investors in as fiscally efficient a manner as is practicable. The Company has made certain assumptions regarding taxation. However, if these assumptions are not borne out in practice, taxes may be imposed with respect to any of the Company's assets, or the Company may be subject to tax on its income, profits, gains or distributions in a particular jurisdiction or jurisdictions in excess of taxes that were anticipated. This could alter the post-tax returns for Shareholders (or Shareholders in certain jurisdictions). Any change in laws or tax authority practices could also adversely affect any post-tax returns of capital to Shareholders or payments of dividends. In addition, the Company may incur costs in taking steps to mitigate any such adverse effect on the post-tax returns for Shareholders.

Shareholder taxation

The tax consequences to each Shareholder of owning Ordinary Shares will depend, amongst other things, on tax laws in the jurisdiction in which that Shareholder is resident or domiciled. Prospective investors should consult their professional advisers on the possible tax consequences of subscribing for, buying, holding, selling or transferring Ordinary Shares under the laws of their country of citizenship, residence or domicile.

EIS and VCT status

The Company has obtained advance assurance from HMRC that a subscription for Ordinary Shares by individuals should qualify under the EIS. The Company also anticipates that subscription by VCTs in Ordinary Shares should be regarded as a subscription in eligible shares and form a qualifying holding under the relevant legislation, however HMRC has informed the Company that it no longer considers speculative advance assurance applications.

The advance assurance relates only to the qualifying status of the Company and its shares and does not guarantee that any particular investor will qualify for relief in respect of an acquisition of Ordinary Shares. The continuing availability of EIS relief and the status of the relevant Ordinary Shares as a qualifying holding for VCT purposes (if granted) will be conditional, *inter alia*, on the Company continuing to satisfy the requirements for a qualifying company throughout the period of three years from the date of the investor making their investment (under EIS) and, for VCT purposes, throughout the period the Ordinary Shares are held as a ''qualifying holding''. Neither the Company nor the Company's advisers are giving any warranties or undertakings that any relief under the EIS or that VCT qualifying status will be available in respect of this Placing, or that in due course such relief or status will not be withdrawn.

Circumstances may arise where the Board believes that the interests of the Company are not best served by acting in a way that preserves the EIS or VCT qualifying status (if granted). In such circumstances, the Company cannot undertake to conduct its activities in a way designed to preserve any such relief or status. Should the law regarding the EIS or VCTs change then any relief or qualifying status previously obtained may be lost.

Any person who is in any doubt as to their taxation position should consult their professional taxation adviser in order that they may fully understand how the rules apply in their individual circumstances.

The risks noted above do not necessarily comprise all those faced by the Company and are not intended to be presented in any assumed order of priority.

There may be special risks if an investor holds Ordinary Shares in certain jurisdictions. At this time, the Company does not intend to make accommodations regarding its financial information to assist any holders with their tax obligations.

The investment described in this document is speculative and may not be suitable for all recipients of this document. Potential investors are accordingly advised to consult an independent financial adviser authorised under the FSMA who specialises in advising in investments of this kind before making any investment decisions. A prospective investor should consider carefully whether an investment in the Company is suitable in the light of their personal circumstances and the financial resources available to them.

PART III

COMPETENT PERSONS REPORT

Competent Person's Report for Norio, West Rustavi and Satskhenisi Fields Republic of Georgia

Date of this Report: January 1, 2018

Effective Date: January 1, 2018

Prepared for:

Block Energy, plc

And

SPARK Advisory Partners Limited

Prepared By:

GUSTAVSON ASSOCIATES
5757 CENTRAL AVE. SUITE D BOULDER, COLORADO 80301 USA

Phone: 1-303-443-2209, Fax: 1-303-443-3156
E-mail: gustavson@gustavson.com

Competent Person's Report for Norio, West Rustavi and Satskhenisi Fields Republic of Georgia

Date of this Report: January 1, 2018

Effective Date: January 1, 2018

Prepared for:

Block Energy, plc

And

SPARK Advisory Partners Limited

Prepared By:

Letha C. Lencioni
Registered Petroleum Engineer
State of Colorado #29506

Jan J. Tomanek
Certified Petroleum Geologist
AAPG #6239

GUSTAVSON ASSOCIATES
5757 CENTRAL AVE. SUITE D BOULDER, COLORADO 80301 USA

Phone: 1-303-443-2209, Fax: 1-303-443-3156
E-mail: gustavson@gustavson.com

1. EXECUTIVE SUMMARY

This report addresses the Norio, West Rustavi and Satskhenisi oil and gas assets owned by Block Energy plc in the Republic of Georgia. These assets are summarized in Table 1-1.

Table 1-1 Summary of Assets owned by Block Energy plc

Asset	Contractor	Operator	Working Interest (%)	Status	Expiry Date	License Area (acres)[1]
Norio PSA	GOG Norioskhevi Ltd[3]	Norio Operating Company	100%[2]	3 wells producing	4/2026	5,570
Satskhenisi PSA	Satskhenisi Ltd/ GOG [3]	Norio Operating Company	90%	3 wells producing	4/2026	6,024
West Rustavi PSA	GOG/GNV[3]	Norio Operating Company	Current 5% with option to 75%[4]	2 wells with prior production, no current production	3/2043	9,290

Oil and natural gas Reserves, Contingent Resources, and Prospective Resources have been estimated for these assets, based on a probabilistic analysis. Reserves and future cash flows are summarized for the total of all three blocks in Table 1-2. The summaries for the individual assets are in Table 1-3 for the Norio Block, Table 1-4 for the West Rustavi Block and Table 1-5 for Satskhenisi. Gross Unrisked Contingent Resources for the blocks are summarized in Table 1-6, with Block Energy's working interest share shown in Table 1-7. Gross Unrisked Prospective Resources for the blocks are summarized in Table 1-8.[5] Note that due to the nature of the Production Sharing Agreement (PSA) with cost recovery based on expenses, it is not possible to calculate net resources (after government share) due to the lack of a plan to develop the entire accumulations.

[1] Approximate
[2] Block Energy currently holds 100% of the working interest in the Norio PSA, at the date of this report, having acquired 31% following the effective date of the report.
[3] 100% owned Georgian subsidiaries of Block Energy
[4] Subject to completion of the the farm-in workplan in conjunction with the West Rustavi PSA.
[5] Block's working interest share is the same as the gross for the Prospective Resources.

Table 1-2 Reserves and Future Cash Flow Projections, Total

	Oil Reserves, MBbl											
	Gross			Net			Net Cash Flow, MM$			Net Present Value Discounted at 10%, MM$		
Reserve Classification	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)
Producing	32.5	37.0	41.6	19.1	24.0	30.8	0.18	0.27	0.39	0.16	0.23	0.31
Developed Non-Producing	543.9	1,009.2	1,786.6	277.8	436.0	709.0	7.4	16.2	31.7	4.8	11.3	22.5
Undeveloped	805.2	1,505.3	2,328.6	603.5	1,005.2	1,334.9	20.0	43.1	61.3	10.9	27.8	41.0
Total	**1,381.6**	**2,551.5**	**4,156.8**	**900.4**	**1,465.2**	**2,074.8**	**27.5**	**59.5**	**93.4**	**15.9**	**39.3**	**63.8**

(MBbl = thousand barrels of oil; MM$ = millions of US$)

Table 1-3 Reserves and Future Cash Flow Projections, Norio

	Oil Reserves, MBbl											
	Gross			Net			Net Cash Flow, MM$			Net Present Value Discounted at 10%, MM$		
Reserve Classification	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)
Producing	28.1	32.7	37.2	16.7	21.7	28.5	0.2	0.2	0.4	0.1	0.2	0.3
Developed Non-Producing	65.8	93.0	167.5	61.6	80.9	133.5	1.0	2.3	5.7	0.6	1.5	3.8
Undeveloped	805.2	1,505.3	2,328.6	603.5	1,005.2	1,334.9	20.0	43.1	61.3	10.9	27.8	41.0
Total	**899.2**	**1,630.9**	**2,533.3**	**681.8**	**1,107.8**	**1,496.9**	**21.2**	**45.6**	**67.4**	**11.6**	**29.5**	**45.1**

For 100% Working Interest. Net is net of government share.
(MBbl = thousand barrels of oil; MM$ = millions of US$)

Table 1-4 Reserves and Future Cash Flow Projections, West Rustavi

	Oil Reserves, MBbl											
	Gross			Net			Net Cash Flow, MM$			Net Present Value Discounted at 10%, MM$		
Reserve Classification	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)
Producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Developed Non-Producing	470.8	906.8	1,606.2	210.7	347.8	565.2	6.1	13.6	25.6	4.1	9.6	18.4
Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**470.8**	**906.8**	**1,606.2**	**210.7**	**347.8**	**565.2**	**6.1**	**13.6**	**25.6**	**4.1**	**9.6**	**18.4**

For 75% Working Interest. Net is net of government share and partner's interests. Block Energy has no interest in the West Rustavi PSA at the time of this report.

(MBbl = thousand barrels of oil; MM$ = millions of US$)

Table 1-5 Reserves and Future Cash Flow Projections, Satskhenisi

	Oil Reserves, MBbl											
	Gross			Net			Net Cash Flow, MM$			Net Present Value Discounted at 10%, MM$		
Reserve Classification	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)	P_{90} (1P)	P_{50} (2P)	P_{10} (3P)
Producing	4.4	4.4	4.4	2.3	2.3	2.4	0.03	0.03	0.03	0.03	0.03	0.03
Developed Non-Producing	7.2	9.4	12.9	5.6	7.3	10.3	0.19	0.26	0.39	0.16	0.20	0.29
Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00
Total	**11.6**	**13.8**	**17.3**	**7.9**	**9.6**	**12.7**	**0.22**	**0.29**	**0.42**	**0.18**	**0.23**	**0.32**

For 90% Working Interest. Net is net of government share and partner's interests.

(MBbl = thousand barrels of oil; MM$ = millions of US$)

Table 1-6 Gross Unrisked Contingent Resource Estimates by Area

	Contingent Oil/Condensate Resources, MMBbl			Contingent Associated/Free Gas Resources, Bcf			Risk Factor
Block	Low Estimate(1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	
Norio	3.1	7.2	13.9	0.8	1.9	3.7	75%
Satskhenisi	16.4	27.8	43.7	9.3	16.4	26.5	75%
Subtotal	19.5	35	57.6	10.1	18.3	30.2	
West Rustavi	18.6	37.9	69.3	314	608	1,000	75%
TOTAL	**38.1**	**72.9**	**126.9**	**324**	**626**	**1,030**	

(MMBbl = million barrels of oil; BCF = billion cubic feet)

Table 1-7 Block Energy WI Share Unrisked Contingent Resource Estimates by Area

	Contingent Oil/Condensate Resources, MMBbl			Contingent Associated/Free Gas Resources, Bcf			Risk Factor
Block	Low Estimate(1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	
Norio	3.1	7.2	13.9	0.8	1.9	3.7	75%
Satskhenisi	14.7	25	39.3	8.4	14.7	23.9	75%
Subtotal	17.8	32.2	53.2	9.2	16.6	27.6	
West Rustavi	13.9	28.4	52	235	456	750	75%
TOTAL	**31.8**	**60.6**	**105.2**	**244**	**473**	**778**	

(MMBbl = million barrels of oil; BCF = billion cubic feet)

Table 1-8 Gross Unrisked Prospective Resource Estimates by Area

	Prospective Oil Resources, MMBbl			Prospective Associated Gas Resources, Bcf			Risk Factor
Block	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	
Norio	1.4	3.1	5.2	1	2.2	3.7	60%
Satskhenisi	0	0	0	0	0	0	---
Subtotal	1.4	3.1	5.2	1	2.2	3.7	
West Rustavi	0	0	0	0	0	0	---
TOTAL	**1.4**	**3.1**	**5.2**	**1**	**2.2**	**3.7**	

(MMBbl = million barrels of oil; BCF = billion cubic feet)

Note that these estimates do not include consideration for the risk of failure in exploring for and developing these resources.

Contingent Resources are defined as "those quantities of petroleum 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 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 subclassified based on project maturity and/or characterized by their economic status."[6] There is no certainty that it will be commercially viable to produce any portion of the resources. The contingency associated with these resources is that, although they are known accumulations that have been penetrated and produced or tested, preparation of a development plan is contingent on acquisition of more data and additional funding. In addition, the Contingent Gas Resources currently lack a firm market and infrastructure, although limited gas purchase contracts have been executed by other operators in the area.

Prospective Resources are defined as "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 discovery and a chance of development."[7] There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The two reservoirs with Prospective Resources were not categorized as Contingent Resources because of the lack of firm data showing hydrocarbons in significant quantities.

The Low Estimate represents the P_{90} values from the probabilistic analysis (in other words, the value is greater than or equal to the P_{90} value 90% of the time), while the Best Estimate represents the P_{50} and the High Estimate represents the P_{10}. The totals given are simple arithmetic summations of values and are not themselves P_{90}, P_{50}, or P_{10} probabilistic values.

---

[6] http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf
[7] http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf

2. TABLE OF CONTENTS

PAGE

LIST OF APPENDICES

LIST OF FIGURES

FIGURE PAGE

LIST OF TABLES

TABLE PAGE

3. INTRODUCTION

3.1 OVERVIEW

Gustavson Associates LLC (the Consultant) has been retained by Block Energy plc and SPARK Advisory Partners Limited to prepare a Competent Person's Report for them in accordance with the AIM Note for Mining and Oil and Gas Companies for the purposes of the Clients' admission to the AIM of the London Stock Exchange. The report covers the interests owned by Block Energy plc in oil and gas license blocks located in the Republic of Georgia. The general location of the report study area is shown in Figure 3-1. The purpose of the report is to provide a baseline for the company's reserve and resource base and to support the Client's admission to the AIM of the London Stock Exchange (AIM).

The Block Energy assets that are the subject of this report include interests in the Norio and Satskhenisi Production Sharing Agreement (PSA) contracts and Permit XIf (West Rustavi). The report contains independent estimates of reserves and resources for the above described assets and the effective date of this report is January 1, 2018. Reserves and resources have been estimated according to the standards and resources definitions found in the Petroleum Resources Management System (PRMS)[8] and the AIM Rules for Companies which includes specifically the Note for Mining and Oil and Gas Companies. This report also contains the results of a financial model that projects future income from the production and development of the reserves and resources. A site visit was not made, and inspection of the petroleum assets is judged not likely to reveal information or data that is material to this Report.

3.2 SUMMARY ASSET DESCRIPTION

The three license blocks are located in the eastern part of the Republic of Georgia, in an area where oil and gas exploration and development has been ongoing since the early part of the twentieth century. Figure 3-2 shows the location of the three subject blocks relative to other license blocks in the country.

---

[8] http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf

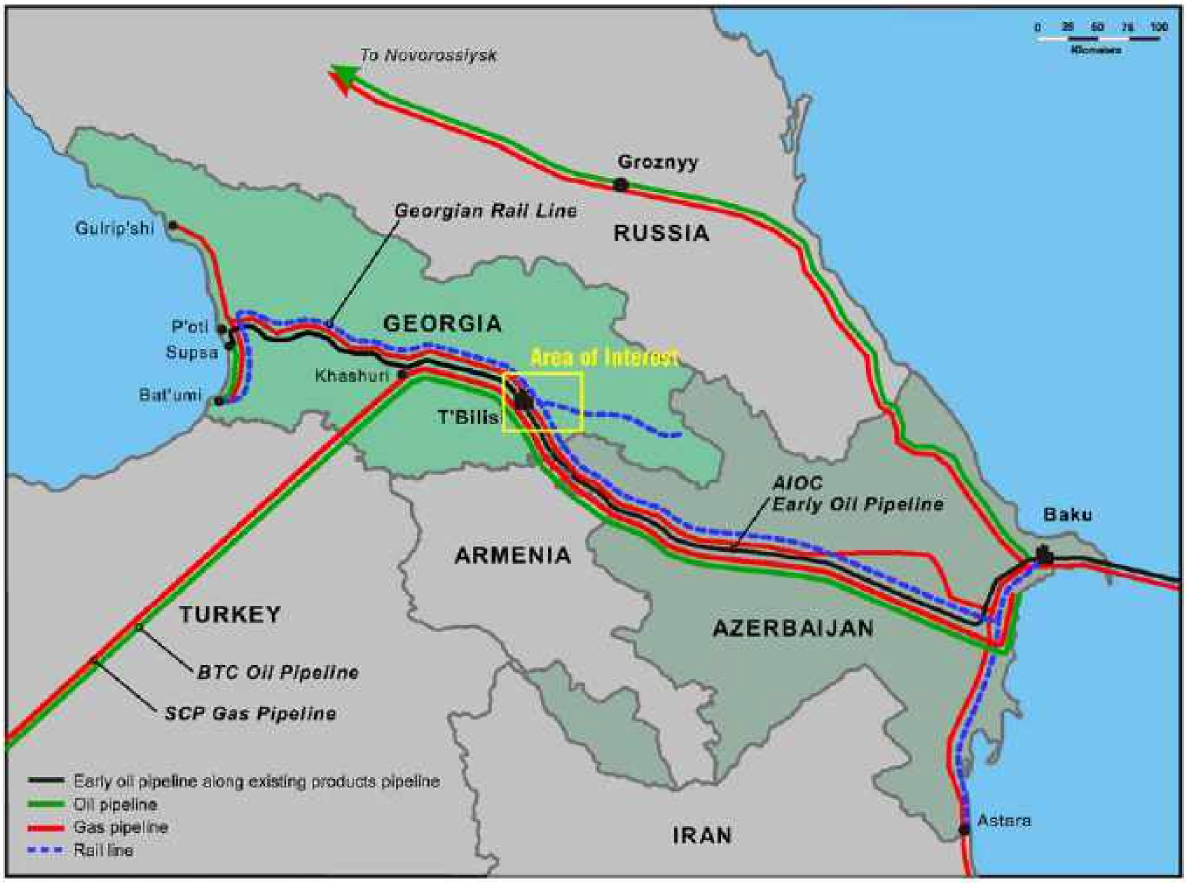


Figure 3-1 Index Map of the Republic of Georgia and the Area of Interest

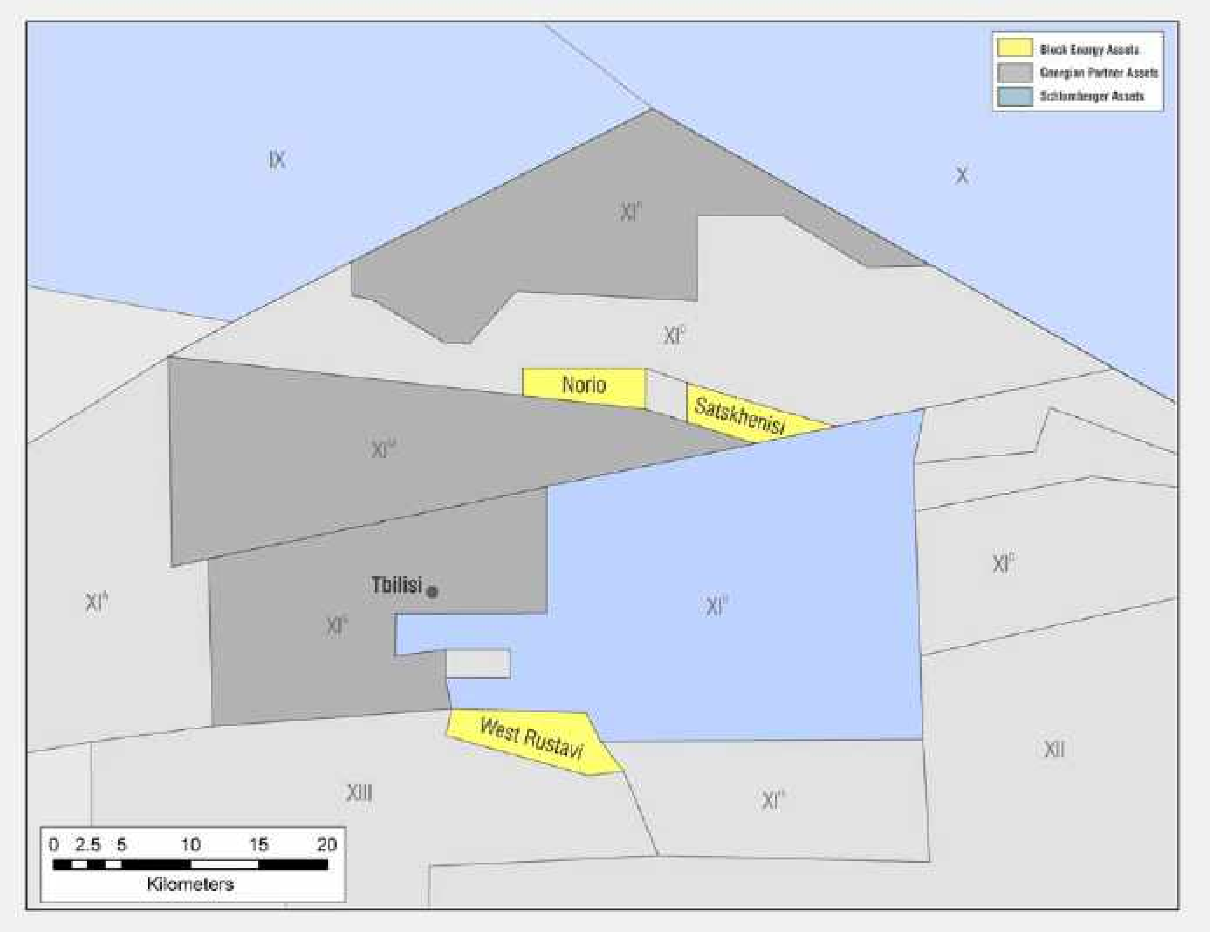


Figure 3-2 Map of Georgia License Blocks with Block Energy License Areas

3.2.1 Norio PSA License Block

The Norio PSA license block contains the Norio Field, which was discovered in 1938. To date, a total of 55 oil wells have been drilled on the block. Out of the 55 wells, 31 produced oil from the Miocene age Chokrak formation. This reservoir is a fractured, volcanic-sourced arkosic sandstone formation that has been subjected to complex thrust faulting that has created compartments of oil accumulation. Production from the field commenced in 1939 with an estimated cumulative production of 1.8 MMBbl and continues producing today from three wells at a total rate of 17.5 barrels of oil per day. The block area is approximately 5,570 acres (22.54 km^2) and is located 22 miles (35 km) north of Tbilisi.

3.2.2 Permit XIf (West Rustavi)

Permit XIf contains the West Rustavi Field, which was discovered in 1988 by well 16a. A total of 13 wells have been drilled on the block. The field has produced 41 MBbl and 41 MMcf from two wells completed in the Middle Eocene horizon and is currently not producing. The block area is approximately 9,328 acres (37.75 km^2) and is located 6 miles (10 km) south-east of Tbilisi and approximately 14 miles (23 km) south of Norio Field.

3.2.3 Satskhenisi PSA License Block

The Satskhenisi PSA license block contains the Satskhenisi Field, which was discovered in 1956. To date, a total of 64 oil wells have been drilled on the block. Out of the 64 wells, 14 wells produced oil from the Lower Miocene age Maikop formation. This reservoir is a fractured, volcanic-sourced arkosic sandstone formation that has been subjected to complex thrust faulting that has created compartments of oil accumulation similar to Norio. Production from the field commenced in 1956 with an estimated cumulative production of 326.5 MBbl and continues producing today from four wells at a total rate of 5 barrels of oil per day with very little water. The block area is approximately 6,024 acres (24.38 km^2) and is located 20 miles (32 km) north of Tbilisi.

3.3 SCOPE OF WORK

The scope of work for this assignment included a review and analysis of technical information provided by Block Energy and Georgia Oil and Gas for the Norio, West Rustavi and Satskhenisi assets in Georgia for the purpose of estimating oil and natural reserves, contingent resources and prospective resources. The dataset was made up of many different components that Gustavson had to compile, reconcile and interpret. The Georgia Oil and Gas (GOG) data was the main source of information relied upon for the interpretations of reservoir parameters. The principal pieces of data relied upon were the Petra database, wellbore diagrams, the Schlumberger reports and well test information.

Based on the GOG data in Norio field, it is our opinion that all of the reported production has come from the Chokrak reservoir. Utilizing the GOG net sand estimates in the Petra database, a net sand isopach was constructed for the Chokrak sand and this was the basis for the net sand parameters used in the probabilistic analysis. The reservoir limits for the Chokrak, Maikop and Sarmatian sands were generally based on well test information and well control data.

The West Rustavi field Petra database information was used with the well test information to interpret and establish the reservoir limits. The fault pattern was based on well control and test information as well as previous technical reports that were provided. The other reservoir parameters such as porosity, water saturation, pressure, and net pay were obtained from technical reports provided by Block Energy.

The Satskhenisi field parameters were based on the 2012 Schlumberger study and report. The Schlumberger work was audited utilizing data from the Petra database, seismic database and parameter limits and ranges were modified accordingly.

Gustavson was requested to prepare reserves and economics based on Block Energy owning 100 percent interest in the Norio, 90 percent interest in Satskhenisi and 75 percent interest in the West Rustavi PSA License Blocks (assuming completion of the Farm-in workplan).

Resources were estimated using @Risk software for probabilistic simulation, and volumetric parameters from the geologic analysis and all available reservoir data. Reserves were estimated for producing wells and workovers and new drilling planned by the operator. Reserve forecasts were based on a probabilistic analysis of initial rates and decline curve parameters based on all available analogous data.

The results of this work are independent estimates of oil and natural gas reserves, contingent resources, and prospective resources contained within Norio, West Rustavi and Satskhenisi Fields. Reserves and resources have been evaluated in accordance with the Petroleum Resources Management System (Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council, and Society of Petroleum Evaluation Engineers) guidelines.

3.4 DISCLAIMER

Gustavson Associates LLC has acted independently in the preparation of this Report. The company and its employees have no direct or indirect ownership in Block Energy, plc, the property appraised or the area of study described. Ms. Letha Lencioni and Mr. Jan Tomanek are signing this Competent Persons Report, which has been prepared by Ms. Lencioni as a Qualified Reserves Evaluator and Mr. Tomanek as a Certified Petroleum Geologist, with the assistance of others on Gustavson's staff. Our fee for this Report and the other services that may be provided is not dependent on the amount of resources or reserves estimated. The accuracy of any estimate is a function of available time, data and of geological, engineering, and commercial interpretation and judgment. While the interpretation and estimates presented herein are believed to be reasonable, they should be viewed with the understanding that additional analysis or new data may justify their revision. Gustavson Associates reserves the right to revise its opinions, if new information is deemed sufficiently credible to do so. Gustavson Associates has not personally inspected the subject properties.

4. DESCRIPTION OF ASSETS

4.1 LOCATION AND BASIN NAME

The subject license blocks are located east of the Black Sea in the Kartli Basin (also referred to as the Kura Basin), an oil and gas province located in the eastern part of the country. Within the Kartli Basin, approximately 15 oil and gas fields have been discovered over the years, amongst which the 236 MMBbl Samgori-Patardzeuli and the 58 MMBbl Ninotsminda fields are the best known. The Kartli Basin is coincident with the Kura River valley and is a tectonically complex area situated to the south of the Greater Caucasus.

4.2 NORIO PSA LICENSE BLOCK

4.2.1 Geographic Description

The Norio PSA license block encompasses an area of approximately 5,570 acres (22.54 km^2). The general outline of the block with the X, Y Coordinates in UTM WGS 1984 Zone 38N projection are shown on Figure 4-1.

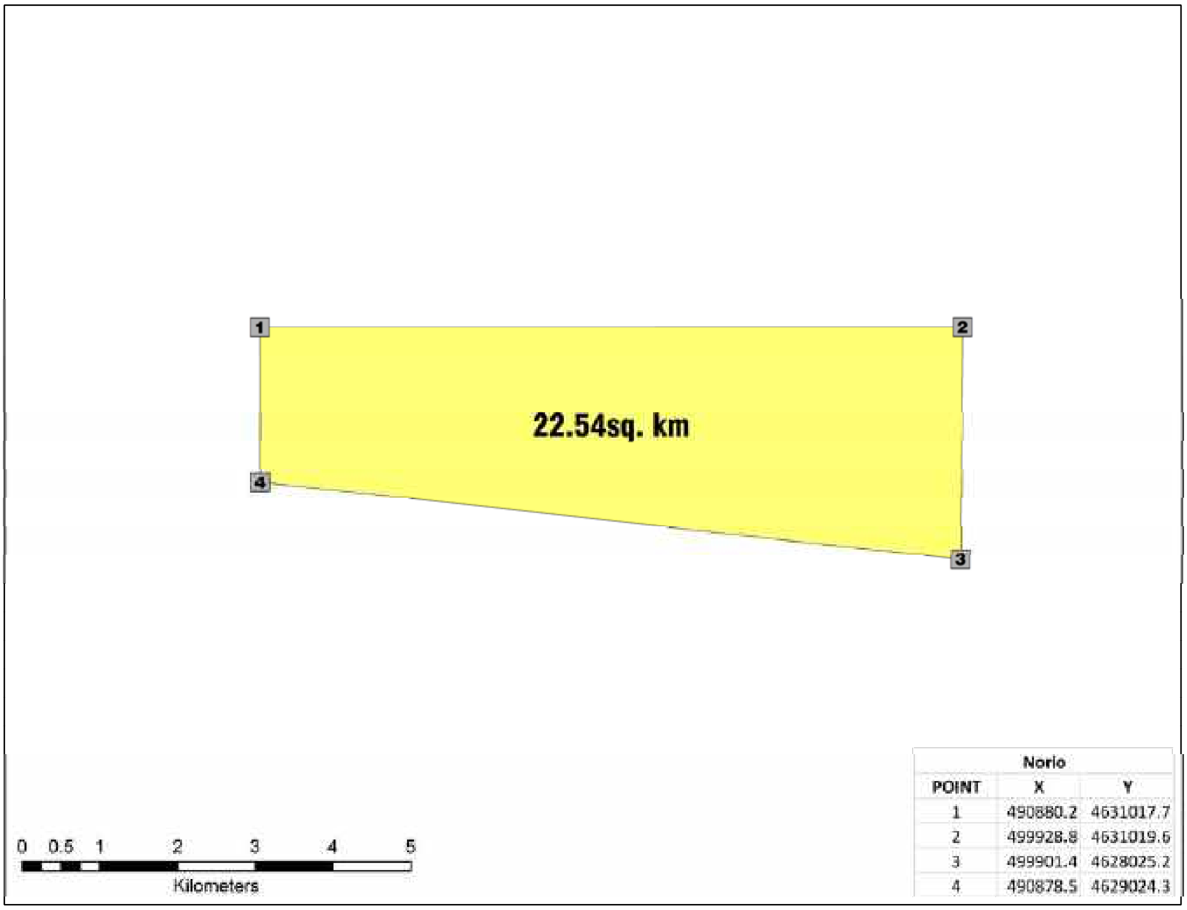


Figure 4-1 Outline of the Norio Block

4.2.2 PSA Contract Terms

The PSA license in the Norio Block was originally awarded to Canargo Energy Corporation in December 2000 for an initial term of 25 consecutive years. The PSA was then assigned to GOG in October 2008. In April 2017, Block Energy, through their wholly owned subsidiary GOG Norioskhevi, purchased an initial 38% interest in the Norio PSA. On July 17, 2017, Block Energy announced in a press release that it had increased its interest in the Norio PSA to 69% as a result of a payment to GOG. As of September 9, 2017, the company has purchased the remaining interest in the Norio PSA prior to take its interest to 100% ownership.

The Norio PSA is effective until April 2026 with an optional five-year renewal. According to Block Energy, there are no outstanding work obligations related to the Permit. The provisions of the agreement include that 100% of the revenue from sales of hydrocarbons are available for cost recovery of operating costs before sharing with the government. Capital costs, including an historic cost recovery pool of US$20 million, can be recovered from 50% of the production revenue before sharing with the government. The government pays all taxes from their share of Profit Oil. Profit Oil is split 50/50 until "Payment Date," defined as the time when all cumulative revenues from Cost Recovery and Profit Oil exceed cumulative capital expenditure, including the historic cost recovery pool. After the Payment Date, the Profit Oil split is 60% for the Government and 40% for the Block.

4.2.3 Database

As noted elsewhere in this report, the production history data provided for this field were found to be incomplete as is the case with most permits and fields located in former Soviet Union states. Gustavson attempted to reconcile and interpret these data, with the results presented in this report. The database provided for Norio consisted of the following information:

Petra Database

This database included horizon tops (from several operators), several well logs, production, and perforation data. This database was updated which was updated with additional information from various reports and spreadsheets of production and test information.

Kingdom – SMT Database

The seismic database that contained 2D seismic data, well information and horizon interpretations was provided. This database was updated with additional information as available. It was found, as noted in the Schlumberger report, that the existing 2D seismic data over the Norio Field does not have the resolution necessary to image and interpret with any certainty the multiple thrust faults and horizon boundaries.

Reports

Several reports from Schlumberger and others with varying data, interpretations and conclusions along with wellbore diagrams, well histories; production and test information were considered.

Production Data

Numerous partial production databases were provided that were consolidated into one master production database which was used in the analysis. Production history data was provided by Block Energy in several MS Excel format files and is described below.

Annual Production by Well from 1939 to 2011:

This file contained annual total production data for 32 Norio Field wells from 1939 through 2011. There is an additional 24 Norio Field wells in the spreadsheet for which there is no production data and these are assumed to never have been produced. The data for gas, oil and water were provided in metric units, cubic meters for gas, tonnes for oil and water. Data were transposed from a years-in-columns to years-in-rows format. The volumes were converted from metric to US units using a conversion factor of 7.0 Bbl/tonne for oil and 6.3 Bbl/tonne for water. The annual volumes were then converted to monthly volumes by dividing by 12 (an assumption was made that the volumes were accumulated over an entire year). The monthly production volumes were imported into an Aries™ database for analysis.

Monthly Production by Well from 2008 to June 2015:

This file contained monthly oil, gas and water production data in metric units for 16 Norio Field wells from October 2008 to June 2015. The volumes were converted to US units using the previously listed conversion factors and imported into the Aries™ database for analysis.

Daily Production, July – December 2015:

This file contains daily production data for six Norio Field wells from May 31, 2015 to December 31, 2015, in metric units for oil, gas, and water. The volumes were converted to US units using the previously listed conversion factors, summed to the monthly level and imported into the Aries™ database for analysis.

Daily Production, 2016:

This file contains daily production data for four Norio Field wells from January 1, 2016 to December 31, 2016, in metric units for oil, gas, and water. The volumes were converted to US units using the previously listed conversion factors, summed to the monthly level and imported into the Aries™ database for analysis.

Daily Production, 2017:

This file contains daily production data for three Norio Field wells from January 1, 2017 to April 23, 2017, in metric units for oil, gas, and water. The volumes were converted to US units using the previously listed conversion factors, summed to the monthly level and imported into the Aries™ database for analysis.

4.2.4 Market and Infrastructure

The terrain in the area of the Norio Block is hilly and forested. Three-phase electrical power is readily available from the grid that runs through the field. Images from Google Maps indicate that there are numerous lease roads that run through the field. The surface is state owned and there are no access issues.

Existing oil storage capacity in the Norio Field is 1,700 cubic meters (10,700 Bbls) in total. This capacity is sufficient to handle production for the proposed plan of development. In addition to the in-field storage, Georgia Oil and Gas rents 800 cubic meters (5,032 Bbl) of storage capacity at a rail siding located at the town of Lilo. As of April 2017, three wells are being produced in the Norio Block.

Oil production is sold to the local market or is transported by rail to the Black Sea port of Batumi. Under agreement with local oil buyers (Lucky2 Oil Company, etc.), oil production from the Satskhenisi field is sold to for Brent Crude Index minus US$9.00/Bbl. This differential includes all marketing and transportation. Similar terms exist for oil produced from the Norio Field and it is anticipated that similar terms will be negotiated for oil produced from the West Rustavi Field.

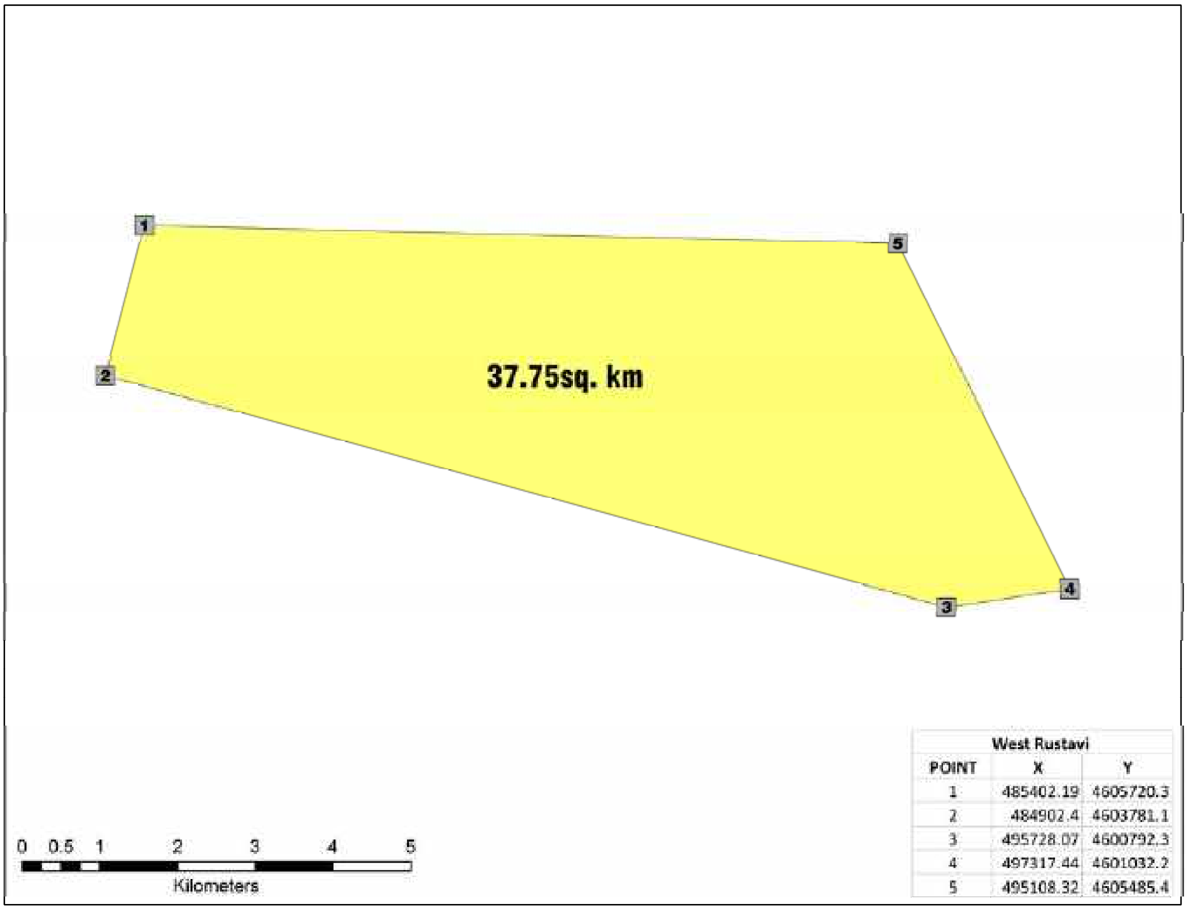
The Norio Field has an existing water disposal system with unknown current capacity. The system consists of two tanks with 400 cubic meter (2,516 Bbl) capacity, a centrifugal pump and a disposal well.

Any associated gas produced in the Norio Field is used on lease. Gas production volumes have not justified the installation of gas gathering and processing infrastructure. Any future increases in gas production resulting from the proposed development will be used to fuel field operations.

4.3 WEST RUSTAVI BLOCK

4.3.1 Geographic Description

The subject area is approximately 9,328 acres (37.75 km^2) in size and is located 6 miles (10 km) south-east of Tbilisi and approximately 14 miles (23 km) south of Norio Field. The general outline of the block and X, Y Coordinates in UTM WGS 1984 Zone 38N projection are shown on Figure 4-2. Block Energy has an agreement with the co-owner of the PSA (Georgia Oil and Gas) to farm-in from its current 5% interest up to a 75% interest in the West Rustavi Permit by completing and paying 100% of the costs associated with a work program of the re-entry and sidetracking of two existing wells, spending $1M on a program of 3-4 workovers and upgrading production facilities as may be required from the enhanced production.



West Rustavi		
POINT	X	Y
1	485402.19	4605720.3
2	484902.4	4603781.1
3	495728.07	4600792.3
4	497317.44	4601032.2
5	495108.32	4605485.4

Figure 4-2 Outline of the West Rustavi Block

4.3.2 <u>PSA Contract Terms</u>

The West Rustavi PSA is effective for 25 years from the date on which it becomes effective with an optional renewal. The West Rustavi PSA will become effective following the satisfaction of routine conditions precedent. This asset will be held by GNV (Georgian New Ventures) which is a wholly owned subsidiary of Block Energy. The Minimum Work Program is described in Table 4-1 below. The provisions of the agreement include that cost recovery of both capital and operating costs is limited to 50% of the revenue from sales of hydrocarbons before sharing with the government. The government pays all taxes from their share of Profit Oil. Profit Oil is split 50/50 until payout, defined as the time when all cumulative revenues from Cost Recovery and

Profit Oil exceed cumulative capital expenditure, including the historic cost recovery pool. After payout, the Profit Oil split is 60% for the Government and 40% for the Contractor.

Table 4-1 West Rustavi Minimum Work Program

Stage I - within 6 (six) months from the effective date of the Contract;

1. To procure and obtain all necessary geological, geophysical (seismic) data and field geophysical data, transfer it to digital and standard format, reprocess and interpret.
2. The environmental assessment of the existed situation and elaboration of environmental recommendations due to the Oil and Gas operations (before commencement of oil and gas operations).

Stage II- within 24 (twenty-four) months from the effective date of the Contract:
Re-enter one deep well for field geophysical works and testing or side-track drilling to produce hydrocarbons; According to the results – 3D seismic-exploration activities of the selected area - not less than 30 km^2.

Stage III - According to the data acquired from the II Stage and from the completion of this II Stage within 24 (twenty-four) months, drill one deep well sufficient to test the deepest prospective horizon.

Note: The 1st and 2nd stages of the ***Minimum Work Program*** constitute the mandatory minimum of work to be completed. Any correction and update may be applied upon agreement by and between the ***Parties*** in accordance with the outcomes obtained at each completed stage of the minimum work program.

4.3.3 <u>Database</u>

The data provided for the West Rustavi field was found to be incomplete; however, the Consultant relied upon several reports that were provided, the Petra database and a sparse 2D seismic dataset.

The Petra Database included horizon tops (from multiple operators) and well logs. This database was updated with additional information from various reports and spreadsheets of wellbore and test information. The production data provided was also incomplete. Cumulative production was provided for the wells in the block and other nearby wells. Limited monthly data were also provided for wells to the north of the block.

4.3.4 Market and Infrastructure

The terrain in the West Rustavi Block is very accessible with gravel and paved roads throughout the permit area, with a major highway at the eastern boundary of the permit. Three-phase electrical power is available throughout the area.

There are currently five shut-in wells within the permit area with wellheads intact - that will facilitate wellbore re-entry and return to production. Eight other wells exist in the permit area which were abandoned but potentially recoverable.

Most land surface in the permit is state owned making access quite simple and straight forward. Water for drilling operations may have to be trucked or a water source well drilled. Kumisi Lake at the western end of the permit is a saltwater lake and likely not suitable for drilling mud.

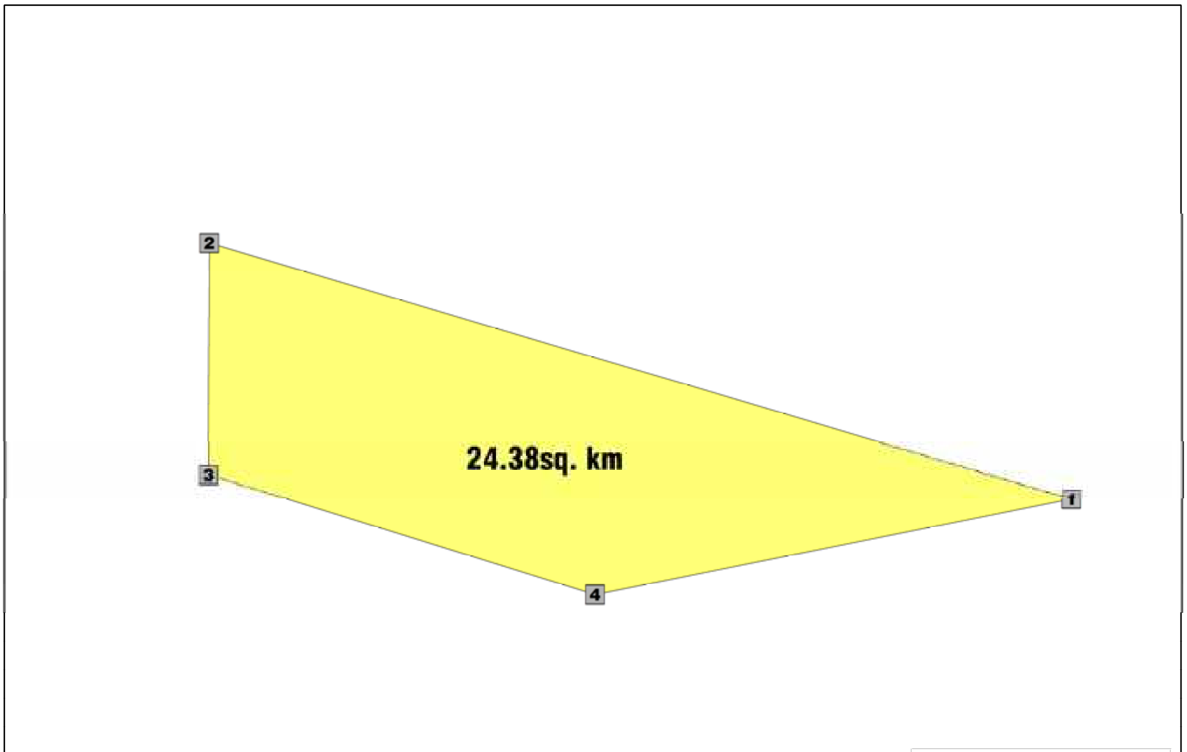
The terrain is suitable for 2D and 3D seismic operations. Population within the permit area is relatively sparse with only one village in the permit area. The city of Rustavi is less than one kilometer from the southern boundary of the West Rustavi Block.

Gas Market: A low-pressure 16-inch diameter gas pipeline runs through the West Rustavi Block, which supplies the City of Rustavi and industrial customers. There are at least two major industrial gas consumers in Rustavi, a fertilizer and a steel plant.

4.4 SATSKHENISI PSA LICENSE BLOCK

4.4.1 Geographic Description

The Satskhenisi PSA license block encompasses an area of approximately 6,024 acres (24.38 km^2). The general outline of the block and the X, Y Coordinates in UTM WGS 1984 Zone 38N projection are shown on Figure 4-3.



Satskhenisi		
POINT	X	Y
1	514011	4626735
2	502914	4630031
3	502895	4627048
4	507880	4625504

Figure 4-3 Outline and Coordinates of the Satskhenisi Block

4.4.2 PSA Contract Terms

The PSA license in the Satskhenisi Block was originally awarded to Canargo Energy Corporation in December 2000 for an initial term of 25 consecutive years. The PSA was then assigned to Georgia Oil and Gas in October 2008. Iskander Energy entered into a farmout agreement dated June 14, 2013 to earn a 50% working interest in the Satskhenisi Production Sharing Agreement (the "Satskhenisi PSA") from the holder of the license, Georgia Oil and Gas ("GOG") (the "Farmout Agreement"). In exchange, Iskander paid all of the costs associated with drilling and hydraulic fracture stimulation (fracture) of multiple intervals in each of the three wells. On August 29, 2014, GOG and Iskander entered into an amendment agreement to the Farmout Agreement which: (i) extended the deadline for drilling of the third well by 12 months such that the drilling of the third well of the earn-in program should occur no later than October 9, 2015; and (ii) extended the earn-in completion date to occur no later than December 31, 2015. In consideration for this amendment, Iskander agreed to pay all the costs to recomplete four existing wells in the fourth quarter of 2014 to the second quarter of 2015.

On April 23, 2015, Iskander negotiated with GOG to purchase the remaining 50% of the Satskhenisi PSA for consideration of U.S. $1,000,000, thereby avoiding the obligation to drill the third earning well. The payment for this acquisition was to be made in two installments, $650,000 in April 2015 and $350,000 by December 1, 2015. The second two wells in the recompletion program were tested. Based on the low producing rates resulting from the two new wells drilled and the subsequent recompletion program, GOG agreed to reduce the amount of the second installment from $350,000 to $150,000. The additional working interest that Iskander purchased was also reduced from 50% to 40%, with the result that Iskander through Satskhenisi Ltd, their wholly owned subsidiary, had a 90% working interest in the Satskhenisi PSA. On Aug 1, 2017, Block Energy purchased Satskhenisi Ltd, which holds the 90% interest in the Satskhenisi PSA, from Iskander Energy Corp. Georgia Oil and Gas still owns the remaining 10% interest in the PSA.

The Satskhenisi PSA is effective until April 2026 with an optional five-year renewal. According to Block Energy, there are no outstanding work obligations related to the Permit. The provisions of the agreement are identical to the terms for the Norio Permit that include that 100% of the revenue from sales of hydrocarbons are available for cost recovery of operating costs before sharing with the government. Capital costs, including an historic cost recovery pool of US$ 10.276 million, can be recovered from 50% of the production revenue before sharing with the government. The government pays all taxes from their share of Profit Oil. Profit Oil is split 50/50 until "Payment Date," defined as the time when all cumulative revenues from Cost Recovery and Profit Oil exceed cumulative capital expenditure, including the historic cost recovery pool. After the Payment Date, the Profit Oil split is 60% for the Government and 40% for the Contractor.

4.4.3 Database

As noted elsewhere in this report, the production history data provided for this field were found to be incomplete as is the case with most permits and fields located in former Soviet Union states. Gustavson attempted to reconcile and interpret these data, with the results presented in this report. The database provided for Satskhenisi consisted of the following information:

Petra Database

This database includes horizon tops (from several operators), several well logs, production, and perforation data. This database was updated with additional information from various reports and spreadsheets of production and test information.

Kingdom – SMT Database

A seismic database that contained 2D seismic data, well information and horizon interpretations was provided. This database was updated with additional information as available. It was found that the existing 2D seismic data over the Satskhenisi Field is too sparse to image and interpret with any certainty the multiple thrust faults and horizon boundaries. It was useful to audit the structural form of the field.

Reports

Several reports from Schlumberger and others with varying data, interpretations and conclusions along with wellbore diagrams, well histories; production and test information were considered. Schlumberger had consolidated the available data and created a model of the Gross Rock Volume for the Maikop and the Chokrak horizons. These results were audited and found to be a reasonable interpretation for the purposes of estimating resources.

Production

Numerous partial production databases were provided that were consolidated into one master production database which was used in the analysis. Production history data was provided by Block Energy in several MS Excel format files and is described below.

Production History Data

We were provided with production history data for the Satskhenisi Field in several Excel format files. As is frequently the case in former Soviet states, the data was incomplete with monthly production data missing for the years 1960 through 2007 and 2013 through the end of 2014. Data time frames were daily for the years 1957 to 1959, monthly for 2008 to 2012 and daily from January 2015 through August 2017. The previously mentioned report prepared by Schlumberger[9] provided cumulative oil, gas and water production volumes through 2008. As shown below, we have combined the cumulative production from the Schlumberger report with the other data sources to arrive at an estimate of cumulative production volumes through 2017. The calculation of cumulative oil production from the various sources is shown in Table 4-2 below.

Table 4-2 Satskhenisi Cumulative Oil Production

Data Source/File Name	Reported Volume	Conversion	Volume in Bbl
Schlumberger report: Cumulative production to 01/01/2010	40,260 tonnes	7.6 Bbl/tonne	305,976
Sats Daily Well Production (Oct 1 2008 - Mar 4, 2014).xls: Production from 01/01/2010 to 01/01/2014	1,133 m3	6.2898 Bbl/m3	7,126
SKN 2014 Monthly Summary production.xlsx: Production for 2014	797 tonnes	7.6 Bbl/tonne	6,056
Satskhenisi Daily Production 2015 - 2017.xlsx Production from 01/01/2015 to 08/01/2017	7,338 Bbl	------	7,338
Total Cumulative Oil Production as of 08/01/2017	------	------	326,496

4.4.4 Market and Infrastructure

The terrain in the area of the Satskhenisi Block is low relief terraces and ridges interspersed with small valleys with intermittent streams. The northern portion of the field has topography typical

[9] Schlumberger Data and Consulting Services, Almaty: "Geological and Hydrodynamic Modeling of Maikopian Formation and Field Development Plan, Satskhenisi oilfield, Georgia (Part II: Hydrodynamic Modeling)", prepared for Norio Oil Company, 2010.

of low foothills with elevations ranging from 900 m to 1,100 m. The southern portion is more flat with elevations ranging from 800 m to 1,100 m. The surface is a mix of pasture, cultivated fields with shrubs and trees along the natural drainages. Three-phase electrical power is available in the area. Google Earth imagery indicates that there are numerous paved or gravel lease roads that run through the field. The village of Satskhenisi occupies the west central portion of the field area. The surface is predominantly state owned and there are no access issues.

Existing oil storage capacity in the Satskhenisi Field is 750 Bbls (120 m^3) in total. In addition to the in-field storage, Block Energy through its operator Norio Operating Company rents 5,032 Bbl (800 m^3) of storage capacity at a rail siding located at the nearby town of Lilo. As of April 2017, four wells are being produced (two intermittently) in the Satskhenisi Block.

Oil production is sold to the local market or is transported by rail to the Black Sea port of Batumi. Under agreement with local oil buyers (Lucky2 Oil Company, etc.), oil production from the Satskhenisi field is sold to for Brent Crude Index minus US$9.00/Bbl. This differential includes all marketing and transportation. It is anticipated that similar terms will continue for oil produced from the Satskhenisi Field.

The Satskhenisi Field produces small quantities of water and consequently has no need for water disposal infrastructure.

Any associated gas production in the Satskhenisi Field is used on lease or vented. Gas production volumes have not justified the installation of gas gathering and processing infrastructure. Any future increases in gas production resulting from the proposed development will be used to fuel field operations.

4.5 IDENTITY AND RELEVANT EXPERIENCE OF BLOCK ENERGY

Block Energy plc is an exploration and production company focused on the acquisition of discovered oil fields in and around the Caucuses region. The company was formerly known as Goldcrest Resources and previously focused on gold exploration. In May 2017, Goldcrest

Resources changed its name to Block Energy plc and shifted the company focus to petroleum projects with an emphasis on opportunities in the Republic of Georgia. The company has made strategic hires to bring expertise in the petroleum industry in order to manage its portfolio of petroleum projects.

5. PETROLEUM GEOLOGY

5.1 EXPLORATION HISTORY

Numerous surface oil seeps have been known and utilized in Georgia (Nibladze and Janiashvili, 2014). Exploration in the country began in the late 19th century with shallow drilling beneath surface seeps. By 1866, more than 100 shallow wells (less than 100 meters (328 feet)) had been drilled in eastern Georgia. As oil production grew, two oil refineries were built.

Modern exploration began in 1928 with a deep oil well drilled to 540 meters. This oil discovery opened the Mirzaani field located in southeast Georgia. Total production is reported at 7.9 MMBBL (Nibladze and Janiashvili, 2014).

After World War II, drilling targets were anticlines identified on seismic. More than 1,300 deep wells were drilled during the Soviet Era and small discoveries were made.

The state company GruzNeft was the only license holder in the country between 1930 and 1994, during which time 197 MMBBL were produced. Peak production was achieved in 1981 with rates around 70 MBOPD. Also during this time, seventeen oil fields were discovered, but only 5 were commercially successful.

Only two large discoveries were made in the Kura Basin, the Samgori-Patardzeuli-South Dome (Samgori) Field and its eastward extension, the Ninotsminda Field. The Samgori Field was discovered in 1974. It has a cumulative production of 210 MMBBL and is still producing. Initial flow rates in the field were as high as 5,000 BOPD per well. The Ninotsminda Field has produced 12 MMBBL of oil and 8.5 BCF of gas to date and is still being developed. Well flow at rates around 1,200-1,500 BOPD have been achieved. Performance in both these fields is dependent on fractures and has been from the thick middle Eocene section. Ninotsminda is significant as 5 horizontal sidetrack re-entries were drilled in the mid/late '90's by Canargo. According to GOG, these horizontal wells intersected multiple natural fractures and in excess of 4 MMBbls was produced from these five wells. The program was terminated by Canargo due to the very low oil prices being realized during this period.

Approximately fifteen companies have held PSA’s in Georgia since 1994, with nine companies at present. Between 1994 and 2012, 10.7 MMBBL of oil was produced from existing fields, but no new commercial discoveries have been made. The distribution of discovered oil and gas fields is shown in Figure 5-1.

Many of the discoveries in Georgia have been in the foreland basins and fold and thrust belts. To date, five oil fields have been discovered and eighteen additional discoveries have been made, fifteen of which are in Georgia’s portion of the Kura Basin.

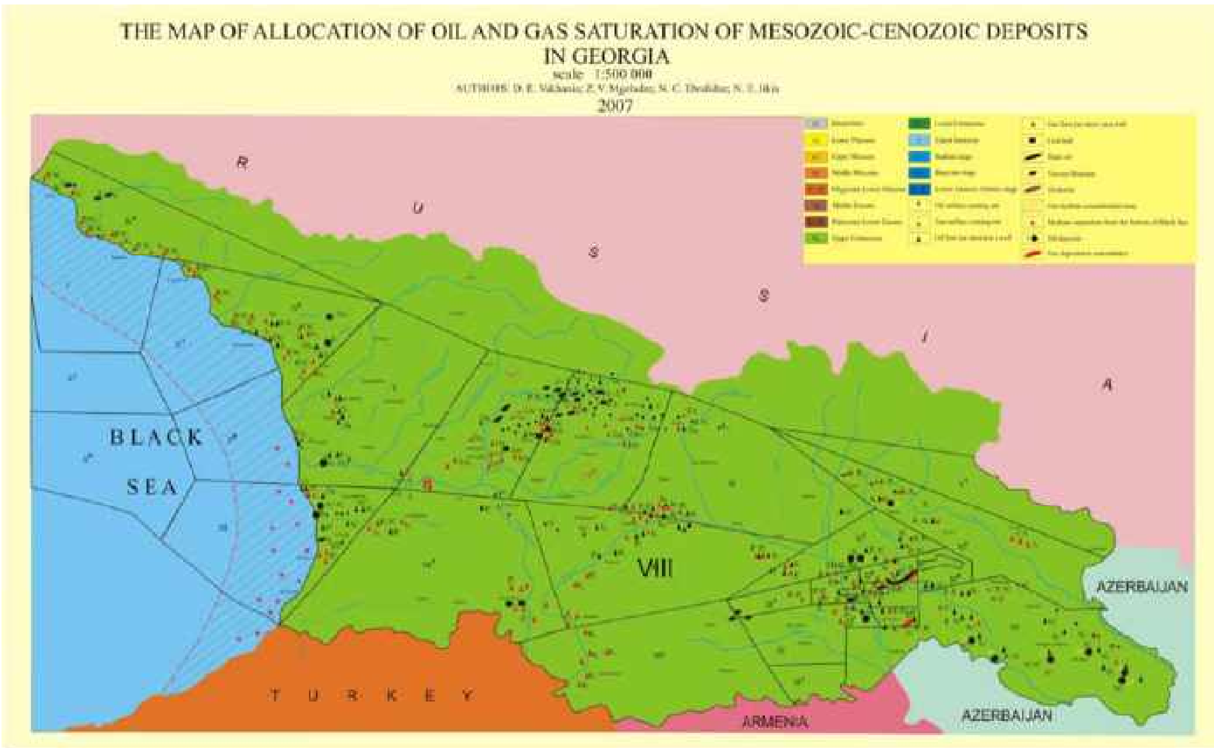


Figure 5-1 Map of Oil and Gas Occurrences in Georgia

5.2 REGIONAL GEOLOGY

5.2.1 Structure

The subject fields are located east of the Black Sea in the Kartli Basin, which is a tectonically complex area to the south of the Greater Caucasus and to the north of the Achara-Trialet Thrust Belt or Lesser Caucasus. Oil and gas production has been established primarily from the Rioni Basin near the Black Sea and the Kartli Basin (also referred to as the Kura Basin) on the eastern side of Georgia (also known as the Karthaliny or Western or Upper Kura basin) which are flexural foreland basins formed in Neogene time by loading of the Achara-Trialet Thrust Belt (Lesser Caucasus) (Figure 5-2). Both basins are bounded on the north by the Greater Caucasus fold and thrust area, which is composed of shallow marine carbonate rocks. The Achara-Trialet Thrust Belt is composed of Paleogene age strata formed in a rifted extensional basin (Robinson et al., 1997). This area is characterized by large anticlines and associated faulting involving Cretaceous through Paleogene rocks and complex thrust faults. The pre-rift basement rocks include the Dziruli Massif that now separates the Rioni Basin from the Kartli Basin. The basin complex extends eastward through Azerbaijan to the Caspian Sea.

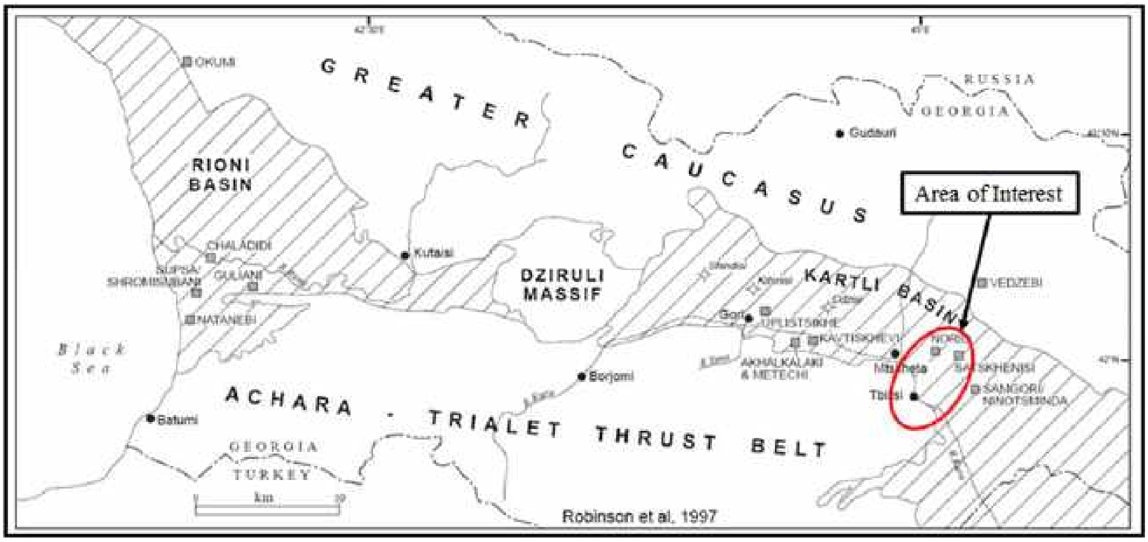


Figure 5-2 Map Showing Oil and Gas Fields, Basins, and Mountain Areas

The region of Georgia and Azerbaijan between the Black Sea and the Caspian Sea is composed of accreted terranes[10]. These terranes include island arcs and continental fragments that separated from Gondwana and accreted to the Eurasian Plate in several stages (Adamia et al., 2011; Zakariadze et al., 2007; Robinson et al., 1997; Zonenshain, et al., 1990). The paleogeographic maps included in Figure 5-3 trace the process through time. The Cretaceous carbonate rocks and the Cenozoic age clastic rocks that are exploration targets in Georgia were deposited in rift basins, back-arc and foreland style basins that were formed in the area of what is now the Black Sea and Caspian Sea over and between these terranes during the Mesozoic and Cenozoic (Figure 5-3) (Adamia, et al., 2011).

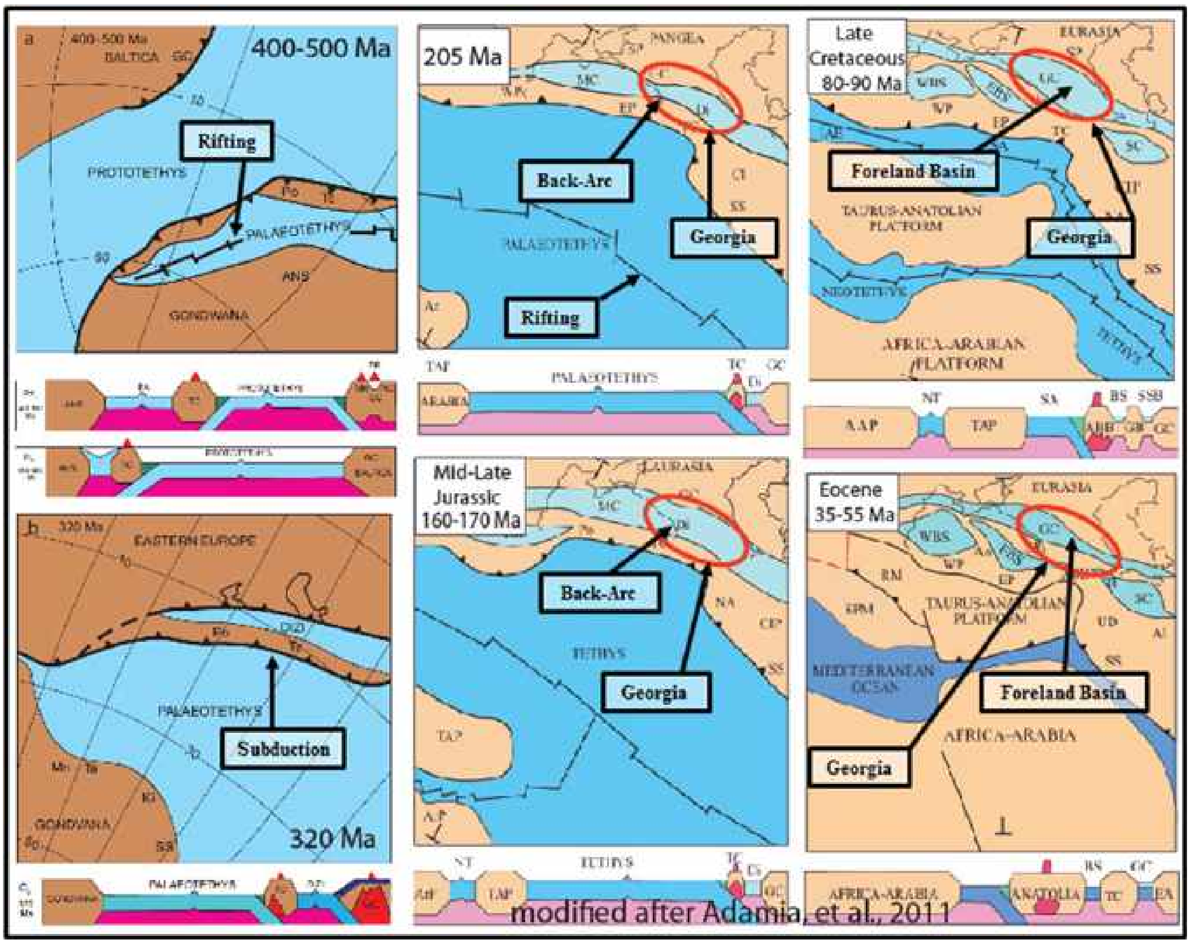


Figure 5-3 Paleogeographic Reconstruction Maps of the Kartli Basin Region

[10] A continental or oceanic plate fragment added to the margin of another tectonic plate by collision and welding.

The collision and rotation of the Africa-Arabian plate with the Eurasian Plate resulted in the Alpine Orogeny, which formed the Rioni and Kartli basins and the folded and thrusted structural traps that are being explored for hydrocarbons. The structural complexity of the area is shown in Figure 5-4.

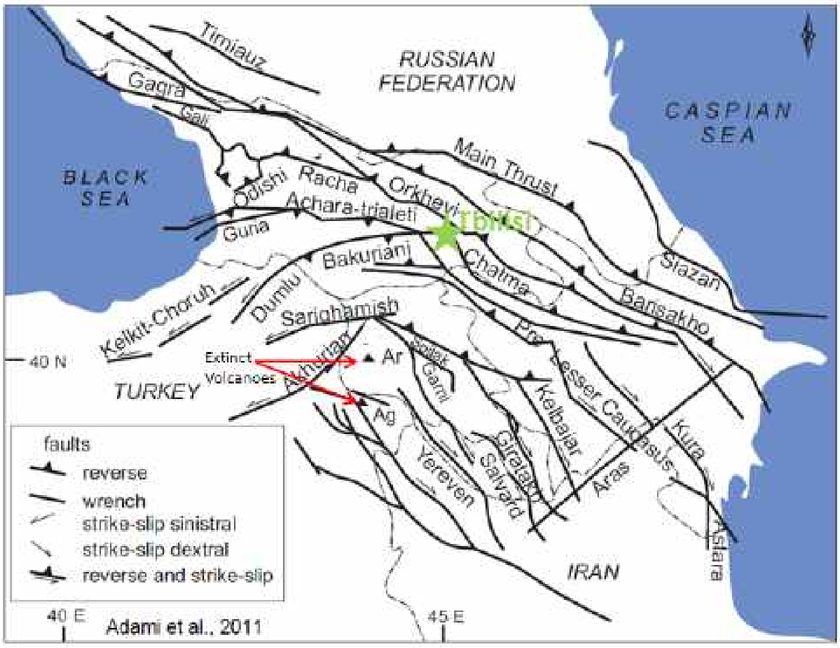


Figure 5-4 Regional Structural Map Showing Major Faults

5.2.2 <u>Stratigraphy</u>

Paleozoic and Mesozoic rocks in the Kartli (Kura) Basin are dominated by marine carbonates. Cretaceous age marine carbonates give way to marine sandy limestones and clastics during the Paleocene (Figure 5-5). Cenozoic age sedimentary rocks consist of marine sandstone, clay, and limestone that can total approximately 9 meters of section where present. Igneous intrusions are also present on the surface as well as basement highs.

The Eocene was characterized by the advent of submarine volcanic eruptions that deposited lava, tuffs and tuffaceous turbidites interbedded with marine clastic and marine carbonate deposits. Reservoirs of Middle Eocene age are characterized as volcanoclastic interbedded with siltstones and some volcanic andesitic flows. The volcanoclastic sandstones were deposited as gravity flows, or turbidites, in deep marine settings. The reservoir quality of these volcanoclastic sandstones has reportedly been improved by diagenetic alteration to laumontite and by fracturing (Robinson et al., 1997). Volcanism decreased as shallow marine clastic and carbonate deposits dominated the Late Eocene.

Oligocene age rocks contain interbedded sandstone and shale deposited in shallow marine depositional settings in restricted basins. The Oligocene succession of sandstones and gypsiferous clays continues into the Miocene. Oligocene through early Miocene is regionally known as Maikopian.

Miocene age deposits range from marine turbidites to fluvial and deltaic deposits indicating a change from marine to shallow marine to continental setting. The Maikop Series of Oligocene to Early Miocene age contains both source rocks and reservoir rocks that produce oil in the Kura Basin. The Chokrak Series consists of Middle Miocene rocks that are productive of oil in the Norio Field and the Sarmatian Series consists of Upper Miocene rocks and are also productive in the basin.

The Norio field produces from the Middle Miocene Chorak and has tested oil and gas from the Maikop and the upper Miocene age Sarmatian rocks. This reservoir interval includes sandstones, clays and some limestones, the Maikop typically grades into the Chokrak (from bottom up) with a decrease in carbonate content. The productive interval in the Satskhenisi field, which is located to the east of Norio field along strike of the structure, is currently only in the lower Miocene age Maikop clastic reservoirs. The West Rustavi hydrocarbon production and occurrence is contained within the Eocene and Upper Cretaceous aged rocks.

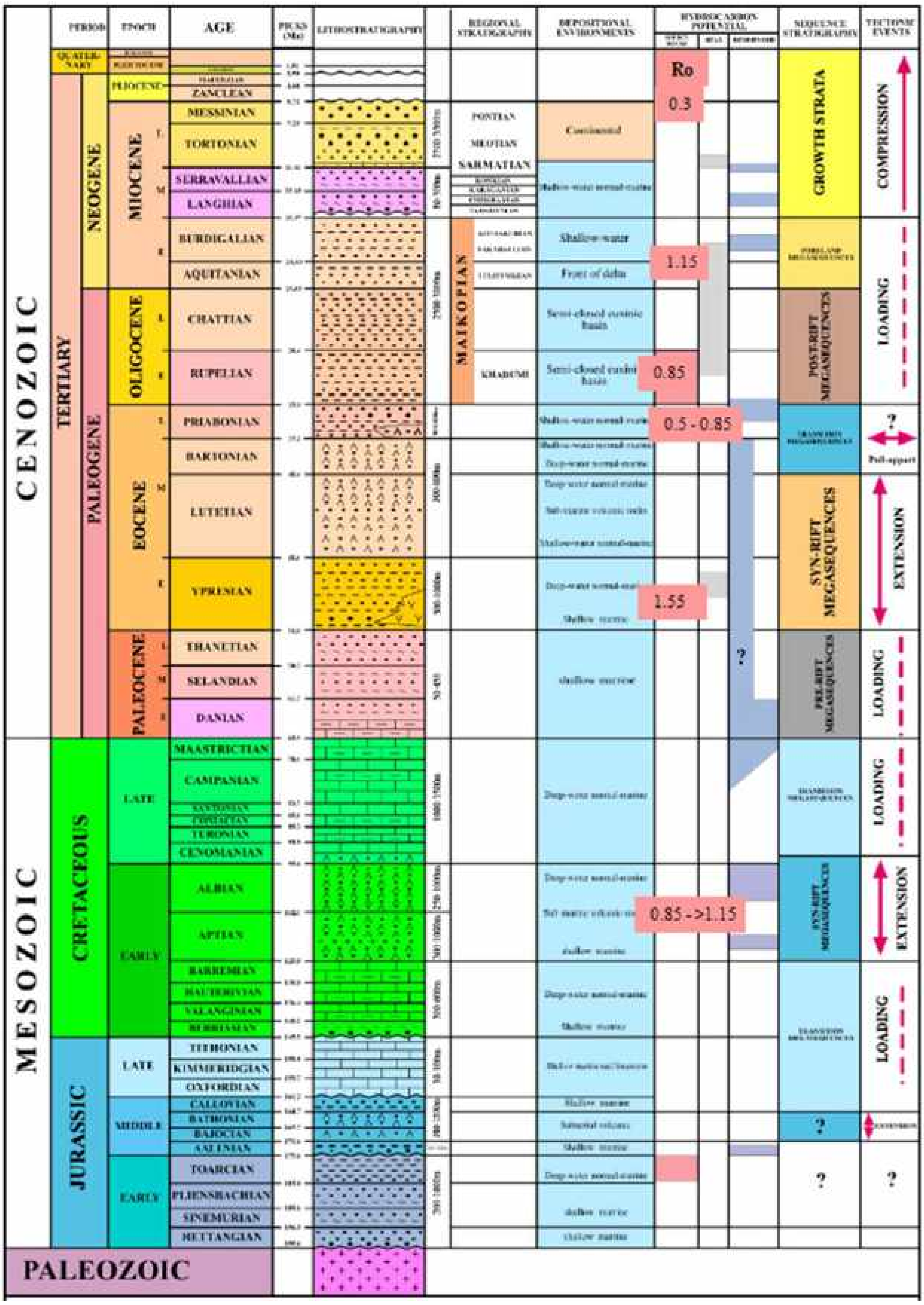


Figure 5-5 Stratigraphic Column of the Kura Basin Region
(modified by Adamia et al., 2011; Alania et al., 2005; Papava, 1976)

5.2.3 Petroleum System

The Kura Basin has active petroleum systems as evidenced by the presence of natural surface oil seeps, oil and gas shows and tests in wells, and oil and gas production.

A petroleum system is a pod of mature source rocks and all the discovered and undiscovered hydrocarbon accumulations that are or can be sourced from it[11]. Petroleum systems are based on the factors affecting hydrocarbon accumulations including the following:[12]

- Trap: a structure or limit to the quality of the reservoir rock that is capable of holding hydrocarbons
- Seal: a layer or rock that is impermeable to hydrocarbon and prevents the hydrocarbon from escaping the trap
- Reservoir rock: one or more rock layers that has sufficient porosity and permeability to store hydrocarbons
- Source Rock: a rock layer in the region that has sufficient organic content to provide for hydrocarbons
- Maturation: the burial of the source rock sufficient to generate hydrocarbons from the organic material within the source rock
- Migration: the path of movement of the generated hydrocarbons from the source rock to a trap
- Timing: the events must occur in the correct order to create and preserve a hydrocarbon accumulation. For example, the trap and seal of the reservoir rock must be present when migration of the hydrocarbons occurs.

The Trap and Seal can be combined into a single aspect for evaluation since they are closely related as are the Migration and Timing aspects can be combined into a single aspect.

[11] Magoon and Dow, 1994
[12] Magoon, 1988

5.2.3.1 Source Rocks

Intervals of potential source rock shown in Figure 5-5 were deposited as marine shale in the Tethys Ocean during the Cretaceous period and marine shale deposited in back-arc-basins during the Paleogene period, and the Neogene period, as depicted in Figure 5-3. The Vitrinite reflectance (Ro) values shown in Figure 5-5 are a measure of maturity of the kerogen organic material within a potential source rock and the stage of oil or gas generation the organic material has reached.

Numerous source rocks have been investigated for the oils found in the Kartli (Kura) Basin and the Lesser Caucasus. These consist of shale, chalkstone, and mudrock of Cretaceous, Paleogene and Neogene age (Gudushauri and Sanishvili, 2000) (Table 5-1). Cretaceous Aptian and Albian age marl source rocks have also been identified. Jurassic rocks are also potential source rocks.

Much of the historic production from wells in eastern Georgia is considered to be sourced from the Oligocene-Miocene age Maikop Series. The total organic carbon content typically ranges between 0.3 and 1.6% (Strait and Georgian, 2011). Table 5-1 shows the organic content of some source rocks of Neogene (N), Paleogene (P), and one Cretaceous (K) sample.

Oil typing was done on produced oils, well head seeps, and natural oil seep samples from the Shromisubani, Natanebi, Guliani, and Okumi fields in West Georgia, the Uplistsikhe field and the surface at Akhalkalaki in the Kartli Basin and Vedzebi North and Ninotsminda fields in East Georgia (Robinson, et al., 1997). Comparison with extracts from upper Eocene rocks in two wells in the Kavtiskhevi field in the Kartli basin indicated these upper Eocene rocks were the source of the oil (Robinson, et al., 1997). Other oils were considered to be of mixed multi-migration origin, interpreted as originating from source rocks of Tertiary to Late Cretaceous in age (Robinson, et al., 1997). An analysis of oil from the Vedzebi North discovery suggests a Late Cretaceous age source rock for this oil.

5.2.3.2 Maturation

The evaluated source rocks reported by Gudshauri and Sanishvili (2000) were also evaluated in relation to maturity (Table 5-1). Source rock maturity was reported in the scheme of katagenetic stages, protokatagenesis (PK), mezokatagenesis (MK), and apokatagenesis (AK) (Gudshauri and Sanishvili, 2000; Trofimuk et al., 1984). The system of maturity values known as Vitrinite Reflectance (Ro) has been correlated with the katagenetic system and added to the chart from Gudshauri and Sanishvili (2000). Protokatagenesis roughly compares to immature to submature source rocks up to vitrinite reflectance values of Ro 0.50 % (Trofimuk et al., 1984). Mezokatagenesis begins Ro 0.50 % just before the beginning of the oil window and ends at Ro 2.00 % at the base of the wet gas window (Dow, 1977). Apokatagenesis begins at Ro 2.00 % and ranges to Ro 6.00 %, past the dry gas preservation limit (Dow, 1977).

Table 5-1 Kura Basin Source Rock Maturity, TOC, and Age

Tectonic Zone	Rock's Age	Lithology	Maturity of the Source Rock	Vitrinite Reflectance Ro %	Content of C organic,%	Content of HC, gr/cm^3
Kura depression	N_1^3-N_1^2	Clay, siltstone	PK_{2-3}-MK_{2-3}	0.30-0.50-- 0.65-1.15	0.1-1.0	50-320
Kura depression	N_1^1-P_3	Clay	PK_3-MK_2	0.40-0.85	0.3-1.4	150-730
Kura depression	P_2^3	Clay	PK_3-MK_2	0.40-0.85	0.3-1.5	240-500
Kura depression	P_2^1-P_1	Mudstone	MK_5	1.55-2.00	0.2-0.7	70-95
Kura depression	K_1 ap-al	Marl	MK_{3-5}	0.85-2.00	0.2-1.7	150
Modified from Gudushauri and Sanishvili, 2000			Katagenesis to Vitrinite Reflectance comparison based on Trofimuk et al., 1984			

5.2.3.3 Reservoir Rocks

Miocene age rocks are the oil reservoirs in the Norio and Satskhenisi fields in the Kartli Basin (Robinson, 1997). They include the Sarmatian, Chokrak, and Maikop reservoirs deposited primarily in shallow marine to continental settings.

Middle Eocene age reservoir rocks account for more than 90% of historic production within the other fields in the Kartli Basin. In West Rustavi the production has come from the Eocene section and the clastic rocks of this age are also proven reservoirs in the Samgori-Patardzeuli, South Dome, Ninotsminda and Teleti fields. These reservoirs are predominately volcanoclastic rocks.

Reservoir properties are good where tuffaceous rocks have been partially altered to laumontite, which has increased average porosity to 12 percent and average permeability to 15 millidarcies (Robinson, 1997). Microfractures within the altered laumontite intervals and tectonic fractures also enhance reservoir permeability.

Cretaceous reservoir rocks are productive in the North Caucasus, particularly the Terek-Caspian Basin of Russia (Ulmishek, 2001). In the North Caucasus Cretaceous carbonate reservoirs produce at rates from 3,000 to 15,000 barrels of oil per day. Recovery factors in these reservoirs are reportedly 50 percent (Morariu and Noual, 2009). The Cretaceous reservoirs consist of carbonate rocks where the normally low porosity and permeability have been enhanced by fracturing due to tectonic movement (Ulmishek, 2001).

5.2.3.4 Traps and Seals

The historic exploration targets in Georgia have been traps involving Eocene strata (Robinson et al., 1997). There are anticlines present that have been defined by surface mapping and have been drilled. Some of these structures may also have exploration potential in deeper Cretaceous and Jurassic age strata. Additional traps include sub-thrust anticlines and other thrust related traps that are not detectable from surface geologic mapping. Seismic data are necessary to delineate these traps and find exploration targets. The shallower Miocene reservoirs are cut by multiple faults creating compartment traps sealed by the faults and overlying low permeability rocks.

Oil accumulations in the North Caucasus and in Georgia are mainly in brachia anticlines and monoclines, complicated by thrust faults (Norio-Satskhenisi, Malgobek-Voznensk, Siazan-Nardaran, etc.). Two reservoir types are developed in both areas: layered and lithologically trapped ones. The most developed ones are roof deposits and layered-screened reservoirs. The Maikop and Middle Miocene deposits are mainly multi-layered.

5.3 NORIO FIELD

5.3.1 Exploration and Development History

The exploration of Norio oil field area commenced in 1938. During 1938-40 the exploration efforts were mainly focused on the oil-saturated Maikopian section on the north flank of the Norio-Khashmi anticline. During this period, commercial oil was discovered in the Middle Miocene Chokrak reservoirs on the northern limb of the anticline. After this, the entire exploration effort concentrated on the oil-bearing features of the Middle Miocene. During World War II, through 1942-45, no drilling operations were conducted, but they were restarted in 1946.

During the time period of 1938-1958 a total of 52 exploration and development wells were drilled in Norio. After the collapse of the Soviet Union, funding of oil and gas exploration and development ceased followed by the civil wars in Georgia which completely ruined its oil and gas industry.[13] The production history of the Norio field is shown on Figure 5-6.

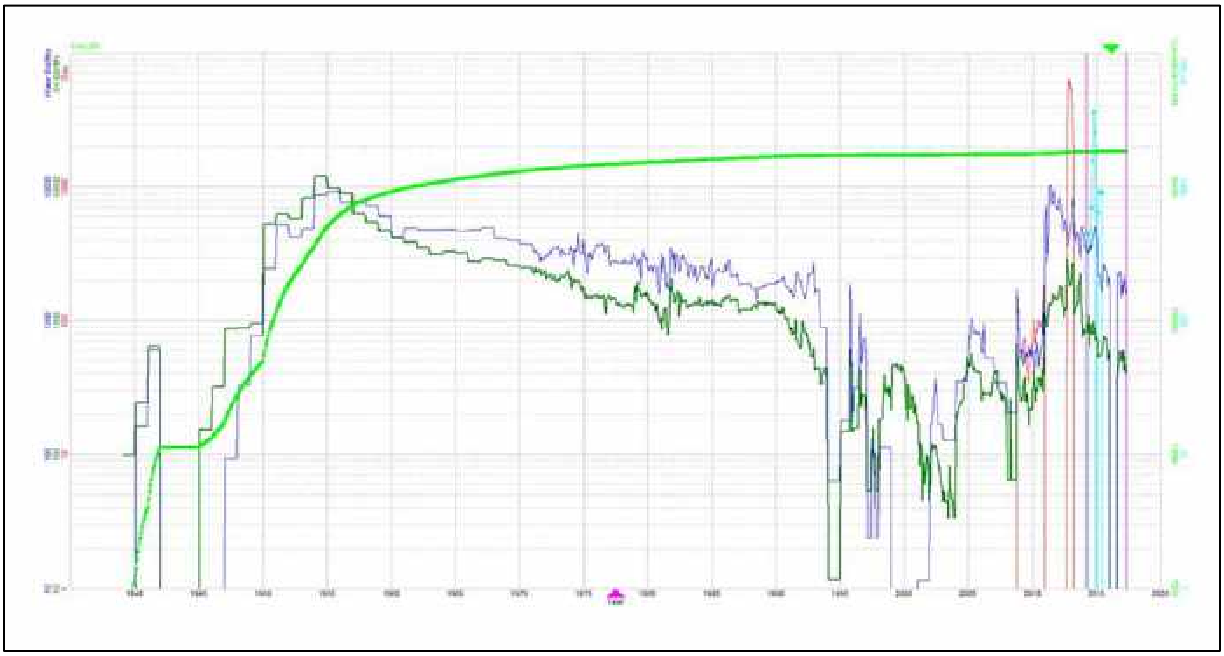


Figure 5-6 Norio Field Production History Plot

[13] History of Petroleum Geology in Georgia; M. Nibladze and A. Janiashvili

The Norio oil field was discovered in 1939 with the discovery of oil in Maikopian sandstones of Miocene age on the Norio-Khashmi anticline (Nibladze and Janiashvili, 2014). The focus of exploration shifted when commercial oil was discovered on the anticline in Middle Miocene reservoirs. An exploration hiatus ran from 1942 until 1946. Fifty-two exploration and development wells were drilled in the field from 1939 to 1958. The complex structural nature of the Norio field is illustrated diagrammatically in Figure 5-7.

Many of the wells were tested in the deeper Maikopian and shallower Sarmatian formations with positive results.

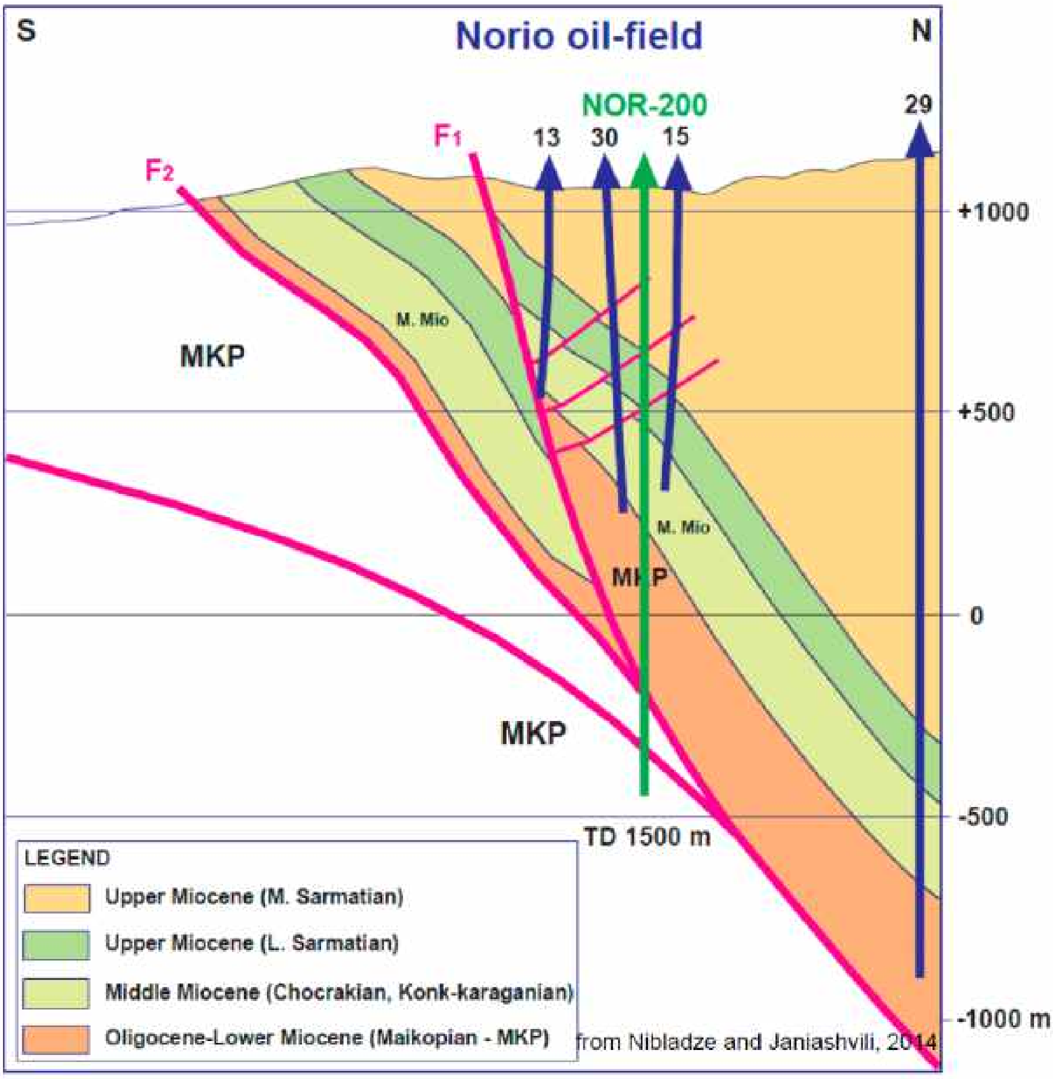


Figure 5-7 Schematic Section of Norio Field

The Satskhenisi oil field is located east of the Norio field and was discovered in 1956. This field consists of 15 wells and produced from Maikop sandstones of Oligocene through Early Miocene age. Total oil produced from the Norio and Satskhenisi fields is reported as approximately 2.1 MMBBL (Nibladze and Janiashvili, 2014.)

5.3.2 Description of Reservoirs

The target reservoir rocks for the Norio Field are the Chorak, Maikop and Sarmatian. The Norio field is made up of volcanic rock sourced clastic sediments that have had multiple thrust faults superimposed on the structure. These thrust faults are difficult to discern on the current 2D seismic data set; however, they are apparent in the NOR201 well (Figure 5-8) image log. The presence of multiple faults likely enhances production in the different reservoirs.

5.3.2.1 Chokrak

Based on the well information, which is incomplete, the Chokrak reservoir is compartmentalized by the faulting and stratigraphic variations. The well test and production information and the Georgia Oil and Gas (GOG) correlations indicate that all of the production in Norio has come from the Chokrak.

The existing data is not adequate to determine the exact volume or geometry of the multiple Chokrak reservoirs. There are disagreements by the various operators (Figure 5-9) and ambiguity as to the proper well-to-well correlations of the Chokrak section. The well log and test data is incomplete. Therefore, the methodology employed to estimate STOOIP volumes primarily used the provided well data including logs, cross-sections, wellbore diagrams, test information and production information. These data were pieced together in order to estimate the updip and downdip reservoir limits as well as lateral extent.

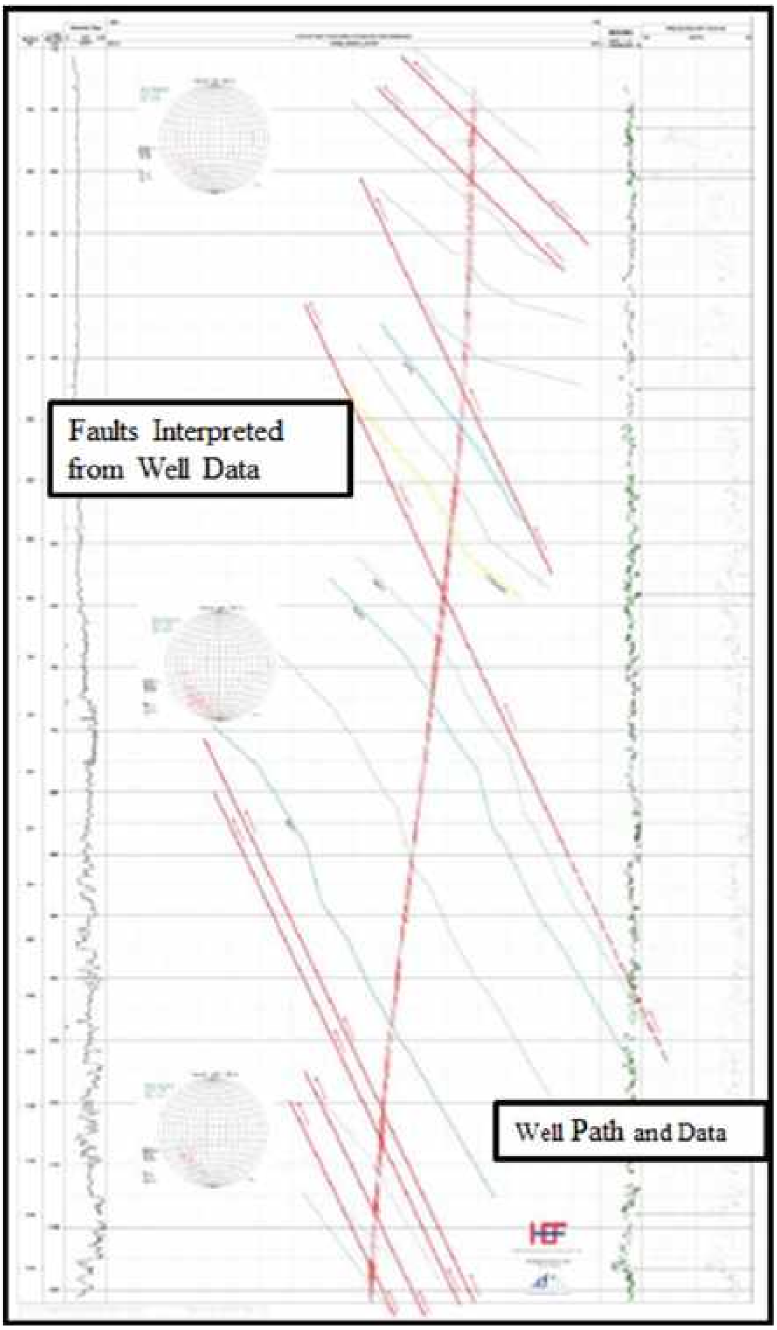


Figure 5-8 Interpretation showing Multiple Fault Cuts in the NOR201 well (Iskander/HEF)

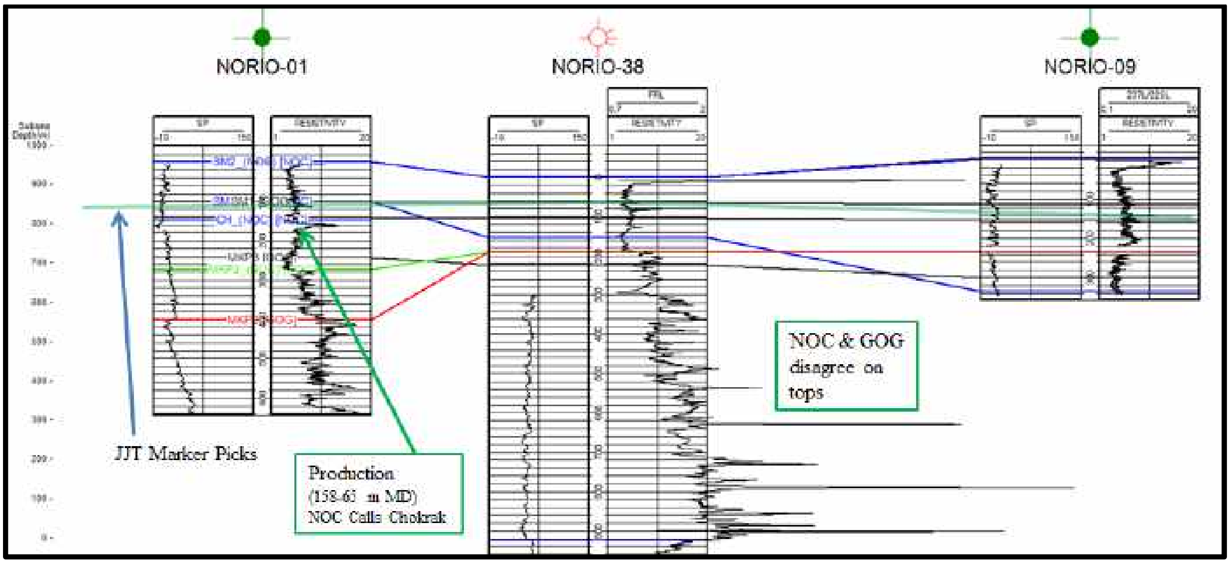


Figure 5-9 Cross-section showing Correlation Issues

Maps from GOG of the cumulative production (Figure 5-10) and the initial production rates (Figure 5-11) clearly show that sweet spots occur in this reservoir. Based on this conclusion, the future work plans are concentrated in these areas.

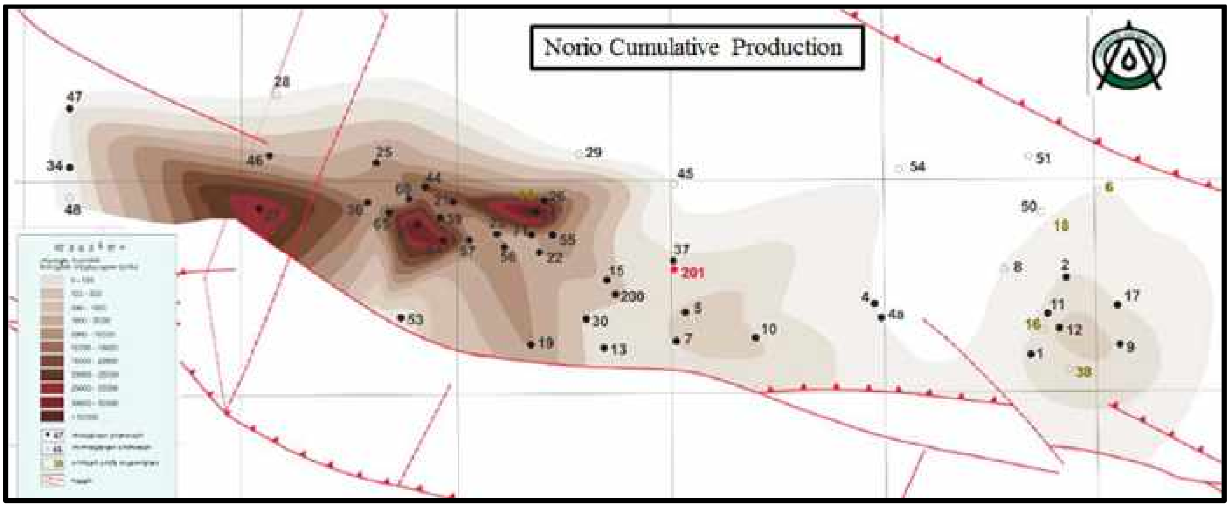


Figure 5-10 Map Depicting the Cumulative Production from the Chokrak (GOG)

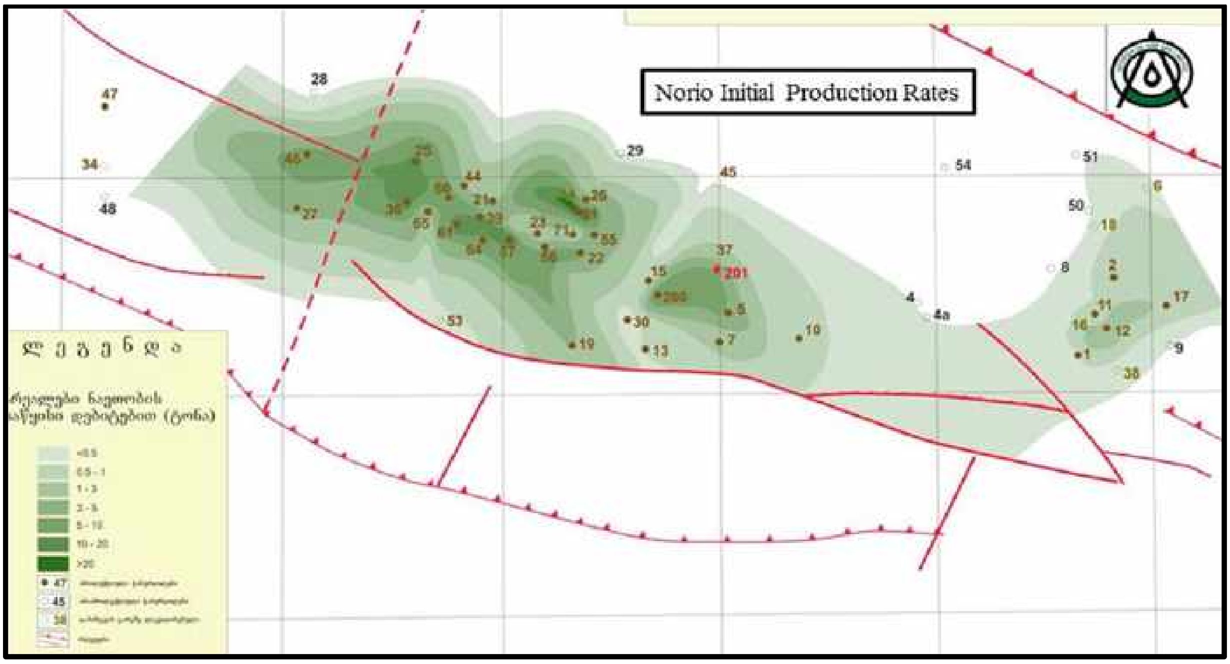


Figure 5-11 Map Depicting the Initial Production Rates from the Chokrak (GOG)

The net sand data in the Petra Project attributed to Georgia Oil and Gas are the basis for the Net Sand Map (Figure 5-12). This isopachous map was used to determine the average net reservoir sand in the Chorak.

The reservoir area limits for the Chorak (Figure 5-13) were interpreted by using the well test and log data that was available. The P_{90} area was estimated using the lowest known production perforations and the P_{10} area was estimated by water and no-flow tests.

5.3.2.2 Maikop

The Maikop, based on an ambiguous report, apparently tested at a rate of 70 BO/D from the NOR 39 well in 1959 but the well production history starts in 1961. The Maikop produces in the nearby Satskhenisi field to the east along the same trend.

5.3.2.3 Sarmatian

Oil and gas shows have been observed in the Sarmatian section in a number of wells in the field. The NOR 37 well tested oil and gas, the NOR 9 well tested only gas and the well Nor 200 was recompleted in the Sarmatian and fracture stimulated by Iskander energy producing 220 Bbls of light oil and 900 Bbls of water. Other reported well tests indicated a tight or wet Sarmatian formation.

5.3.3 Analysis of Net Pay

For the Chokrak reservoir, the net sand data in the Petra Project attributed to Georgia Oil and Gas are the basis for the Net Sand Map (Figure 5-12). This isopach was used to determine the average reservoir quality sand in the Chokrak.

For the Maikop and Sarmatian reservoirs, the net pay range was derived from reports in the database and the petrophysical analysis from the NOR 201 well. The net pay ranges used in the reserve and resources estimates for all three reservoirs are presented in Table 5-2.

Table 5-2 Summary of Norio Net Pay (feet)

Reservoir, feet	Minimum	Most Likely	Maximum
Sarmatian	3.3	15.0	33.0
Chokrak	32.8	52.5	98.4
Maikop	36.0	72	105

5.3.4 Reservoir Limits

5.3.4.1 Chokrak

The reservoir area limits for the Chorak (Figure 5-13) was interpreted by using the well test and log data that was available. The P90 area of 630.6 acres (Area A) was estimated using the lowest known production perforations and the P10 area of 1,360.0 acres (Area A + Area B) was estimated by water and no-flow tests.

5.3.4.2 Maikop

The reservoir limits for the Maikop (Figure 5-14) were also based on the well test and log data that was available. The P90 area of 425.0 acres was estimated using the lowest known tested intervals and the P10 area of 1,380.0 acres was estimated by water and no-flow tests.

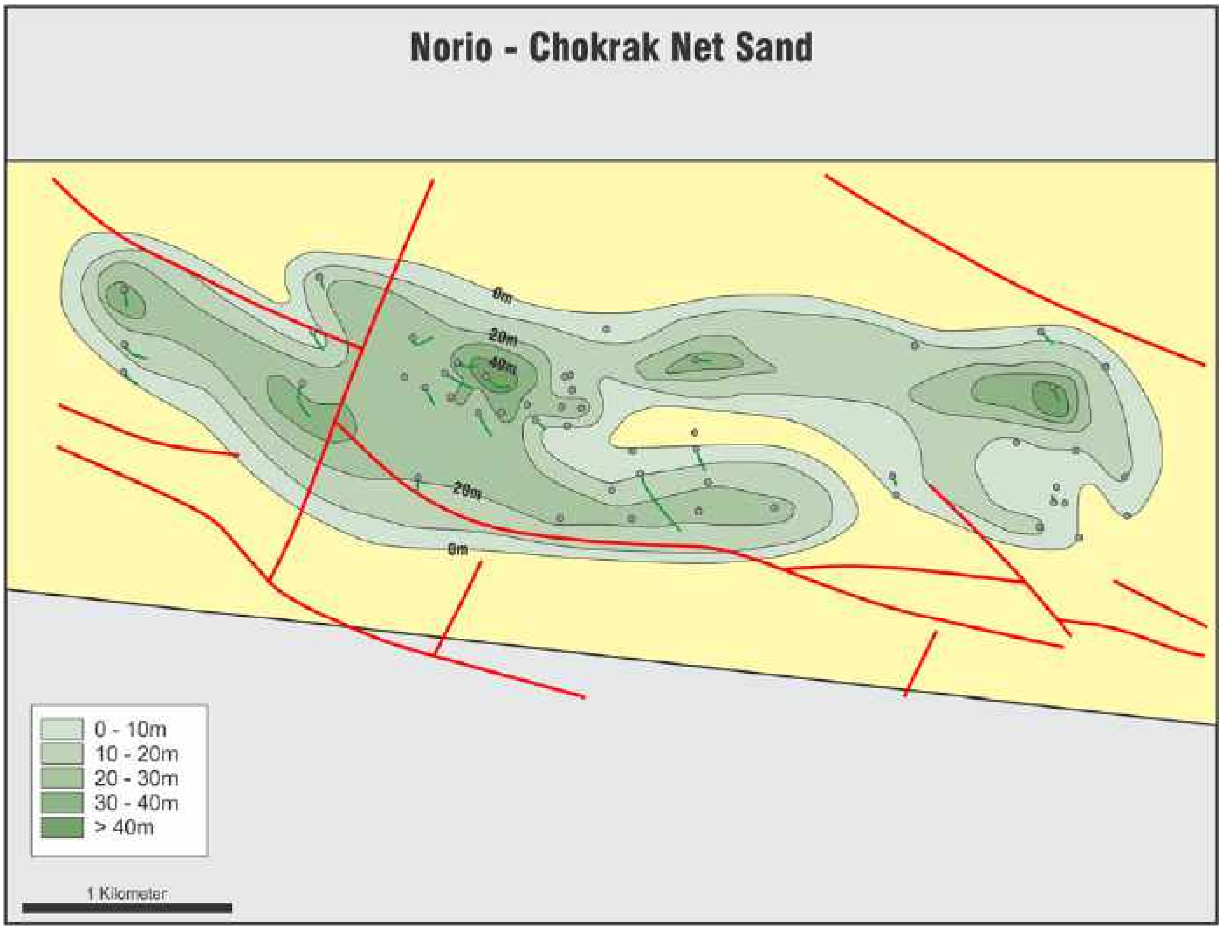


Figure 5-12 Chokrak Net Sand Isopachous Map Based on GOG Data in Petra Project

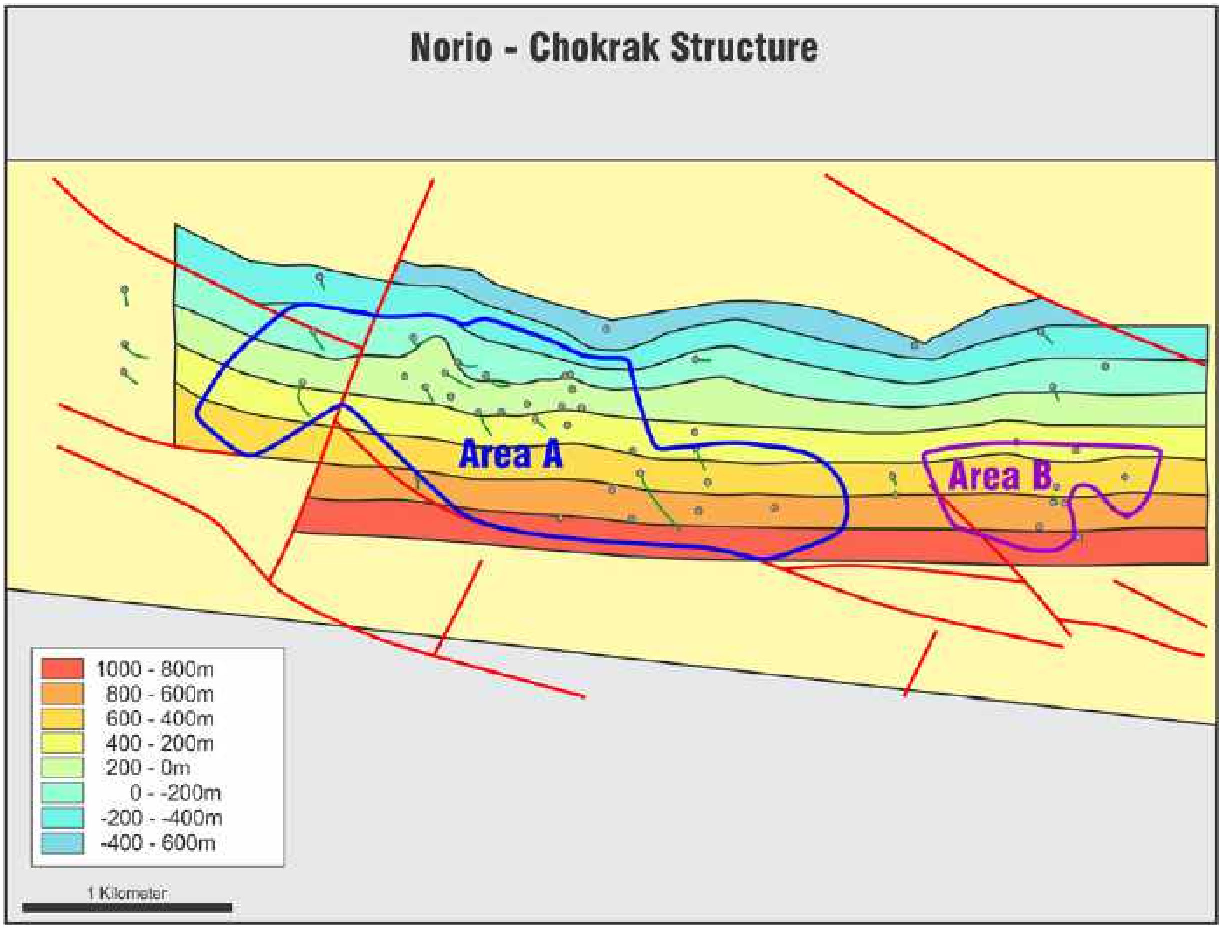


Figure 5-13 Chokrak Reservoir Areas

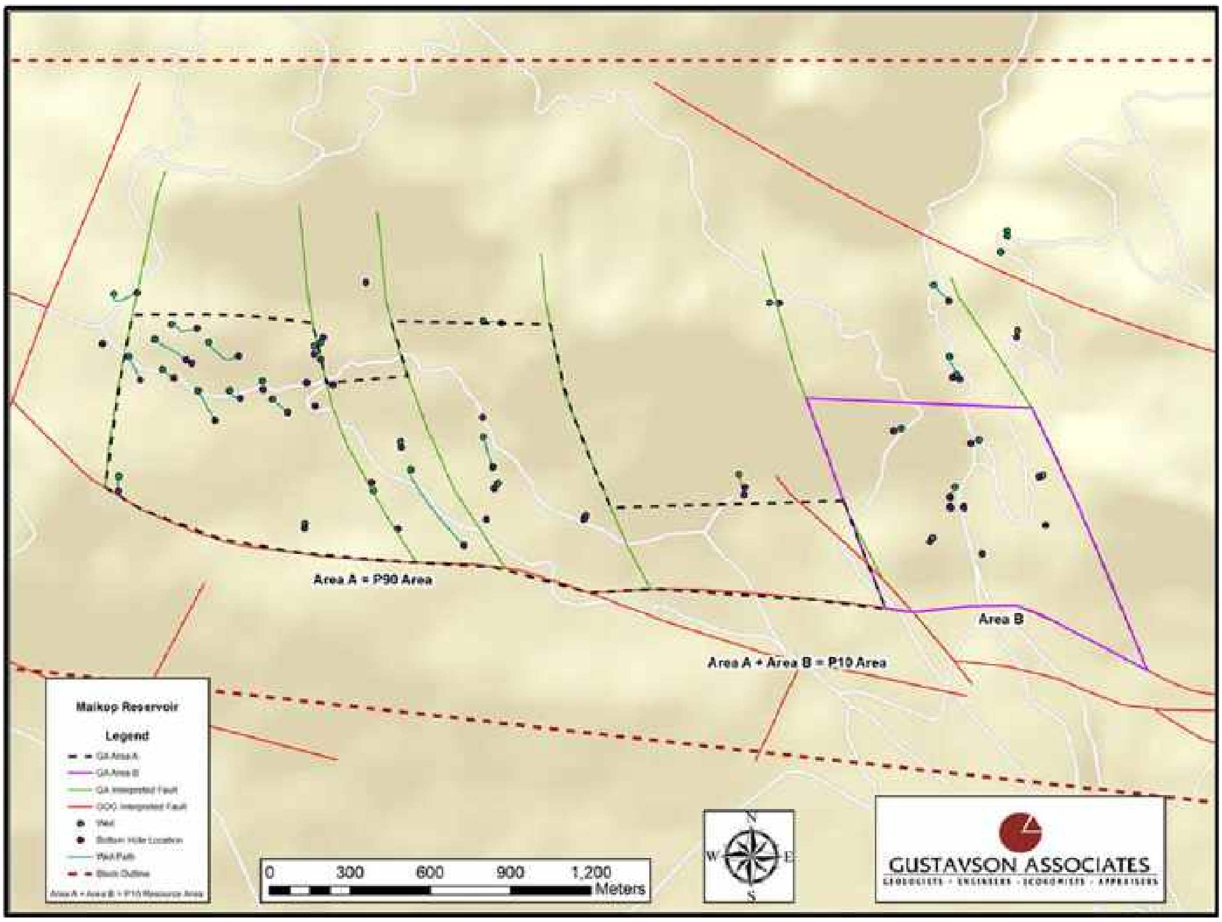


Figure 5-14 Maikop Reservoir Area

5.3.4.3 Sarmatian

The productive area for the Sarmatian, based on positive tests from the NOR 37, Nor 200 and 9 wells, was estimated to be from 49 to 400 acres (Table 5-3).

Table 5-3 Norio Reservoir Areas

Lead/Prospect	Minimum (P10) Acres	Most Likely (P50) Acres	Maximum (P90) Acres
Chokrak	630.6	995.3	1360
Maikop	425.0	902.5	1380.0
Sarmatian	49.0	200.0	400.0

5.3.5 Conclusions

The Chokrak reservoir, based on the GOG correlations, is the source of all of the reported production in the Norio field. The Maikop reservoir, which produces in Satskhenisi field to the east, has had positive well tests in the past and should contribute to the future production. The Sarmatian reservoir may be limited in area on the block, but may have suffered significant damage during drilling which could have caused the negative test results. The Sarmatian appears to be largely a gas reservoir while the Maikop and Chokrak are proven oil reservoirs. The efficient exploitation and development of this field could be better accomplished with the acquisition of a 3D seismic survey, which could be used to locate future wellbores.

5.4 WEST RUSTAVI FIELD

5.4.1 Exploration and Development History

In 1987 the Rustavi 1, 3 and 16a wells were drilled into the Upper Cretaceous on a structure identified on 2D seismic data which was acquired in 1984. The West Rustavi field started commercial oil production in October of 1988 from the Middle Eocene in the 16a well. Two additional wells produced from the Middle Eocene, the 38 well which is within the block boundary and the 39 well which is located just north of the block boundary and designated to be in the Krtsanisi field. Production on the West Rustavi Block ceased in December 1990.

5.4.2 Description of Reservoirs

5.4.2.1 Upper Eocene

This reservoir is mostly fine to medium-grained sandstone with siltstone and calcareous clay. Oil shows were observed in Well Nos. 1, 16a and 50 while the 36 tested oil at a rate of 12 B/D. Total matrix porosity ranges from less than 5 up to 20%, although this may not all be effective porosity.

5.4.2.2 Middle Eocene

The Middle Eocene is characterized by volcaniclastics with a total thickness that ranges from 194 meters to 287 meters thinning to the south. The fractured tuffaceous sandstone acts as the reservoir portion of this interval. Porosities vary from 3.3% to 18.0% as seen in the 16a and 38 wells with effective porosities reported from 1.6 to 14.0%. This reservoir produced oil from the 16a and 38 wells on the block and the 39 well just north of the block. In addition, the 31, 34, 36, 37, 50 and 51 wells on the block had tests at a rate of 3 to 9.4 B/D of oil. The 2 and 21 wells to the east, which are fault separated from West Rustavi, produced gas and condensate from this horizon.

5.4.2.3 Lower Eocene

The Lower Eocene is described as two separate units. The lower section is characterized by calcareous siltstone, mudstone, fine grained sandstone and occasional marl. The upper section contains mostly sandstone, clay, siltstone and mudstone. Total thickness ranges from 1,150meters in the west as seen in the Kumisi 1 well to 1,272 meters as seen in the 16a well. Matrix porosity is approximately 6.0% and the zone was tested in the 1, 30 and 3 wells at rates of 1.0 MMcf/D, 0.9 MMcf/D and 0.3 MMcf/D respectively while gas shows were also noted in the 2 and other wells in the area. An effective porosity of 14.5% has been reported in the 16a; however, there are no reports of this interval being tested.

5.4.2.4 Upper Cretaceous

Only three wells in West Rustavi have penetrated the Upper Cretaceous, the 1, 3 and 16a. The 16a well had been tested at a rate of 1 MMcf/D gas and the 3 well, which is fault separated from the 16a, had an oil show with a 38ºAPI gravity. In addition, multiple gas shows were reported from the Kumisi 1 well to the west. The horizon can be separated into two distinct units: the upper is made up of calcareous sediments while the lower is made up of volcanoclastic sediments. Matrix porosity ranges from less than 4.0% up to 8.4% based on information from the 16a well. Effective porosities can be as low as 0.8% as seen in the Chechnya Field. Gas has been produced from the nearby Teleti and Varketili fields from this horizon.

5.4.3 Analysis of Net Pay

The net pay limits for the West Rustavi field were derived from several reports which in turn largely relied upon the core analysis summary from the Rustavi area. The summary of Net Pay thickness for the West Rustavi reservoirs used in the reserve and resources estimates is in Table 5-4.

Table 5-4 Net Pay Thickness for West Rustavi (feet)

Reservoir, feet	Minimum	Most Likely	Maximum
Upper Eocene	33	75	98
Middle Eocene	72	180	360
Lower Eocene	164	198	262
Upper Cretaceous	52	130	360

5.4.4 Reservoir Limits

The maps used for reserve and resource estimates were based on well control, test information and seismic data. The field area is broken up into numerous fault blocks by nearly vertical faults that apparently have contributed to a fracture system that enhances the low matrix porosity. The conclusion from the interpretation is that the fault block that contains the 16a and 38 wells is high relative to the east-west oriented fault blocks that occur to the north and south. This is the basis for the determination of the Minimum areas for all of the reservoirs in this block. The reservoir quality appears to deteriorate to the west based on results from the Kumisi wells, located off the block.

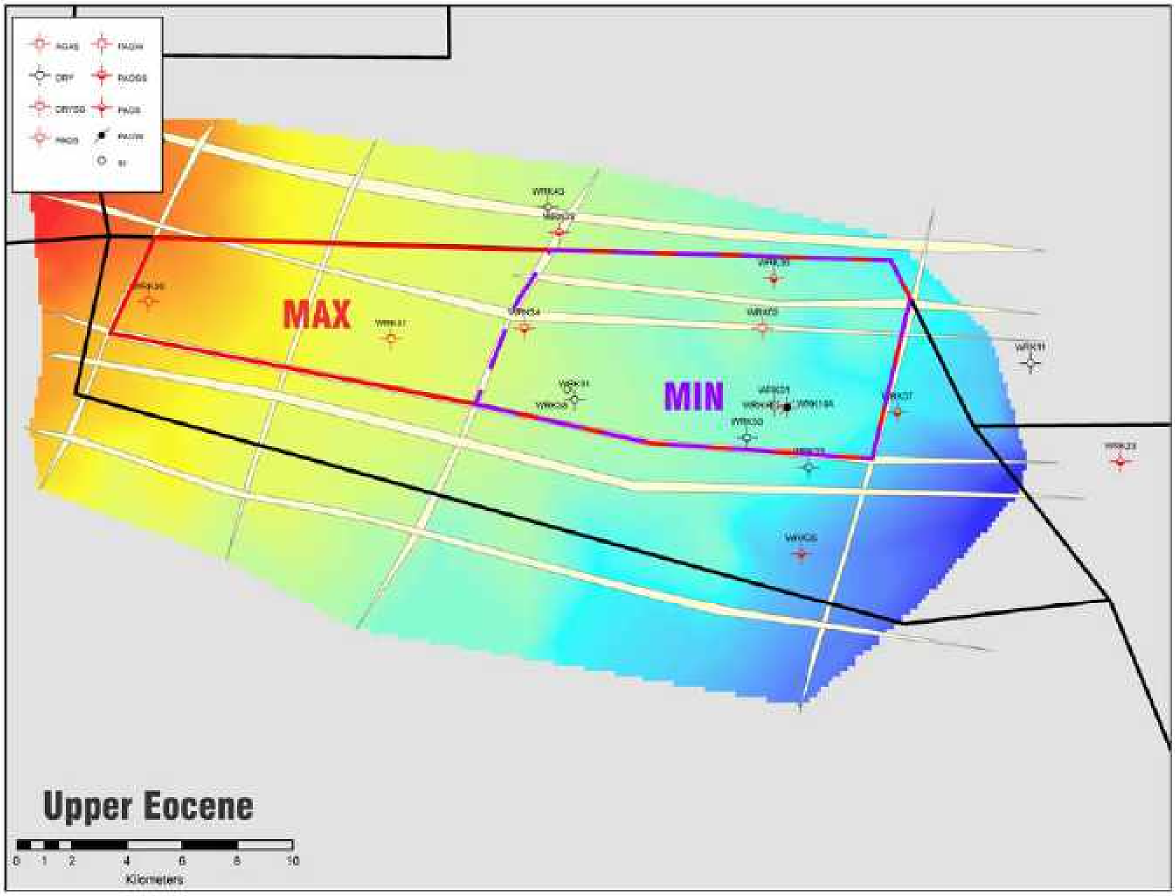


Figure 5-15 Upper Eocene Reservoir Area

5.4.4.1 Upper Eocene

Upper Eocene, which is considered to contain oil, Contingent resource reservoir limits are depicted in Figure 5-15. The minimum P90 area of 2,976 acres includes the 36 well which had a maximum test rate of 12 B/D oil. The maximum area of 4,936 acres includes the areas to the north and west that are likely to be productive. The most likely, P50 area of 3,956 acres is the average of the minimum and maximum. The 35 well in the south part of the block tested only water from this formation.

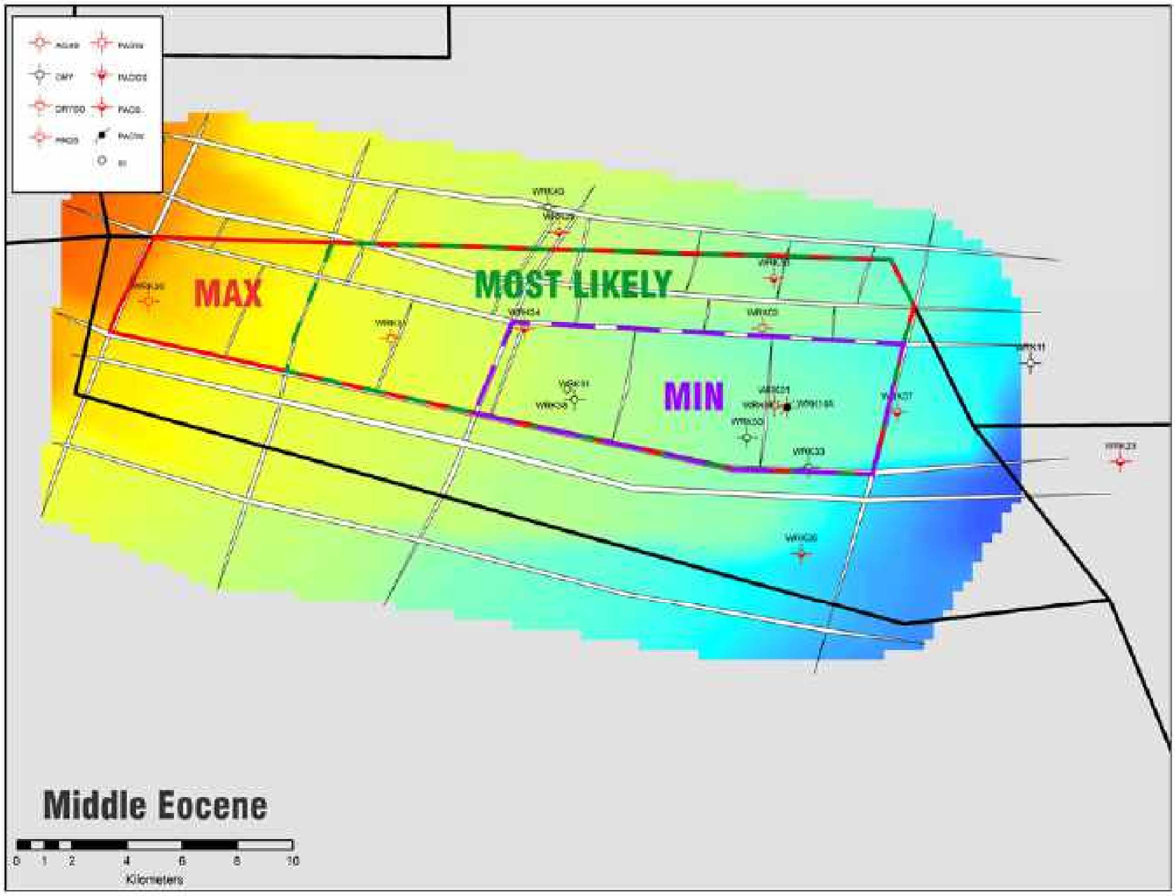


Figure 5-16 Middle Eocene Reservoir Area

5.4.4.2 Middle Eocene

Middle Eocene reserve and contingent resource reservoir limits are depicted in Figure 5-16. The minimum P90 area, 2,164 acres includes the 16a and 38 wells which produced a total of 32 MBbl from 1986 to 2001. The most likely, P50, area of 4,577 acres includes the area just south of the 39 well which produced oil just off the block. The maximum, P10, area of 5,398 acres includes the area to the west that is likely to be productive. The Middle Eocene is a proven oil reservoir in this block.

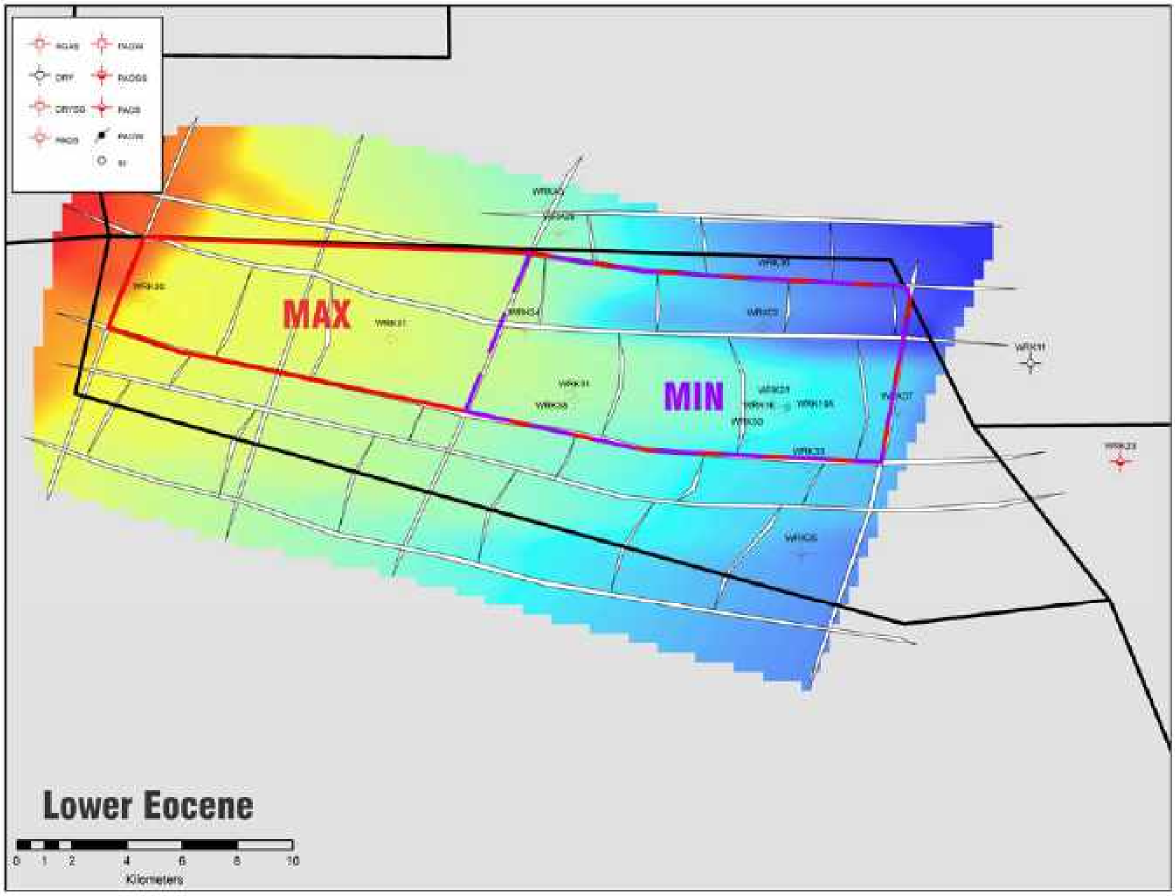


Figure 5-17 Lower Eocene Reservoir Area

5.4.4.3 Lower Eocene

Lower Eocene contingent resource reservoir limits are depicted in Figure 5-17. The minimum, P90, area of 2,660 acres includes the 1 and 3 wells which tested gas at rates of 1.8 MMcf/D and 0.32 MMcf/D, respectively. The maximum area of 4,598 acres includes the area to the west considered to be productive. The most likely area of 3,629 acres is the average of the minimum and maximum areas and contains the 30 well which had tested gas at a rate of 0.9 MMcf/D.

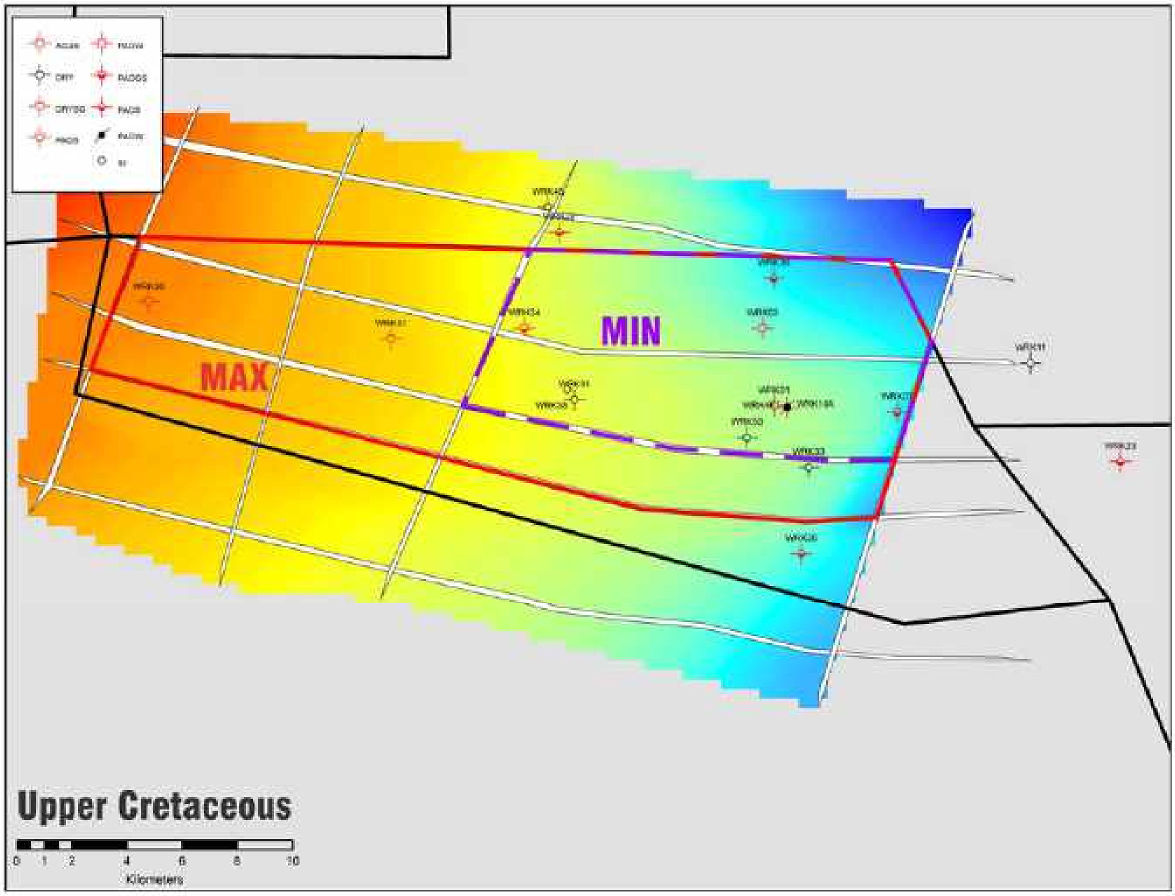


Figure 5-18 Upper Cretaceous Reservoir Area

5.4.4.4 Upper Cretaceous

Upper Cretaceous contingent resource reservoir limits are depicted in Figure 5-18. The minimum area of 3,036 acres contains the 16a well which tested gas at a rate of approximately 1 MMcf/D and the 3 well which had a gas show. The maximum area of 6,655 acres includes a large part of the block. The most likely, P50, area of 4,845.5 acres is the average of the minimum and maximum areas.

The areas used for the West Rustavi reserve and resource estimates are summarized in Table 5-5.

Table 5-5 Reservoir Areas

Reservoir	Minimum (P10) Acres	Most Likely (P50) Acres	Maximum (P90) Acres
Upper Eocene	2,976.0	3,956.0	4,936.0
Middle Eocene	2,164.0	4,577.0	5,398.0
Lower Eocene	2,660.0	3,629.0	4,598.0
Upper Cretaceous	3,036.0	4,845.5	6,655.0

5.4.5 Conclusions

The fault block that contains the 16a and 38 wells is interpreted to be upthrown relative to the blocks on the north and the south. The reservoirs in this area with their low matrix porosities rely on a fracture network to enhance storage and productivity. The Middle Eocene has proven production and the Lower Eocene and Upper Cretaceous have had good tests for gas and condensate. The Upper Eocene needs further evaluation and testing. The efficient exploitation and development of this field could be better accomplished with the acquisition of a 3D seismic survey, which could be used to locate future wellbores.

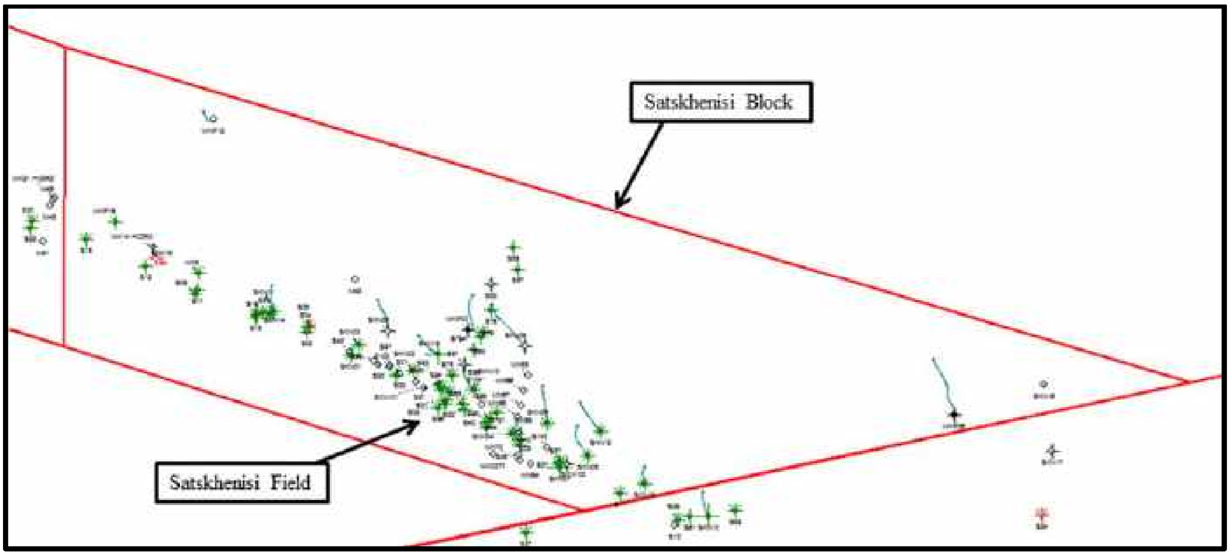


Figure 5-19 Map of Satskhenisi Block with Shallow and Deep Well Locations

5.5 SATSKHENISI FIELD

5.5.1 Exploration and Development History

During the time period from 1934-1939 five structural test wells were drilled in the area which found indications of oil in the Maikopian section. In 1956, the #1 well was drilled and discovered the Satskhenisi Field and through 1959 a total of 51 wells were drilled by Georgian Oil. An additional 9 wells were drilled from 1966 through the end of 1967. Numerous shallow wells were also drilled over the years many of which flowed oil from the Maikop (Figure 5-19). Seismic data was acquired starting in 1984 and again in 1986 through 1988 by Gruzneft-Geophysika and by GOG in 1997 and in 2000 by Dagang Geophysical Company from China. A gravimetric survey was conducted in 2001. Production from the field started in 1956 (Figure 5-20) and continues today at a rate of 5 B/D. Production has come from up to 14 wells with the #4 well having the highest cumulative production of 60.6 MBbl (Figure 5-21). Total cumulative production for the field to date is 326,496 barrels of oil. (Figure 5-22)

On June 14, 2013, Iskander entered into a farmout agreement with Georgia Oil and Gas. In 2013 Iskander commenced a two well drilling program which was completed in the first quarter of 2014. Both wells were subsequently fracked in multiple intervals (five intervals in one well and seven intervals in the second well) and production tested. The results of both wells were sub-economic. In the fourth quarter of 2014 to the second quarter of 2015, four existing wells were recompleted. The first two existing wells were perforated both in existing and new zones and new pumping equipment was installed. There was no increase in oil production resulting from these two workovers. The second two wells were worked over in the first quarter of 2015 to repair the primary cement integrity behind casing across one prospective zone in each well. The second two wells in the recompletion program were then fractured in one zone in each well and then production tested. One well produced oil at rates of 5 - 10 Bbls oil per day and the other produced 99% water at very low total fluid rates.

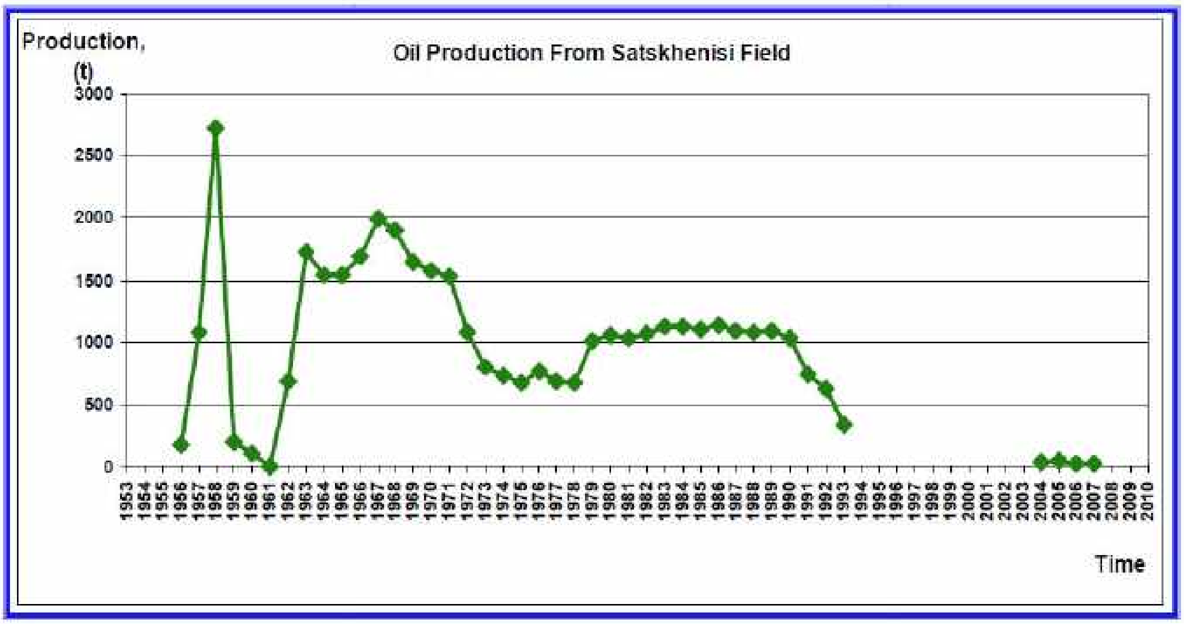


Figure 5-20 Satskhenisi Field Total Production Plot

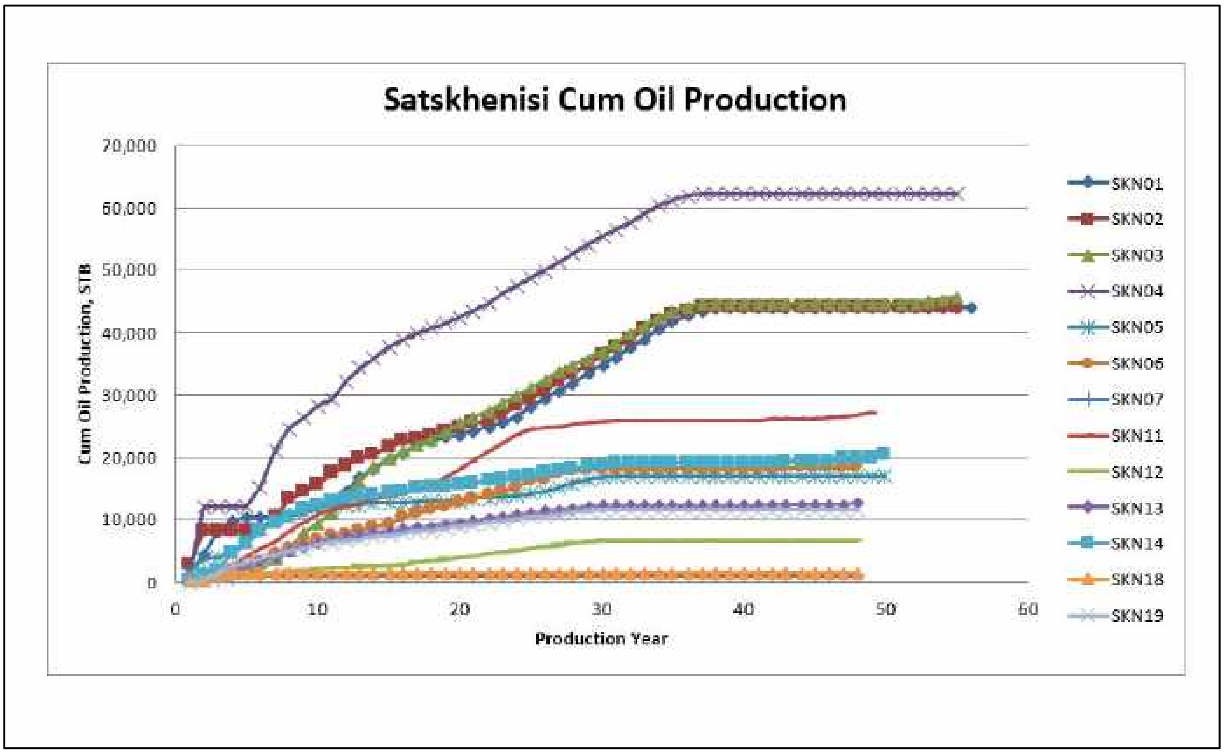


Figure 5-21 Satskhenisi Cumulative Production by Well

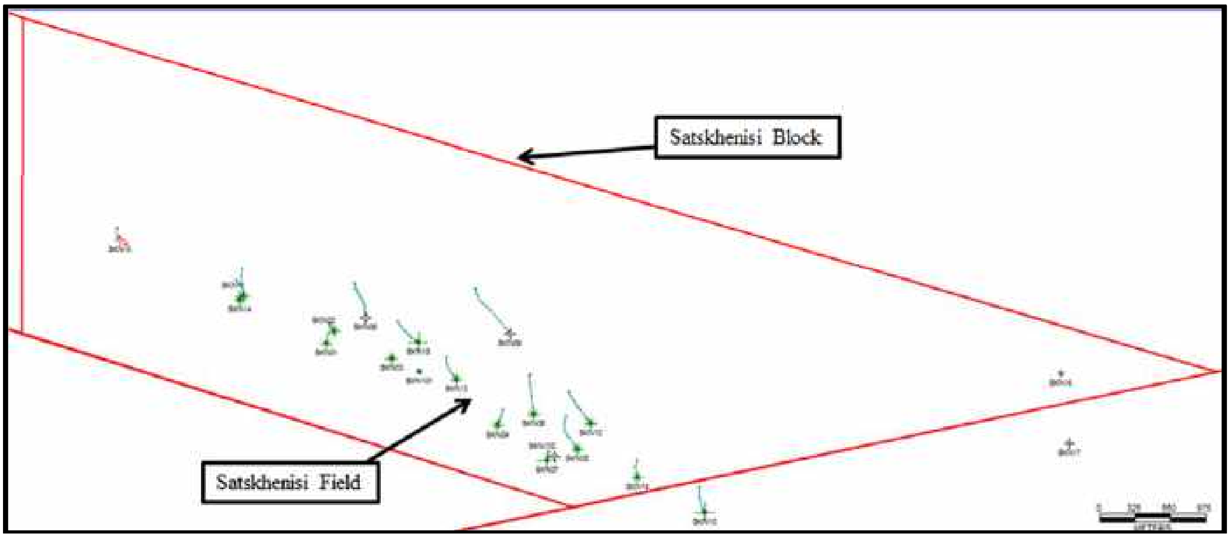


Figure 5-22 Map of Satskhenisi Field Wells with Block Outline

5.5.2 <u>Description of Reservoirs</u>

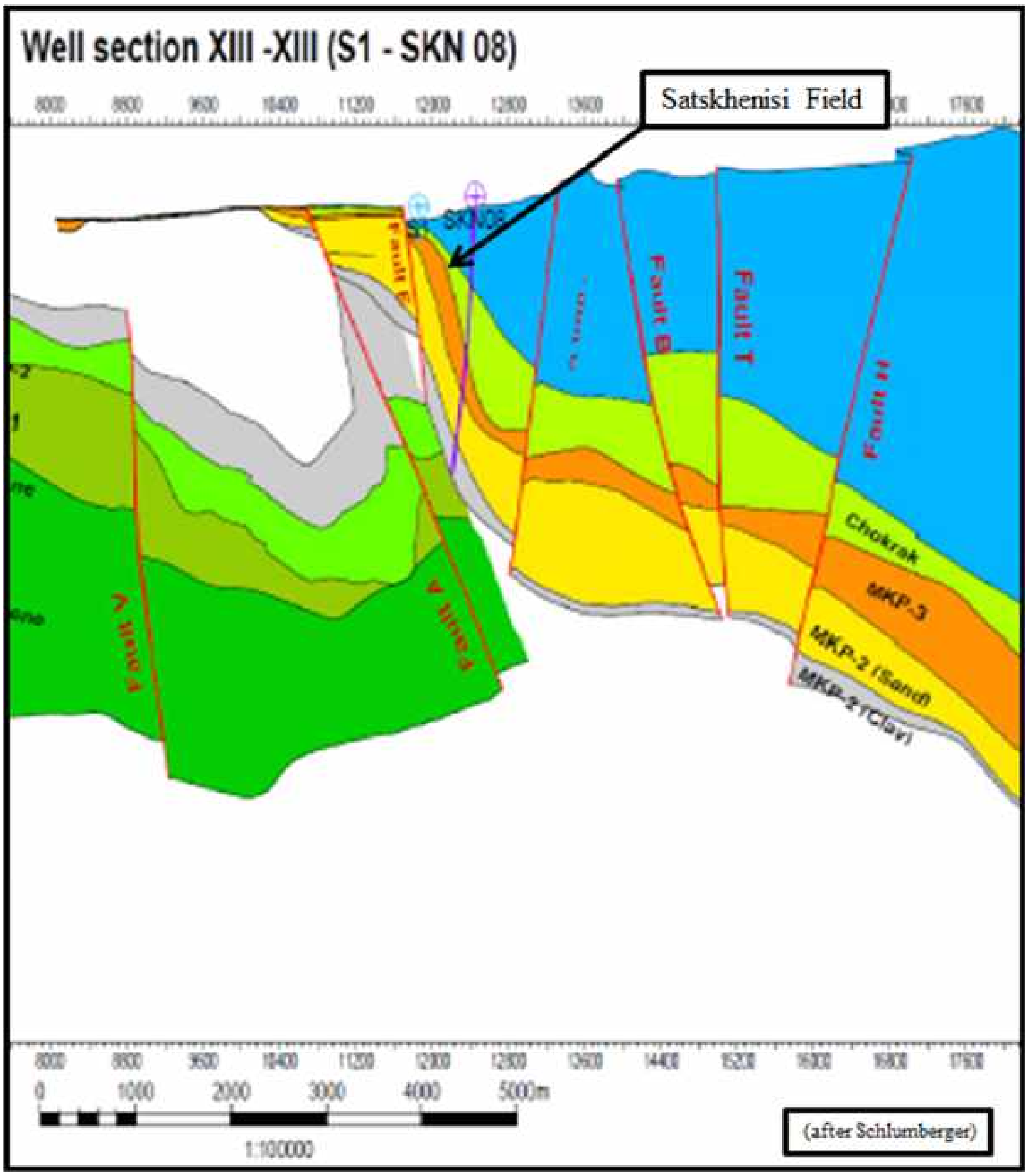


Figure 5-23 Cross section of Satskhenisi Field

The Satskhenisi Field (Figure 5-23) is a faulted and fractured steeply dipping structure similar to the Norio Field. The proven pay here is the Maikop section while in Norio the production has come from the Chorak.

5.5.2.1 Maikop

The Maikopian suite, based on lithologic characteristics, is subdivided into three major parts. The deepest section of the Oligocene aged sediment consists of greenish-grey fine grained sandstones and clays which can be up to 2,296 feet thick. The Lower Miocene aged Middle Maikop, which contains the productive section, is made up of thick bedded quartz and feldspar sandstones and interbedded clays which can be 1,640 to 1,800 feet thick. The upper part of this section, which is mostly white sandstone with interbedded clays can be up to 590 feet thick, is the reservoir portion of the Maikop. This part of the Maikop is commonly referred to as the Maikop 2 and is sometimes subdivided into as many as nine sands. The Upper Maikop, up to 655 feet thick, is made up of clays with occasional white sandstones. The Upper Maikop and bitumen filled sands form the seal for the oil accumulation. The steep dip of the structure is illustrated in Figure 5-24.

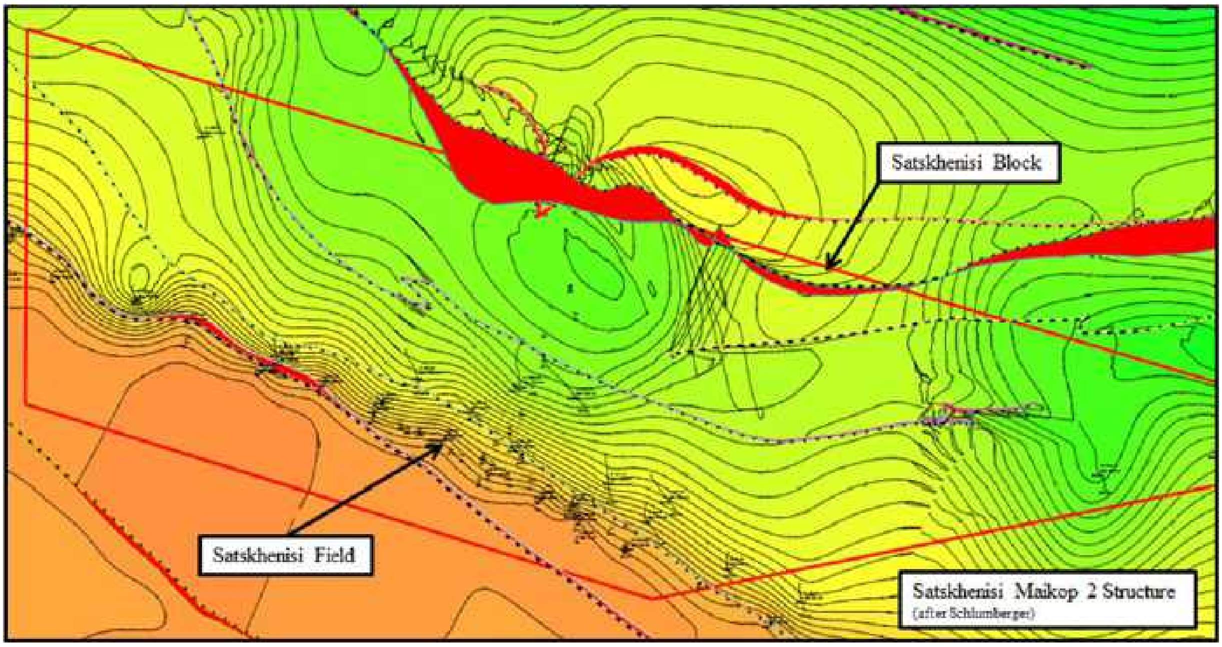


Figure 5-24 Satskhenisi Field Structure map of the Maikop horizon

The porosity for the reservoir section of the Middle Maikop ranges from 12 to 20% and the water saturation ranges from 30 to 50%.

5.5.2.2 Chokrak

The Chokrak is composed of marls with interspersed medium to coarse sandstones and calcareous clays. The section thickens from west to east from 490 to 980 feet while less sand is encountered. Many of the wells that were drilled in the field encountered shows in the Chokrak, but only the 10 well was reported to have been tested with minor rates. The porosity for the reservoir section of the Middle Miocene ranges from 12 to 17% and the water saturation ranges from 30 to 52%.

5.5.3 Gross Rock Volume

The gross rock volume (GRV) limits for the Satskhenisi field were derived from the Schlumberger model presented in the field study report. The GRV incorporates the gross interval thickness with the areal extent of the reservoir. An audit of the Schlumberger work showed that the parameters and results were reasonable. The available data in the Petra database and other reports and spreadsheets provided was used for the audit. A summary of gross rock volume for the Satskhenisi reservoirs used in the reserve and resources estimates is in Table 5-6.

Table 5-6 Gross Rock Volume for Satskhenisi (acre-feet)

Reservoir	Minimum Ac-ft	Most Likely Ac-ft	Maximum Ac-ft
Maikop	1,199,531	1,332,812	1,466,093
Chokrak	700,464	1,663	1,300,862

5.5.4 Net to Gross

A Net to Gross ratio was used in the Schlumberger work. These values were reasonable based on an audit of the information provided. Both of the subject reservoirs are interbedded sand and shale sequences. Because of this characteristic it is reasonable to apply a net to gross ratio to the GRV in order to estimate the reservoir volume. The summary of the Net to Gross ratio used for the Satskhenisi reserve and resource estimates are summarized in Table 5-7.

Table 5-7 Net to Gross Pay, %

Reservoir	Minimum %	Most Likely %	Maximum %
Maikop	6	14	20
Chokrak	3	10	14

5.5.5 Conclusions

The Schlumberger study on the Satskhenisi Field apparently utilized all of the available well information and data, which was consolidated into a Petrel database from which models of the gross rock volumes were generated. This study was audited and it was determined that the results were reasonable for the purposes of estimating resources. The porosity and water saturation values used by Schlumberger were used as a guideline, but were found to be slightly pessimistic based on the audit. Therefore, the ranges of values for porosity and water saturation were expanded relative to the Schlumberger results. The efficient exploitation and development of this field could be better accomplished with the acquisition of a 3D seismic survey, which could be used to locate future wellbores. In addition, the Chokrak reservoir should be tested in the available wells and evaluated for future production. We note that Block Energy plans to conduct a lateral hydraulic jetting treatment in the Chokrak in Satskhenisi Well #12 in 2018.

6. PROBABILISTIC RESERVE ESTIMATE

6.1 OVERVIEW

Gustavson Associates has performed an evaluation of the reserves associated with the Norio, West Rustavi, and Satskhenisi PSAs located in the Kura Basin of the Republic of Georgia (Figure 6-1).

Figure 6-1 Map of Analog Fields with Local Infrastructure and Block License Areas

6.1.1 Norio

Reserves have been estimated for three producing wells based on production decline analysis. Three wells that are currently shut-in have been assigned Developed Non-Producing reserves based on Block Energy's plans to perform workovers to complete in additional reservoir intervals which are currently behind pipe, as well as a review of these wells' previous production history, and the production history other wells in the field. Five wells, one currently producing and four shut-in, have also been assigned reserves or incremental reserves in the Developed Non-Producing classification based on Block Energy's plans to perform workovers including lateral hydraulic jetting into the reservoir, such as the services offered by Radial Drilling Services (RDS). These five workovers are considered separately because the lateral jetting technique has not been utilized in Norio Field previously, nor in any nearby analogous fields. The expected production response for these workovers was estimated at three different levels of certainty, based on analysis of available data on performance of wells where this technique was used world-wide, along with previous production data from the subject wells.

Finally, Undeveloped Reserves were assigned to five offset locations (Figure 6-2), based on the Block Energy's plans to drill horizontal wells, and analysis of performance data from horizontal wells drilled in the Ninotsminda Field, along with some consideration of analysis of dynamic reservoir simulation forecasts for horizontal wells in the neighboring Satskhenisi Field prepared by Schlumberger,[14] initial production rates from all Norio wells, and other available geologic and engineering data. Another well has been assigned Undeveloped Reserves associated with a planned sidetrack with a length of 300-400 meters, similar to the new horizontal wells.

Table 6-1 shows the names of the wells in each of these classifications, along with estimated capital costs.

[14] Schlumberger Data and Consulting Services, Almaty: "Geological and Hydrodynamic Modeling of Maikopian Formation and Field Development Plan, Satskhenisi oilfield, Georgia (Part II: Hydrodynamic Modeling)", prepared for Norio Oil Company, 2010.

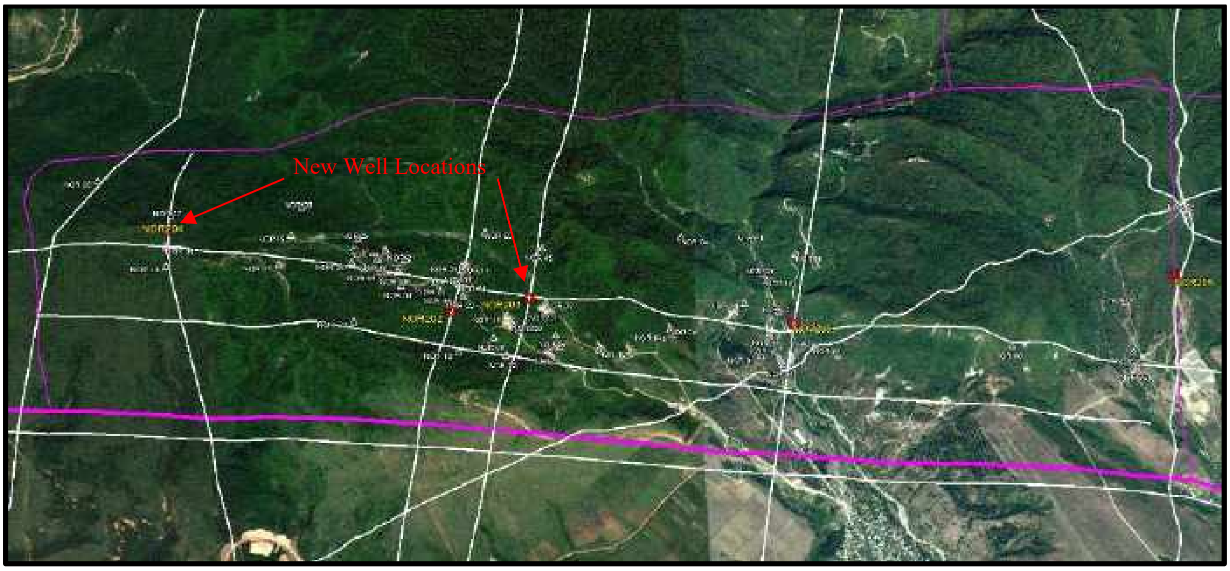


Figure 6-2 Map Showing Planned Horizontal Well Locations, Norio

Table 6-1 Norio Wells with Reserves Assigned

Classification	Well Name & Number	Estimated Capital Investment, M$	Date Planned
Developed Producing	Norio 27	N/A	Jan-18
	Norio 31	N/A	Jan-18
	Norio 64	N/A	Jan-18
Developed Non-Producing (Behind Pipe)	Norio 56	75	May-18
	Norio 57	75	May-18
	Norio 64	100	Nov-18
Developed Non-Producing (lateral jetting)	Norio 27	212	Oct-18
	Norio 36	225	Nov-18
	Norio 44	254	Nov-18
	Norio 55	215	Nov-18
	Norio 61	170	Oct-18
Undeveloped	Norio 60	800	Apr-19
	Norio 202	3,000	Jun-19
	Norio 203	3,000	Aug-19
	Norio 204	3,000	Oct-19
	Norio 205	3,000	Dec-19
	Norio 206	3,000	Feb-20

Note that because of the uncertainty in each of the reserves classifications, a probabilistic analysis was conducted with input distributions for initial rates and decline parameters. More information about this analysis is provided in the following sections of this report.

6.1.2 West Rustavi

No wells in the West Rustavi license area are currently producing. Block Energy plans to perform workovers to reactivate two Middle Eocene wells (#16a, 51) that are currently shut-in, including changing perforation intervals to limit water production and increase oil production. Two additional workovers are planned by the operator, in the West Rustavi #3 and #30 wells, with an attempted re-completion into the Lower Eocene and/or Upper Cretaceous gas zones that tested from 320 MCF/d up to about 1 MMCF/d during initial completion. Because of the lack of monthly production history on these wells, and the current lack of a gas market and infrastructure, it is difficult to prepare production forecasts and assign reserves at this time. However, these workovers will serve to demonstrate the producibility of these wells, and establish gas production in order to justify a gas sales contract and associated infrastructure.

Four shut-in wells (#3, 16a, 38, and 51) are planned for re-entry and drilling of deviated sidetracks with a length of 400 meters at a cost of $1,500,000 per well. The expected production response for these workovers was estimated at three different levels of certainty, based on of monthly production data from the Samgori South Dome Field, which also produces from Middle Eocene (Figure 6-3), along with all available monthly production and initial test data from West Rustavi. Note that the P_{10} case assumes a one-year plateau at the initial rate to reflect high-end early behavior at Samgori South Dome, and the possibility of a similar strong water drive at West Rustavi.

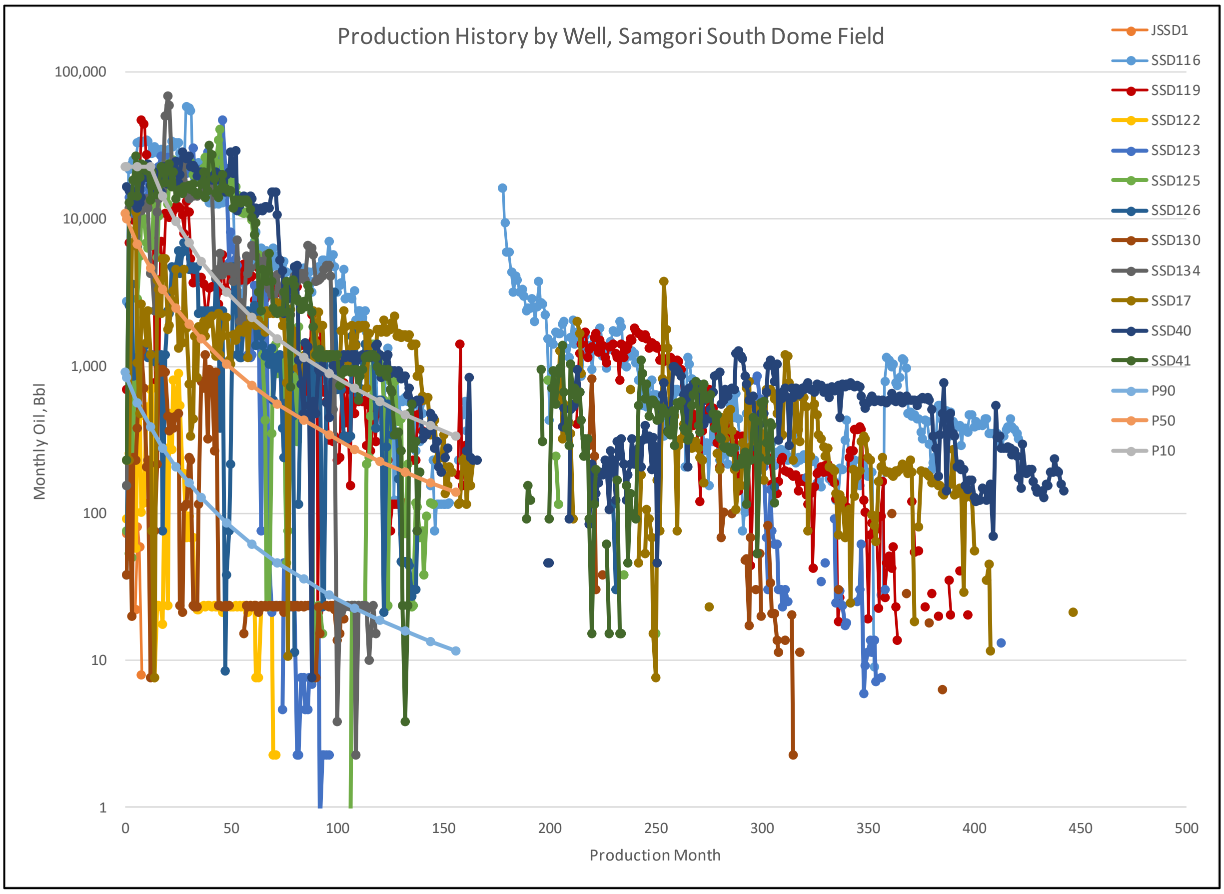


Figure 6-3 Samgori South Dome Production Data with West Rustavi Sidetrack Forecasts

Table 6-2 shows the names of the wells in each of these classifications, along with estimated capital costs.

Table 6-2 West Rustavi Wells with Reserves Assigned

Classification	Well Name & Number	Estimated Capital Investment, M$	Date Planned
Developed Non-Producing (sidetrack)	West Rustavi #3	1,500	Feb-19
	West Rustavi #16a	1,500	Apr-19
	West Rustavi #38	1,500	May-19
	West Rustavi #51	1,500	Jun-19

6.1.3 Satskhenisi

Reserves have been estimated for five producing wells based on production decline analysis. Three of these wells have been assigned additional Developed Non-Producing reserves based on Block Energy's plans to perform workovers to perform small workovers to repair tubing and install or repair pumps, as well as a review of these wells' previous production history, and the production history other wells in the field. Table 6-3 shows the names of the wells in these classifications, along with estimated capital costs.

Table 6-3 Satskhenisi Wells with Reserves Assigned

Classification	Well Name & Number	Estimated Capital Investment, M$	Date Planned
Producing	Satskhenisi #3	N/A	Feb-18
	Satskhenisi #11	N/A	Feb-18
	Satskhenisi #13	N/A	Feb-18
	Satskhenisi #14	N/A	Feb-18
	Satskhenisi #101	N/A	Feb-18
Developed Non-Producing	Satskhenisi #3	10	Apr-18
	Satskhenisi #13	15	Apr-18
	Satskhenisi #101	7	Apr-18

6.2 GENERAL

A probabilistic analysis is applicable for evaluating the reserves of any field where uncertainty exists about future performance. Uncertainty in the reservoir or well performance data is quantified by probability distributions, and an iterative approach yields a probability distribution for reserves. This approach allows for consideration of the range of reserves and their relative likelihood. The median estimate can be used for planning purposes, while the analysis also reveals upside and downside potential. Uncertainty is expected to lessen as more wells are drilled and more field data are available. As of the effective date, there were several wells in the Norio Field; however, recent production data are limited, and available analog data for the planned lateral jetting and horizontal drilling operations are not ideal analogs.

6.3 PROBABILISTIC SIMULATION

Probabilistic reserve analysis was performed using Monte Carlo simulation software called "@ Risk". This software allows for input of a variety of probability distributions for any uncertain parameter. The program performs a large number of iterations as specified by the user, to reach a reasonable level of stability in the output. The number of iterations used in this analysis was 10. The results include a probability distribution for the output and sampled probability for the inputs.

6.4 INPUT PARAMETERS

The approach taken involves estimating probability distributions for uncertain well performance parameters, and performing a statistical risk analysis involving multiple iterations of reserves calculations generated by random numbers and the reservoir parameter distributions. A triangular distribution with specification of P_{90}, most likely, and P_{10} values[15] was used for all the parameters, with the exception of the initial rates for the horizontal wells and lateral jetting at Norio, and sidetracks at West Rustavi. The triangular distribution for the initial rates for the horizontal wells and sidetracks yielded results below zero at the low end of the distribution; therefore, a cumulative distribution was used with a minimum value of zero, P_{90}, P_{10}, and maximum values equal to those from the triangular distribution, and P_{50} set at the most likely value from the triangular distribution.

For the initial rates for the lateral jetting, a different approach was taken. A distribution was fit to the data on production improvement factors from the various world-wide analogs (Figure 6-4). A factor determined from this distribution was then multiplied by the previous rate for each well from its historic production data. For Norio 60, a higher base rate was assumed because of the planned sidetrack. Table 6-4 shows the input parameters for Norio, with West Rustavi shown in Table 6-5. Where only a most likely value is shown, the parameter was treated as a constant. Where no b factor data are shown, an exponential decline was assumed. Other declines were assumed to be modeled by a hyperbolic equation:

[15] In this report, a designation of P_{90} indicates that 90 % of the input or output values are likely to be greater than or equal to that value. A designation of P_{10} indicates that 10 % of the input or output values are likely to be greater than or equal to that value. The most likely value is the mode of the distribution.

$$q = q_i \times (1+b \times D_i \times t)^{(-1/b)}$$

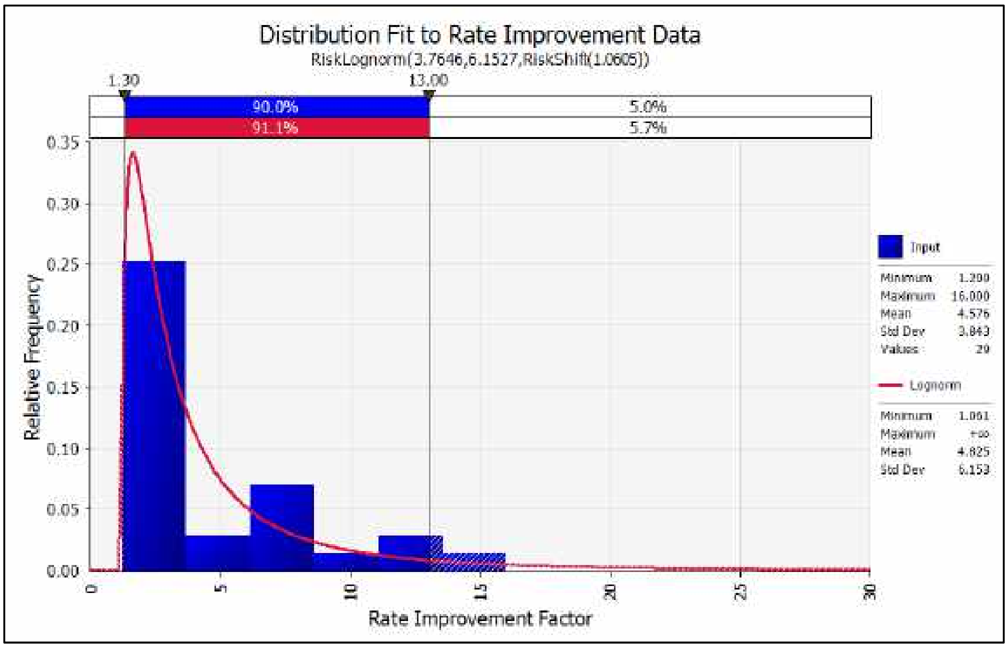


Figure 6-4 Distribution Fit to Lateral Jetting Rate Improvement Data

Table 6-4 Input Parameters, Norio

		Initial Production Rate (Bbl/day)				Initial Decline Factor (Di)			b factor		
Category	Well Name		P_{90}	Most Likely	P_{10}	P_{90}	Most Likely	P_{10}	P_{90}	Most Likely	P_{10}
Producing	Norio 27			4.5		0.16	0.20	0.29			
	Norio 31			11.4		0.08	0.11	0.16			
	Norio 64		0.6	1.0	1.7	0.027	0.03	0.04			
Workover, SI or BP	Norio 55		6	12	19	0.80	0.92	1.00	0.7	0.85	1.01
	Norio 56		6	12	19	0.80	0.92	1.00	0.7	0.85	1.01
	Norio 57		6	12	19	0.80	0.92	1.00	0.7	0.85	1.01
		Rate Pre-Workover	P_{90}	Most Likely	P_{10}						
Lateral Jetting	Norio 27	4.5	6.7	13.5	42.4	0.60	0.80	1.00	0.7	0.85	1.01
	Norio 44	2.6	4.0	8.0	25.1	0.60	0.80	1.00	0.7	0.85	1.01
	Norio 56	6.6	10.0	19.9	62.7	0.60	0.80	1.00	0.7	0.85	1.01
	Norio 60	2.6	4.0	8.0	25.1	0.60	0.80	1.00	0.7	0.85	1.01
	Norio 61	5.9	9.0	17.9	56.4	0.60	0.80	1.00	0.7	0.85	1.01
	Norio 64	4.5	6.7	13.5	42.4	0.60	0.80	1.00	0.7	0.85	1.01
			P_{90}	Most Likely	P_{10}						
New Horizontal Wells	Norio 202		58	200	1,100	0.51	1.29	3.50	0.7	0.85	1.20
	Norio 203		58	200	1,100	0.51	1.29	3.50	0.7	0.85	1.20
	Norio 204		58	200	1,100	0.51	1.29	3.50	0.7	0.85	1.20
	Norio 205		58	200	1,100	0.51	1.29	3.50	0.7	0.85	1.20
	Norio 206		58	200	1,100	0.51	1.29	3.50	0.7	0.85	1.20

Table 6-5 Input Parameters, West Rustavi

		Initial Production Rate (Bbl/day)			Initial Decline Factor (Di)			b factor		
Category	Well Name	P_{90}	Most Likely	P_{10}	P_{90}	Most Likely	P_{10}	P_{90}	Most Likely	P_{10}
Workover, SI or BP	WR16a	7	15	25	0.80	0.92	1.00	0.4	0.45	0.5
	WR38	7	15	25	0.80	0.92	1.00	0.4	0.45	0.5
	WR50	7	15	25	0.80	0.92	1.00	0.4	0.45	0.5
Sidetrack	ST1	30	360	750	1.00	1.05	1.10	0.4	0.45	0.5
	ST2	30	360	750	1.00	1.05	1.10	0.4	0.45	0.5
	ST3	30	360	750	1.00	1.05	1.10	0.4	0.45	0.5
	ST4	30	360	750	1.00	1.05	1.10	0.4	0.45	0.5

Table 6-6 Input Parameters, Satskhenisi

Category	Well Name	Initial Production Rate (Bbl/day) P_{90}	Most Likely	P_{10}	Initial Decline Factor (Di) P_{90}	Most Likely	P_{10}
Producing	3	1.9	2.1	2.3	0.17	0.33	0.45
	11	1.3	1.4	1.4	0.17	0.29	0.43
	13	0.26	0.30	0.33	0.13	0.20	0.29
	14	0.53	0.59	0.66	0.13	0.20	0.29
	101	0.79	0.82	0.86	0.17	0.29	0.43
Workover	3	4.0	4.9	6.0	0.17	0.33	0.45
	13	0.5	0.6	1.0	0.17	0.29	0.43
	101	1.7	2.5	3.1	0.17	0.29	0.43

Figure 6-5 through Figure 6-13 below show the forecast for each of the three categories of reserves, for each classification, plus a single example new horizontal well and example sidetrack.

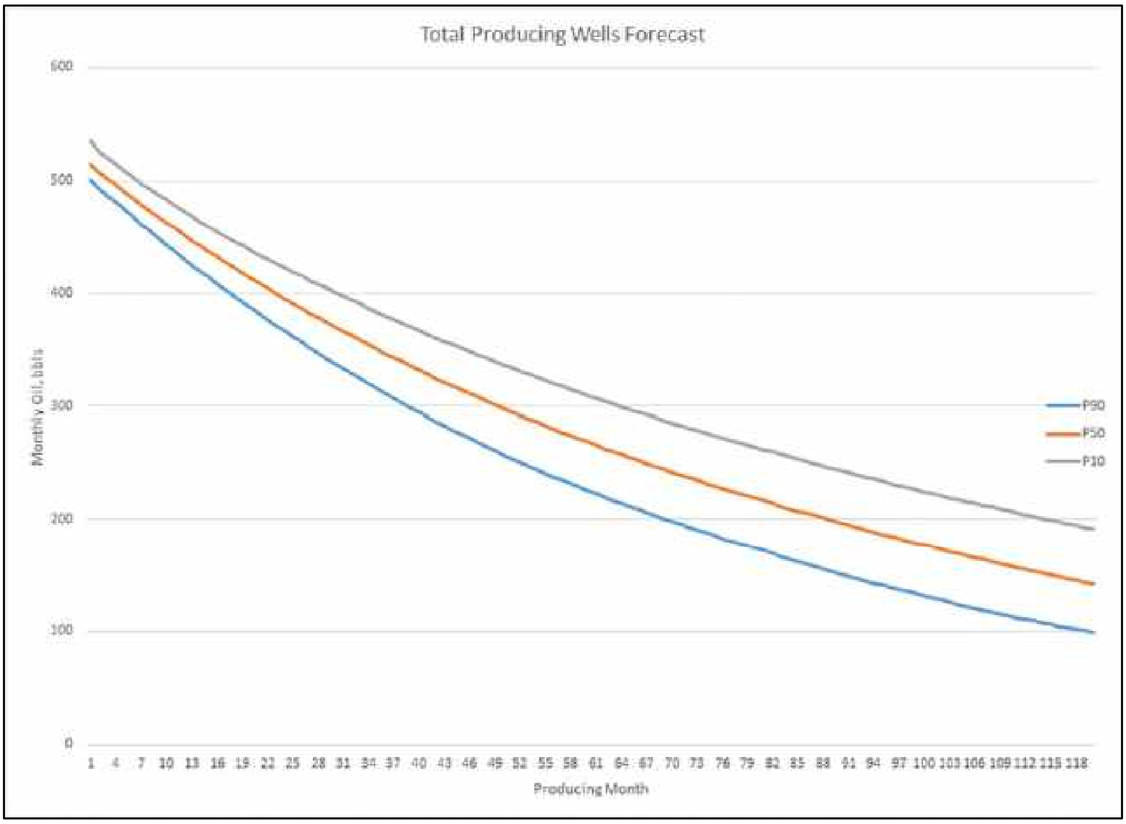


Figure 6-5 Production Forecasts, Norio Producing Reserves

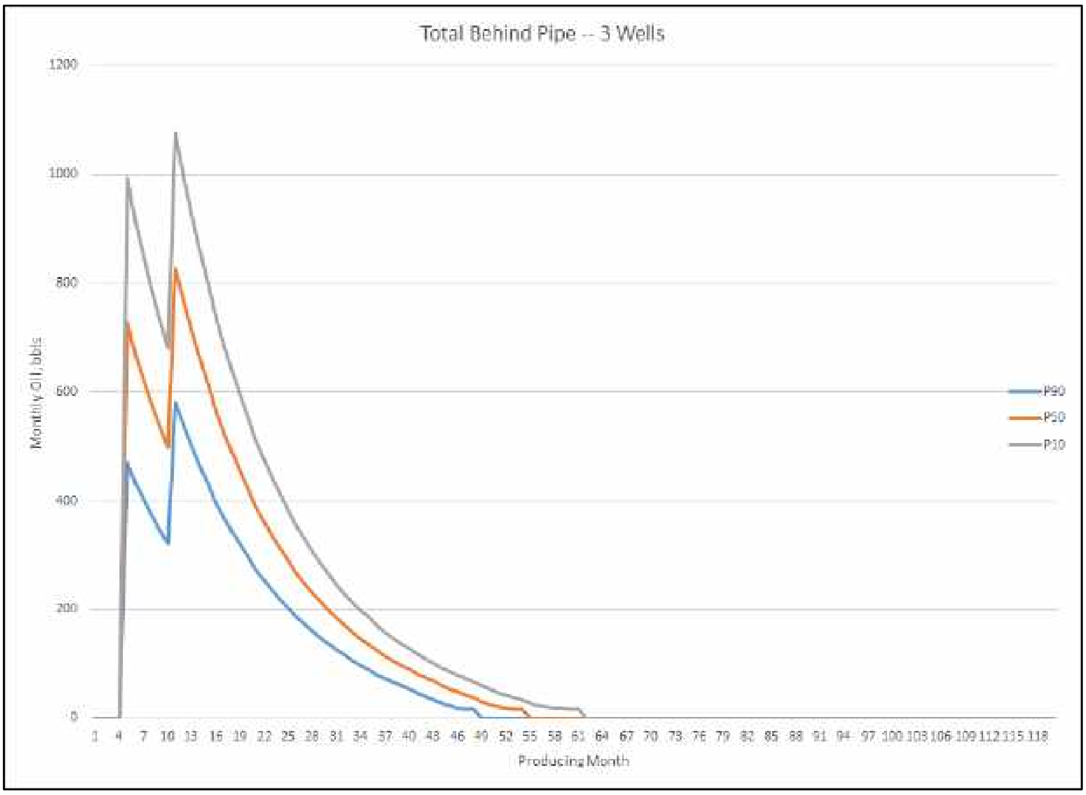


Figure 6-6 Production Forecasts, Norio Developed Non-Producing, Behind Pipe Reserves

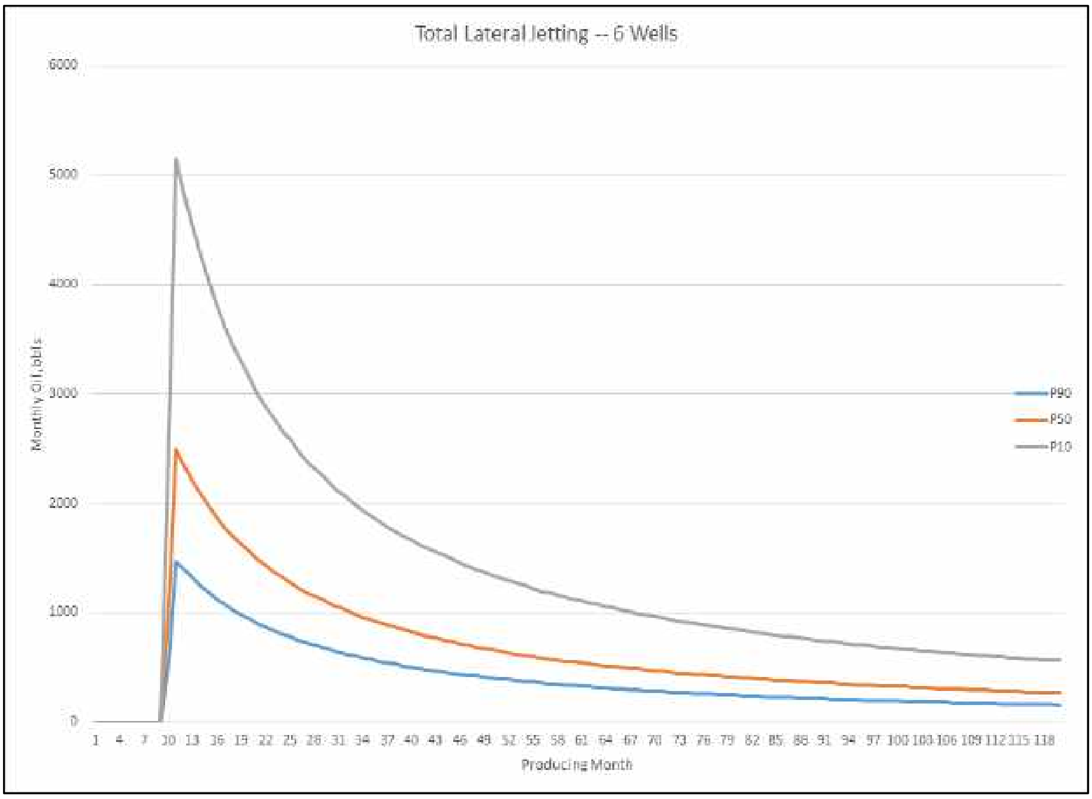


Figure 6-7 Production Forecasts, Norio Developed Non-Producing, Lateral Jet Reserves

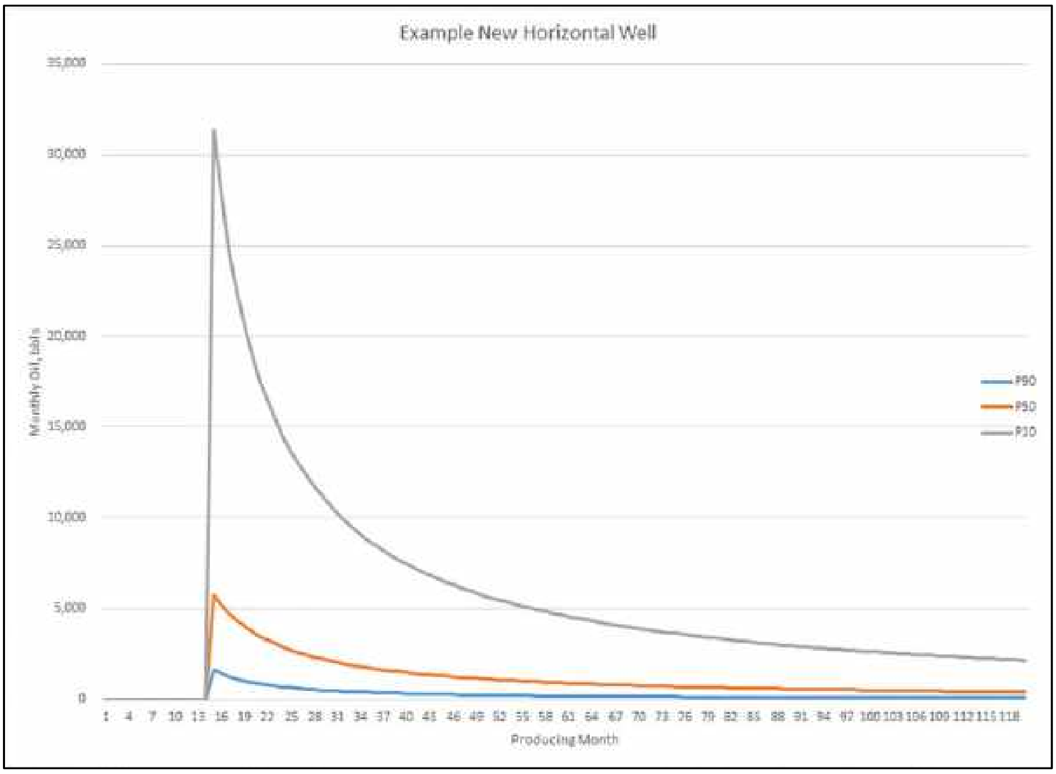


Figure 6-8 Production Forecasts, Norio Example New Horizontal Well

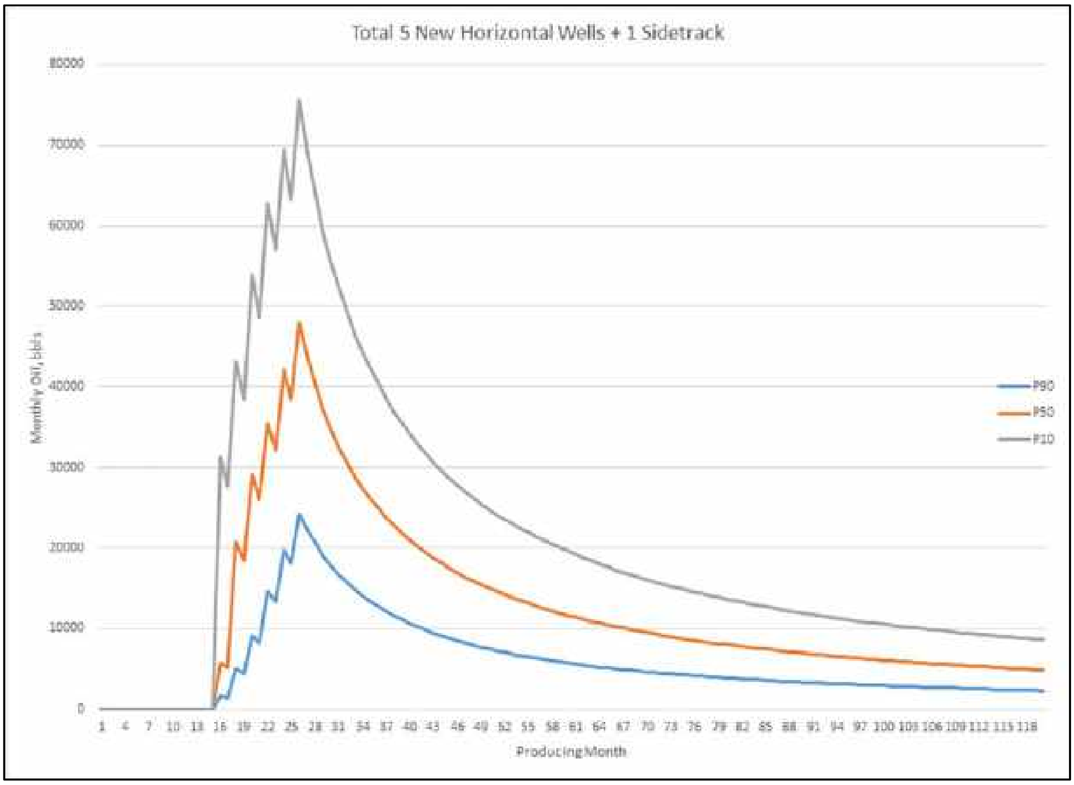


Figure 6-9 Production Forecasts, Norio Undeveloped Horizontal Well Reserves

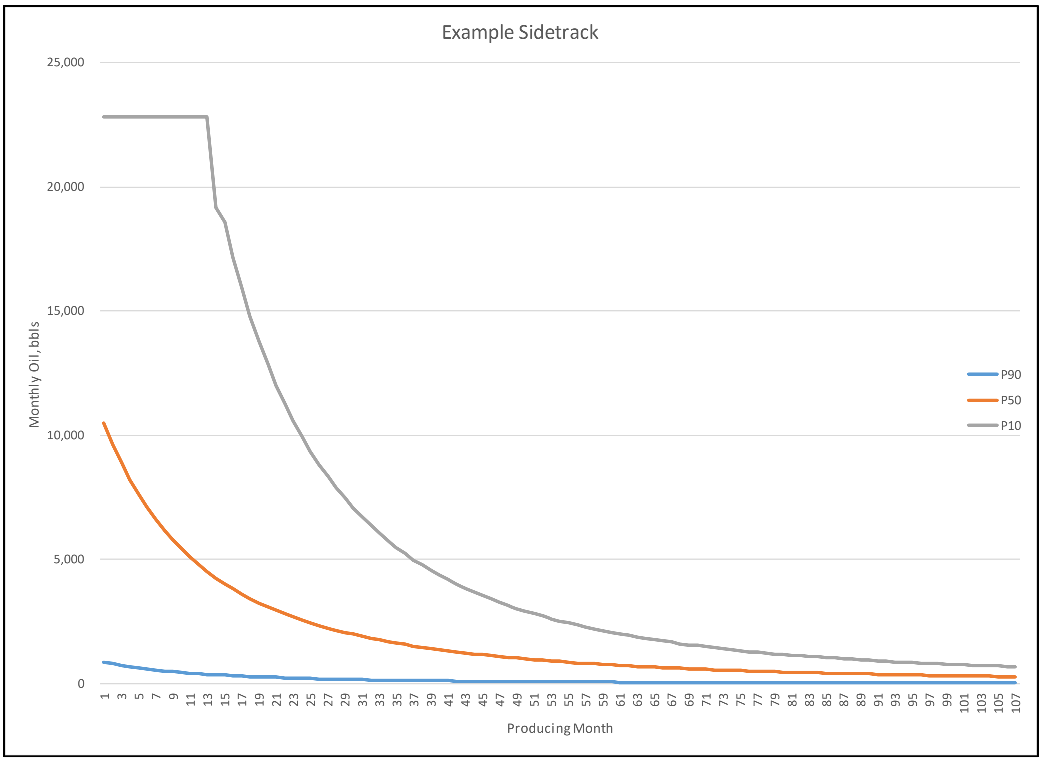


Figure 6-10 Production Forecasts, West Rustavi Example Sidetrack

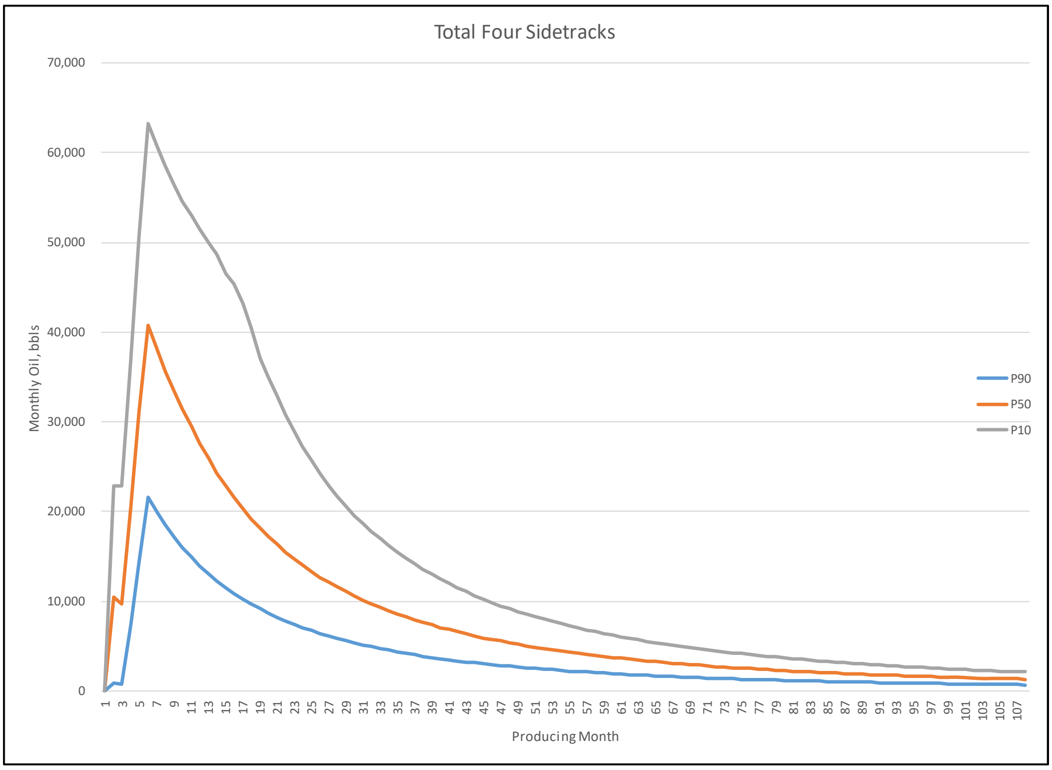


Figure 6-11 Production Forecasts, West Rustavi Total Four Sidetracks

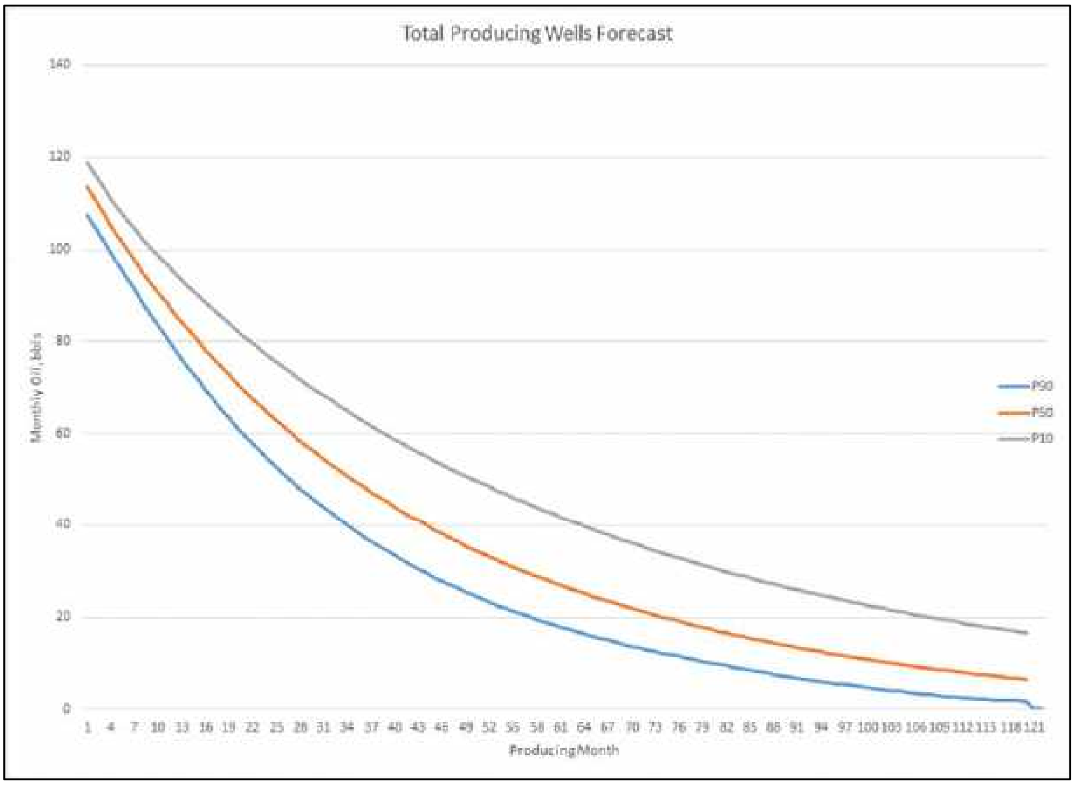


Figure 6-12 Production Forecasts, Satskhenisi Producing Reserves

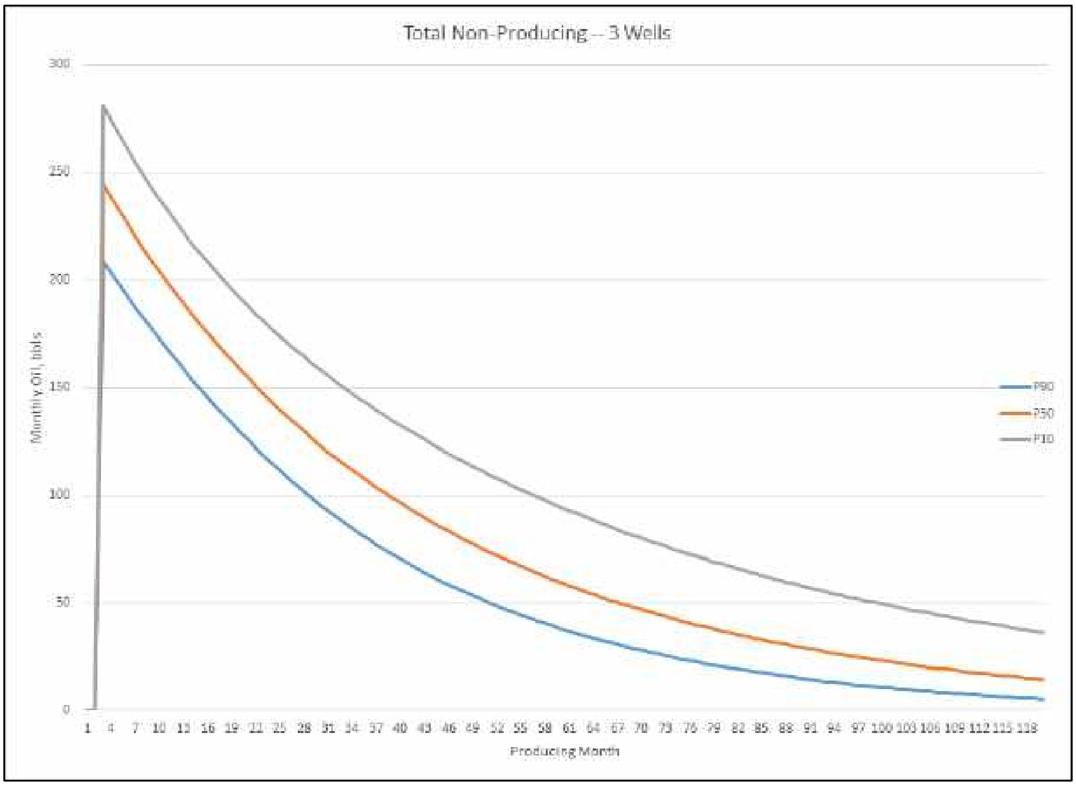


Figure 6-13 Production Forecasts, Satskhenisi Workover Reserves, Three Wells

6.5 ECONOMICS

6.5.1 Assumptions

The State pays all taxes associated with the PSA (Production Sharing Agreement) on behalf of the contractor.

For Norio, operating costs include fixed costs of 13.6 M$/month for the first year. For all cases including more than the three producing wells and three behind pipe workovers, this rate goes up to 15.8 M$/month after year one. These estimates were provided by Block Energy, and appear reasonable to this Consultant. For West Rustavi, operating costs include fixed costs of 11.6 M$/month for the first year. This rate goes up to 12.5 M$/month after year one. Operating costs for Satskhenisi were estimated at $2,500 per month with no additional variable cost. A variable operating cost in US$/Bbl was also included for all fields, as a triangular probabilistic input distribution with P_{90} value at $0.6/Bbl, Most Likely value at $1/Bbl, and P_{10} at $2.4/Bbl, based on the experience of this Consultant.

Assumptions are summarized in Table 6-7 through Table 6-9.

Table 6-7 Summary of Economic Assumptions, Norio

Basic Information:	
Days per year	347
Discount Rate	10%
Monthly Discount Rate	0.80%
Norio Opex Escalation, %/yr	2%
Norio Historic Cost Recovery Pool ($MM)	10.276
Minimum Production Rate per well, Bbl/day	0.5
Cost Recovery Limit (Opex)	100%
Cost Recovery Limit (Capex)	50%
Profit Split to Contractor	
Before Payment Date	50%
After Payment Date	40%
Working Interest	100%

Table 6-8 Summary of Economic Assumptions, West Rustavi

Basic Information:	
Days per year	347
Discount Rate	10%
Monthly Discount Rate	0.80%
West Rustavi Opex Escalation, %/yr	2%
West Rustavi Historic Cost Recovery Pool ($MM)	6.7
Minimum Production Rate per well, Bbl/day	0.5
Cost Recovery Limit (Opex)	50%
Cost Recovery Limit (Capex)	50%
Profit Split to Contractor	
Before Payout	50%
After Payout	40%
Working Interest	75%

Table 6-9 Summary of Economic Assumptions, Satskhenisi

Basic Information:	
Days per year	347
Discount Rate	10%
Monthly Discount Rate	0.80%
Satskhenisi Opex Escalation, %/yr	2%
Satskhenisi Historic Cost Recovery Pool ($M)	10.276
Minimum Production Rate per well, Bbl/day	0.05
Cost Recovery Limit (Opex)	100%
Cost Recovery Limit (Capex)	50%
Profit Split to Contractor	
Before Payout	50%
After Payout	40%
Working Interest	90%

There are two common international crude oil benchmarks: West Texas Intermediate and Brent. Brent is often used to provide guidance for energy prices in Europe and Central Asia. Due to the volatile nature of energy markets, it is rare that actual oil prices are aligned with previous forecasts of those prices. However, it is essential to prepare forecasts in order to determine valuations.

Gustavson conducted a review of other forecasts of the price of Brent. The forecasts and their average are shown on Table 6-10. The average is selected as a reasonable consensus forecast of the price of Brent in the future.

Table 6-10 Forecasts of Brent Oil Price[16]

Year	Sproule[17]	McDaniel[18]	Deloitte[19]	EIA STEO[20]	Average
2018	$58.00	$63.50	$61.00	$59.74	$60.56
2019	$67.00	$61.30	$61.50	$61.43	$62.81
2020	$72.00	$63.40	$62.00		$65.80
2021	$75.00	$70.10	$67.00		$70.70
2022	$76.50	$74.20	$72.00		$74.23
2023	$78.03	$75.60	$72.00		$75.21
2024	$79.59	$77.10	$72.00		$76.23
2025	$81.18	$78.60	$72.00		$77.26
2026	$82.81	$80.30	$72.00		$78.37
2027	$84.46	$81.90	$72.00		$79.45

Block Energy expects to receive a wellhead price of Brent minus 9 US$/Bbl for their blended oil stream, which is supported by other purchase agreements in the area. We consider this to be reasonable and have used the $9/Bbl differential.

6.5.2 Results

Reserves and economics results are summarized in Table 6-11 through Table 6-16. Detailed spreadsheets showing cash flow for the mean case for each reserve classification are included in Appendix D.

[16] Blue numbers are extrapolations from the forecasts
[17] 12-2017-Escalated.xlsx
[18] mcdan_180101.xlsx
[19] ca-en-rea-price-forecast-12-31-2017_AODA.pdf
[20] Table 2 Jan2018 Short Term Energy Outlook, EIA

Table 6-11 Summary of Gross and Net Reserves, Norio

	Gross Reserves, Thousands of Bbl			Net Reserves, Thousands of Bbl		
Reserve Classification	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})
Producing Only	28.1	32.7	37.2	16.7	21.7	28.5
Incremental Workovers, BP/SI Proved Developed Non-Producing	12.7	14.5	16.5	10.3	11.2	11.8
Producing + BP/SI Workovers	40.8	47.2	53.6	27.0	32.9	40.3
Incremental Workovers, RDS Proved Developed Non-Producing	53.1	78.5	151.0	51.3	69.8	121.7
Producing + Workovers + RDS	94.0	125.7	204.7	78.3	102.6	162.0
Incremental New Drilling Undeveloped	805.2	1,505.3	2,328.6	603.5	1,005.2	1,334.9
Producing + Workovers + RDS + New Drilling	899.2	1,630.9	2,533.3	681.8	1,107.8	1,496.9

Table 6-12 Summary of Projected Cash Flow, Norio

	Cash Flow, MM$			NPV10, MM$		
v	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})
Producing Only	0.15	0.24	0.36	0.13	0.20	0.28
Incremental Workovers, BP/SI Proved Developed Non-Producing	0.21	0.33	0.43	0.16	0.26	0.35
Producing + BP/SI Workovers	0.37	0.57	0.79	0.29	0.46	0.63
Incremental Workovers, RDS Proved Developed Non-Producing	0.83	2.02	5.28	0.42	1.22	3.45
Producing + Workovers + RDS	1.20	2.59	6.06	0.71	1.68	4.08
Incremental New Drilling Undeveloped	20.00	43.05	61.29	10.92	27.83	40.97
Producing + Workovers + RDS + New Drilling	21.19	45.64	67.35	11.63	29.51	45.06

Table 6-13 Summary of Gross and Net Reserves, West Rustavi

	Gross Reserves, Thousands of Bbl			Net Reserves, Thousands of Bbl		
Reserve Classification	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})
Producing	0.0	0.0	0.0	0.0	0.0	0.0
Workovers, BP/SI	0.0	0.0	0.0	0.0	0.0	0.0
Producing + BP/SI Workovers	0.0	0.0	0.0	0.0	0.0	0.0
Sidetracks	470.8	906.8	1,606.2	210.7	347.8	565.2
Producing + BP/SI Workovers + Sidetracks	470.8	906.8	1,606.2	210.7	347.8	565.2

For 75% Working Interest. Net is net of government share and partner's interests. Block Energy has no interest in the West Rustavi PSA at the time of this report.

Table 6-14 Summary of Projected Cash Flow, West Rustavi

	Cash Flow, MM$			NPV10, MM$		
Reserve Classification	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})
Producing	0.0	0.0	0.0	0.0	0.0	0.0
Workovers, BP/SI	0.0	0.0	0.0	0.0	0.0	0.0
Producing + BP/SI Workovers	0.0	0.0	0.0	0.0	0.0	0.0
Sidetracks	6.1	13.6	25.6	4.1	9.6	18.4
Producing + BP/SI Workovers + Sidetracks	6.1	13.6	25.6	4.1	9.6	18.4

For 75% Working Interest. Net is net of government share and partner's interests. Block Energy has no interest in the West Rustavi PSA at the time of this report.

Table 6-15 Summary of Gross and Net Reserves, Satskhenisi

	Gross Reserves, Thousands of Bbl			Net Reserves, Thousands of Bbl		
Reserve Classification	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})
Producing	4.4	4.4	4.4	2.3	2.3	2.4
Workovers	7.2	9.4	12.9	5.6	7.3	10.3
Producing + Workovers	11.6	13.8	17.3	7.9	9.6	12.7

For 90% Working Interest. Net is net of government share and partner's interests.

Table 6-16 Summary of Projected Cash Flow, Satskhenisi

	Cash Flow, MM$			NPV10, MM$		
Reserve Classification	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})	Proved (P_{90})	Proved + Probable (P_{50})	Proved + Probable + Possible (P_{10})
Producing	0.03	0.03	0.03	0.03	0.03	0.03
Workovers	0.19	0.26	0.39	0.16	0.20	0.29
Producing + Workovers	0.22	0.29	0.42	0.18	0.23	0.32

For 90% Working Interest. Net is net of government share and partner's interests.

7. PROBABILISTIC RESOURCE ANALYSIS

7.1 GENERAL

A probabilistic resource analysis is highly applicable for projects such as evaluating the Contingent and/or Prospective Resources of an exploratory area or an area with a relatively small portion of the reservoir developed, where a range of values exists in the reservoir parameters. The range of the expected reservoir data is quantified by probability distributions, and an iterative approach yields an expected probability distribution for potential resources. This approach allows consideration of most likely resources for planning purposes, while gaining an understanding of what volumes of resources may have higher certainty, and what potential upside may exist for the project.

The analysis for this project was carried out considering the range of values for all parameters in the volumetric resource equations. Both Contingent and Prospective Resource estimates were calculated for Norio and West Rustavi. Contingent Resources have been assigned to the Chokrak and Sarmatian reservoirs at Norio, and the Upper, Middle, and Lower Eocene and the Upper Cretaceous at West Rustavi, since they have been established as productive reservoirs. Prospective Resources have been assigned to the Maikop reservoir at Norio, because the nature and quantity of the available data regarding its productivity is not judged to be sufficient to quality as Contingent Resources.

7.2 INPUT PARAMETERS

This method involves estimating probability distributions for the range of reservoir parameters and performing a statistical risk analysis involving multiple iterations of resource calculations generated by random numbers and the specified distributions of reservoir parameters. To do this, each parameter incorporated in our resource calculation was evaluated for its expected probability distribution.

Because few data are available regarding the likely distribution of the reservoir parameters, simple triangular distributions with specification of minimum, most likely or mode, and maximum values were used for most of the parameters. Note that these parameters represent average parameters over the entire lead or prospect. So, for example, the porosity ranges do not represent the range of what porosity might be in a particular well or a particular interval, but rather the reasonable range of the average porosity for the whole lead or prospect. A summary of input parameters is shown in Table 7-1 through Table 7-4.

In a probabilistic analysis, dependent relationships can be established between parameters if appropriate. For example, portions of a reservoir with the lowest effective porosity generally may be expected to have the highest connate water saturation, whereas higher porosity sections have lower water saturation. In such a case, it is appropriate to establish an inverse relationship between porosity and water saturation, such that if a high porosity is randomly estimated in a given iteration, corresponding low water saturation is estimated. The degree of such a correlation can be controlled to be very strong or weak. This type of dependency, with a medium strength of -0.7, was used in this study for porosity with water saturation and with net/gross ratio. Similarly, the low end of the gross thickness distributions for this prospective accumulation would generally be expected to occur when the productive area is small; therefore, a positive correlation of 0.7 was assigned to gross thickness and productive area.

Table 7-1 Norio Input Parameters

Parameter	Minimum	Most Likely	Maximum
Norio/Chokrak			
Oil Gravity, API	25.0	26.0	27.0
Gas-Oil Ratio, cuft/bbl	200.0	250.0	350.0
Gas Gravity, rel. to air	0.60	0.65	0.70
Reservoir Depth, ft	2,575	2,625	2,675
Pressure Gradient, psi/ft	0.405	0.419	0.435
Temperature Gradient, °F/ft	0.009	0.012	0.013
Porosity, %	18.0	23.0	28.0
Water Sat., %	25.0	35.0	45.0
Area (within Block), acres	631	995	1,360
Net Pay, ft	33	52	98
% Recovery	10%	15%	25%
Norio/Sarmation			
Oil Gravity, API	25.0	26.0	27.0
Gas-Oil Ratio, cuft/bbl	200.0	250.0	350.0
Gas Gravity, rel. to air	0.60	0.65	0.70
Reservoir Depth, ft	1,663	1,713	1,763
Pressure Gradient, psi/ft	0.405	0.419	0.435
Temperature Gradient, °F/ft	0.009	0.012	0.013
Porosity, %	12.0	14.0	16.0
Water Sat., %	20.0	32.5	45.0
Area (within Block), acres	49	150	400
Net Pay, ft	3	15	33
% Recovery	10%	15%	25%
Norio/Maikop			
Oil Gravity, API	39.0	45.4	49.9
Gas-Oil Ratio, cuft/bbl	550.0	700.0	850.0
Gas Gravity, rel. to air	0.60	0.65	0.70
Reservoir Depth, ft	340	400	510
Pressure Gradient, psi/ft	0.405	0.419	0.435
Temperature Gradient, °F/ft	0.009	0.012	0.013
Porosity, %	13.0	17.0	20.0
Water Sat., %	40.0	45.0	50.0
Area (within Block), acres	425	903	1,380
Net Pay, ft	36	72	105
% Recovery	10%	15%	25%

Table 7-2 West Rustavi Input Parameters, Oil Reservoirs

Parameter	Minimum	Most Likely	Maximum
West Rustavi/ Upper Eocene			
Oil Gravity, API	31.5	36.0	41.0
Gas-Oil Ratio, cuft/bbl	100.0	400.0	500.0
Gas Gravity, rel. to air	0.65	0.70	0.75
Reservoir Depth, ft	4,616	5,341	6,066
Temperature Gradient, °F/ft	0.011	0.014	0.017
Pressure Gradient, psi/ft	0.450	0.465	0.480
Porosity, %	2.5	3.8	6.8
Water Sat., %	20.0	35.0	45.0
Productive Area, acres	2,976	3,956	4,936
Net Pay, ft	33	75	98
% Recovery	15%	25%	35%
West Rustavi/ Middle Eocene			
Oil Gravity, API	31.5	36.0	41.0
Gas-Oil Ratio, cuft/bbl	100.0	400.0	500.0
Gas Gravity, rel. to air	0.65	0.70	0.75
Reservoir Depth, ft	6,010	6,901	7,792
Temperature Gradient, °F/ft	0.011	0.014	0.017
Pressure Gradient, psi/ft	0.450	0.465	0.480
Porosity, %	0.7	3.0	5.0
Water Sat., %	20.0	35.0	45.0
Productive Area, acres	2,164	4,577	5,398
Net Pay, ft	72	180	360
% Recovery	15%	25%	30%

Table 7-3 West Rustavi Input Parameters, Gas Reservoirs

Parameter	Minimum	Most Likely	Maximum
West Rustavi/ Lower Eocene			
GAS GRAVITY	0.6	0.7	0.7
fraction N2	0.0	0.0	0.1
fraction CO2	0.0	0.0	0.0
fraction H2S	0.0	0.0	0.0
Temperature Gradient, °F/ft	0.0	0.0	0.0
Pressure Gradient, psi/ft	0.3	0.3	0.4
Productive Area, acres	2,660	3,629	4,598
Net Pay, ft	164	198	262
WATER SAT, %	20	25	40
POROSITY, %	2.8	12.0	14.5
AVG. DEPTH, feet	8,484	9,337	10,190
RECOVERY	0.7	0.8	0.9
CGR, bbl/MMCF	0.0	17.0	20.6
West Rustavi/ Upper Cretaceous			
GAS GRAVITY	0.6	0.7	0.7
fraction N2	0.0	0.0	0.1
fraction CO2	0.0	0.0	0.0
fraction H2S	0.0	0.0	0.0
Temperature Gradient, °F/ft	0.0	0.0	0.0
Pressure Gradient, psi/ft	0.3	0.4	0.4
Productive Area, acres	3,036	4,846	6,655
Net Pay, ft	52	130	360
WATER SAT, %	20	25	40
POROSITY, %	0.8	5.3	7.5
AVG. DEPTH, feet	10,764	12,077	13,389
RECOVERY	0.7	0.8	0.9
CGR, bbl/MMCF	0.0	0.0	0.0

Table 7-4 Satskhenisi Input Parameters

Parameter	Minimum	Most Likely	Maximum
Satskhenisi/Maikop			
Oil Gravity, API	38.5	39.4	42.0
Gas-Oil Ratio, cuft/bbl	400	843	1,000
Gas Gravity, rel. to air	0.64	0.68	0.72
Reservoir Depth, ft	2,720	3,210	3,700
Pressure Gradient, psi/ft	0.280	0.300	0.340
Temperature Gradient, °F/ft	0.009	0.012	0.013
Porosity, %	12.0	17.0	20.0
Water Sat., %	30.0	40.0	50.0
Bulk Volume, acre-ft	1,199,531	1,319,484	1,466,093
Net/Gross, %	6.0%	14.0%	20.0%
% Recovery	10%	15%	25%
Satskhenisi/Chokrak			
Oil Gravity, API	25.0	26.0	27.0
Gas-Oil Ratio, cuft/bbl	200.0	250.0	350.0
Gas Gravity, rel. to air	0.60	0.65	0.70
Reservoir Depth, ft	820	1,723	2,625
Pressure Gradient, psi/ft	0.280	0.300	0.340
Temperature Gradient, °F/ft	0.009	0.012	0.013
Porosity, %	12.0	15.0	17.0
Water Sat., %	30.0	45.0	52.0
Bulk Volume, acre-ft	700,464	1,000,663	1,300,862
Net/Gross, %	2.6%	10.0%	14.0%
% Recovery	10%	15%	25%

7.3 PROBABILISTIC SIMULATION

Probabilistic resource analysis was performed using the Monte Carlo simulation software called @Risk™. This software allows for input of a variety of probability distributions for any parameter. Then the program performs a large number of iterations, either a large number specified by the user, or until a specified level of stability is achieved in the output. The results include a probability distribution for the output, sampled probability for the inputs, and sensitivity analysis showing which input parameters have the most effect on the uncertainty in each output parameter.

After distributions and relationships between input parameters were defined, a series of simulations were run wherein points from the distributions were randomly selected and used to calculate a single iteration of estimated potential resources. The iterations were repeated until stable statistics (mean and standard deviation) result from the resulting output distribution. This occurred after 10 iterations.

7.4 GEOLOGIC RISKS AND PROBABILITY OF SUCCESS

Since these are fields with established hydrocarbons, there is a 100% Probability of Success in finding hydrocarbons in the Chokrak, Maikop and Sarmatian in Norio, the Upper, Middle, and Lower Eocene and Upper Cretaceous in West Rustavi, and the Maikop and Chokrak in Satskhenisi. The main risk in both of these areas is commercial. The probability of establishing commercial production of all the Contingent Resources is estimated at 75%. The Probability of Success for the Prospective Resources in the Maikop at Norio is estimated at 60%.

7.5 RESULTS

The output distributions were then used to characterize the Contingent and Prospective Resources. The gross (8/8ths) results are summarized in Table 7-5, with Block's working interest share in Table 7-6. Note that these estimates do not include consideration for the risk of failure in exploring for these resources. Also note that it is not possible to assign net resources to these areas, because the net hydrocarbon volumes are determined by the cost and profit oil calculations as specified by the PSA. A development plan is required for all recoverable hydrocarbon volumes for these calculations.

Table 7-5 Gross Unrisked Contingent and Prospective Resource Estimates by Reservoir

	Oil in Place, MMBbl			Estimated Ultimate Recovery, MMBbl			Oil Reserves, MMBbl			Cumulative Production, MMBbl			Oil Resources, MMBbl			Associated Gas Resources, BCF		
	P_{90}	P_{50}	P_{10}	P_{90}	P_{50}	P_{10}	P_{90}	P_{50}	P_{10}	P_{90}	P_{50}	P_{10}	Low Estimate (C1)	Best Estimate (C2)	High Estimate (C3)	Low Estimate (C1)	Best Estimate (C2)	High Estimate (C3)
Norio Block																		
Contingent Resources																		
Chokrak Reservoir	36.2	62.0	99.4	5.7	10.2	17.2	0.8	1.5	2.3	1.85	1.88	1.92	3.0	6.8	12.9	0.8	1.8	3.5
Sarmation Reservoir	0.6	2.2	5.5	0.1	0.4	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	0.9	0.03	0.09	0.25
Prospective Resources																		
Maikop Reservoir	9.1	19.4	30.2	1.4	3.1	5.2	0.0	0.0	0.0	0.0	0.0	0.0	1.4	3.1	5.2	1.0	2.2	3.7
West Rustavi Block																		
Contingent Resources																		
Middle Eocene Reservoir	44.8	95.6	177.5	10.0	22.1	42.4	0.5	0.8	1.3	0.04	0.04	0.04	9.5	21.2	41.1	2.9	6.8	14.1
Upper Eocene Reservoir	30.6	49.0	77.2	7.2	12.1	19.9	0.0	0.0	0.0	0.0	0.0	0.0	7.2	12.1	19.9	2.1	3.9	7.0
Satskhenisi Block																		
Contingent Resources																		
Maikop Reservoir	78.1	118.3	165.6	11.9	19.2	29.1	0.008	0.010	0.015	0.326	0.326	0.326	11.6	18.9	28.8	8.1	14.0	22.5
Chokrak Reservoir	30.6	54.9	86.7	4.8	8.9	14.9	0.0	0.0	0.0	0.0	0.0	0.0	4.8	8.9	14.9	1.2	2.4	4.0
	Gas in Place, BCF			Gas Resources, BCF			Condensate Resources, MBbl											
	P_{90}	P_{50}	P_{10}	Low Estimate (C1)	Best Estimate (C2)	High Estimate (C3)	Low Estimate (C1)	Best Estimate (C2)	High Estimate (C3)									
West Rustavi Block																		
Contingent Resources																		
Lower Eocene Reservoir	281	502	728	217	388	565	1,848	4,617	8,341									
Upper Cretaceous Reservoir	119	270	535	92	209	414												

Table 7-6 Block Energy's Working Interest Share Unrisked Contingent and Prospective Resource Estimates by Reservoir

	Oil in Place, MMBbl			Estimated Ultimate Recovery, MMBbl			Oil Reserves, MMBbl			Cumulative Production, MMBbl			Oil Resources, MMBbl			Associated Gas Resources, BCF		
	P_{90}	P_{50}	P_{10}	P_{90}	P_{50}	P_{10}	P_{90}	P_{50}	P_{10}	P_{90}	P_{50}	P_{10}	Low Estimate (C1)	Best Estimate (C2)	High Estimate (C3)	Low Estimate (C1)	Best Estimate (C2)	High Estimate (C3)
Norio Block																		
Contingent Resources																		
Chokrak Reservoir	36.2	62.0	99.4	5.7	10.2	17.2	0.8	1.5	2.3	1.85	1.88	1.92	3.0	6.8	12.9	0.8	1.8	3.5
Sarmation Reservoir	0.6	2.2	5.5	0.1	0.4	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	0.9	0.03	0.09	0.25
Prospective Resources																		
Maikop Reservoir	9.1	19.4	30.2	1.4	3.1	5.2	0.0	0.0	0.0	0.00	0.00	0.00	1.4	3.1	5.2	1.0	2.2	3.7
West Rustavi Block																		
Contingent Resources																		
Middle Eocene Reservoir	33.6	71.7	133.1	7.5	16.6	31.8	0.4	0.6	0.9	0.03	0.03	0.03	7.1	15.9	30.8	2.2	5.1	10.6
Upper Eocene Reservoir	23.0	36.7	57.9	5.4	9.0	14.9	0.0	0.0	0.0	0.00	0.00	0.00	5.4	9.0	14.9	1.6	2.9	5.2
Satskhenisi Block																		
Contingent Resources																		
Maikop Reservoir	70.3	106.5	149.0	10.7	17.3	26.2	0.0	0.0	0.0	0.29	0.29	0.29	10.4	17.0	25.9	7.3	12.6	20.2
Chokrak Reservoir	27.5	49.4	78.0	4.3	8.0	13.4	0.0	0.0	0.0	0.00	0.00	0.00	4.3	8.0	13.4	1.1	2.1	3.6
	Gas in Place, BCF			Gas Resources, BCF			Condensate Resources, MBbl											
	P_{90}	P_{50}	P_{10}	Low Estimate (C1)	Best Estimate (C2)	High Estimate (C3)	Low Estimate (C1)	Best Estimate (C2)	High Estimate (C3)									
West Rustavi Block																		
Contingent Resources																		
Lower Eocene Reservoir	210.7	376.6	546.2	162.5	291.1	423.7	1385.7	3462.5	6256.1									
Upper Cretaceous Reservoir	89.6	202.5	401.1	68.9	156.8	310.5												

Contingent Resources are defined in the Petroleum Resource Management System as "those quantities of petroleum 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 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."[21]

There is no certainty that any portion of the resources will be produced. The contingency for the oil and gas resources is generally, the lack of a full-field development plan, and uncertainty in the economic producibility of some of the reservoirs.

Prospective Resources are defined as "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 discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity."[22] There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The Low Estimate represents the P_{90} values from the probabilistic analysis (in other words, the value is greater than or equal to the P_{90} value 90% of the time), while the Best Estimate represents the P_{50} and the High Estimate represents the P_{10}.[23]

Note that a deterministic calculation with any set of the input parameters will not necessarily be close to any of the results shown in Table 7-5. Specifically, the most likely input parameters do not necessarily yield a result very close to the Best Estimate. This is because some of the distributions are skewed towards the minimum value rather than the maximum value where the

21 http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf
22 http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf
23 http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf

minimum to maximum range is large, so that the mean is rather different from the most likely value.

The distribution graphs for the resource estimates can be found in Appendix B. It should be noted that the shape of the probability distributions all result in wide spacing between the minimum and maximum expected resources. This is reflective of the high degree of uncertainty associated with any evaluation such as this one prior to actual field discovery, development, and production. Also note that, in general, the high probability resource estimates at the left side of these distributions represents downside risk, while the low probability estimates on the right side of the distributions represent upside potential. These distributions do not include consideration of the probability of success of discovering commercial quantities of oil, but rather represent the likely distribution of oil discoveries, if successfully found.

8. REFERENCES

Adamia, Shota, Guram Zakariadze, Tamar Chkhotua, Nino Sadradze, Nini Tsereteli, Aleksandre Chabukiani, and Aleksandre Gventsadze, 2011, Geology of the Caucasus: A Review: Turkish Journal of Earth Sciences, Vol. 20, p 489-544.

Dow, W. G., 1977, Kerogen Studies and Geological Interpretations: Journal of Geochemical Exploration, Vol. 7, p. 79-99.

Georgia Oil and Gas Limited, 2013, GOG drilling and seismic plan 2013-2016; pp 39 & 42

Gudushauri, Soso V., and Sanishvili, Artem V., 2000, Geological and Geochemical Promises of Oil and Gas Prospects of the West Georgia and Georgian Sector of the Black Sea Basin: AAPG Search and Discovery Article #90024.

Nibladze, Michael, and Alexander Janiashvili, 2014, History of Petroleum Geology in Georgia: AAPG Search and Discovery Article #20273.

Robinson, Andrew G., Eric T. Griffith, Andrew R. Gardiner, and Andrew K. Home, 1997, Petroleum Geology of the Georgian Fold and Thrust Belts and Foreland Basins, *in* A. G. Robinson, ed., Regional and Petroleum Geology of the Black Sea and surrounding Region: AAPG Memoir 68, p. 347-367.

Trofimuk, A. A, V. S. Vyshemirsky, A. E. Kontorovich, S. G. Neruchev, E. A. Rogozina, B. A. Sokolov, V. L. Sokolov, 1984, Stages and Deep Zoning of Oil and Gas Generation in Basins of Different Type and Their Impact Upon Oil and Gas Distribution: Proceedings 27th International Geological Congress, Vol. 13, pp. 193-210.

Ulmishek, Gregory F., 2001, Petroleum Geology and Resources of the Middle Caspian Basin, Former Soviet Union: U. S. Geological Survey, Bull. 2201-A, 42 p.

Zakariadze, Guram S., Yildirim Dilek, S. A. Adamia, R. E. Oberhansli, S. F. Karpendo, B. A. Bazylev, and N. Soloveva, 2007, Geochemistry and geochronology of the Neoproterozoic Pan-African Transcaucasian Massif (Republic of Georgia) and implications for island arc evolution of the late Precambrian Arabian-Nubian Shield: Gondwana Research, Vol. 11, 1-1, p. 92-108.

Zonenshain, Lev P., Michael I. Kuzmin, and Lev M Natapov, 1990, Geology of the USSR: A Plate-Tectonic Synthesis: American Geophysical Union, Geodynamics Series, Vol 21, 242 p.

9. CERTIFICATES OF QUALIFICATION

I, Letha Chapman Lencioni, Professional Engineer of 5757 Central Avenue, Suite D, Boulder, Colorado, 80301, USA, hereby certify:

1. I am an employee of Gustavson Associates, which prepared a detailed analysis of the oil and gas properties of Block Energy, plc. The effective date of this evaluation is January 1, 2018.
2. I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Block Energy, plc or their affiliated companies, nor any interest in the subject property.
3. I attended the University of Tulsa and I graduated with a Bachelor of Science Degree in Petroleum Engineering in 1980; I am a Registered Professional Engineer in the State of Colorado, and I have in excess of 35 years' experience in the conduct of evaluation and engineering studies relating to oil and gas fields.
4. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of information available from public information and records, and the files of Block Energy, plc.

Letha Chapman Lencioni
Chief Reservoir Engineer/
Vice-President, Petroleum Engineering
Gustavson Associates, LLC
Colorado Registered Engineer #29506

I, Jan Joseph Tomanek, Certified Petroleum Geologist of 5757 Central Avenue, Suite D, Boulder, Colorado, 80301, USA, hereby certify:

1. I am an employee of Gustavson Associates, which prepared a detailed analysis of the oil and gas properties of Block Energy, plc. The effective date of this evaluation is January 1, 2018.
2. I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Block Energy, plc or their affiliated companies, nor any interest in the subject property.
3. I attended the University of Connecticut and I graduated with a Bachelor of Science Degree in Geology in 1975; I am an American Association of Petroleum Geologists Certified Petroleum Geologist and an American Institute of Professional Geologist Certified Professional Geologist, and I have in excess of 35 years' experience in the oil and gas field.
4. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of information available from public information and records, and the files of Block Energy, plc.

Jan Joseph Tomanek
Vice-President, Oil and Gas
Gustavson Associates, LLC
AIPG CPG #11566
AAPG CPG # 6239

Additional Professional Personnel who contributed to this Report:

<u>Michele G. Bishop</u>

Chief Geologist - Master of Science Degree in Geology from Duke University. Professional Geologist of the State of Wyoming and an American Institute of Professional Geologists Certified Professional Geologist with over 30 years of experience in studies relating to oil and gas fields, including estimating quantities of reserves and resources. She is a member in good standing of the following professional organizations: Society for Sedimentary Geology (SEPM), Rocky Mountain Association of Geologists (RMAG), The Research Society (Sigma Xi), and the American Institute of Professional Geologists (AIPG).

Credentials include: Wyoming Professional Geologist PG-783 and AIPG Certified Professional Geologist CPG-11291.

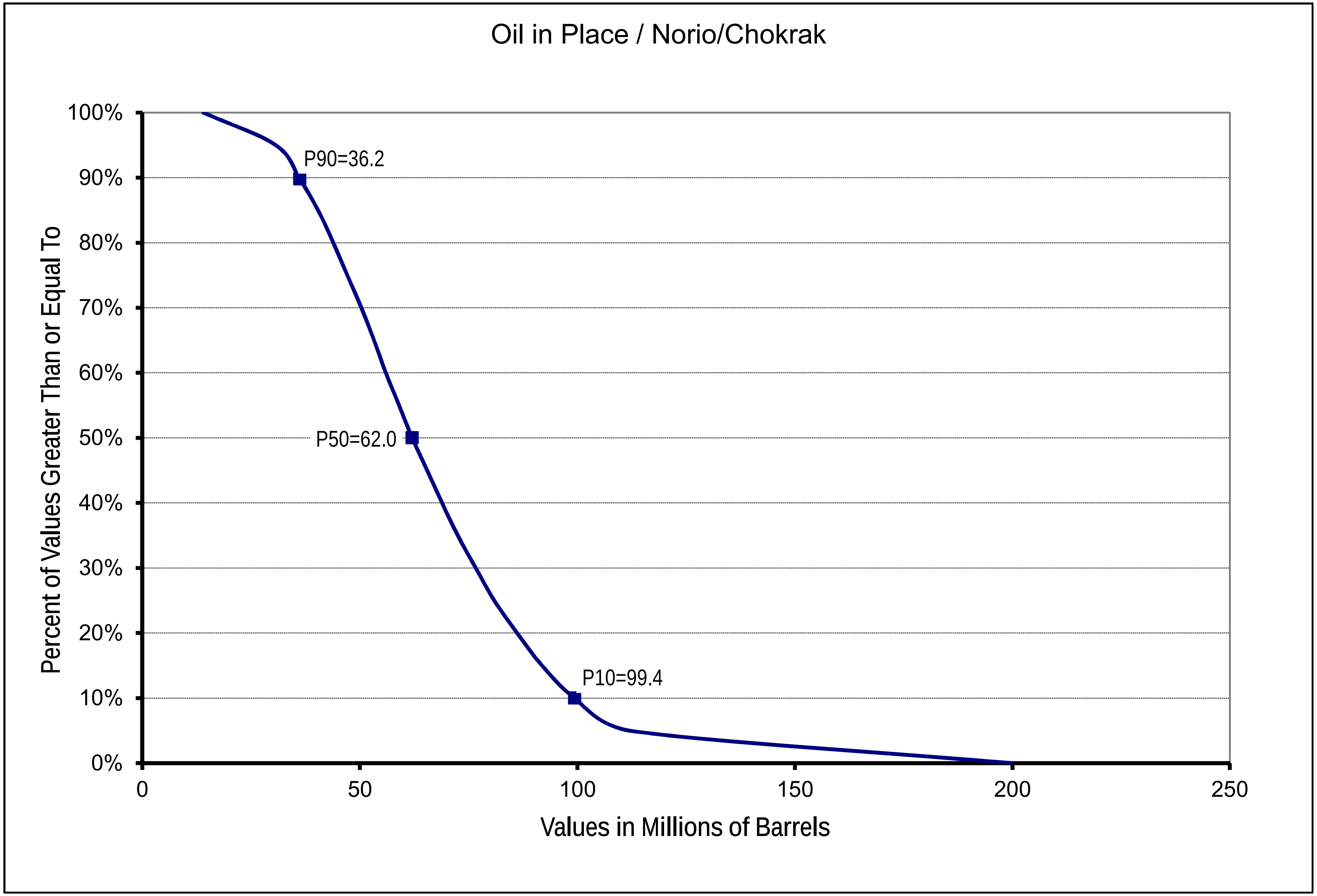
<u>Kevin S. Weller</u>

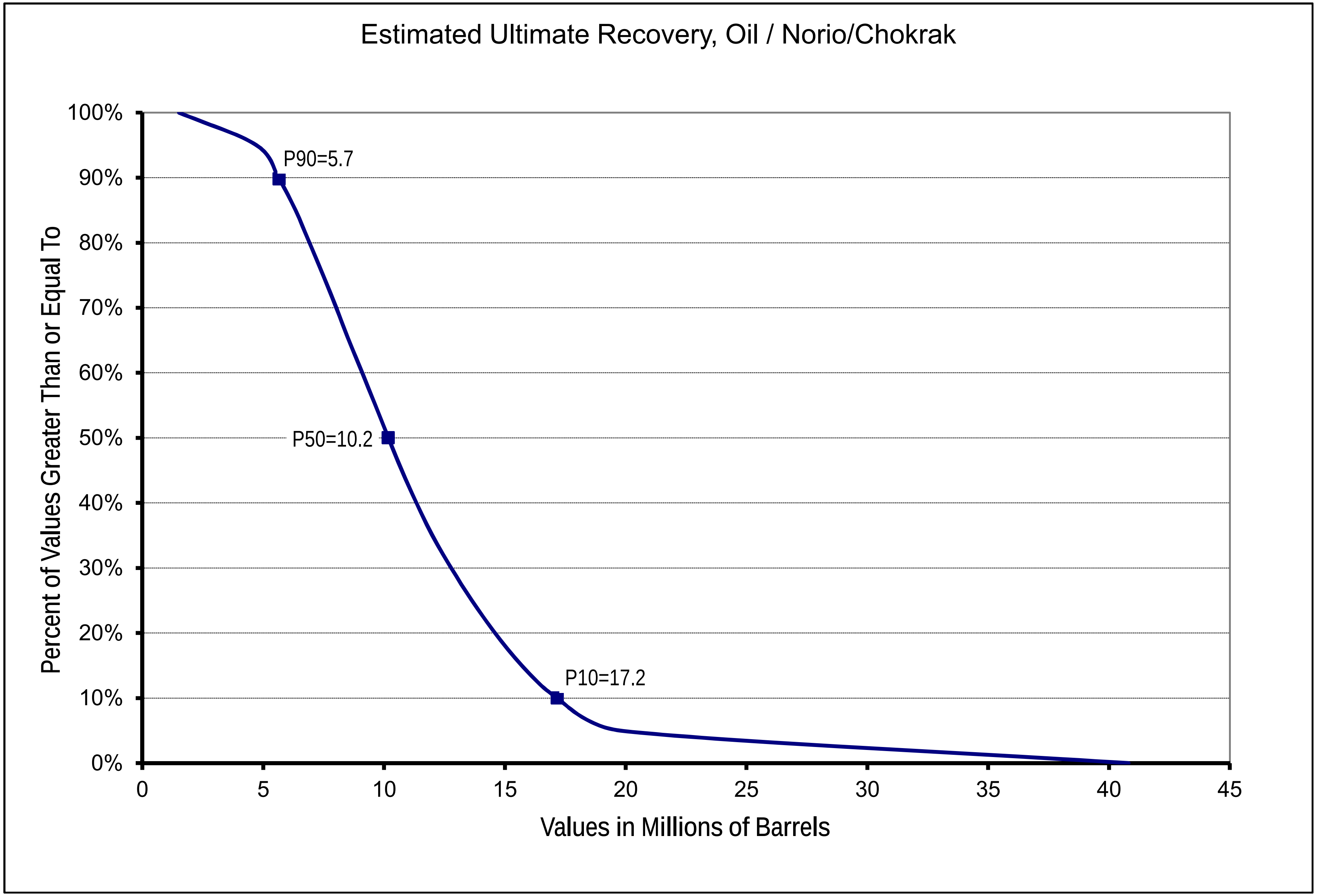
Executive Vice-President and Registered Professional Petroleum Engineer earned a BSc Geological Engineering from Colorado School of Mines with over 35 years of experience in reservoir evaluation, production engineering and field operations. He is a member in good standing of the following professional organizations: Society of Petroleum Evaluation Engineers (SPEE), Society of Petroleum Engineers (SPE), and American Association of Petroleum Geologists (AAPG).

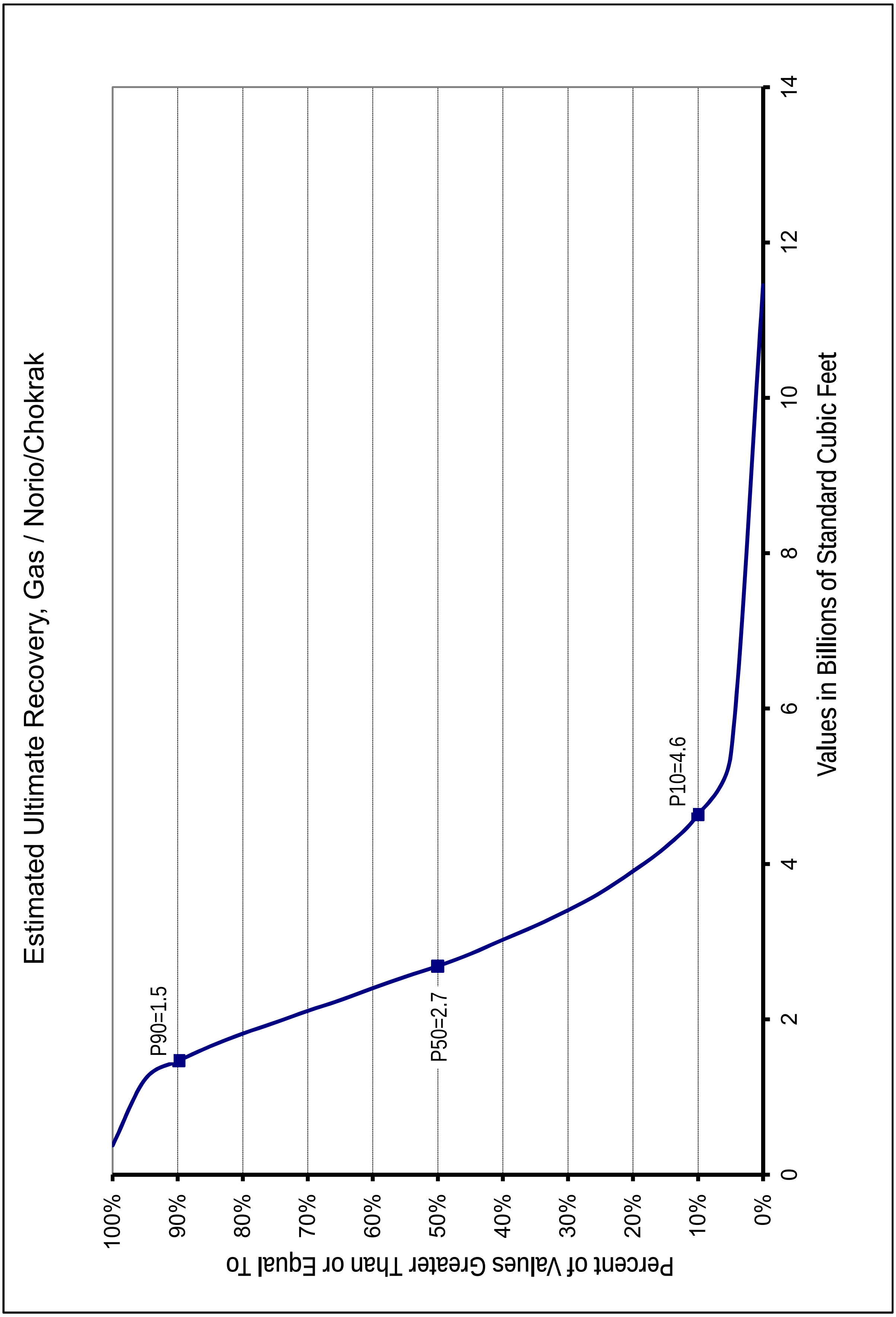
Credentials include: Registered Engineer in the states of Colorado, Texas, Wyoming, Utah and New Mexico.

Appendix A

Probability Distributions of Contingent and Prospective Oil Resources

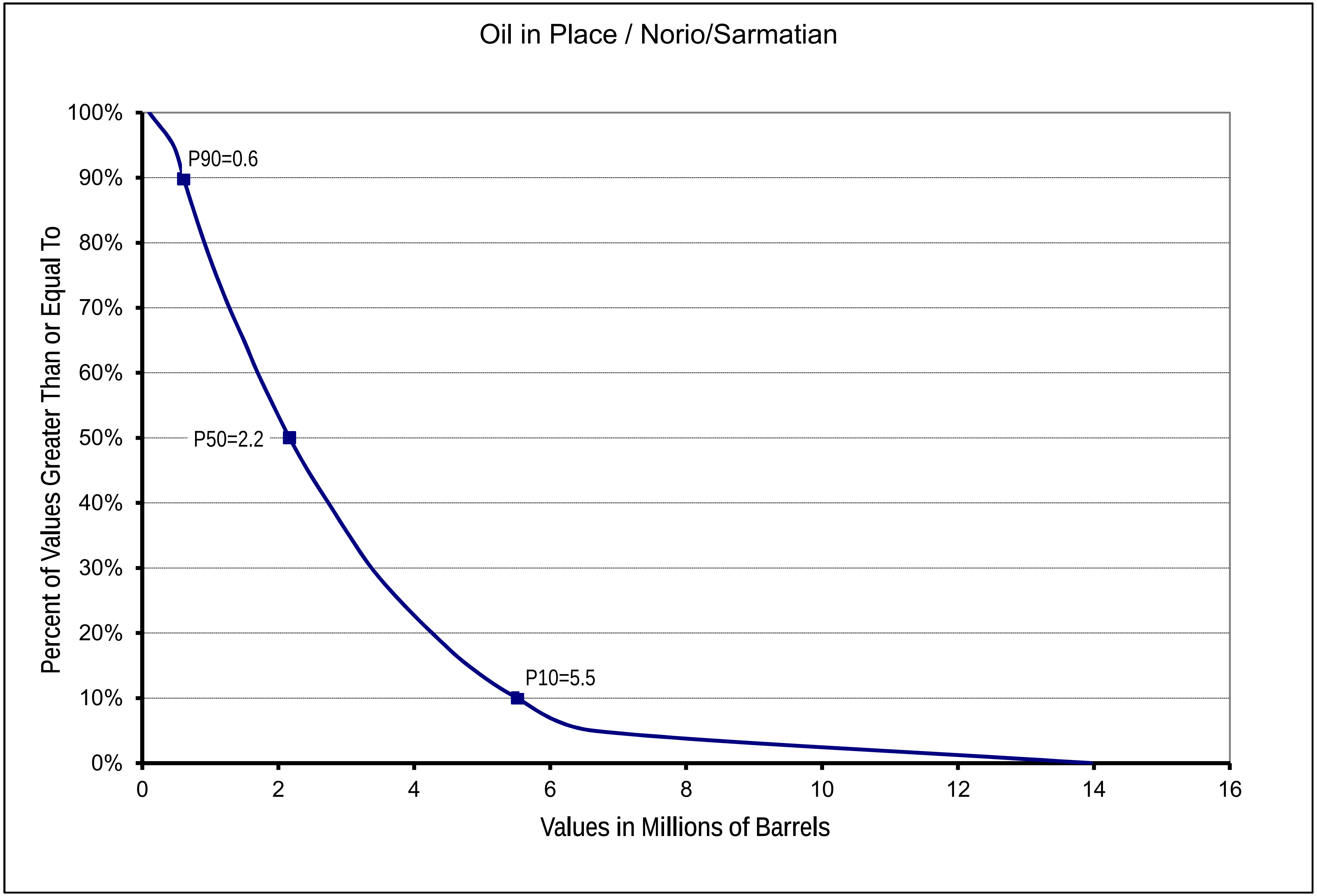

Oil in Place / Norio/Chokrak
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
50
100
150
200
250
Values in Millions of Barrels
P90=36.2
P50=62.0
P10=99.4


Estimated Ultimate Recovery, Oil / Norio/Chokrak
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=5.7
P50=10.2
P10=17.2
0
5
10
15
20
25
30
35
40
45
Values in Millions of Barrels

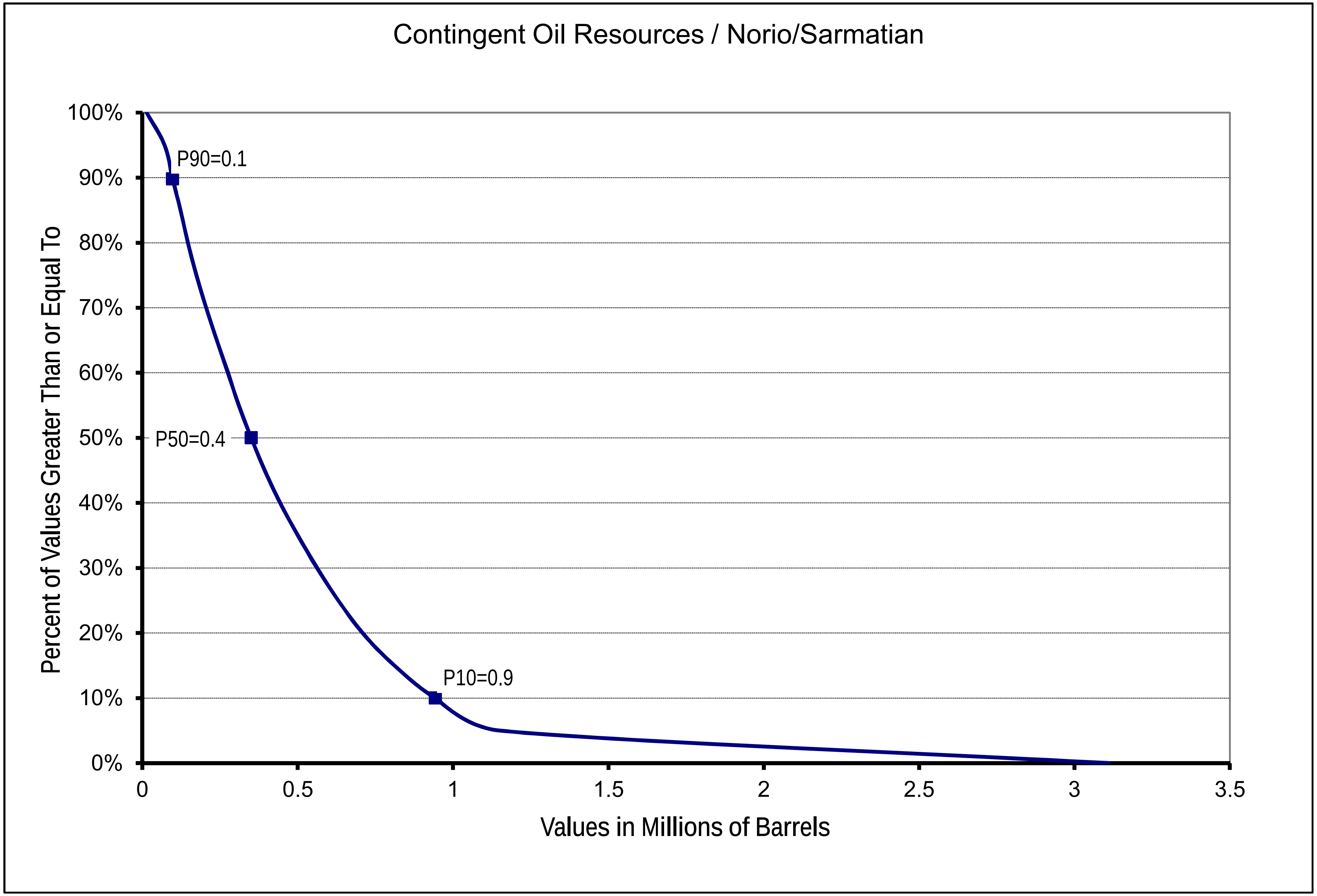


Estimated Ultimate Recovery, Gas / Norio/Chokrak
P90=1.5
P50=2.7
P10=4.6
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
0
2
4
6
8
10
12
14
Values in Billions of Standard Cubic Feet

A-3

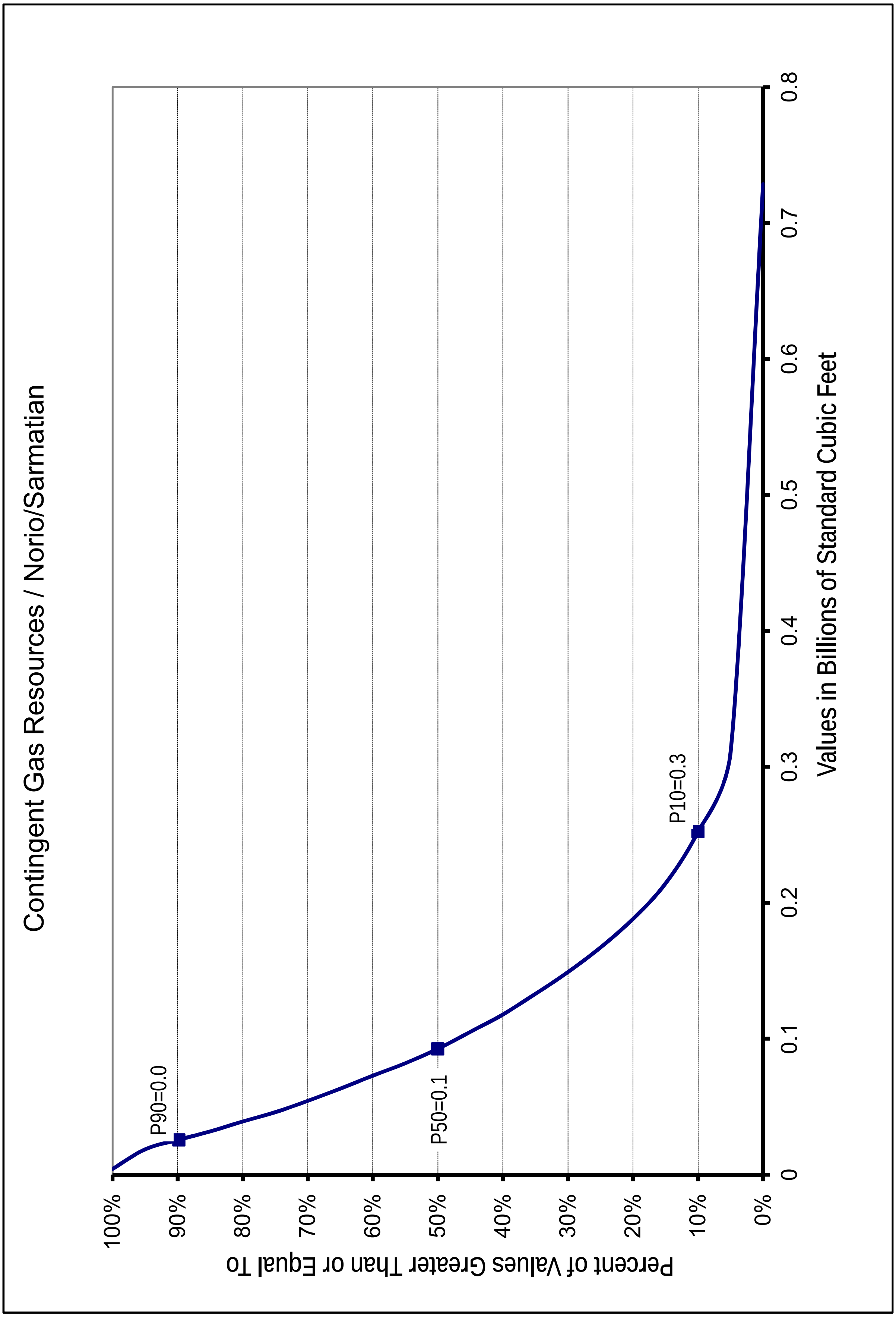


Oil in Place / Norio/Sarmatian
P90=0.6
P50=2.2
P10=5.5
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
0
2
4
6
8
10
12
14
16
Values in Millions of Barrels

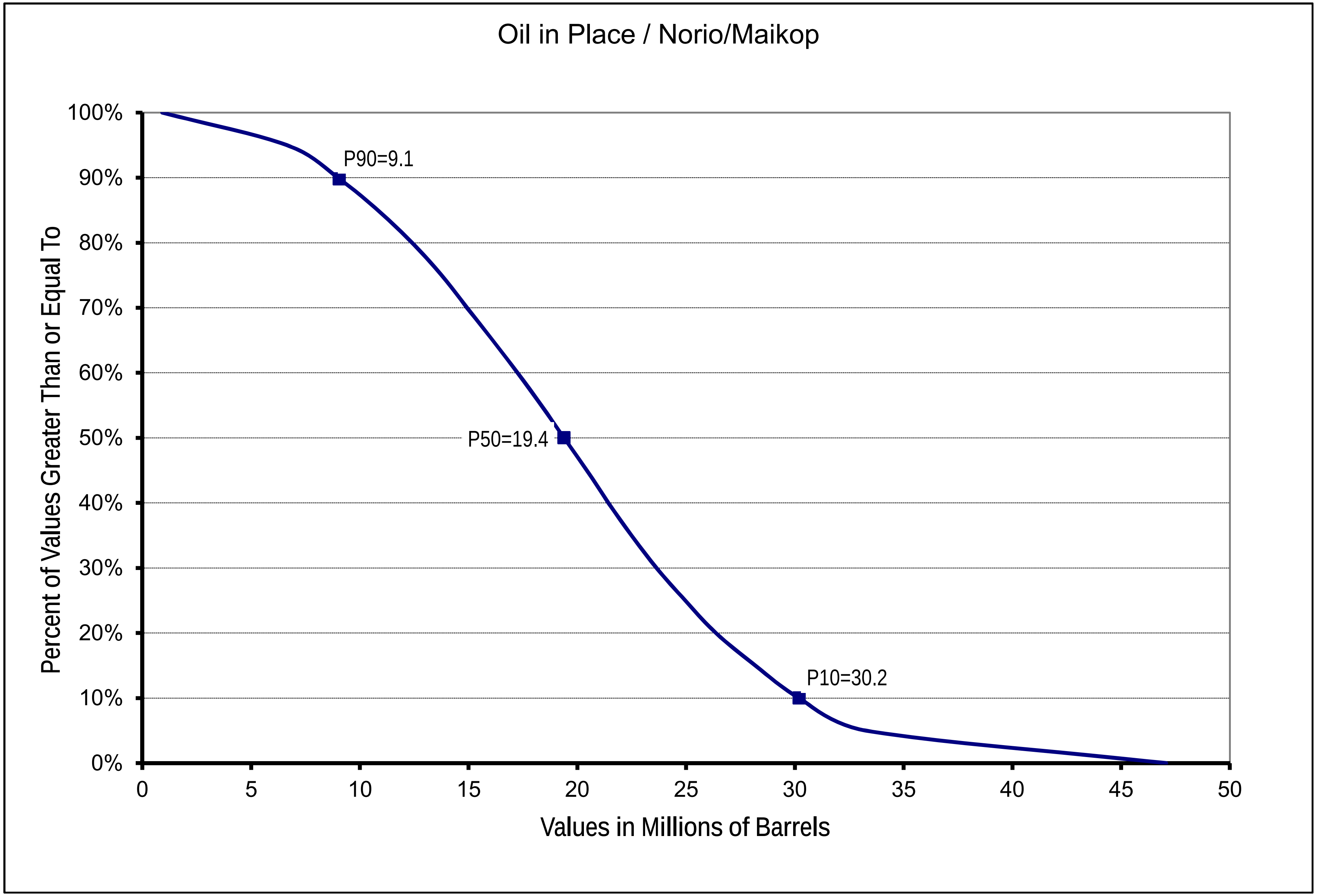


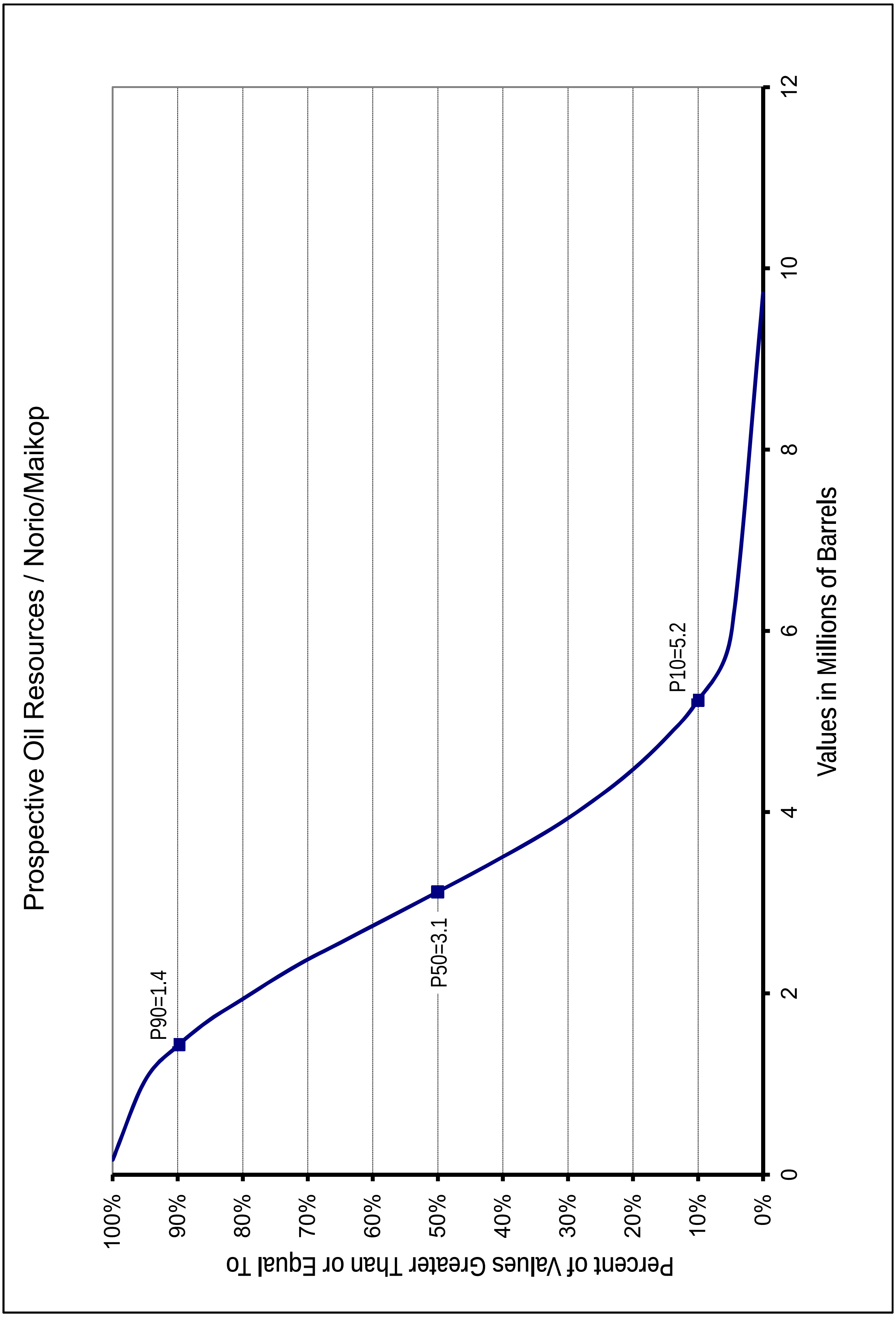
Contingent Oil Resources / Norio/Sarmatian
Percent of Values Greater Than or Equal To
Values in Millions of Barrels
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
0.5
1
1.5
2
2.5
3
3.5
P90=0.1
P50=0.4
P10=0.9

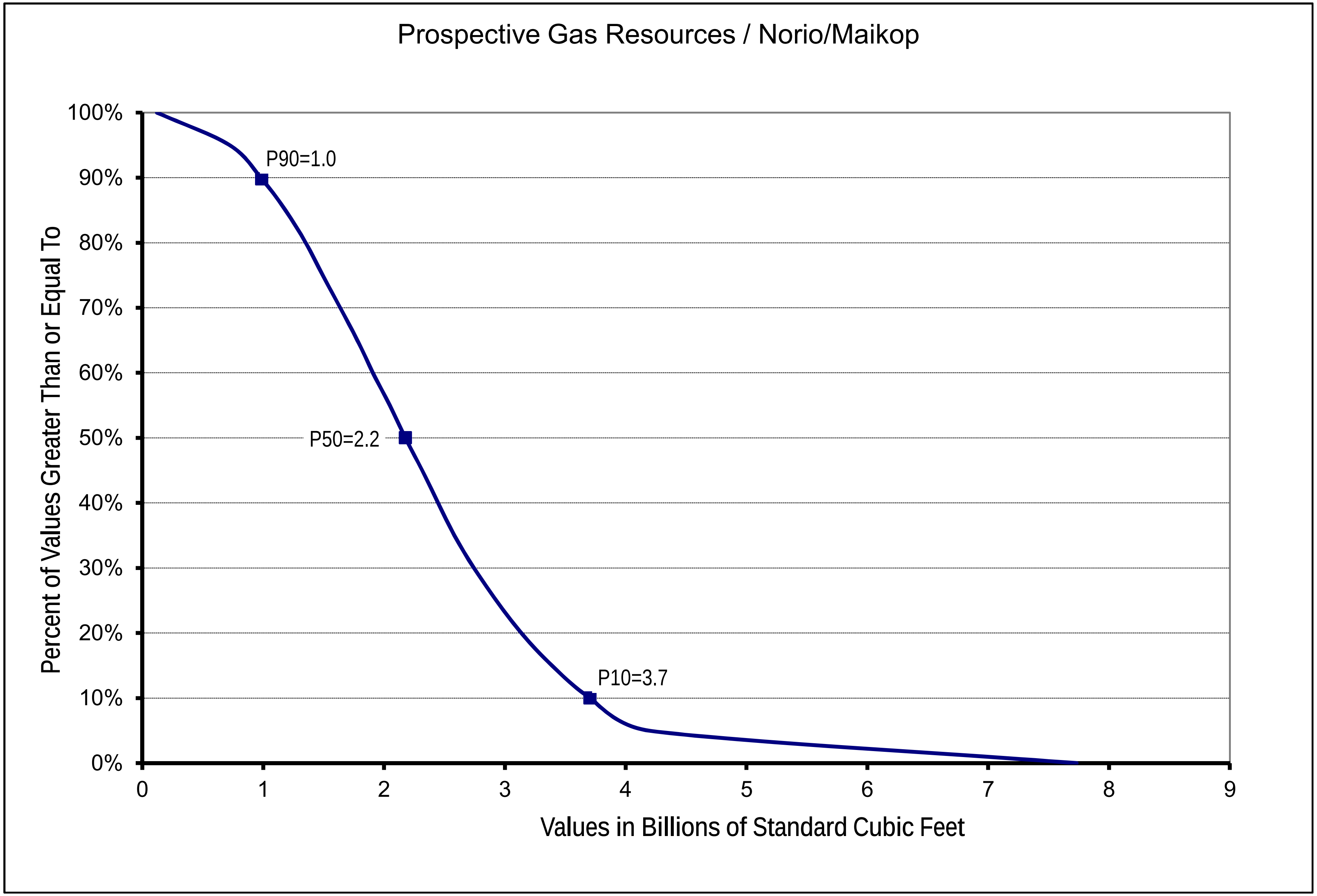
A-5



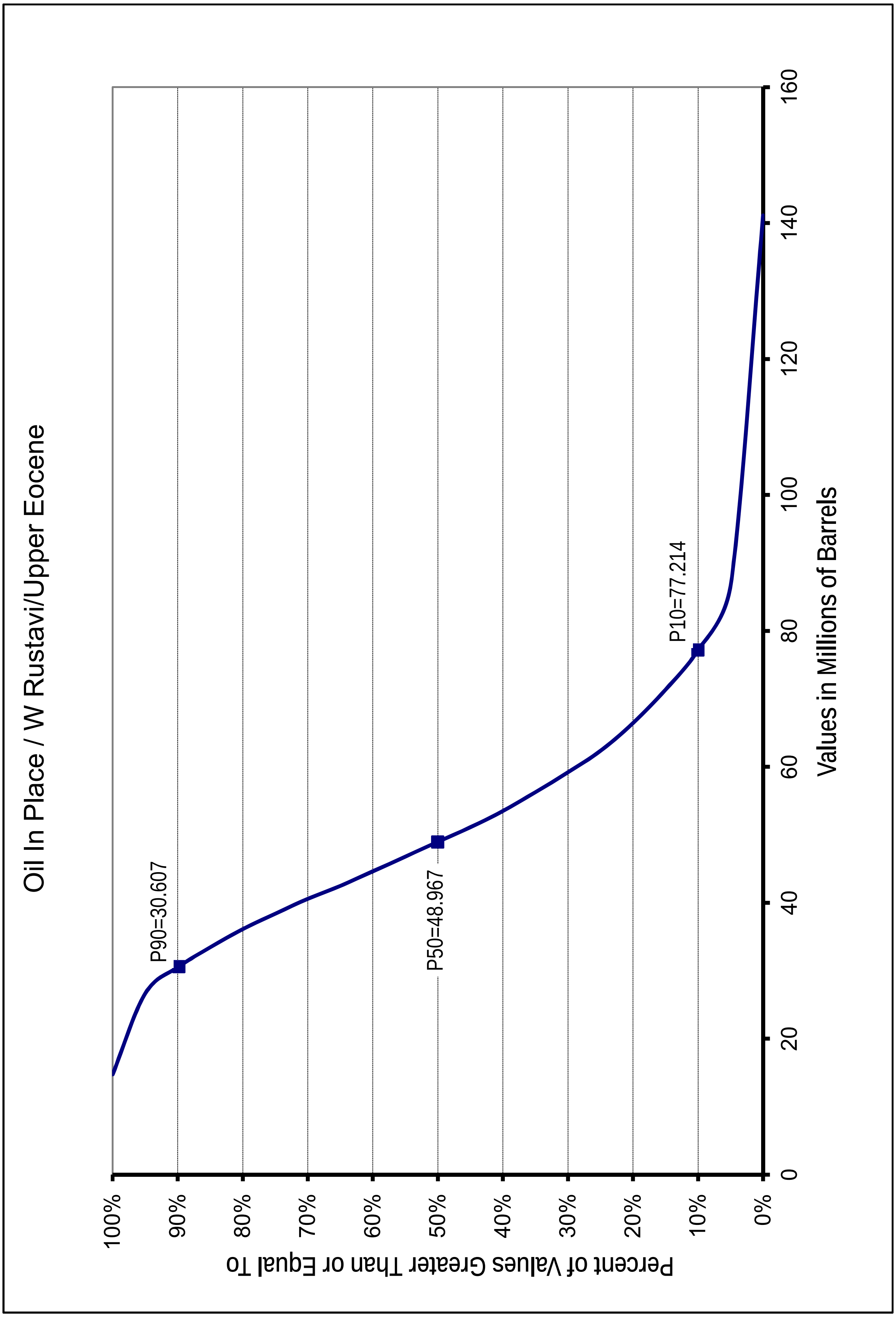
Contingent Gas Resources / Norio/Sarmatian
P90=0.0
P50=0.1
P10=0.3
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
Values in Billions of Standard Cubic Feet


Oil in Place / Norio/Maikop
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=9.1
P50=19.4
P10=30.2
0
5
10
15
20
25
30
35
40
45
50
Values in Millions of Barrels


Prospective Oil Resources / Norio/Maikop
P90=1.4
P50=3.1
P10=5.2
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
0
2
4
6
8
10
12
Values in Millions of Barrels

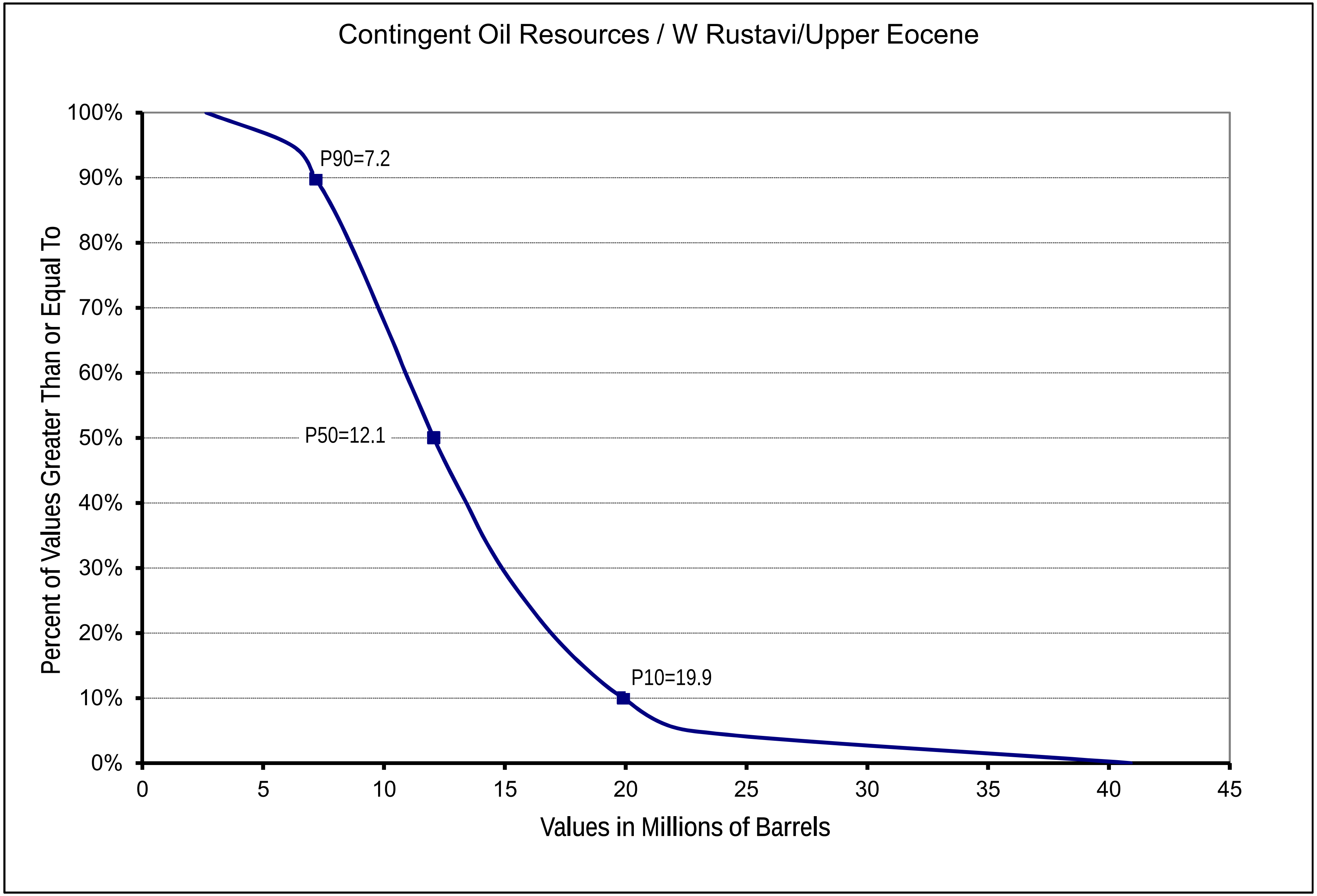


Prospective Gas Resources / Norio/Maikop
P90=1.0
P50=2.2
P10=3.7
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
0
1
2
3
4
5
6
7
8
9
Values in Billions of Standard Cubic Feet



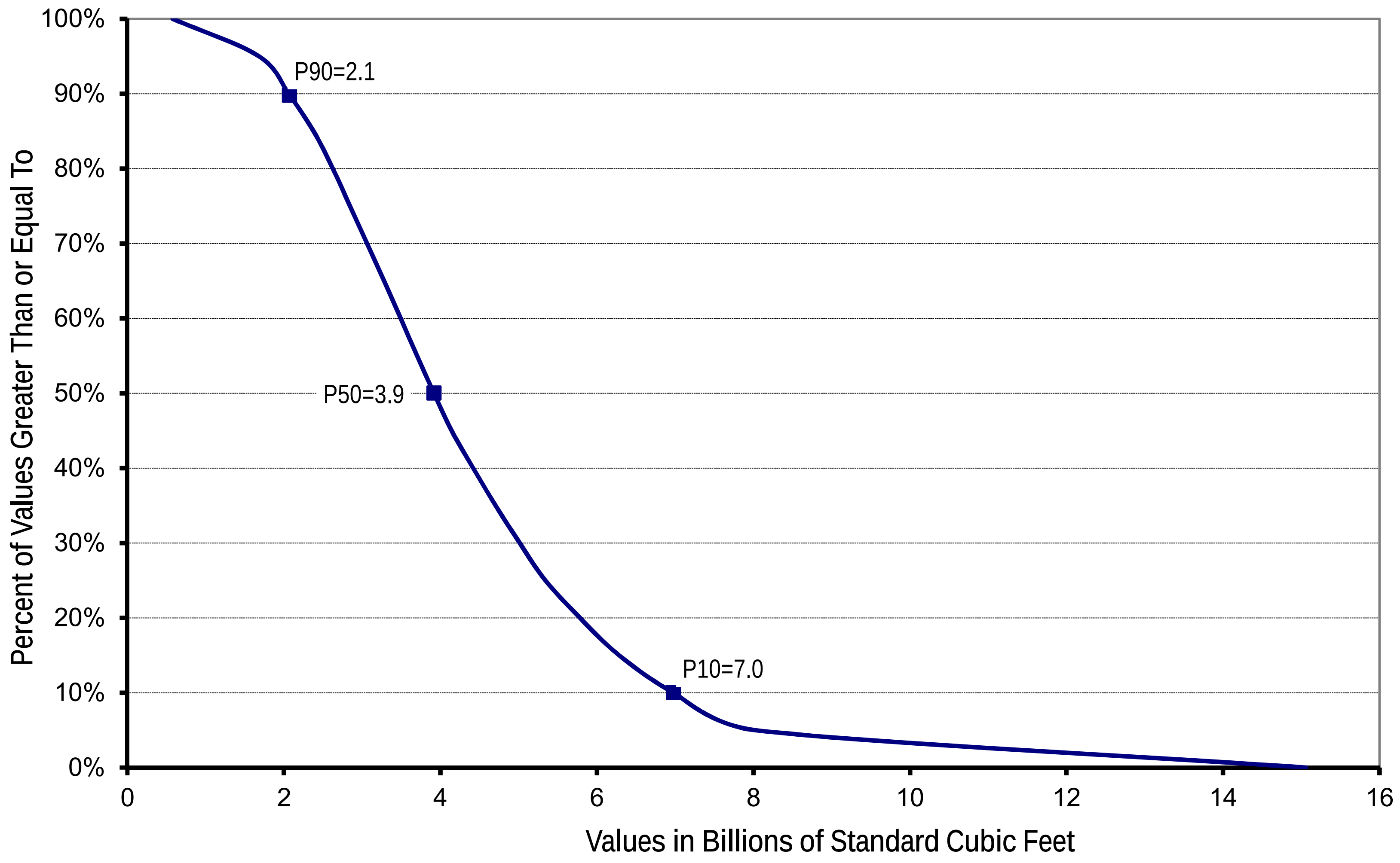
Oil In Place / W Rustavi/Upper Eocene
P90=30.607
P50=48.967
P10=77.214
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
20
40
60
80
100
120
140
160
Values in Millions of Barrels

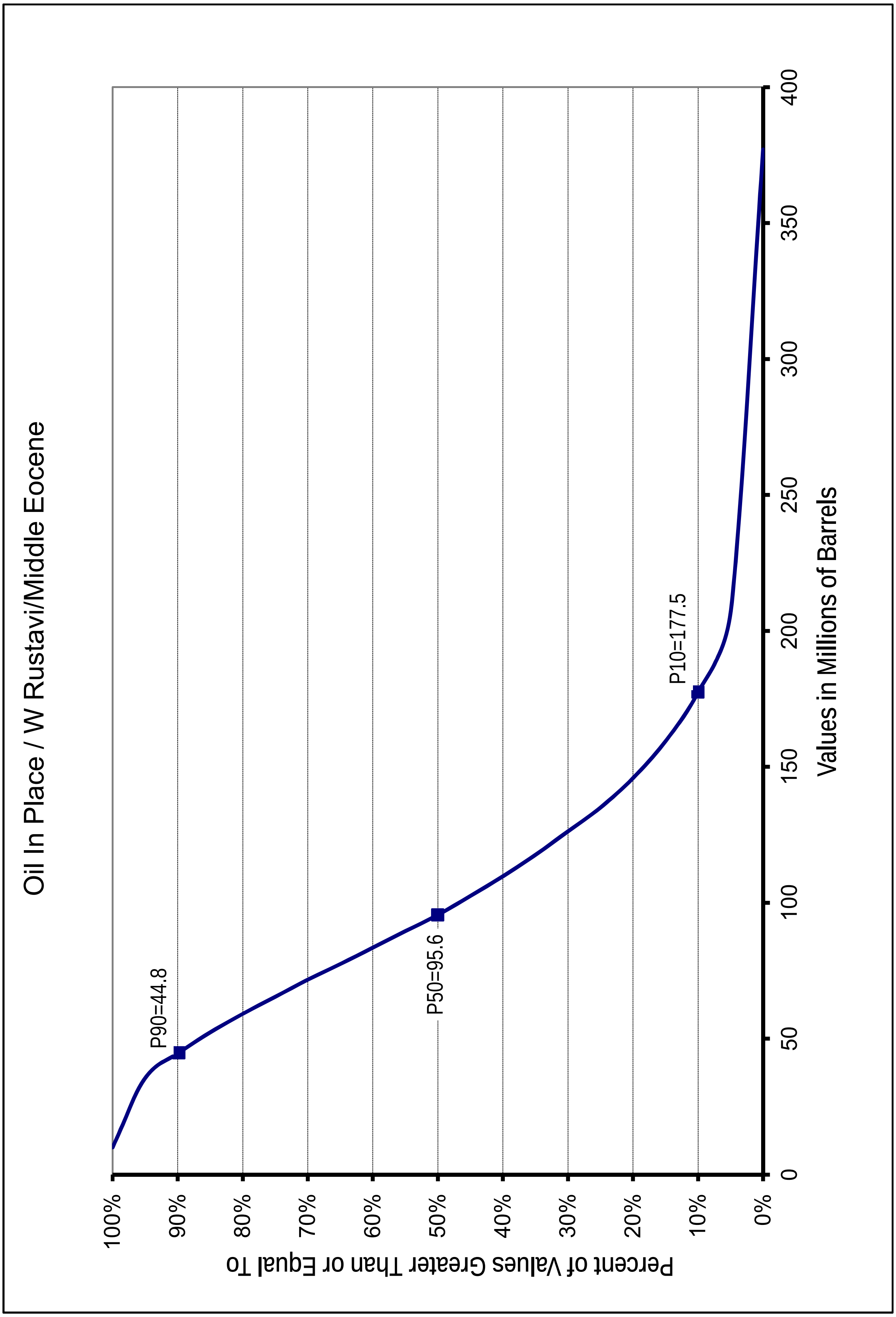
A-10



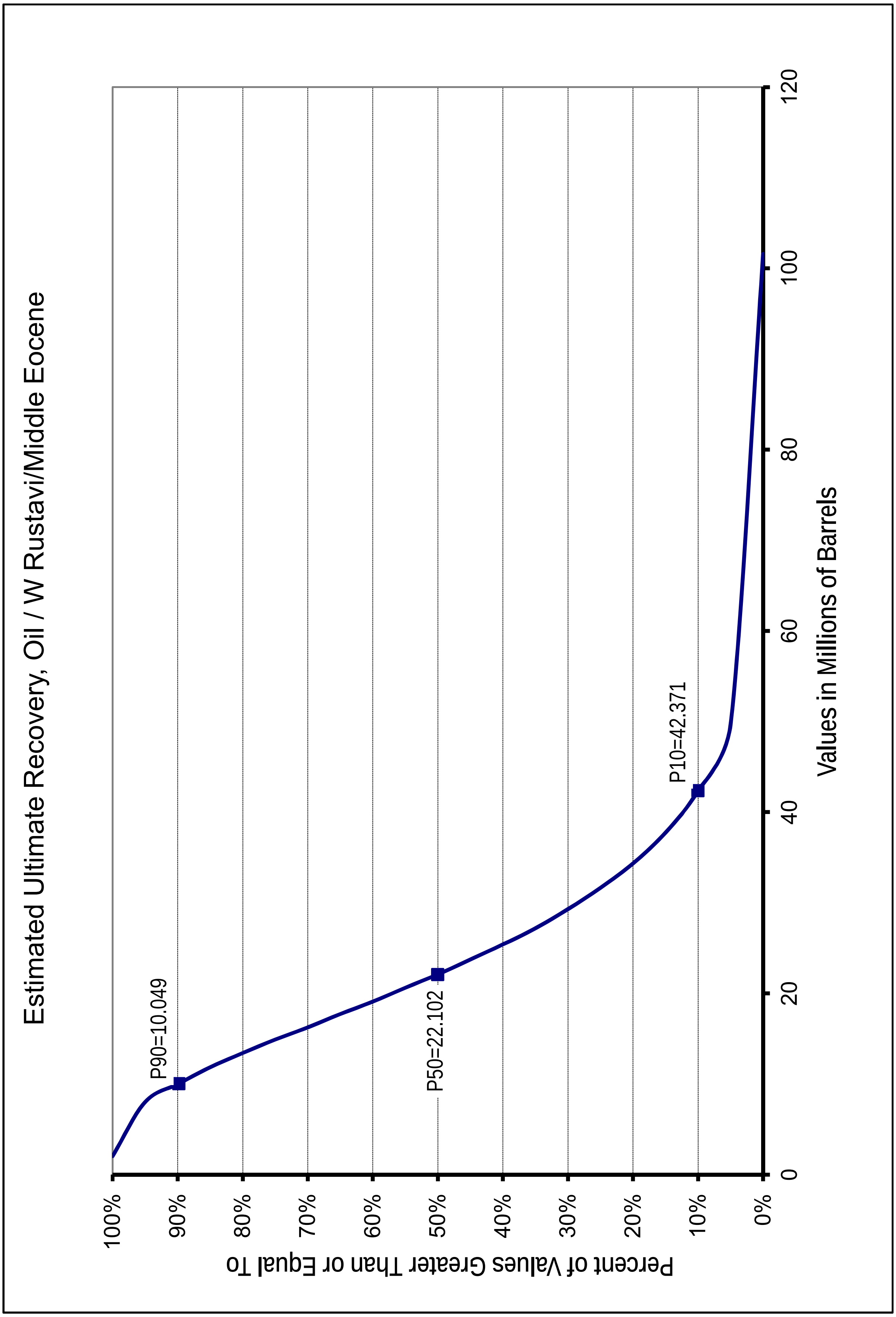
Contingent Oil Resources / W Rustavi/Upper Eocene
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=7.2
P50=12.1
P10=19.9
0
5
10
15
20
25
30
35
40
45
Values in Millions of Barrels

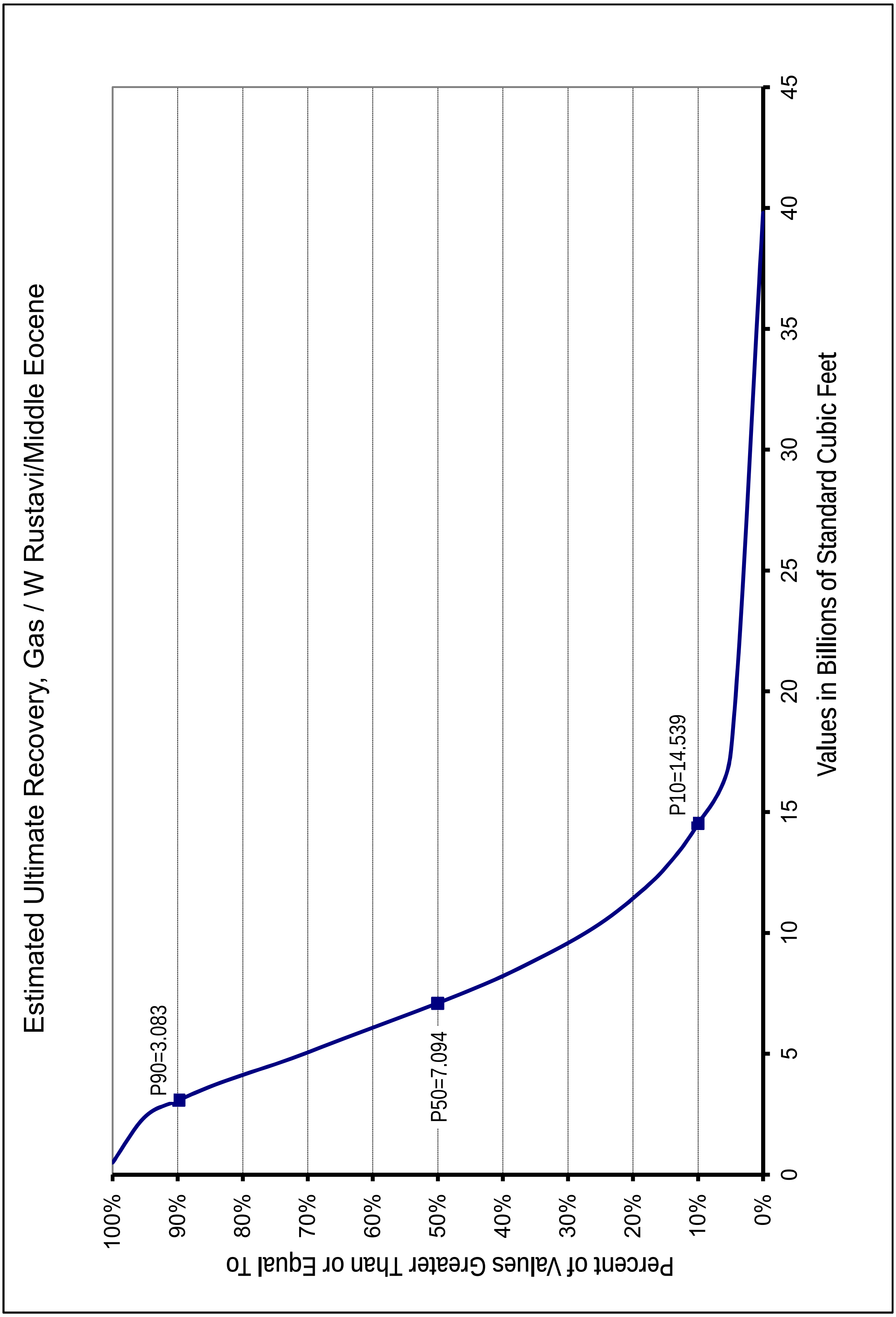
Contingent Gas Resources / W Rustavi/Upper Eocene

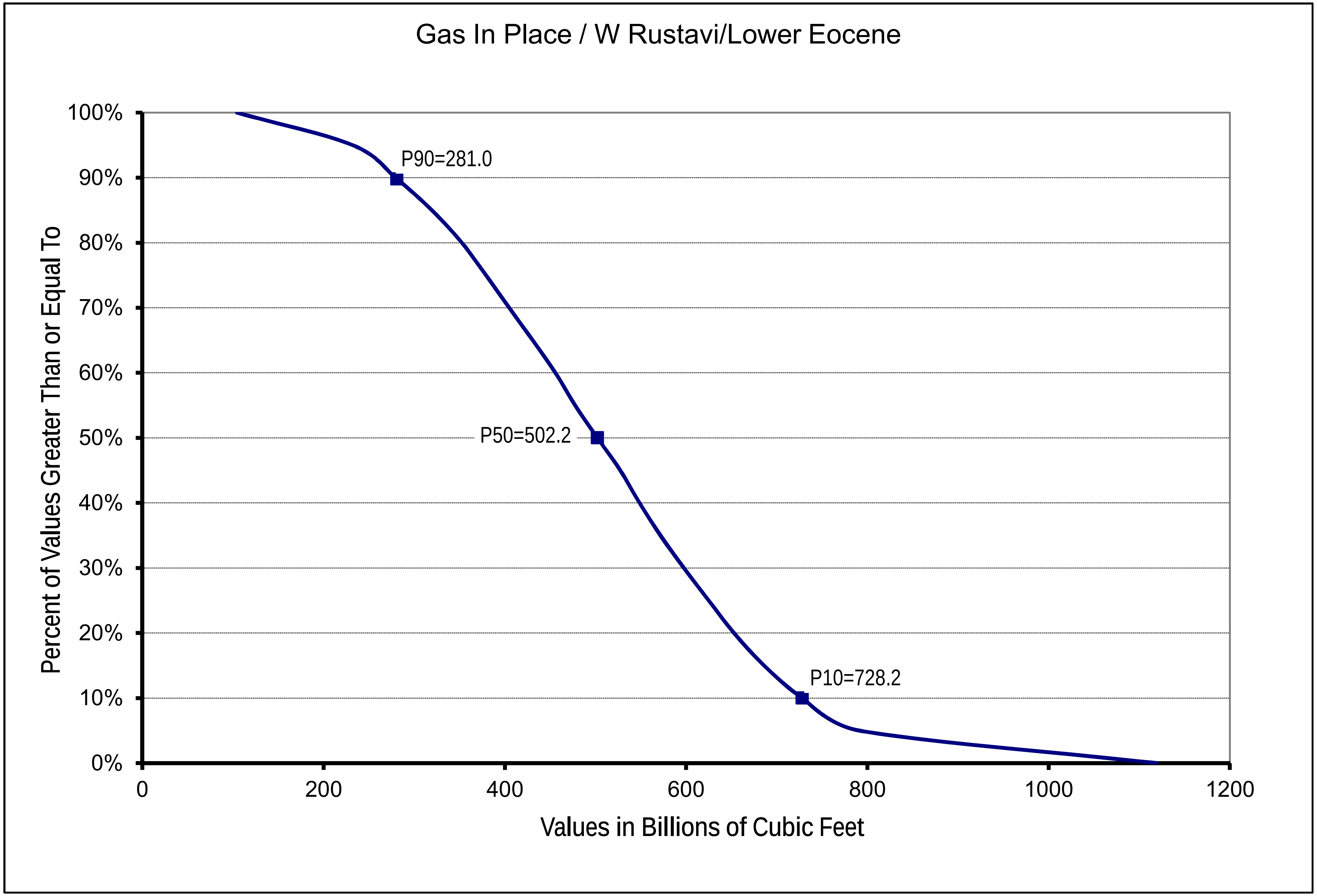


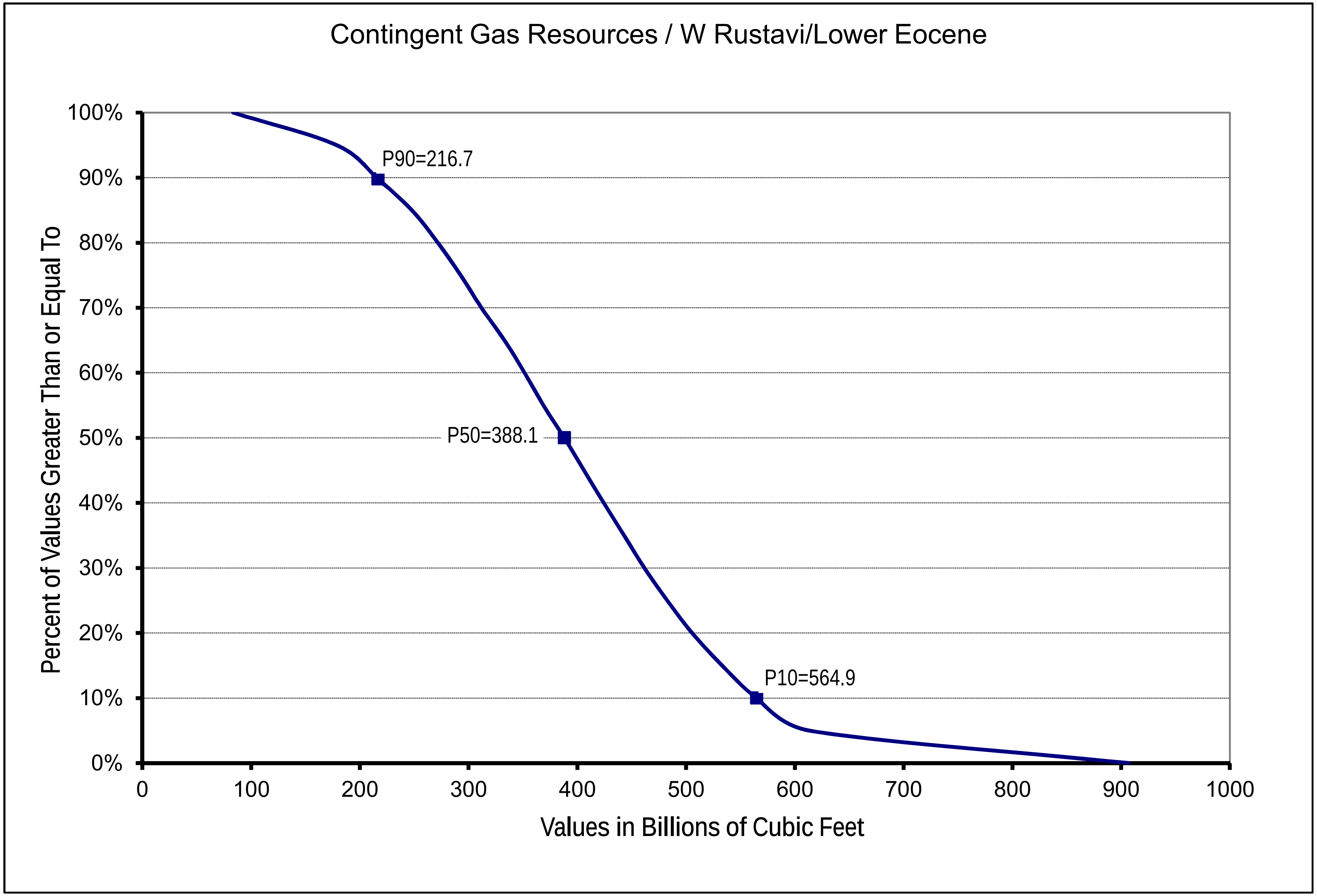

Oil In Place / W Rustavi/Middle Eocene
P90=44.8
P50=95.6
P10=177.5
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
50
100
150
200
250
300
350
400
Values in Millions of Barrels

A-13

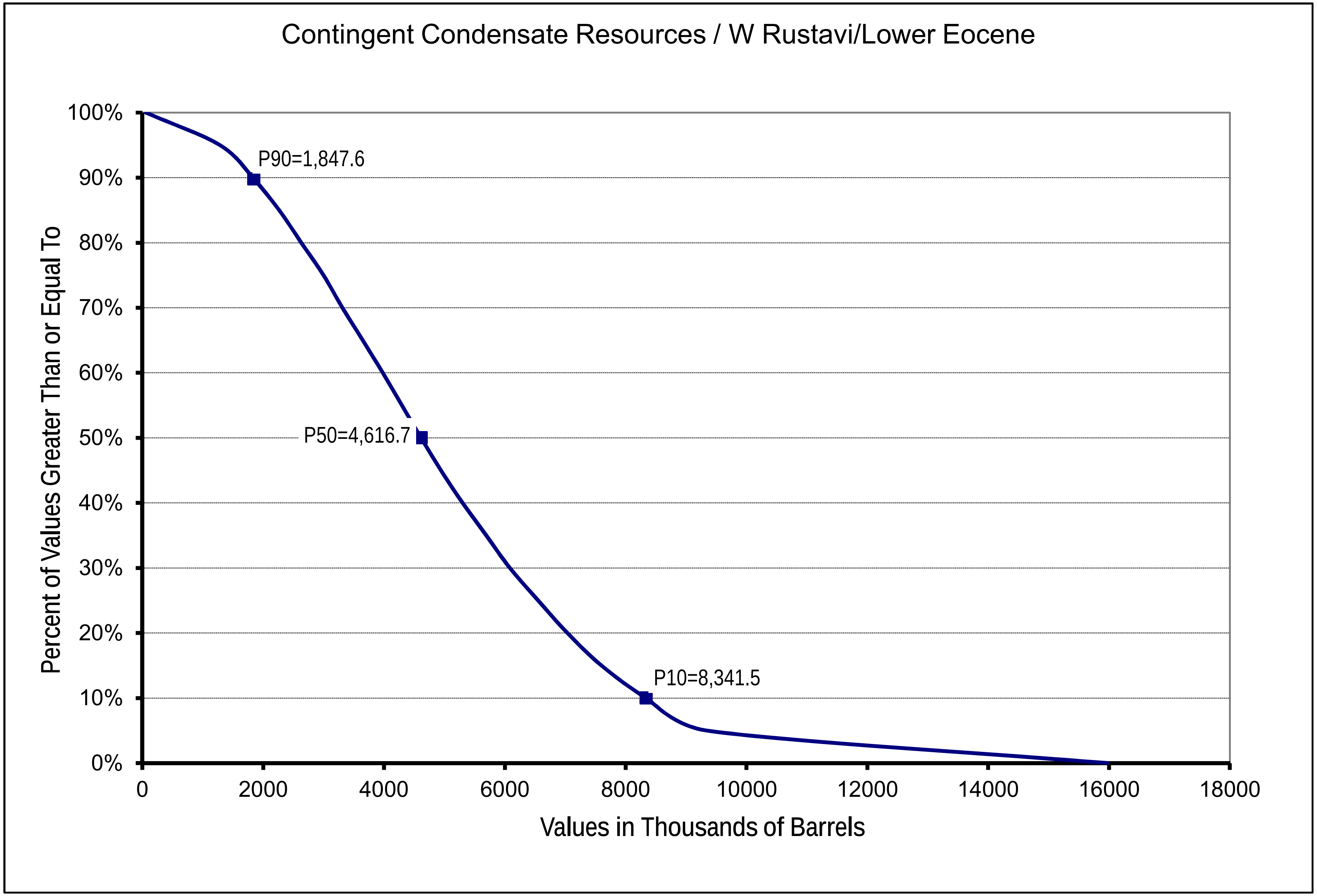

Estimated Ultimate Recovery, Oil / W Rustavi/Middle Eocene
P90=10.049
P50=22.102
P10=42.371
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
20
40
60
80
100
120
Values in Millions of Barrels


Estimated Ultimate Recovery, Gas / W Rustavi/Middle Eocene
P90=3.083
P50=7.094
P10=14.539
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
5
10
15
20
25
30
35
40
45
Values in Billions of Standard Cubic Feet

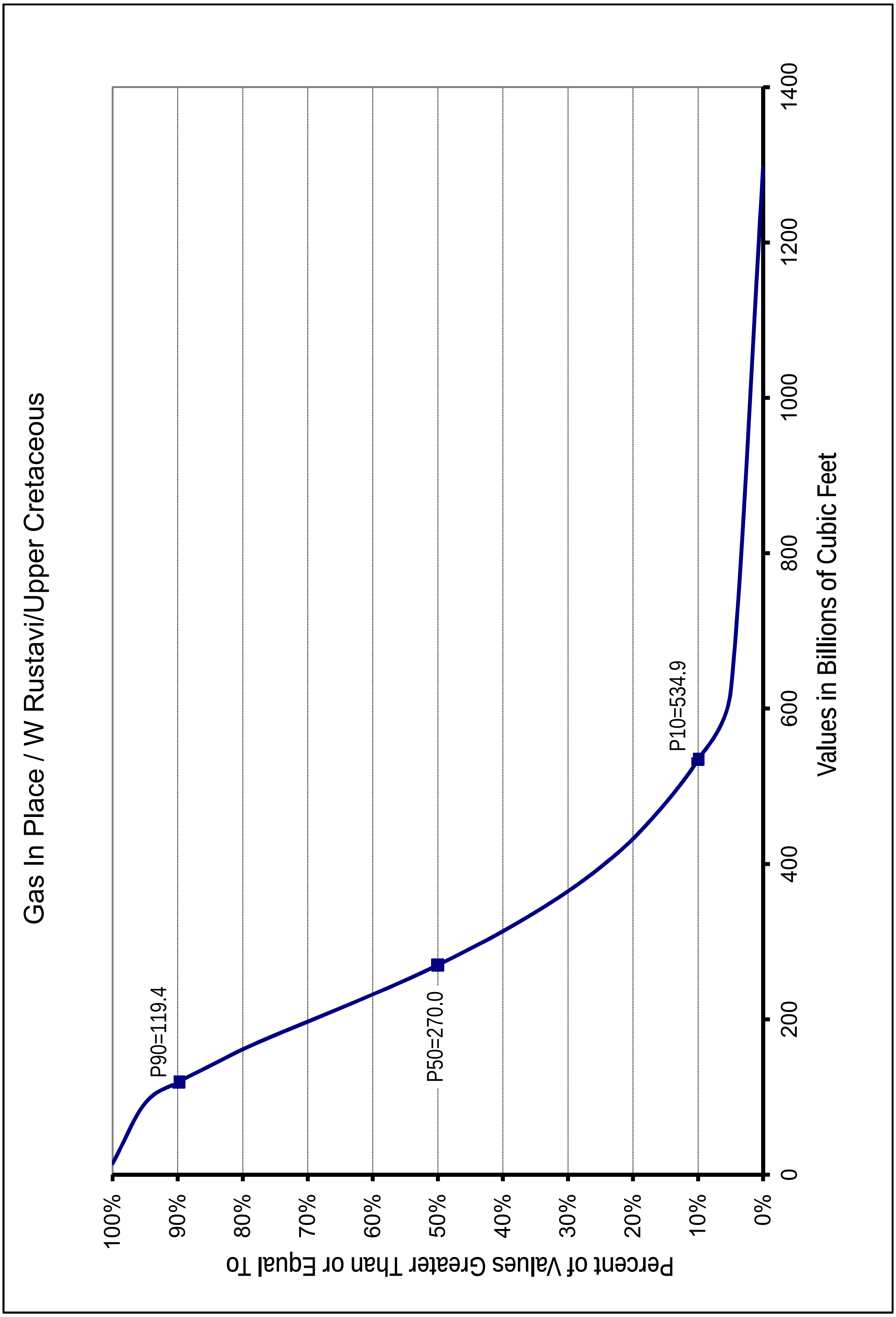

Gas In Place / W Rustavi/Lower Eocene
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
200
400
600
800
1000
1200
Values in Billions of Cubic Feet
P90=281.0
P50=502.2
P10=728.2



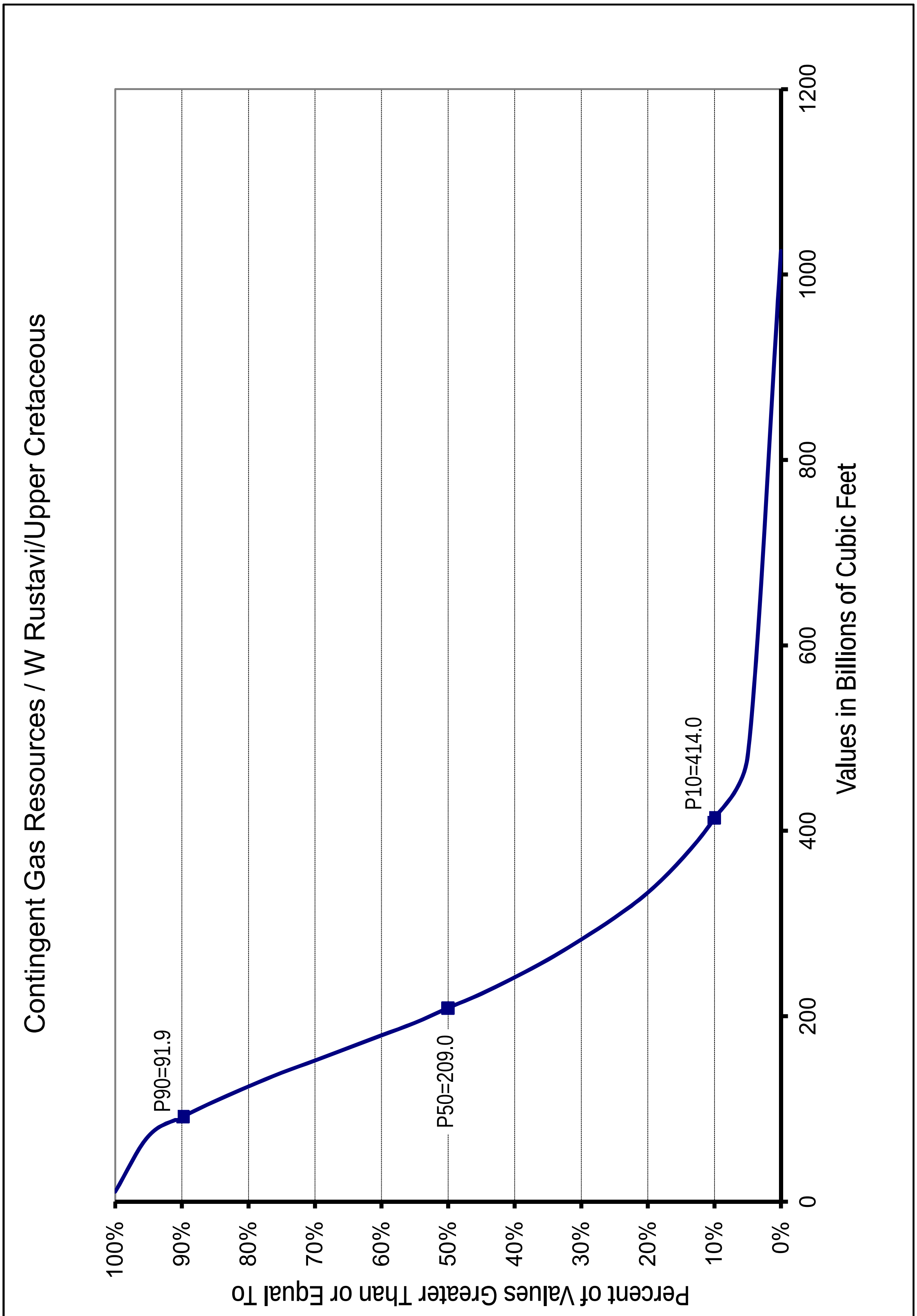
Contingent Gas Resources / W Rustavi/Lower Eocene
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=216.7
P50=388.1
P10=564.9
0
100
200
300
400
500
600
700
800
900
1000
Values in Billions of Cubic Feet

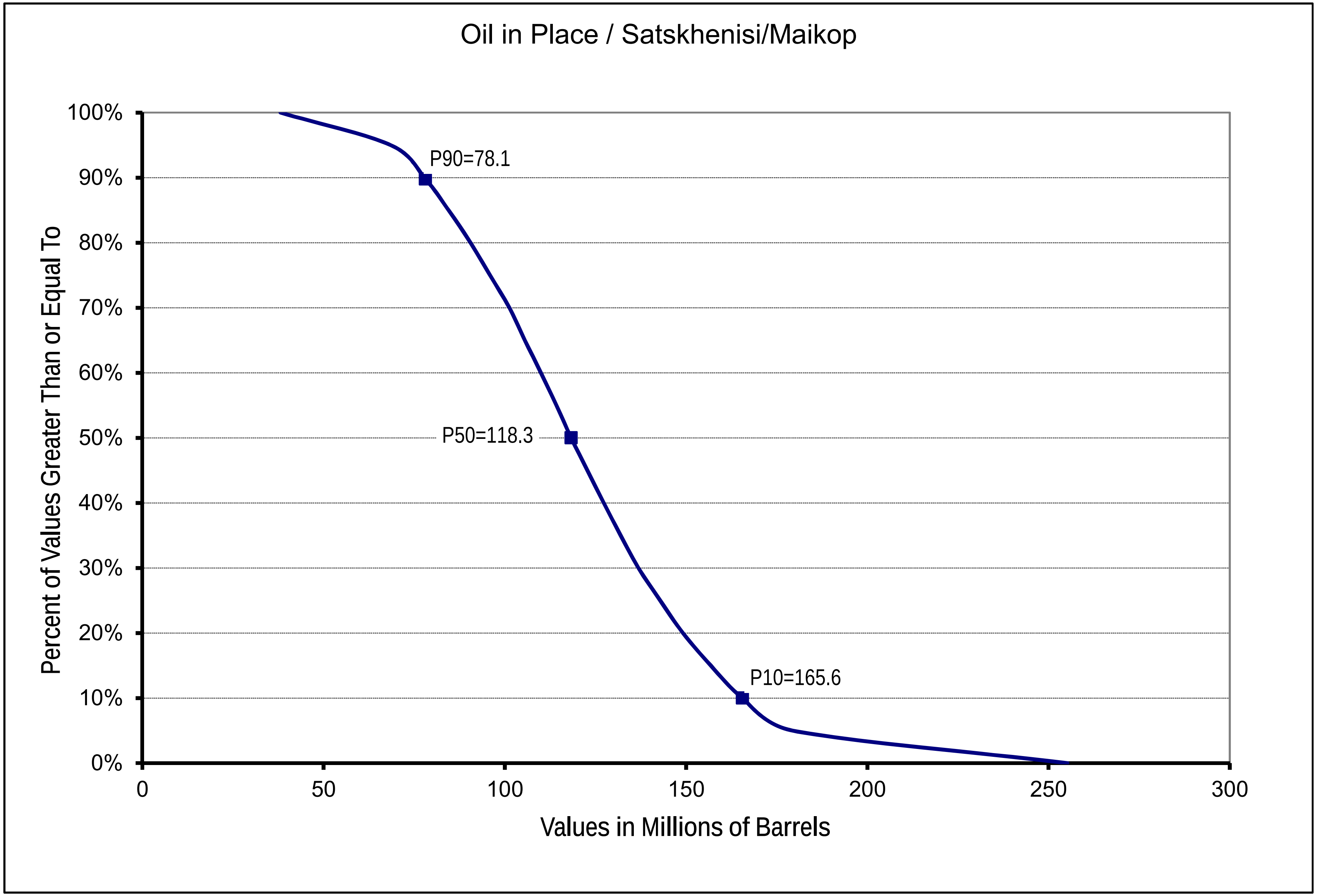


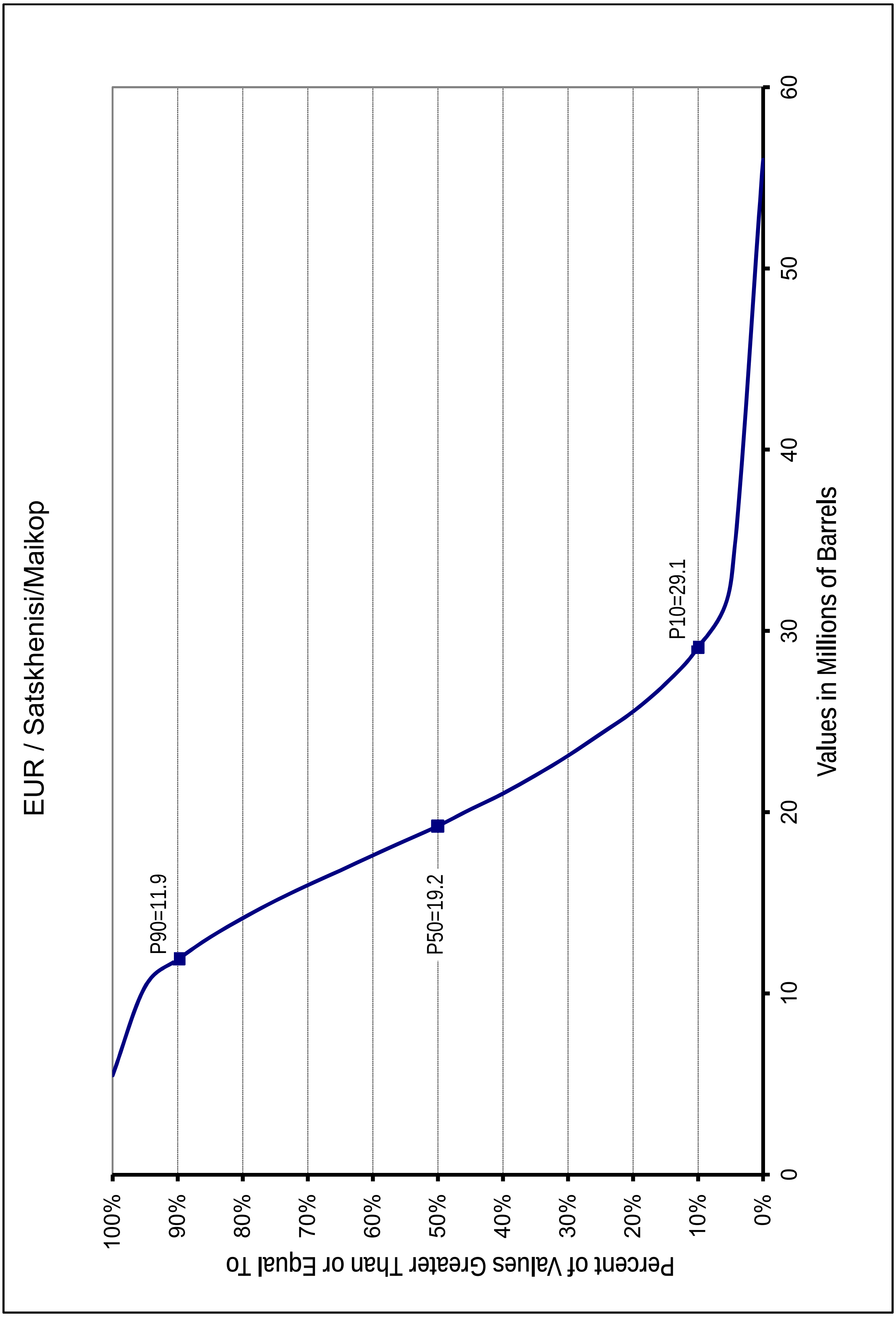
Contingent Condensate Resources / W Rustavi/Lower Eocene
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=1,847.6
P50=4,616.7
P10=8,341.5
0
2000
4000
6000
8000
10000
12000
14000
16000
18000
Values in Thousands of Barrels



Gas In Place / W Rustavi/Upper Cretaceous
P90=119.4
P50=270.0
P10=534.9
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
0
200
400
600
800
1000
1200
1400
Values in Billions of Cubic Feet

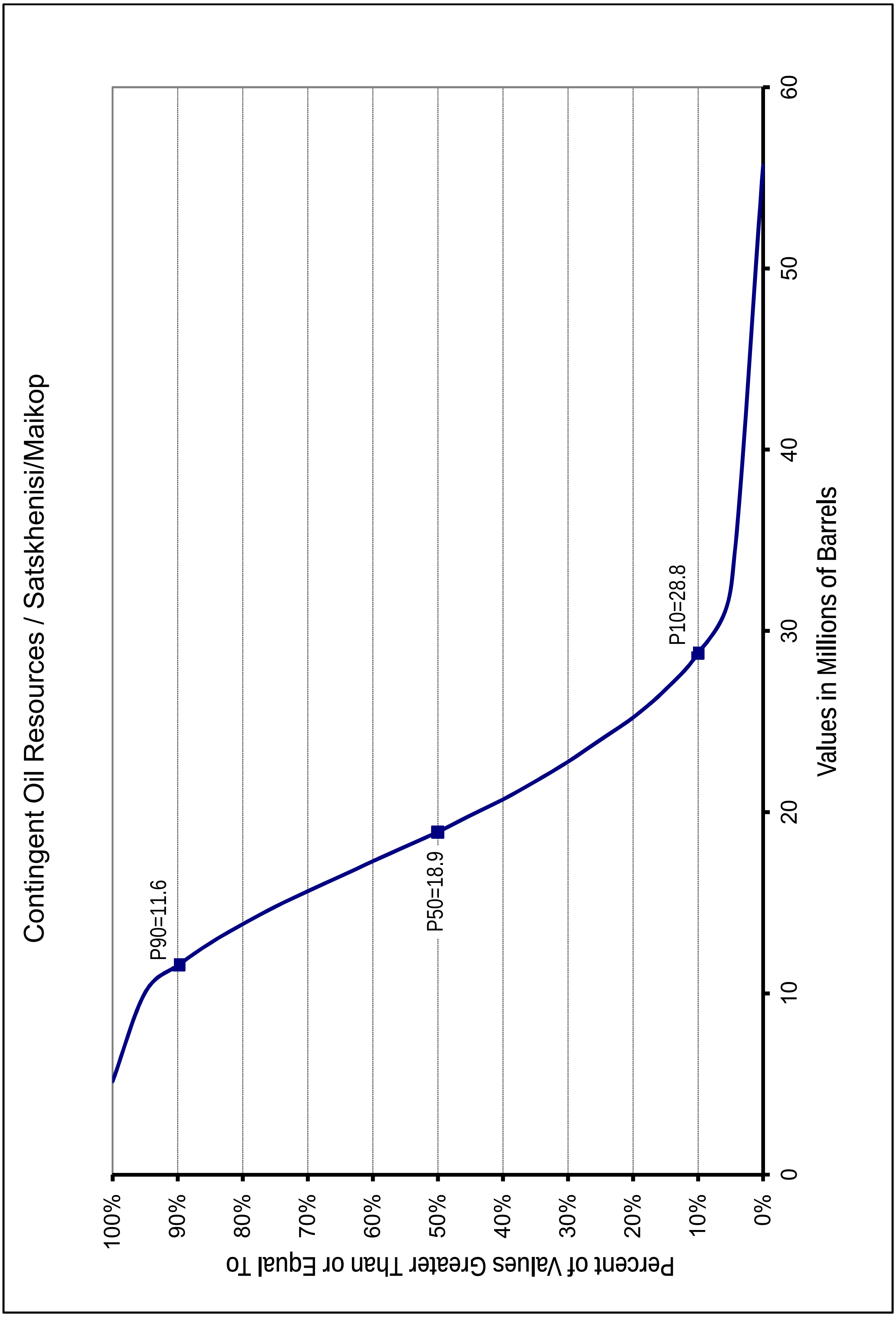

Contingent Gas Resources / W Rustavi/Upper Cretaceous
P90=91.9
P50=209.0
P10=414.0
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
200
400
600
800
1000
1200
Values in Billions of Cubic Feet


Oil in Place / Satskhenisi/Maikop
P90=78.1
P50=118.3
P10=165.6
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
0
50
100
150
200
250
300
Values in Millions of Barrels

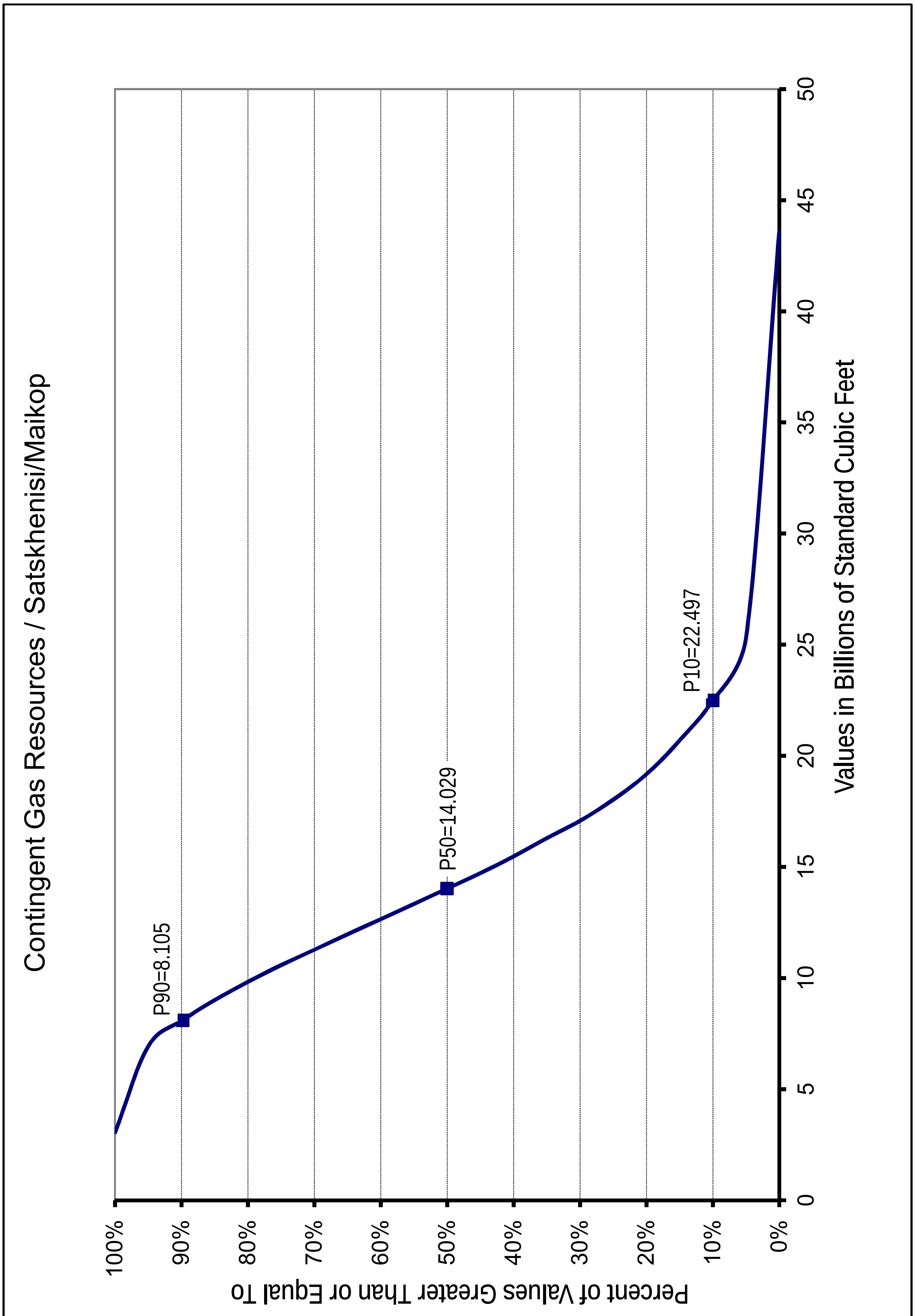


EUR / Satskhenisi/Maikop
P90=11.9
P50=19.2
P10=29.1
Values in Millions of Barrels
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
10
20
30
40
50
60

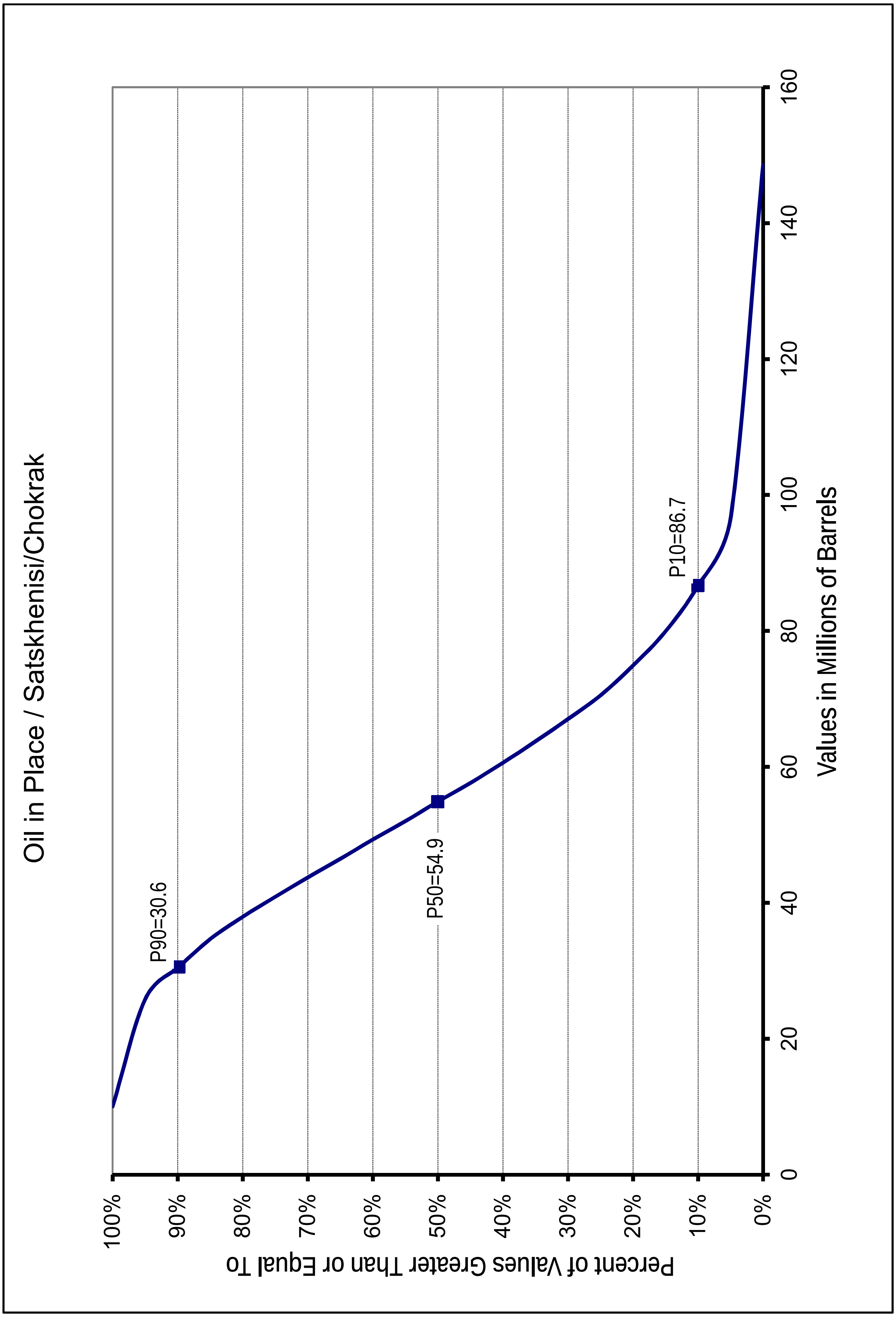
A-22



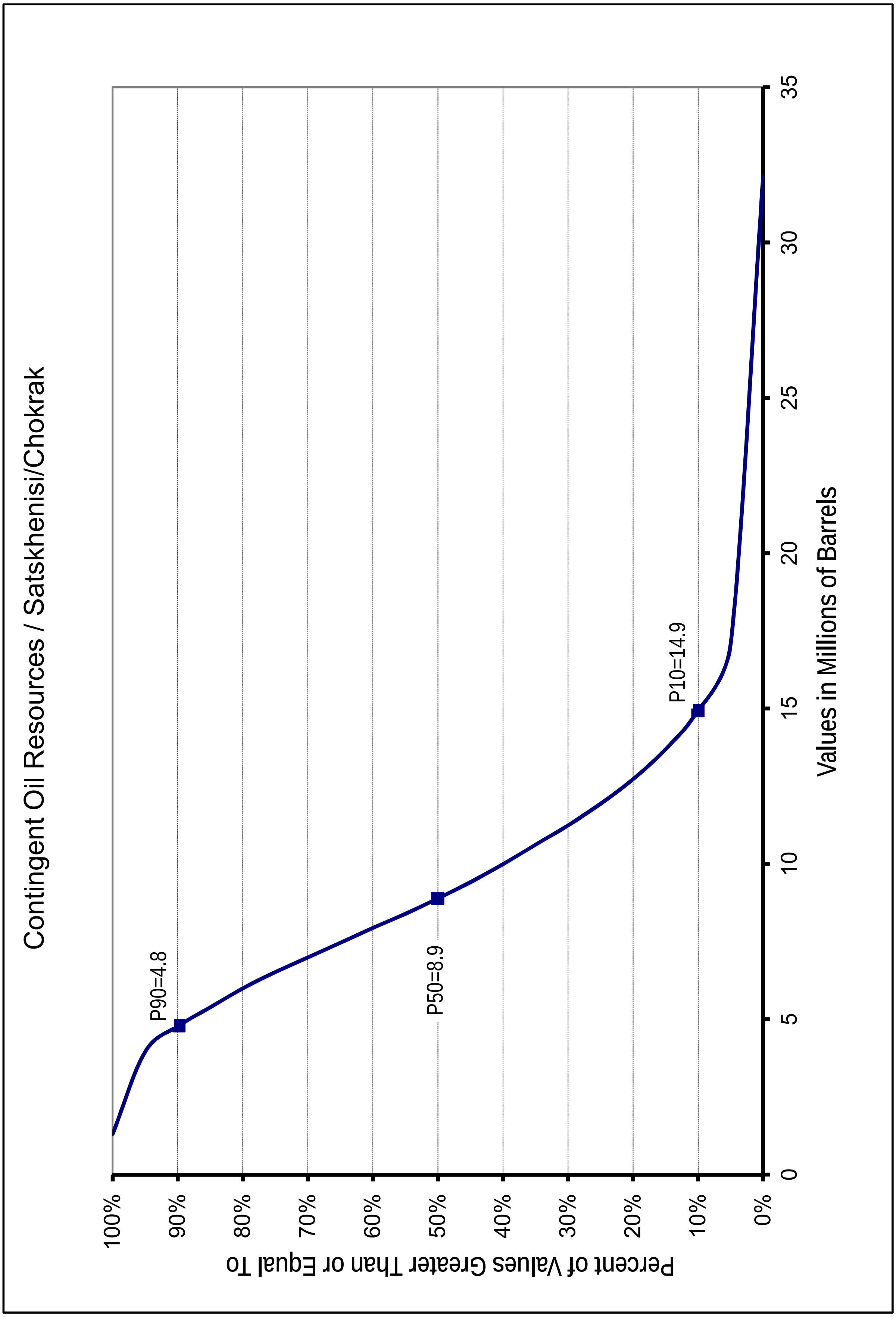
Contingent Oil Resources / Satskhenisi/Maikop
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
10
20
30
40
50
60
Values in Millions of Barrels
P90=11.6
P50=18.9
P10=28.8


Contingent Gas Resources / Satskhenisi/Maikop
P90=8.105
P50=14.029
P10=22.497
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
5
10
15
20
25
30
35
40
45
50
Values in Billions of Standard Cubic Feet

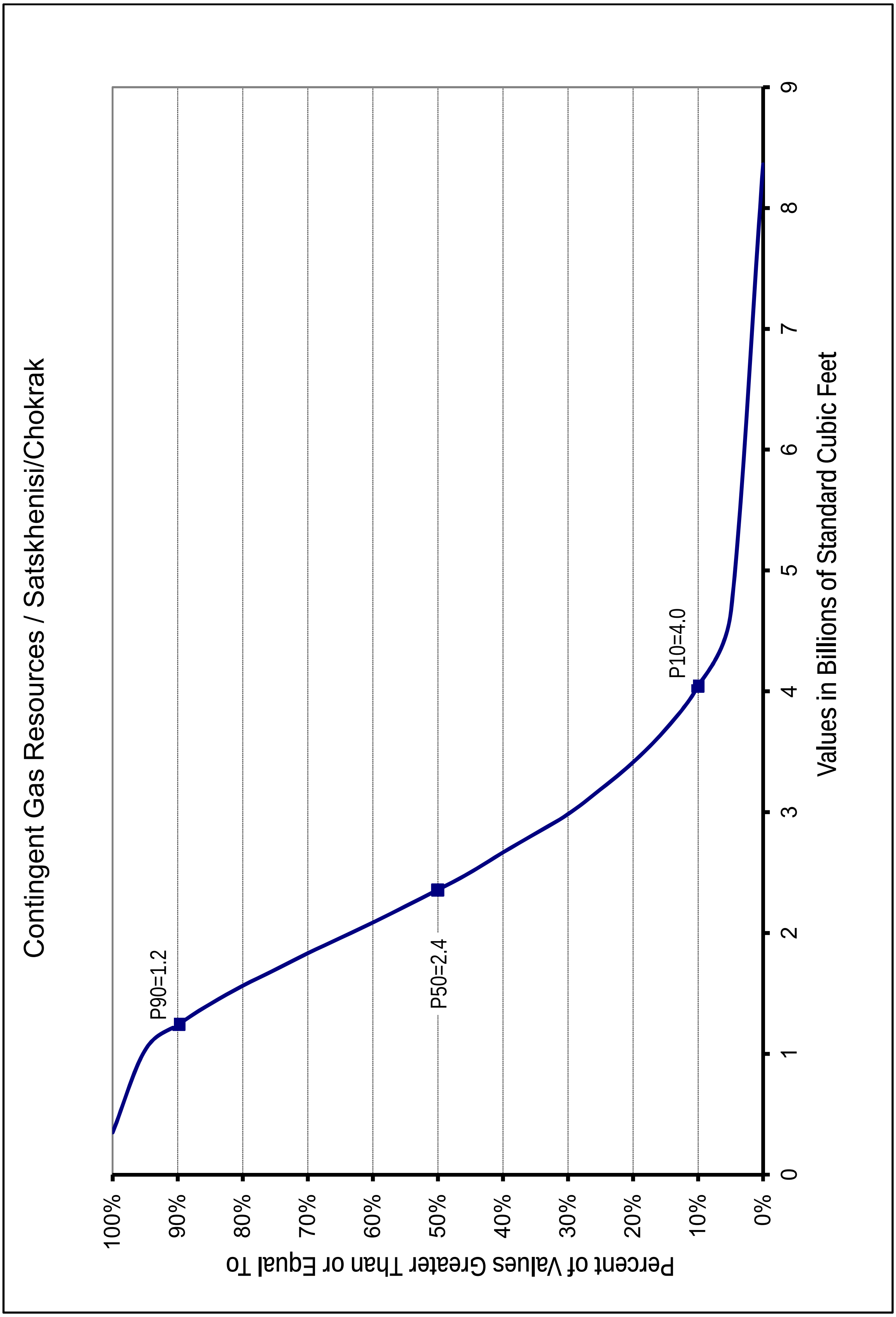
A-24


Oil in Place / Satskhenisi/Chokrak
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
20
40
60
80
100
120
140
160
Values in Millions of Barrels
P90=30.6
P50=54.9
P10=86.7

A-25



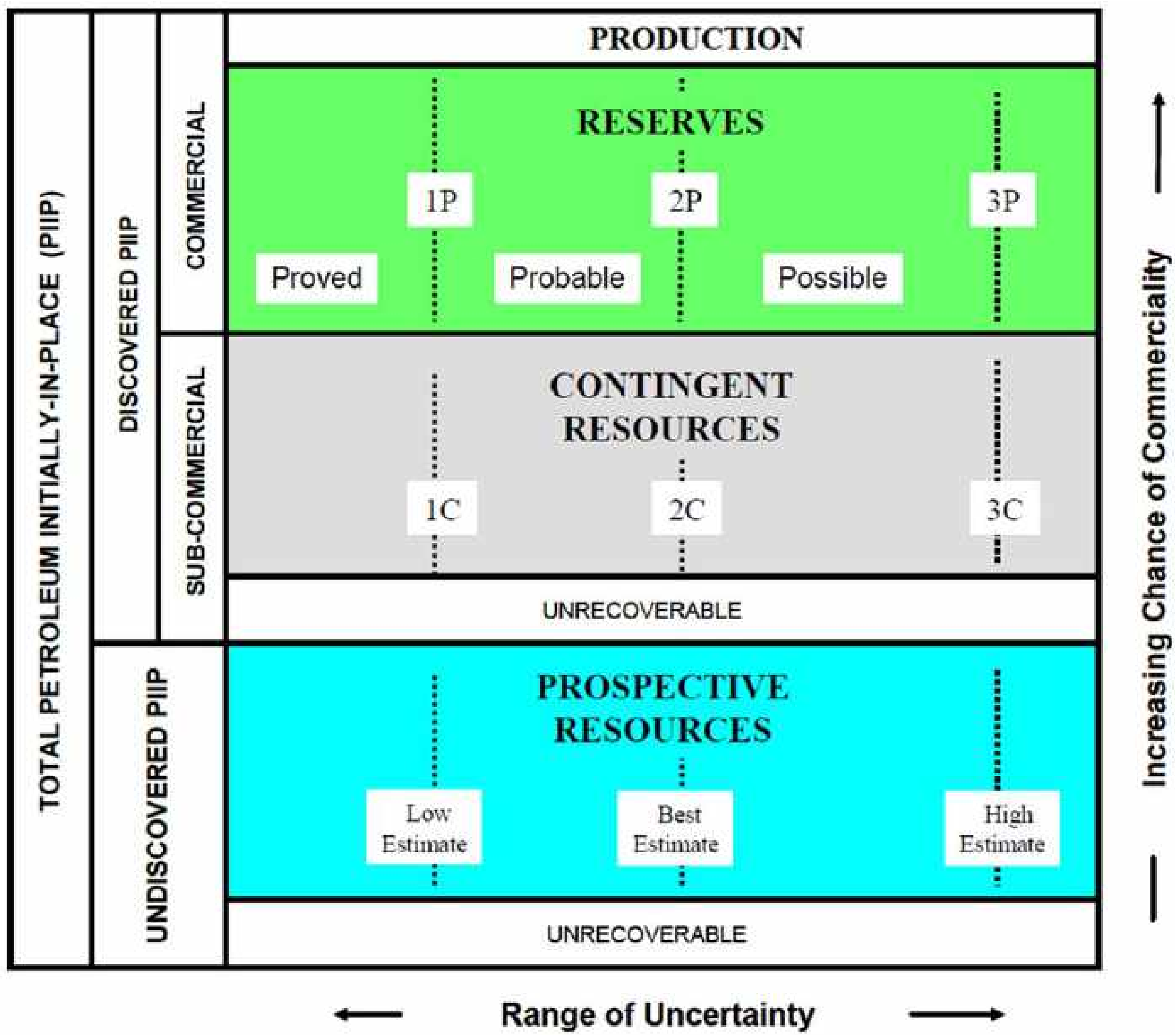
Contingent Oil Resources / Satskhenisi/Chokrak
P90=4.8
P50=8.9
P10=14.9
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
5
10
15
20
25
30
35
Values in Millions of Barrels


Contingent Gas Resources / Satskhenisi/Chokrak
P90=1.2
P50=2.4
P10=4.0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
0
1
2
3
4
5
6
7
8
9
Values in Billions of Standard Cubic Feet

Appendix B

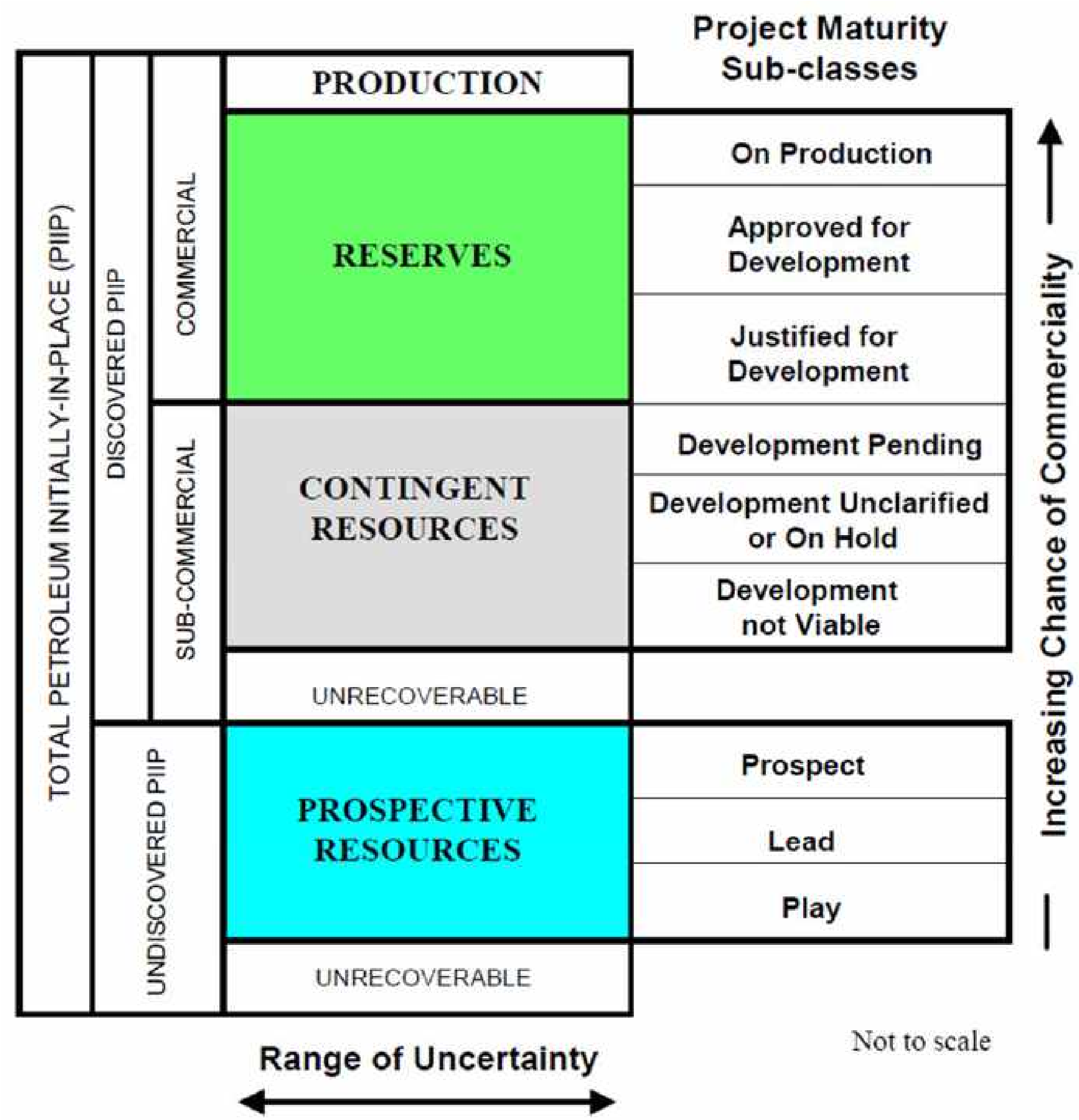
Excerpt from Petroleum Resources Management System

The following are select terms or phrases as defined by Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), and Society of Petroleum Evaluation Engineers (SPEE) in Petroleum Resources Management System, 2007, see figures below. Note that these figures and definitions are consistent with the figures and definitions provided in the COGEH[24]: the PRMS versions are reproduced here due to their completeness.



Resources Classification Framework

[24] Canadian Oil and Gas Evaluation Handbook as referenced earlier in this report.



Sub-Classes based on Project Maturity

An **Accumulation** is an individual body of naturally occurring petroleum in a reservoir.

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.

Conventional Resources exist in discrete petroleum accumulations related to localized geological structural features and/or stratigraphic conditions, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.

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

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

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

Estimated Ultimate Recovery (EUR) are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

A **Lead** is 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.

Low/Best/High Estimates are the range of uncertainty that reflects a reasonable range of estimated potentially recoverable volumes at varying degrees of uncertainty (using the cumulative scenario approach) for an individual accumulation or a project.

A **Play** is 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. A Pool is an individual and separate accumulation of petroleum in a reservoir.

Possible Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable that Probable 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.

Probabilistic Estimate is the method of estimation used when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.

A **Prospect** is a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Prospective Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

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 and under defined economic conditions, operating methods, and government regulations.

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 further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied.

Unconventional Resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basic-centered gas, shale gas, gas hydrate, natural bitumen (tar sands), and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders). (Also termed "Non-Conventional" Resources and "Continuous Deposits".)

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

Appendix C

Glossary of Terms and Abbreviations

The following are abbreviations and definitions for common petroleum terms.

10^3m^3	thousands of cubic meters
AVO	amplitude versus offset
Bbl, Bbls	barrel, barrels
BCF	billions of cubic feet
BCM	billions of cubic meters
B_g	gas formation volume factor
BHT	bottom hole temperature
BHP	bottom hole pressure
B_o	oil formation volume factor
BOE	barrels of oil equivalent
BOPD	barrels of oil per day
BPD	barrels per day
Btu	British thermal units
BV	bulk volume
CNG	compressed natural gas
CO_2	carbon dioxide
DHI	direct hydrocarbon indicators
DHC	dry hole cost
DST	drill-stem test
E & P	exploration and production
EOR	enhanced oil recovery
EUR	estimated ultimate recovery
ft	feet
ft^2	square feet
FVF	formation volume factor
G & A	general and administrative
G & G	geological and geophysical
g/cm^3	grams per cubic centimeter
Ga	billion (10^9) years
GIIP	gas initially in place
GOC	gas-oil contact
GOR	gas-oil ratio
GR	gamma ray (log)
GRV	gross rock volume
GWC	gas-water contact
ha	hectare
Hz	hertz
IDC	intangible drilling cost
IOR	improved oil recovery
IRR	internal rate of return
J & A	junked and abandoned
km	kilometers
km^2	square kilometers
LoF	life of field
M & A	mergers and acquisitions

m	meters
M	thousands
MM	million
m^3/day	cubic meters per day
Ma	million years (before present)
max	maximum
MBOPD	thousand barrels of oil per day
MCFD	thousand cubic feet per day
MCFGD	thousand cubic feet of gas per day
MD	measured depth
mD	millidarcies
MDSS	measured depth subsea
min	minimum
ML	most likely
MBbl	thousand barrels of oil
MMBbl	million barrels of oil
MMBOE	million barrels of oil equivalent
MMBOPD	million barrels of oil per day
MMCFGD	million cubic feet of gas per day
MMTOE	million tons of oil equivalent
mSS	meters subsea
NGL	natural gas liquids
NPV	net present value
NTG	net-to-gross ratio
OGIP	original gas in place
OOIP	original oil in place
OWC	oil-water contact
P10	high estimate
P50	best estimate
P90	low estimate
P & A	plugged and abandoned
ppm	parts per million
PRMS	Petroleum Resources Management System
psi	pounds per square inch
RB	reservoir barrels
RCF	reservoir cubic feet
RF	recovery factor
ROI	return on investment
ROP	rate of penetration
SCF	standard cubic feet
SS	subsea
STB	stock tank barrel
STOIIP	stock tank oil initially in place
S_g	gas saturation
S_o	oil saturation
S_w	water saturation

TCF	trillion cubic feet
TD	total depth
TDC	tangible drilling cost
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWT	two-way time
US$	US dollar

Appendix D

Detailed Cash Flow Sheets

NORIO

		Yr-Mo	Units	Total	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
		Oil Volume																				
Production	**Norio**	**Existing Production**	**Bbl**	**32,417**	485	480	474	469	463	458	453	448	443	438	433	428	423	418	413	409	404	399
		Workovers - SI or BP	**Bbl**	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	**Bbl**	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	**Bbl**	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	**Wells**		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Existing Production	**Wells**		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	**Wells**		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	**Wells**		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**$/Bbl**		**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**
Revenue	**NORIO**	**Norio Oil Production**	**BOPM**	**32,417**	485	480	474	469	463	458	453	448	443	438	433	428	423	418	413	409	404	399
		Daily Production	**BOPD**		17	17	16	16	16	16	16	15	15	15	15	15	15	14	14	14	14	14
		Monthly Oil MMbbls	**MMBbl**	**0.0324**	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
		Norio Revenue	**M$**	**2.0**		0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Total Production	**Bbl**	**32,417**	485	480	474	469	463	458	453	448	443	438	433	428	423	418	413	409	404	399
		Total Project Revenue M$	**M$**	**2.0**	0.00	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
CAPEX	**Norio**	**Workovers**	**MM$**	**0.0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	**MM$**	**0.0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	**MM$**	**0.0**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	**Norio**	**Fixed Opex+OH**	**MM$**	**1.8**	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
		Floating Opex	**MM$**	**0.0**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	**MM$**	**0.0**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	**MM$**	**1.8**	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		OPEX TOTAL	**MM$**	**1.8**	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Cost Recovery	**Norio**	**Recoverable Opex**	**MM$**	**0.99**	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	0.0142	0.0142	0.0142	0.0142	0.0145	0.0145	0.0145	0.0145	0.0146	0.0146
		Contractor Opex Cost Oil	**MM$**	**0.99**	0.0000	0.0250	0.0179	0.0143	0.0143	0.0143	0.0143	0.0143	0.0142	0.0142	0.0142	0.0142	0.0145	0.0145	0.0145	0.0145	0.0146	0.0146
		Unrecovered Opex	**MM$**		0.0143	0.0036	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	**MM$**		0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	**MM$**		20.00	20.00	20.00	20.00	19.99	19.99	19.98	19.98	19.97	19.97	19.96	19.96	19.96	19.95	19.95	19.94	19.94	19.94
		Contractor Capex Cost Oil	**MM$**	**0.16**	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	**MM$**		20.00	20.00	20.00	19.99	19.99	19.98	19.98	19.97	19.97	19.96	19.96	19.96	19.95	19.95	19.94	19.94	19.94	19.93
		Total Cost Oil	**MM$**		**0.00**	**0.03**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**
Profit Share	**Norio**	**Total Profit Oil**	**MM$**	**0.1561**	0.0000	0.0000	0.0034	0.0051	0.0049	0.0048	0.0047	0.0045	0.0044	0.0043	0.0042	0.0040	0.0038	0.0041	0.0040	0.0038	0.0037	0.0036
		Contractor Profit Oil	**MM$**	**0.0780**	0.0000	0.0000	0.0017	0.0025	0.0025	0.0024	0.0023	0.0023	0.0022	0.0021	0.0021	0.0020	0.0019	0.0021	0.0020	0.0019	0.0019	0.0018
		Govt. Profit Oil	**MM$**	**0.0780**	0.0000	0.0000	0.0017	0.0025	0.0025	0.0024	0.0023	0.0023	0.0022	0.0021	0.0021	0.0020	0.0019	0.0021	0.0020	0.0019	0.0019	0.0018
		Total Contrctr Cost and Profit Oil, MMBbl	**MMBbl**	**0.0213**	0.0000	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
		Evaluated Net Oil, MMBbl	**MMBbl**	**0.0213**	0.0000	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Cash Flow	**Norio**	**Cash Flow**	**MM$**	**0.23**	-0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		DCF @10%	**MM$**	**0.19**	-0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
		Cumulative CF			-0.01	0.00	0.01	0.01	0.02	0.03	0.03	0.04	0.05	0.05	0.06	0.07	0.07	0.08	0.08	0.09	0.10	0.10
Payment Date	**Norio**	**Total Costs Incurred for Production, MM$**	**MM$**	**21.85**	20.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Cumulative Total Costs, MM$	**MM$**	**21.85**	20.01	20.03	20.04	20.06	20.07	20.09	20.10	20.11	20.13	20.14	20.16	20.17	20.19	20.20	20.21	20.23	20.24	20.26
		Cntrctr's Total Profit from Sales of Oil, MM$	**MM$**	**1.23**	0.00	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Profit, MM$	**MM$**	**1.23**	0.00	0.03	0.05	0.07	0.09	0.11	0.13	0.16	0.18	0.20	0.22	0.24	0.26	0.28	0.30	0.32	0.34	0.36
		Payout? 1=yes, 0=no			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells Only Case, Mean Values

		Yr-Mo	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21
		Oil Volume																					
Production	Norio	Existing Production	395	390	386	382	377	373	369	365	361	357	353	349	345	341	338	334	330	327	323	320	316
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**70.70**	**70.70**	**70.70**
Revenue	NORIO	Norio Oil Production	395	390	386	382	377	373	369	365	361	357	353	349	345	341	338	334	330	327	323	320	316
		Daily Production	14	14	13	13	13	13	13	13	12	12	12	12	12	12	12	12	11	11	11	11	11
		Monthly Oil MMbbls	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
		Norio Revenue	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Total Production	395	390	386	382	377	373	369	365	361	357	353	349	345	341	338	334	330	327	323	320	316
		Total Project Revenue M$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		OPEX TOTAL	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Cost Recovery	Norio	Recoverable Opex	0.0146	0.0146	0.0146	0.0146	0.0147	0.0147	0.0147	0.0147	0.0147	0.0147	0.0148	0.0148	0.0148	0.0148	0.0148	0.0149	0.0149	0.0149	0.0149	0.0149	0.0149
		Contractor Opex Cost Oil	0.0146	0.0146	0.0146	0.0146	0.0147	0.0147	0.0147	0.0147	0.0147	0.0147	0.0148	0.0148	0.0148	0.0148	0.0148	0.0149	0.0149	0.0149	0.0149	0.0149	0.0149
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	19.93	19.93	19.93	19.92	19.92	19.92	19.91	19.91	19.91	19.90	19.90	19.90	19.90	19.89	19.89	19.89	19.89	19.89	19.88	19.88	19.88
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	19.93	19.93	19.92	19.92	19.92	19.91	19.91	19.91	19.90	19.90	19.90	19.90	19.89	19.89	19.89	19.89	19.89	19.88	19.88	19.88	19.88
		Total Cost Oil	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**
Profit Share	Norio	Total Profit Oil	0.0035	0.0033	0.0032	0.0031	0.0029	0.0028	0.0027	0.0031	0.0030	0.0029	0.0028	0.0026	0.0025	0.0024	0.0023	0.0022	0.0020	0.0019	0.0018	0.0025	0.0024
		Contractor Profit Oil	0.0017	0.0017	0.0016	0.0015	0.0015	0.0014	0.0013	0.0016	0.0015	0.0014	0.0014	0.0013	0.0013	0.0012	0.0011	0.0011	0.0010	0.0010	0.0009	0.0013	0.0012
		Govt. Profit Oil	0.0017	0.0017	0.0016	0.0015	0.0015	0.0014	0.0013	0.0016	0.0015	0.0014	0.0014	0.0013	0.0013	0.0012	0.0011	0.0011	0.0010	0.0010	0.0009	0.0013	0.0012
		Total Contrctr Cost and Profit Oil, MMBbl	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
		Evaluated Net Oil, MMBbl	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Cash Flow	Norio	Cash Flow	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.11	0.11	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.19
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Cumulative Total Costs, MM$	20.27	20.29	20.30	20.32	20.33	20.35	20.36	20.38	20.39	20.41	20.42	20.43	20.45	20.46	20.48	20.49	20.51	20.52	20.54	20.55	20.57
		Cntrctr's Total Profit from Sales of Oil, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Profit, MM$	0.38	0.40	0.42	0.44	0.46	0.48	0.49	0.51	0.53	0.55	0.57	0.59	0.61	0.63	0.64	0.66	0.68	0.70	0.72	0.74	0.75
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells Only Case, Mean Values

Section		Yr-Mo	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
		Oil Volume																					
Production	Norio	Existing Production	313	309	306	303	299	296	293	290	287	284	281	278	275	272	269	266	263	260	258	255	252
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**
Revenue	NORIO	Norio Oil Production	313	309	306	303	299	296	293	290	287	284	281	278	275	272	269	266	263	260	258	255	252
		Daily Production	11	11	11	10	10	10	10	10	10	10	10	10	9	9	9	9	9	9	9	9	9
		Monthly Oil MMbbls	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
		Norio Revenue	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Total Production	313	309	306	303	299	296	293	290	287	284	281	278	275	272	269	266	263	260	258	255	252
		Total Project Revenue M$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	0.0150	0.0150	0.0150	0.0150	0.0150	0.0151	0.0151	0.0151	0.0151	0.0151	0.0152	0.0152	0.0152	0.0152	0.0152	0.0153	0.0153	0.0153	0.0153	0.0153	0.0154
		Contractor Opex Cost Oil	0.0150	0.0150	0.0150	0.0150	0.0150	0.0151	0.0151	0.0151	0.0151	0.0151	0.0152	0.0152	0.0152	0.0152	0.0152	0.0153	0.0153	0.0153	0.0153	0.0153	0.0154
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	19.88	19.87	19.87	19.87	19.87	19.87	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.85	19.85	19.85	19.85	19.85	19.85	19.85	19.85
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	19.87	19.87	19.87	19.87	19.87	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.85	19.85	19.85	19.85	19.85	19.85	19.85	19.85	19.85
		Total Cost Oil	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**
Profit Share	Norio	Total Profit Oil	0.0023	0.0022	0.0020	0.0019	0.0018	0.0017	0.0016	0.0015	0.0014	0.0013	0.0017	0.0016	0.0015	0.0013	0.0012	0.0011	0.0010	0.0009	0.0008	0.0007	0.0006
		Contractor Profit Oil	0.0011	0.0011	0.0010	0.0010	0.0009	0.0009	0.0008	0.0007	0.0007	0.0006	0.0008	0.0008	0.0007	0.0007	0.0006	0.0006	0.0005	0.0005	0.0004	0.0004	0.0003
		Govt. Profit Oil	0.0011	0.0011	0.0010	0.0010	0.0009	0.0009	0.0008	0.0007	0.0007	0.0006	0.0008	0.0008	0.0007	0.0007	0.0006	0.0006	0.0005	0.0005	0.0004	0.0004	0.0003
		Total Contrctr Cost and Profit Oil, MMBbl	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
		Evaluated Net Oil, MMBbl	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Cash Flow	Norio	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cumulative CF		0.19	0.19	0.19	0.20	0.20	0.20	0.21	0.21	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.22	0.23	0.23	0.23	0.23	0.23
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	20.58	20.60	20.61	20.63	20.64	20.66	20.67	20.69	20.70	20.72	20.73	20.75	20.76	20.78	20.79	20.81	20.83	20.84	20.86	20.87	20.89
		Cntrctr's Total Profit from Sales of Oil, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Profit, MM$	0.77	0.79	0.81	0.83	0.84	0.86	0.88	0.90	0.91	0.93	0.95	0.97	0.98	1.00	1.02	1.03	1.05	1.07	1.08	1.10	1.12
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells Only Case, Mean Values

		Yr-Mo	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24
		Oil Volume																				
Production	Norio	Existing Production	250	247	244	242	239	237	234	232	230	227	225	222	220	218	216	213	211	209	207	205
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**
Revenue	NORIO	Norio Oil Production	250	247	244	242	239	237	234	232	230	227	225	222	220	218	216	213	211	209	207	205
		Daily Production	9	9	8	8	8	8	8	8	8	8	8	8	8	8	7	7	7	7	7	7
		Monthly Oil MMbbls	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
		Norio Revenue	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Total Production	250	247	244	242	239	237	234	232	230	227	225	222	220	218	216	213	211	209	207	205
		Total Project Revenue M$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.016
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	0.0154	0.0154	0.0154	0.0155	0.0155	0.0155	0.0155	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0154	0.0154	0.0154	0.0155	0.0155	0.0155	0.0155	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	19.85	19.85	19.85	19.84	19.84	19.84	19.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	19.85	19.85	19.84	19.84	19.84	19.84	19.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	Norio	Total Profit Oil	0.0005	0.0006	0.0005	0.0004	0.0003	0.0002	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0003	0.0003	0.0002	0.0002	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0003	0.0003	0.0002	0.0002	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	Norio	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cumulative CF		0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	20.90	20.92	20.93	20.95	20.96	20.98	20.99	21.01	21.03	21.04	21.06	21.07	21.09	21.10	21.12	21.14	21.15	21.17	21.18	21.20
		Cntrctr's Total Profit from Sales of Oil, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	1.13	1.15	1.17	1.18	1.20	1.21	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells Only Case, Mean

		Yr-Mo	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26
		Oil Volume																				
Production	Norio	Existing Production	203	201	199	197	195	193	191	189	187	185	183	181	180	178	176	174	173	171	169	168
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**76.23**	**76.23**	**76.23**	**76.23**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**78.37**	**78.37**	**78.37**	**78.37**
Revenue	NORIO	Norio Oil Production	203	201	199	197	195	193	191	189	187	185	183	181	180	178	176	174	173	171	169	168
		Daily Production	7	7	7	7	7	7	7	7	6	6	6	6	6	6	6	6	6	6	6	6
		Monthly Oil MMbbls	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
		Norio Revenue	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Total Production	203	201	199	197	195	193	191	189	187	185	183	181	180	178	176	174	173	171	169	168
		Total Project Revenue M$	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	Norio	Total Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	Norio	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cumulative CF		0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	21.21	21.23	21.25	21.26	21.28	21.29	21.31	21.33	21.34	21.36	21.37	21.39	21.41	21.42	21.44	21.45	21.47	21.49	21.50	21.52
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Values

Produc

		Yr-Mo	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
		Oil Volume																				
Production	Norio	Existing Production	166	164	163	161	159	158	156	155	153	152	150	149	148	131	129	128	126	125	124	123
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**
Revenue	NORIO	Norio Oil Production	166	164	163	161	159	158	156	155	153	152	150	149	148	131	129	128	126	125	124	123
		Daily Production	6	6	6	6	6	5	5	5	5	5	5	5	5	5	4	4	4	4	4	4
		Monthly Oil MMbbls	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		Norio Revenue	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Total Production	166	164	163	161	159	158	156	155	153	152	150	149	148	131	129	128	126	125	124	123
		Total Project Revenue M$	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.017	0.017	0.017
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	Norio	Total Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	Norio	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	21.54	21.55	21.57	21.58	21.60	21.62	21.63	21.65	21.67	21.68	21.70	21.72	21.73	21.75	21.77	21.78	21.80	21.82	21.83	21.85
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

ing Wells Only Case, Mean Values

Producing Wells Only Case, Mean Values

		Yr-Mo	Units	Total	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
		Oil Volume																				
Production	Norio	Existing Production	Bbl	32,417	485	480	474	469	463	458	453	448	443	438	433	428	423	418	413	409	404	399
		Workovers - SI or BP	Bbl	14,436	0	0	0	0	728	676	627	581	539	500	828	768	712	661	613	568	527	489
		Workovers - RDS	Bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	Bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	Wells		3	3	3	3	5	5	5	5	5	5	6	6	6	6	6	6	6	6
		Existing Production	Wells		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	Wells		0	0	0	0	2	2	2	2	2	2	3	3	3	3	3	3	3	3
		Lateral Jetting			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	Wells		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	$/Bbl		60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	62.81	62.81	62.81	62.81	62.81	62.81
Revenue	NORIO	Norio Oil Production	BOPM	46,853	485	480	474	469	1,192	1,134	1,080	1,029	982	938	1,261	1,196	1,135	1,079	1,026	977	931	888
		Daily Production	BOPD		17	17	16	16	41	39	37	36	34	32	44	41	39	37	35	34	32	31
		Monthly Oil MMbbls	MMBbl	0.0469	0.0005	0.0005	0.0005	0.0005	0.0012	0.0011	0.0011	0.0010	0.0010	0.0009	0.0013	0.0012	0.0011	0.0011	0.0010	0.0010	0.0009	0.0009
		Norio Revenue	M$	2.7		0.03	0.02	0.02	0.02	0.06	0.06	0.06	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.05	0.05
		Total Production	Bbl	46,853	485	480	474	469	1,192	1,134	1,080	1,029	982	938	1,261	1,196	1,135	1,079	1,026	977	931	888
		Total Project Revenue M$	M$	2.7	0.00	0.03	0.02	0.02	0.02	0.06	0.06	0.06	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.05	0.05
CAPEX	Norio	Workovers	MM$	0.3	0	0	0	0	0.15	0	0	0	0	0	0.1	0	0	0	0	0	0	0
		New Wells	MM$	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	MM$	0.3	0.00	0.00	0.00	0.00	0.15	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	MM$	1.8	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
		Floating Opex	MM$	0.1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	MM$	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	MM$	1.9	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	MM$	1.9	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	MM$	1.02	0.0143	0.0143	0.0143	0.0143	0.0153	0.0152	0.0152	0.0151	0.0150	0.0150	0.0154	0.0153	0.0155	0.0155	0.0154	0.0154	0.0153	0.0153
		Contractor Opex Cost Oil	MM$	1.02	0.0000	0.0250	0.0179	0.0143	0.0153	0.0152	0.0152	0.0151	0.0150	0.0150	0.0154	0.0153	0.0155	0.0155	0.0154	0.0154	0.0153	0.0153
		Unrecovered Opex	MM$		0.0143	0.0036	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	MM$		0.00	0.00	0.00	0.01	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Recoverable Capex	MM$		20.00	20.00	20.00	20.00	20.14	20.14	20.11	20.09	20.07	20.05	20.14	20.12	20.09	20.07	20.05	20.03	20.01	19.99
		Contractor Capex Cost Oil	MM$	0.54	0.00	0.00	0.00	0.01	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Unrecovered Capex	MM$		20.00	20.00	20.00	19.99	20.14	20.11	20.09	20.07	20.05	20.04	20.12	20.09	20.07	20.05	20.03	20.01	19.99	19.97
		Total Cost Oil	MM$		0.00	0.03	0.02	0.02	0.02	0.04	0.04	0.04	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.03	0.03
Profit Share	Norio	Total Profit Oil	MM$	0.5357	0.0000	0.0000	0.0034	0.0051	0.0044	0.0231	0.0216	0.0203	0.0190	0.0178	0.0165	0.0248	0.0231	0.0228	0.0213	0.0199	0.0186	0.0174
		Contractor Profit Oil	MM$	0.2679	0.0000	0.0000	0.0017	0.0025	0.0022	0.0116	0.0108	0.0101	0.0095	0.0089	0.0082	0.0124	0.0115	0.0114	0.0107	0.0100	0.0093	0.0087
		Govt. Profit Oil	MM$	0.2679	0.0000	0.0000	0.0017	0.0025	0.0022	0.0116	0.0108	0.0101	0.0095	0.0089	0.0082	0.0124	0.0115	0.0114	0.0107	0.0100	0.0093	0.0087
		Total Contrctr Cost and Profit Oil, MMBbl	MMBbl	0.0321	0.0000	0.0005	0.0004	0.0004	0.0004	0.0010	0.0009	0.0009	0.0008	0.0008	0.0008	0.0010	0.0009	0.0009	0.0009	0.0008	0.0008	0.0008
		Evaluated Net Oil, MMBbl	MMBbl	0.0321	0.0000	0.0005	0.0004	0.0004	0.0004	0.0010	0.0009	0.0009	0.0008	0.0008	0.0008	0.0010	0.0009	0.0009	0.0009	0.0008	0.0008	0.0008
Cash Flow	Norio	Cash Flow	MM$	0.55	-0.01	0.01	0.01	0.01	-0.14	0.03	0.03	0.03	0.03	0.03	-0.08	0.04	0.03	0.03	0.03	0.03	0.03	0.03
		DCF @10%	MM$	0.45	-0.01	0.01	0.01	0.01	-0.14	0.03	0.03	0.03	0.03	0.02	-0.07	0.03	0.03	0.03	0.03	0.03	0.02	0.02
		Cumulative CF			-0.01	0.00	0.01	0.01	-0.13	-0.10	-0.06	-0.03	0.00	0.02	-0.05	-0.02	0.02	0.05	0.08	0.11	0.14	0.17
Payment Date	Norio	Total Costs Incurred for Production, MM$	MM$	22.12	20.01	0.01	0.01	0.01	0.17	0.02	0.02	0.02	0.02	0.01	0.12	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	MM$	22.12	20.01	20.03	20.04	20.06	20.22	20.24	20.25	20.27	20.28	20.30	20.41	20.43	20.44	20.46	20.48	20.49	20.51	20.52
		Cntrctr's Total Profit from Sales of Oil, MM$	MM$	1.82	0.00	0.03	0.02	0.02	0.02	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.04	0.04
		Cumulative Total Profit, MM$	MM$	1.82	0.00	0.03	0.05	0.07	0.09	0.14	0.19	0.23	0.28	0.32	0.36	0.41	0.46	0.51	0.56	0.61	0.65	0.69
		Payout? 1=yes, 0=no			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells + Workovers, Mean Values

Section	Group	Yr-Mo	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21
		Oil Volume																					
Production	Norio	Existing Production	395	390	386	382	377	373	369	365	361	357	353	349	345	341	338	334	330	327	323	320	316
		Workovers - SI or BP	454	421	390	362	336	311	289	268	248	230	214	198	184	171	158	147	136	126	117	109	101
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**70.70**	**70.70**	**70.70**
Revenue	NORIO	Norio Oil Production	848	811	776	744	713	685	658	633	609	587	567	547	529	512	496	481	466	453	440	428	417
		Daily Production	29	28	27	26	25	24	23	22	21	20	20	19	18	18	17	17	16	16	15	15	14
		Monthly Oil MMbbls	0.0008	0.0008	0.0008	0.0007	0.0007	0.0007	0.0007	0.0006	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004
		Norio Revenue	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		Total Production	848	811	776	744	713	685	658	633	609	587	567	547	529	512	496	481	466	453	440	428	417
		Total Project Revenue M$	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	0.0152	0.0152	0.0152	0.0152	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151
		Contractor Opex Cost Oil	0.0152	0.0152	0.0152	0.0152	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Recoverable Capex	19.97	19.95	19.94	19.92	19.91	19.90	19.89	19.88	19.87	19.86	19.85	19.84	19.83	19.82	19.81	19.81	19.80	19.79	19.79	19.78	19.78
		Contractor Capex Cost Oil	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Unrecovered Capex	19.95	19.94	19.92	19.91	19.90	19.89	19.88	19.87	19.86	19.85	19.84	19.83	19.82	19.81	19.81	19.80	19.79	19.79	19.78	19.78	19.77
		Total Cost Oil	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**
Profit Share	Norio	Total Profit Oil	0.0163	0.0152	0.0142	0.0133	0.0124	0.0116	0.0109	0.0111	0.0104	0.0098	0.0091	0.0086	0.0080	0.0075	0.0070	0.0066	0.0061	0.0057	0.0053	0.0060	0.0057
		Contractor Profit Oil	0.0081	0.0076	0.0071	0.0067	0.0062	0.0058	0.0054	0.0056	0.0052	0.0049	0.0046	0.0043	0.0040	0.0037	0.0035	0.0033	0.0031	0.0029	0.0027	0.0030	0.0028
		Govt. Profit Oil	0.0081	0.0076	0.0071	0.0067	0.0062	0.0058	0.0054	0.0056	0.0052	0.0049	0.0046	0.0043	0.0040	0.0037	0.0035	0.0033	0.0031	0.0029	0.0027	0.0030	0.0028
		Total Contrctr Cost and Profit Oil, MMBbl	0.0007	0.0007	0.0007	0.0007	0.0006	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
		Evaluated Net Oil, MMBbl	0.0007	0.0007	0.0007	0.0007	0.0006	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Cash Flow	Norio	Cash Flow	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		DCF @10%	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Cumulative CF	0.19	0.22	0.24	0.26	0.28	0.29	0.31	0.33	0.34	0.36	0.37	0.38	0.40	0.41	0.42	0.43	0.44	0.44	0.45	0.46	0.47
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	20.54	20.55	20.57	20.58	20.60	20.61	20.63	20.64	20.66	20.67	20.69	20.70	20.72	20.73	20.75	20.76	20.78	20.79	20.81	20.82	20.84
		Cntrctr's Total Profit from Sales of Oil, MM$	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Profit, MM$	0.73	0.77	0.80	0.84	0.87	0.91	0.94	0.97	1.00	1.03	1.06	1.09	1.11	1.14	1.16	1.19	1.21	1.24	1.26	1.28	1.31
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells + Workovers, Mean Values

Section		Yr-Mo	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
		Oil Volume																					
Production	Norio	Existing Production	313	309	306	303	299	296	293	290	287	284	281	278	275	272	269	266	263	260	258	255	252
		Workovers - SI or BP	93	87	80	75	69	64	59	24	23	21	19	18	17	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	6	6	6	6	6	6	6	4	4	4	4	4	4	3	3	3	3	3	3	3	3
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	3	3	3	3	3	3	3	1	1	1	1	1	1	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**
Revenue	NORIO	Norio Oil Production	406	396	386	377	369	360	352	314	309	305	300	296	291	272	269	266	263	260	258	255	252
		Daily Production	14	14	13	13	13	12	12	11	11	11	10	10	10	9	9	9	9	9	9	9	9
		Monthly Oil MMbbls	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
		Norio Revenue	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Total Production	406	396	386	377	369	360	352	314	309	305	300	296	291	272	269	266	263	260	258	255	252
		Total Project Revenue M$	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	0.0151	0.0151	0.0151	0.0151	0.0151	0.0152	0.0152	0.0151	0.0152	0.0152	0.0152	0.0152	0.0152	0.0152	0.0152	0.0153	0.0153	0.0153	0.0153	0.0153	0.0154
		Contractor Opex Cost Oil	0.0151	0.0151	0.0151	0.0151	0.0151	0.0152	0.0152	0.0151	0.0152	0.0152	0.0152	0.0152	0.0152	0.0152	0.0152	0.0153	0.0153	0.0153	0.0153	0.0153	0.0154
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	19.77	19.76	19.76	19.75	19.75	19.75	19.74	19.74	19.74	19.73	19.73	19.73	19.73	19.73	19.72	19.72	19.72	19.72	19.72	19.72	19.72
		Contractor Capex Cost Oil	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	19.76	19.76	19.75	19.75	19.75	19.74	19.74	19.74	19.73	19.73	19.73	19.73	19.73	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72
		Total Cost Oil	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**
Profit Share	Norio	Total Profit Oil	0.0053	0.0050	0.0047	0.0044	0.0041	0.0038	0.0035	0.0033	0.0021	0.0020	0.0023	0.0022	0.0020	0.0019	0.0012	0.0011	0.0010	0.0009	0.0008	0.0007	0.0006
		Contractor Profit Oil	0.0027	0.0025	0.0023	0.0022	0.0020	0.0019	0.0018	0.0017	0.0011	0.0010	0.0012	0.0011	0.0010	0.0009	0.0006	0.0006	0.0005	0.0005	0.0004	0.0004	0.0003
		Govt. Profit Oil	0.0027	0.0025	0.0023	0.0022	0.0020	0.0019	0.0018	0.0017	0.0011	0.0010	0.0012	0.0011	0.0010	0.0009	0.0006	0.0006	0.0005	0.0005	0.0004	0.0004	0.0003
		Total Contrctr Cost and Profit Oil, MMBbl	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
		Evaluated Net Oil, MMBbl	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Cash Flow	Norio	Cash Flow	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.48	0.49	0.49	0.50	0.51	0.51	0.52	0.52	0.52	0.53	0.53	0.53	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.55	0.55
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	20.85	20.87	20.88	20.90	20.91	20.93	20.94	20.96	20.97	20.99	21.00	21.02	21.04	21.05	21.07	21.08	21.10	21.11	21.13	21.14	21.16
		Cntrctr's Total Profit from Sales of Oil, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Profit, MM$	1.33	1.35	1.38	1.40	1.42	1.44	1.46	1.48	1.50	1.52	1.54	1.55	1.57	1.59	1.61	1.62	1.64	1.66	1.67	1.69	1.71
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells + Workovers, Mean Values

		Yr-Mo	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24
		Oil Volume																				
Production	**Norio**	**Existing Production**	250	247	244	242	239	237	234	232	230	227	225	222	220	218	216	213	211	209	207	205
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**
Revenue	**NORIO**	**Norio Oil Production**	250	247	244	242	239	237	234	232	230	227	225	222	220	218	216	213	211	209	207	205
		Daily Production	9	9	8	8	8	8	8	8	8	8	8	8	8	8	7	7	7	7	7	7
		Monthly Oil MMbbls	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
		Norio Revenue	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Total Production	250	247	244	242	239	237	234	232	230	227	225	222	220	218	216	213	211	209	207	205
		Total Project Revenue M$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CAPEX	**Norio**	**Workovers**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	**Norio**	**Fixed Opex+OH**	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.016
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	**Norio**	**Recoverable Opex**	0.0154	0.0154	0.0154	0.0155	0.0155	0.0155	0.0155	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0154	0.0154	0.0154	0.0155	0.0155	0.0155	0.0155	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	19.72	19.72	19.72	19.72	19.71	19.71	19.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	19.72	19.72	19.72	19.71	19.71	19.71	19.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	**Norio**	**Total Profit Oil**	0.0005	0.0006	0.0005	0.0004	0.0003	0.0002	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0003	0.0003	0.0002	0.0002	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0003	0.0003	0.0002	0.0002	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	**Norio**	**Cash Flow**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cumulative CF		0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
Payment Date	**Norio**	**Total Costs Incurred for Production, MM$**	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	21.17	21.19	21.20	21.22	21.23	21.25	21.27	21.28	21.30	21.31	21.33	21.34	21.36	21.37	21.39	21.41	21.42	21.44	21.45	21.47
		Cntrctr's Total Profit from Sales of Oil, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	1.72	1.74	1.76	1.77	1.79	1.80	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells + Workovers, Mea

		Yr-Mo	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26
		Oil Volume																				
Production	Norio	Existing Production	203	201	199	197	195	193	191	189	187	185	183	181	180	178	176	174	173	171	169	168
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**76.23**	**76.23**	**76.23**	**76.23**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**78.37**	**78.37**	**78.37**	**78.37**
Revenue	NORIO	Norio Oil Production	203	201	199	197	195	193	191	189	187	185	183	181	180	178	176	174	173	171	169	168
		Daily Production	7	7	7	7	7	7	7	7	6	6	6	6	6	6	6	6	6	6	6	6
		Monthly Oil MMbbls	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
		Norio Revenue	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Total Production	203	201	199	197	195	193	191	189	187	185	183	181	180	178	176	174	173	171	169	168
		Total Project Revenue M$	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	Norio	Total Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	Norio	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	21.49	21.50	21.52	21.53	21.55	21.56	21.58	21.60	21.61	21.63	21.64	21.66	21.68	21.69	21.71	21.73	21.74	21.76	21.77	21.79
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

n Values

Producii

		Yr-Mo	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
		Oil Volume																				
Production	Norio	**Existing Production**	166	164	163	161	159	158	156	155	153	152	150	149	148	131	129	128	126	125	124	123
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**
Revenue	NORIO	**Norio Oil Production**	166	164	163	161	159	158	156	155	153	152	150	149	148	131	129	128	126	125	124	123
		Daily Production	6	6	6	6	6	5	5	5	5	5	5	5	5	5	4	4	4	4	4	4
		Monthly Oil MMbbls	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		Norio Revenue	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Total Production	166	164	163	161	159	158	156	155	153	152	150	149	148	131	129	128	126	125	124	123
		Total Project Revenue M$	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CAPEX	Norio	**Workovers**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	**Fixed Opex+OH**	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.017	0.017	0.017
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	**Recoverable Opex**	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	Norio	**Total Profit Oil**	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	Norio	**Cash Flow**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
Payment Date	Norio	**Total Costs Incurred for Production, MM$**	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	21.81	21.82	21.84	21.86	21.87	21.89	21.90	21.92	21.94	21.95	21.97	21.99	22.00	22.02	22.04	22.05	22.07	22.09	22.10	22.12
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

ıg Wells + Workovers, Mean Values

Producing Wells + Workovers, Mean Values

Section		Yr-Mo	Units	Total	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
		Oil Volume																				
Production	Norio	Existing Production	Bbl	32,417	485	480	474	469	463	458	453	448	443	438	433	428	423	418	413	409	404	399
		Workovers - SI or BP	Bbl	14,436	0	0	0	0	728	676	627	581	539	500	828	768	712	661	613	568	527	489
		Workovers - RDS	Bbl	96,440	0	0	0	0	0	0	0	0	0	1,473	3,065	2,882	2,718	2,570	2,437	2,316	2,206	2,105
		Undeveloped	Bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	Wells		3	3	3	3	5	5	5	5	5	7	11	11	11	11	11	11	11	11
		Existing Production	Wells		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	Wells		0	0	0	0	2	2	2	2	2	2	3	3	3	3	3	3	3	3
		Lateral Jetting			0	0	0	0	0	0	0	0	0	2	5	5	5	5	5	5	5	5
		Undeveloped	Wells		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	$/Bbl		60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	62.81	62.81	62.81	62.81	62.81	62.81
Revenue	NORIO	Norio Oil Production	BOPM	143,292	485	480	474	469	1,192	1,134	1,080	1,029	982	2,410	4,326	4,077	3,853	3,649	3,463	3,293	3,137	2,993
		Daily Production	BOPD		17	17	16	16	41	39	37	36	34	83	150	141	133	126	120	114	108	104
		Monthly Oil MMbbls	MMBbl	0.1433	0.0005	0.0005	0.0005	0.0005	0.0012	0.0011	0.0011	0.0010	0.0010	0.0024	0.0043	0.0041	0.0039	0.0036	0.0035	0.0033	0.0031	0.0030
		Norio Revenue	M$	8.5		0.03	0.02	0.02	0.02	0.06	0.06	0.06	0.05	0.05	0.12	0.22	0.21	0.21	0.20	0.19	0.18	0.17
		Total Production	Bbl	143,292	485	480	474	469	1,192	1,134	1,080	1,029	982	2,410	4,326	4,077	3,853	3,649	3,463	3,293	3,137	2,993
		Total Project Revenue M$	M$	8.5	0.00	0.03	0.02	0.02	0.02	0.06	0.06	0.06	0.05	0.05	0.12	0.22	0.21	0.21	0.20	0.19	0.18	0.17
CAPEX	Norio	Workovers	MM$	1.3	0	0	0	0	0.15	0	0	0	0	0.382	0.794	0	0	0	0	0	0	0
		New Wells	MM$	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	MM$	1.3	0.00	0.00	0.00	0.00	0.15	0.00	0.00	0.00	0.00	0.38	0.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	MM$	2.1	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.016	0.016	0.016	0.016	0.016	0.016
		Floating Opex	MM$	0.2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00
		Workovers	MM$	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	MM$	2.3	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	MM$	2.3	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	MM$	2.27	0.0143	0.0143	0.0143	0.0143	0.0153	0.0152	0.0152	0.0151	0.0150	0.0171	0.0198	0.0195	0.0216	0.0214	0.0211	0.0209	0.0207	0.0205
		Contractor Opex Cost Oil	MM$	2.27	0.0000	0.0250	0.0179	0.0143	0.0153	0.0152	0.0152	0.0151	0.0150	0.0171	0.0198	0.0195	0.0216	0.0214	0.0211	0.0209	0.0207	0.0205
		Unrecovered Opex	MM$		0.0143	0.0036	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	MM$		0.00	0.00	0.00	0.01	0.00	0.02	0.02	0.02	0.02	0.02	0.05	0.10	0.09	0.09	0.09	0.08	0.08	0.07
		Recoverable Capex	MM$		20.00	20.00	20.00	20.00	20.14	20.14	20.11	20.09	20.07	20.43	21.21	21.16	21.06	20.96	20.87	20.78	20.70	20.62
		Contractor Capex Cost Oil	MM$	3.12	0.00	0.00	0.00	0.01	0.00	0.02	0.02	0.02	0.02	0.02	0.05	0.10	0.09	0.09	0.09	0.08	0.08	0.07
		Unrecovered Capex	MM$		20.00	20.00	20.00	19.99	20.14	20.11	20.09	20.07	20.05	20.42	21.16	21.06	20.96	20.87	20.78	20.70	20.62	20.55
		Total Cost Oil	MM$		0.00	0.03	0.02	0.02	0.02	0.04	0.04	0.04	0.03	0.03	0.07	0.12	0.12	0.11	0.11	0.10	0.10	0.09
Profit Share	Norio	Total Profit Oil	MM$	3.1219	0.0000	0.0000	0.0034	0.0051	0.0044	0.0231	0.0216	0.0203	0.0190	0.0168	0.0522	0.1018	0.0943	0.0930	0.0876	0.0827	0.0782	0.0741
		Contractor Profit Oil	MM$	1.5610	0.0000	0.0000	0.0017	0.0025	0.0022	0.0116	0.0108	0.0101	0.0095	0.0084	0.0261	0.0509	0.0471	0.0465	0.0438	0.0414	0.0391	0.0371
		Govt. Profit Oil	MM$	1.5610	0.0000	0.0000	0.0017	0.0025	0.0022	0.0116	0.0108	0.0101	0.0095	0.0084	0.0261	0.0509	0.0471	0.0465	0.0438	0.0414	0.0391	0.0371
		Total Contrctr Cost and Profit Oil, MMBbl	MMBbl	0.1158	0.0000	0.0005	0.0004	0.0004	0.0004	0.0010	0.0009	0.0009	0.0008	0.0008	0.0019	0.0033	0.0030	0.0030	0.0028	0.0027	0.0026	0.0024
		Evaluated Net Oil, MMBbl	MMBbl	0.1158	0.0000	0.0005	0.0004	0.0004	0.0004	0.0010	0.0009	0.0009	0.0008	0.0008	0.0019	0.0033	0.0030	0.0030	0.0028	0.0027	0.0026	0.0024
Cash Flow	Norio	Cash Flow	MM$	3.36	-0.01	0.01	0.01	0.01	-0.14	0.03	0.03	0.03	0.03	-0.36	-0.72	0.15	0.14	0.14	0.13	0.12	0.12	0.11
		DCF @10%	MM$	2.22	-0.01	0.01	0.01	0.01	-0.14	0.03	0.03	0.03	0.03	-0.33	-0.66	0.14	0.13	0.12	0.12	0.11	0.10	0.10
		Cumulative CF			-0.01	0.00	0.01	0.01	-0.13	-0.10	-0.06	-0.03	0.00	-0.36	-1.08	-0.92	-0.78	-0.64	-0.51	-0.39	-0.27	-0.16
Payment Date	Norio	Total Costs Incurred for Production, MM$	MM$	23.60	20.01	0.01	0.01	0.01	0.17	0.02	0.02	0.02	0.02	0.40	0.81	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	MM$	23.60	20.01	20.03	20.04	20.06	20.22	20.24	20.25	20.27	20.28	20.68	21.50	21.52	21.54	21.56	21.58	21.60	21.62	21.64
		Cntrctr's Total Profit from Sales of Oil, MM$	MM$	6.96	0.00	0.03	0.02	0.02	0.02	0.05	0.05	0.05	0.04	0.04	0.10	0.17	0.16	0.16	0.15	0.14	0.14	0.13
		Cumulative Total Profit, MM$	MM$	6.96	0.00	0.03	0.05	0.07	0.09	0.14	0.19	0.23	0.28	0.32	0.42	0.59	0.75	0.91	1.07	1.21	1.35	1.48
		Payout? 1=yes, 0=no			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells + Workovers + Lateral Jetting, Mean Values

		Yr-Mo	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21
		Oil Volume																					
Production	Norio	Existing Production	395	390	386	382	377	373	369	365	361	357	353	349	345	341	338	334	330	327	323	320	316
		Workovers - SI or BP	454	421	390	362	336	311	289	268	248	230	214	198	184	171	158	147	136	126	117	109	101
		Workovers - RDS	2,012	1,927	1,848	1,775	1,707	1,644	1,585	1,529	1,478	1,429	1,383	1,340	1,300	1,261	1,225	1,190	1,158	1,127	1,097	1,069	1,042
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Lateral Jetting	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**70.70**	**70.70**	**70.70**
Revenue	NORIO	Norio Oil Production	2,861	2,738	2,624	2,518	2,420	2,328	2,243	2,162	2,087	2,016	1,950	1,888	1,829	1,773	1,721	1,671	1,624	1,579	1,537	1,497	1,459
		Daily Production	99	95	91	87	84	81	78	75	72	70	67	65	63	61	60	58	56	55	53	52	50
		Monthly Oil MMbbls	0.0029	0.0027	0.0026	0.0025	0.0024	0.0023	0.0022	0.0022	0.0021	0.0020	0.0020	0.0019	0.0018	0.0018	0.0017	0.0017	0.0016	0.0016	0.0015	0.0015	0.0015
		Norio Revenue	0.16	0.15	0.15	0.14	0.14	0.13	0.13	0.13	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.09
		Total Production	2,861	2,738	2,624	2,518	2,420	2,328	2,243	2,162	2,087	2,016	1,950	1,888	1,829	1,773	1,721	1,671	1,624	1,579	1,537	1,497	1,459
		Total Project Revenue M$	0.16	0.15	0.15	0.14	0.14	0.13	0.13	0.13	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.09
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	0.0204	0.0202	0.0201	0.0200	0.0199	0.0198	0.0197	0.0196	0.0195	0.0194	0.0194	0.0193	0.0192	0.0192	0.0191	0.0191	0.0190	0.0190	0.0190	0.0190	0.0189
		Contractor Opex Cost Oil	0.0204	0.0202	0.0201	0.0200	0.0199	0.0198	0.0197	0.0196	0.0195	0.0194	0.0194	0.0193	0.0192	0.0192	0.0191	0.0191	0.0190	0.0190	0.0190	0.0190	0.0189
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.07	0.07	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
		Recoverable Capex	20.55	20.48	20.41	20.35	20.29	20.23	20.17	20.12	20.07	20.02	19.97	19.92	19.87	19.83	19.79	19.75	19.71	19.67	19.63	19.60	19.56
		Contractor Capex Cost Oil	0.07	0.07	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
		Unrecovered Capex	20.48	20.41	20.35	20.29	20.23	20.17	20.12	20.07	20.02	19.97	19.92	19.87	19.83	19.79	19.75	19.71	19.67	19.63	19.60	19.56	19.52
		Total Cost Oil	**0.09**	**0.09**	**0.08**	**0.08**	**0.08**	**0.07**	**0.07**	**0.07**	**0.07**	**0.07**	**0.07**	**0.07**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.05**	**0.06**	**0.06**
Profit Share	Norio	Total Profit Oil	0.0703	0.0668	0.0636	0.0606	0.0578	0.0552	0.0528	0.0539	0.0517	0.0496	0.0476	0.0457	0.0440	0.0423	0.0408	0.0393	0.0379	0.0366	0.0354	0.0379	0.0367
		Contractor Profit Oil	0.0352	0.0334	0.0318	0.0303	0.0289	0.0276	0.0264	0.0270	0.0258	0.0248	0.0238	0.0229	0.0220	0.0212	0.0204	0.0197	0.0190	0.0183	0.0177	0.0190	0.0184
		Govt. Profit Oil	0.0352	0.0334	0.0318	0.0303	0.0289	0.0276	0.0264	0.0270	0.0258	0.0248	0.0238	0.0229	0.0220	0.0212	0.0204	0.0197	0.0190	0.0183	0.0177	0.0190	0.0184
		Total Contrctr Cost and Profit Oil, MMBbl	0.0023	0.0022	0.0021	0.0021	0.0020	0.0019	0.0017	0.0018	0.0017	0.0017	0.0016	0.0015	0.0015	0.0015	0.0014	0.0014	0.0013	0.0013	0.0012	0.0012	0.0012
		Evaluated Net Oil, MMBbl	0.0023	0.0022	0.0021	0.0021	0.0020	0.0019	0.0017	0.0018	0.0017	0.0017	0.0016	0.0015	0.0015	0.0015	0.0014	0.0014	0.0013	0.0013	0.0012	0.0012	0.0012
Cash Flow	Norio	Cash Flow	0.11	0.10	0.10	0.09	0.09	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.05	0.05	0.06	0.06
		DCF @10%	0.09	0.09	0.08	0.08	0.07	0.07	0.06	0.07	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04
	Cumulative CF		-0.05	0.05	0.14	0.23	0.32	0.40	0.48	0.56	0.64	0.71	0.79	0.85	0.92	0.98	1.04	1.10	1.16	1.22	1.27	1.33	1.38
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	21.66	21.68	21.70	21.72	21.74	21.76	21.78	21.80	21.82	21.84	21.86	21.88	21.90	21.92	21.94	21.96	21.97	21.99	22.01	22.03	22.05
		Cntrctr's Total Profit from Sales of Oil, MM$	0.13	0.12	0.12	0.11	0.11	0.10	0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.07	0.07	0.08	0.07
		Cumulative Total Profit, MM$	1.61	1.73	1.84	1.96	2.06	2.16	2.26	2.36	2.46	2.55	2.65	2.73	2.82	2.90	2.98	3.06	3.14	3.21	3.28	3.36	3.43
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells + Workovers + Lateral Jetting, Mean Values

Section	Group	Yr-Mo	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
		Oil Volume																					
Production	**Norio**	**Existing Production**	313	309	306	303	299	296	293	290	287	284	281	278	275	272	269	266	263	260	258	255	252
		Workovers - SI or BP	93	87	80	75	69	64	59	24	23	21	19	18	17	0	0	0	0	0	0	0	0
		Workovers - RDS	1,016	992	968	946	925	904	884	865	847	830	813	796	781	766	751	737	724	710	698	686	674
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	11	11	11	11	11	11	11	9	9	9	9	9	9	8	8	8	8	8	8	8	8
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	3	3	3	3	3	3	3	1	1	1	1	1	1	0	0	0	0	0	0	0	0
		Lateral Jetting	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**
Revenue	**NORIO**	**Norio Oil Production**	1,422	1,388	1,355	1,323	1,293	1,264	1,237	1,179	1,156	1,134	1,113	1,092	1,072	1,037	1,020	1,003	987	971	955	940	926
		Daily Production	49	48	47	46	45	44	43	41	40	39	38	38	37	36	35	35	34	34	33	33	32
		Monthly Oil MMbbls	0.0014	0.0014	0.0014	0.0013	0.0013	0.0013	0.0012	0.0012	0.0012	0.0011	0.0011	0.0011	0.0011	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0009	0.0009
		Norio Revenue	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06
		Total Production	1,422	1,388	1,355	1,323	1,293	1,264	1,237	1,179	1,156	1,134	1,113	1,092	1,072	1,037	1,020	1,003	987	971	955	940	926
		Total Project Revenue M$	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06
CAPEX	**Norio**	**Workovers**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	**Norio**	**Fixed Opex+OH**	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	**Norio**	**Recoverable Opex**	0.0189	0.0189	0.0189	0.0188	0.0188	0.0188	0.0188	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0188
		Contractor Opex Cost Oil	0.0189	0.0189	0.0189	0.0188	0.0188	0.0188	0.0188	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0187	0.0188
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Recoverable Capex	19.52	19.49	19.45	19.42	19.39	19.35	19.32	19.29	19.27	19.24	19.21	19.18	19.16	19.13	19.11	19.08	19.06	19.03	19.01	18.99	18.97
		Contractor Capex Cost Oil	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Unrecovered Capex	19.49	19.45	19.42	19.39	19.35	19.32	19.29	19.27	19.24	19.21	19.18	19.16	19.13	19.11	19.08	19.06	19.03	19.01	18.99	18.97	18.95
		Total Cost Oil	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**
Profit Share	**Norio**	**Total Profit Oil**	0.0356	0.0344	0.0334	0.0324	0.0314	0.0305	0.0296	0.0288	0.0270	0.0263	0.0276	0.0269	0.0263	0.0256	0.0245	0.0239	0.0234	0.0228	0.0223	0.0218	0.0213
		Contractor Profit Oil	0.0178	0.0172	0.0167	0.0162	0.0157	0.0152	0.0148	0.0144	0.0135	0.0132	0.0138	0.0135	0.0131	0.0128	0.0122	0.0120	0.0117	0.0114	0.0111	0.0109	0.0106
		Govt. Profit Oil	0.0178	0.0172	0.0167	0.0162	0.0157	0.0152	0.0148	0.0144	0.0135	0.0132	0.0138	0.0135	0.0131	0.0128	0.0122	0.0120	0.0117	0.0114	0.0111	0.0109	0.0106
		Total Contrctr Cost and Profit Oil, MMBbl	0.0012	0.0011	0.0011	0.0011	0.0011	0.0010	0.0010	0.0010	0.0010	0.0009	0.0009	0.0009	0.0009	0.0009	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008
		Evaluated Net Oil, MMBbl	0.0012	0.0011	0.0011	0.0011	0.0011	0.0010	0.0010	0.0010	0.0010	0.0009	0.0009	0.0009	0.0009	0.0009	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008
Cash Flow	**Norio**	**Cash Flow**	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03
		DCF @10%	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Cumulative CF		1.43	1.49	1.54	1.58	1.63	1.68	1.72	1.76	1.81	1.84	1.89	1.93	1.97	2.00	2.04	2.08	2.11	2.15	2.18	2.21	2.24
Payment Date	**Norio**	**Total Costs Incurred for Production, MM$**	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	22.07	22.09	22.11	22.13	22.14	22.16	22.18	22.20	22.22	22.24	22.26	22.28	22.29	22.31	22.33	22.35	22.37	22.39	22.41	22.43	22.44
		Cntrctr's Total Profit from Sales of Oil, MM$	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05
		Cumulative Total Profit, MM$	3.50	3.57	3.64	3.71	3.78	3.84	3.90	3.97	4.03	4.08	4.14	4.20	4.26	4.32	4.37	4.43	4.48	4.53	4.59	4.64	4.69
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells + Workovers + Lateral Jetting, Mean Values

		Yr-Mo	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24
		Oil Volume																				
Production	Norio	Existing Production	250	247	244	242	239	237	234	232	230	227	225	222	220	218	216	213	211	209	207	205
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	662	651	640	630	620	610	600	591	582	573	565	556	548	540	533	525	518	511	504	497
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**
Revenue	NORIO	Norio Oil Production	912	898	885	872	859	847	835	823	811	800	789	779	768	758	748	739	729	720	711	702
		Daily Production	32	31	31	30	30	29	29	28	28	28	27	27	27	26	26	26	25	25	25	24
		Monthly Oil MMbbls	0.0009	0.0009	0.0009	0.0009	0.0009	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
		Norio Revenue	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
		Total Production	912	898	885	872	859	847	835	823	811	800	789	779	768	758	748	739	729	720	711	702
		Total Project Revenue M$	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.017	0.017	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	0.0188	0.0188	0.0188	0.0188	0.0188	0.0188	0.0188	0.0188	0.0189	0.0189	0.0189	0.0189	0.0189	0.0189	0.0189	0.0190	0.0190	0.0190	0.0190	0.0190
		Contractor Opex Cost Oil	0.0188	0.0188	0.0188	0.0188	0.0188	0.0188	0.0188	0.0188	0.0189	0.0189	0.0189	0.0189	0.0189	0.0189	0.0189	0.0190	0.0190	0.0190	0.0190	0.0190
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01
		Recoverable Capex	18.95	18.92	18.90	18.88	18.86	18.84	18.83	18.81	18.79	18.77	18.75	18.74	18.72	18.70	18.69	18.67	18.66	18.64	18.62	18.61
		Contractor Capex Cost Oil	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01
		Unrecovered Capex	18.92	18.90	18.88	18.86	18.84	18.83	18.81	18.79	18.77	18.75	18.74	18.72	18.70	18.69	18.67	18.66	18.64	18.62	18.61	18.60
		Total Cost Oil	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Profit Share	Norio	Total Profit Oil	0.0208	0.0208	0.0203	0.0199	0.0195	0.0190	0.0186	0.0182	0.0178	0.0174	0.0171	0.0167	0.0163	0.0164	0.0160	0.0157	0.0153	0.0150	0.0147	0.0144
		Contractor Profit Oil	0.0104	0.0104	0.0102	0.0099	0.0097	0.0095	0.0093	0.0091	0.0089	0.0087	0.0085	0.0083	0.0082	0.0082	0.0080	0.0078	0.0077	0.0075	0.0074	0.0072
		Govt. Profit Oil	0.0104	0.0104	0.0102	0.0099	0.0097	0.0095	0.0093	0.0091	0.0089	0.0087	0.0085	0.0083	0.0082	0.0082	0.0080	0.0078	0.0077	0.0075	0.0074	0.0072
		Total Contrctr Cost and Profit Oil, MMBbl	0.0008	0.0008	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006
		Evaluated Net Oil, MMBbl	0.0008	0.0008	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006
Cash Flow	Norio	Cash Flow	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		DCF @10%	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Cumulative CF	2.28	2.31	2.34	2.37	2.40	2.42	2.45	2.48	2.51	2.53	2.56	2.58	2.61	2.63	2.66	2.68	2.70	2.73	2.75	2.77
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	22.46	22.48	22.50	22.52	22.54	22.56	22.58	22.59	22.61	22.63	22.65	22.67	22.69	22.71	22.73	22.75	22.77	22.78	22.80	22.82
		Cntrctr's Total Profit from Sales of Oil, MM$	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
		Cumulative Total Profit, MM$	4.74	4.79	4.84	4.89	4.93	4.98	5.03	5.07	5.12	5.17	5.21	5.25	5.30	5.34	5.38	5.43	5.47	5.51	5.55	5.59
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells + Workovers + Lateral Jetti

Section		Yr-Mo	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26
		Oil Volume																				
Production	Norio	Existing Production	203	201	199	197	195	193	191	189	187	185	183	181	180	178	176	174	173	171	169	168
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	491	484	478	472	466	460	454	449	443	438	433	428	423	418	413	408	404	399	395	391
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**76.23**	**76.23**	**76.23**	**76.23**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**78.37**	**78.37**	**78.37**	**78.37**
Revenue	NORIO	Norio Oil Production	693	685	677	669	661	653	645	638	630	623	616	609	602	596	589	583	577	570	564	558
		Daily Production	24	24	23	23	23	23	22	22	22	22	21	21	21	21	20	20	20	20	20	19
		Monthly Oil MMbbls	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006
		Norio Revenue	0.05	0.05	0.05	0.05	0.04	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
		Total Production	693	685	677	669	661	653	645	638	630	623	616	609	602	596	589	583	577	570	564	558
		Total Project Revenue M$	0.05	0.05	0.05	0.05	0.04	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.019	0.019	0.019	0.019
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	0.0190	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0192	0.0192	0.0192	0.0192	0.0192	0.0193	0.0193	0.0193	0.0193	0.0194	0.0194	0.0194	0.0194
		Contractor Opex Cost Oil	0.0190	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0192	0.0192	0.0192	0.0192	0.0192	0.0193	0.0193	0.0193	0.0193	0.0194	0.0194	0.0194	0.0194
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Recoverable Capex	18.60	18.58	18.57	18.55	18.54	18.53	18.52	18.50	18.49	18.48	18.47	18.45	18.44	18.43	18.42	18.41	18.40	18.39	18.38	18.37
		Contractor Capex Cost Oil	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Unrecovered Capex	18.58	18.57	18.55	18.54	18.53	18.52	18.50	18.49	18.48	18.47	18.45	18.44	18.43	18.42	18.41	18.40	18.39	18.38	18.37	18.36
		Total Cost Oil	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Profit Share	Norio	Total Profit Oil	0.0141	0.0138	0.0135	0.0132	0.0129	0.0130	0.0127	0.0124	0.0122	0.0119	0.0117	0.0114	0.0112	0.0109	0.0107	0.0104	0.0102	0.0103	0.0101	0.0099
		Contractor Profit Oil	0.0070	0.0069	0.0067	0.0066	0.0065	0.0065	0.0064	0.0062	0.0061	0.0060	0.0058	0.0057	0.0056	0.0055	0.0053	0.0052	0.0051	0.0052	0.0050	0.0049
		Govt. Profit Oil	0.0070	0.0069	0.0067	0.0066	0.0065	0.0065	0.0064	0.0062	0.0061	0.0060	0.0058	0.0057	0.0056	0.0055	0.0053	0.0052	0.0051	0.0052	0.0050	0.0049
		Total Contrctr Cost and Profit Oil, MMBbl	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
		Evaluated Net Oil, MMBbl	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Cash Flow	Norio	Cash Flow	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01
		DCF @10%	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Cumulative CF	2.79	2.81	2.83	2.85	2.87	2.89	2.91	2.93	2.95	2.96	2.98	3.00	3.02	3.03	3.05	3.06	3.08	3.09	3.11	3.12
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	22.84	22.86	22.88	22.90	22.92	22.94	22.96	22.97	22.99	23.01	23.03	23.05	23.07	23.09	23.11	23.13	23.15	23.17	23.19	23.21
		Cntrctr's Total Profit from Sales of Oil, MM$	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03
		Cumulative Total Profit, MM$	5.63	5.67	5.71	5.75	5.79	5.83	5.86	5.90	5.94	5.98	6.01	6.05	6.09	6.12	6.16	6.19	6.23	6.26	6.30	6.33
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

ng, Mean Values

Producing Wells

5/14/201810:36 PM

		Yr-Mo	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
		Oil Volume																				
Production	Norio	Existing Production	166	164	163	161	159	158	156	155	153	152	150	149	148	131	129	128	126	125	124	123
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	387	382	378	374	371	367	363	359	356	352	349	345	342	339	335	332	329	326	323	320
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	7	7
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**
Revenue	NORIO	Norio Oil Production	552	547	541	535	530	525	519	514	509	504	499	494	489	470	464	460	456	451	447	443
		Daily Production	19	19	19	19	18	18	18	18	18	17	17	17	17	16	16	16	16	16	15	15
		Monthly Oil MMbbls	0.0006	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004
		Norio Revenue	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		Total Production	552	547	541	535	530	525	519	514	509	504	499	494	489	470	464	460	456	451	447	443
		Total Project Revenue M$	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	Norio	Recoverable Opex	0.0194	0.0195	0.0195	0.0195	0.0195	0.0196	0.0196	0.0196	0.0196	0.0197	0.0197	0.0197	0.0197	0.0197	0.0197	0.0198	0.0198	0.0198	0.0199	0.0199
		Contractor Opex Cost Oil	0.0194	0.0195	0.0195	0.0195	0.0195	0.0196	0.0196	0.0196	0.0196	0.0197	0.0197	0.0197	0.0197	0.0197	0.0197	0.0198	0.0198	0.0198	0.0199	0.0199
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Recoverable Capex	18.36	18.35	18.34	18.33	18.32	18.31	18.30	18.30	18.29	18.28	18.27	18.26	18.26	18.25	18.24	18.23	18.23	18.22	18.22	18.21
		Contractor Capex Cost Oil	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Unrecovered Capex	18.35	18.34	18.33	18.32	18.31	18.30	18.30	18.29	18.28	18.27	18.26	18.26	18.25	18.24	18.23	18.23	18.22	18.22	18.21	18.20
		Total Cost Oil	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Profit Share	Norio	Total Profit Oil	0.0096	0.0094	0.0092	0.0090	0.0088	0.0086	0.0084	0.0082	0.0080	0.0081	0.0079	0.0077	0.0075	0.0074	0.0067	0.0065	0.0063	0.0061	0.0060	0.0058
		Contractor Profit Oil	0.0048	0.0047	0.0046	0.0045	0.0044	0.0043	0.0042	0.0041	0.0040	0.0041	0.0040	0.0039	0.0038	0.0037	0.0033	0.0032	0.0031	0.0031	0.0030	0.0029
		Govt. Profit Oil	0.0048	0.0047	0.0046	0.0045	0.0044	0.0043	0.0042	0.0041	0.0040	0.0041	0.0040	0.0039	0.0038	0.0037	0.0033	0.0032	0.0031	0.0031	0.0030	0.0029
		Total Contrctr Cost and Profit Oil, MMBbl	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
		Evaluated Net Oil, MMBbl	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Cash Flow	Norio	Cash Flow	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		DCF @10%	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	3.14	3.15	3.17	3.18	3.19	3.21	3.22	3.23	3.24	3.26	3.27	3.28	3.29	3.30	3.31	3.32	3.33	3.34	3.35	3.36
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	23.23	23.25	23.26	23.28	23.30	23.32	23.34	23.36	23.38	23.40	23.42	23.44	23.46	23.48	23.50	23.52	23.54	23.56	23.58	23.60
		Cntrctr's Total Profit from Sales of Oil, MM$	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		Cumulative Total Profit, MM$	6.36	6.40	6.43	6.46	6.50	6.53	6.56	6.59	6.63	6.66	6.69	6.72	6.75	6.78	6.81	6.84	6.87	6.90	6.93	6.96
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

+ Workovers + Lateral Jetting, Mean Values

Producing Wells + Workovers + Lateral Jetting, Mean Values

5/14/201810:36 PM

		Yr-Mo	Units	Total	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
		Oil Volume																				
Production	Norio	Existing Production	Bbl	32,417	485	480	474	469	463	458	453	448	443	438	433	428	423	418	413	409	404	399
		Workovers - SI or BP	Bbl	14,436	0	0	0	0	728	676	627	581	539	500	828	768	712	661	613	568	527	489
		Workovers - RDS	Bbl	96,440	0	0	0	0	0	0	0	0	0	1,473	3,065	2,882	2,718	2,570	2,437	2,316	2,206	2,105
		Undeveloped	Bbl	1,438,034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12,518	10,994	22,311
		Number of Producing Wells	Wells		3	3	3	3	5	5	5	5	5	7	11	11	11	11	11	12	12	13
		Existing Production	Wells		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	Wells		0	0	0	0	2	2	2	2	2	2	3	3	3	3	3	3	3	3
		Lateral Jetting			0	0	0	0	0	0	0	0	0	2	5	5	5	5	5	5	5	5
		Undeveloped	Wells		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	2
		Brent Oil Price	$/Bbl		60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	62.81	62.81	62.81	62.81	62.81	62.81
Revenue	NORIO	Norio Oil Production	BOPM	1,581,326	485	480	474	469	1,192	1,134	1,080	1,029	982	2,410	4,326	4,077	3,853	3,649	3,463	15,811	14,131	25,305
		Daily Production	BOPD		17	17	16	16	41	39	37	36	34	83	150	141	133	126	120	547	489	875
		Monthly Oil MMbbls	MMBbl	1.5813	0.0005	0.0005	0.0005	0.0005	0.0012	0.0011	0.0011	0.0010	0.0010	0.0024	0.0043	0.0041	0.0039	0.0036	0.0035	0.0158	0.0141	0.0253
		Norio Revenue	M$	96.1		0.03	0.02	0.02	0.02	0.06	0.06	0.06	0.05	0.05	0.12	0.22	0.21	0.21	0.20	0.19	0.85	0.76
		Total Production	Bbl	1,581,326	485	480	474	469	1,192	1,134	1,080	1,029	982	2,410	4,326	4,077	3,853	3,649	3,463	15,811	14,131	25,305
		Total Project Revenue M$	M$	96.1	0.00	0.03	0.02	0.02	0.02	0.06	0.06	0.06	0.05	0.05	0.12	0.22	0.21	0.21	0.20	0.19	0.85	0.76
CAPEX	Norio	Workovers	MM$	1.3	0	0	0	0	0.15	0	0	0	0	0.382	0.794	0	0	0	0	0	0	0
		New Wells	MM$	15.8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.8	0	3
		CAPEX TOTAL	MM$	17.1	0.00	0.00	0.00	0.00	0.15	0.00	0.00	0.00	0.00	0.38	0.79	0.00	0.00	0.00	0.00	0.80	0.00	3.00
Opex	Norio	Fixed Opex+OH	MM$	2.1	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.016	0.016	0.016	0.016	0.016	0.016
		Floating Opex	MM$	2.3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00	0.02	0.02	0.04
		Workovers	MM$	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	MM$	4.3	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.05
		OPEX TOTAL	MM$	4.3	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.05
Cost Recovery	Norio	Recoverable Opex	MM$	4.33	0.0143	0.0143	0.0143	0.0143	0.0153	0.0152	0.0152	0.0151	0.0150	0.0171	0.0198	0.0195	0.0216	0.0214	0.0211	0.0388	0.0365	0.0525
		Contractor Opex Cost Oil	MM$	4.33	0.0000	0.0250	0.0179	0.0143	0.0153	0.0152	0.0152	0.0151	0.0150	0.0171	0.0198	0.0195	0.0216	0.0214	0.0211	0.0388	0.0365	0.0525
		Unrecovered Opex	MM$		0.0143	0.0036	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	MM$		0.00	0.00	0.00	0.01	0.00	0.02	0.02	0.02	0.02	0.02	0.05	0.10	0.09	0.09	0.09	0.07	0.41	0.35
		Recoverable Capex	MM$		20.00	20.00	20.00	20.00	20.14	20.14	20.11	20.09	20.07	20.43	21.21	21.16	21.06	20.96	20.87	21.58	21.51	24.10
		Contractor Capex Cost Oil	MM$	37.13	0.00	0.00	0.00	0.01	0.00	0.02	0.02	0.02	0.02	0.02	0.05	0.10	0.09	0.09	0.09	0.07	0.41	0.35
		Unrecovered Capex	MM$		20.00	20.00	20.00	19.99	20.14	20.11	20.09	20.07	20.05	20.42	21.16	21.06	20.96	20.87	20.78	21.51	21.10	23.75
		Total Cost Oil	MM$		0.00	0.03	0.02	0.02	0.02	0.04	0.04	0.04	0.03	0.03	0.07	0.12	0.12	0.11	0.11	0.11	0.44	0.41
Profit Share	Norio	Total Profit Oil	MM$	54.6876	0.0000	0.0000	0.0034	0.0051	0.0044	0.0231	0.0216	0.0203	0.0190	0.0168	0.0522	0.1018	0.0943	0.0930	0.0876	0.0737	0.4071	0.3539
		Contractor Profit Oil	MM$	24.3716	0.0000	0.0000	0.0017	0.0025	0.0022	0.0116	0.0108	0.0101	0.0095	0.0084	0.0261	0.0509	0.0471	0.0465	0.0438	0.0369	0.2036	0.1770
		Govt. Profit Oil	MM$	30.3160	0.0000	0.0000	0.0017	0.0025	0.0022	0.0116	0.0108	0.0101	0.0095	0.0084	0.0261	0.0509	0.0471	0.0465	0.0438	0.0369	0.2036	0.1770
		Total Contrctr Cost and Profit Oil, MMBbl	MMBbl	1.0874	0.0000	0.0005	0.0004	0.0004	0.0004	0.0010	0.0009	0.0009	0.0008	0.0008	0.0019	0.0033	0.0030	0.0030	0.0028	0.0028	0.0120	0.0108
		Evaluated Net Oil, MMBbl	MMBbl	1.0874	0.0000	0.0005	0.0004	0.0004	0.0004	0.0010	0.0009	0.0009	0.0008	0.0008	0.0019	0.0033	0.0030	0.0030	0.0028	0.0028	0.0120	0.0108
Cash Flow	Norio	Cash Flow	MM$	44.37	-0.01	0.01	0.01	0.01	-0.14	0.03	0.03	0.03	0.03	-0.36	-0.72	0.15	0.14	0.14	0.13	-0.69	0.61	-2.47
		DCF @10%	MM$	28.72	-0.01	0.01	0.01	0.01	-0.14	0.03	0.03	0.03	0.03	-0.33	-0.66	0.14	0.13	0.12	0.12	-0.61	0.53	-2.14
	Cumulative CF				-0.01	0.00	0.01	0.01	-0.13	-0.10	-0.06	-0.03	0.00	-0.36	-1.08	-0.92	-0.78	-0.64	-0.51	-1.20	-0.59	-3.06
Payment Date	Norio	Total Costs Incurred for Production, MM$	MM$	41.46	20.01	0.01	0.01	0.01	0.17	0.02	0.02	0.02	0.02	0.40	0.81	0.02	0.02	0.02	0.02	0.84	0.04	3.05
		Cumulative Total Costs, MM$	MM$	41.46	20.01	20.03	20.04	20.06	20.22	20.24	20.25	20.27	20.28	20.68	21.50	21.52	21.54	21.56	21.58	22.42	22.45	25.51
		Cntrctr's Total Profit from Sales of Oil, MM$	MM$	65.83	0.00	0.03	0.02	0.02	0.02	0.05	0.05	0.05	0.04	0.04	0.10	0.17	0.16	0.16	0.15	0.15	0.65	0.58
		Cumulative Total Profit, MM$	MM$	65.83	0.00	0.03	0.05	0.07	0.09	0.14	0.19	0.23	0.28	0.32	0.42	0.59	0.75	0.91	1.07	1.22	1.86	2.45
		Payout? 1=yes, 0=no		Nov-21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells + Workovers + Lateral Jetting + Horizontal Wells, Mean Values

		Yr-Mo	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21
		Oil Volume																					
Production	Norio	Existing Production	395	390	386	382	377	373	369	365	361	357	353	349	345	341	338	334	330	327	323	320	316
		Workovers - SI or BP	454	421	390	362	336	311	289	268	248	230	214	198	184	171	158	147	136	126	117	109	101
		Workovers - RDS	2,012	1,927	1,848	1,775	1,707	1,644	1,585	1,529	1,478	1,429	1,383	1,340	1,300	1,261	1,225	1,190	1,158	1,127	1,097	1,069	1,042
		Undeveloped	19,817	30,334	27,170	37,117	33,462	42,983	38,955	48,147	43,825	40,236	37,201	34,598	32,339	30,359	28,607	27,046	25,647	24,384	23,238	22,195	21,240
		Number of Producing Wells	13	14	14	15	15	16	16	17	17	17	17	17	17	17	17	17	17	17	17	17	17
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Lateral Jetting	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Undeveloped	2	3	3	4	4	5	5	6	6	6	6	6	6	6	6	6	6	6	6	6	6
		Brent Oil Price	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**70.70**	**70.70**	**70.70**
Revenue	NORIO	Norio Oil Production	22,678	33,072	29,794	39,635	35,882	45,312	41,198	50,309	45,912	42,252	39,151	36,486	34,168	32,132	30,328	28,718	27,271	25,963	24,775	23,692	22,698
		Daily Production	784	1,144	1,030	1,371	1,241	1,567	1,425	1,740	1,588	1,461	1,354	1,262	1,182	1,111	1,049	993	943	898	857	819	785
		Monthly Oil MMbbls	0.0227	0.0331	0.0298	0.0396	0.0359	0.0453	0.0412	0.0503	0.0459	0.0423	0.0392	0.0365	0.0342	0.0321	0.0303	0.0287	0.0273	0.0260	0.0248	0.0237	0.0227
		Norio Revenue	1.36	1.22	1.78	1.60	2.13	1.93	2.44	2.34	2.86	2.61	2.40	2.22	2.07	1.94	1.83	1.72	1.63	1.55	1.47	1.53	1.46
		Total Production	22,678	33,072	29,794	39,635	35,882	45,312	41,198	50,309	45,912	42,252	39,151	36,486	34,168	32,132	30,328	28,718	27,271	25,963	24,775	23,692	22,698
		Total Project Revenue M$	1.36	1.22	1.78	1.60	2.13	1.93	2.44	2.34	2.86	2.61	2.40	2.22	2.07	1.94	1.83	1.72	1.63	1.55	1.47	1.53	1.46
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	3	0	3	0	3	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	3.00	0.00	3.00	0.00	3.00	0.00	3.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017
		Floating Opex	0.03	0.05	0.04	0.06	0.05	0.06	0.06	0.07	0.07	0.06	0.06	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.03	0.03
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.05	0.06	0.06	0.07	0.07	0.08	0.08	0.09	0.08	0.08	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05
		OPEX TOTAL	0.05	0.06	0.06	0.07	0.07	0.08	0.08	0.09	0.08	0.08	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05
Cost Recovery	Norio	Recoverable Opex	0.0488	0.0637	0.0590	0.0731	0.0678	0.0813	0.0754	0.0885	0.0823	0.0770	0.0726	0.0688	0.0655	0.0627	0.0601	0.0578	0.0558	0.0539	0.0523	0.0507	0.0493
		Contractor Opex Cost Oil	0.0488	0.0637	0.0590	0.0731	0.0678	0.0813	0.0754	0.0885	0.0823	0.0770	0.0726	0.0688	0.0655	0.0627	0.0601	0.0578	0.0558	0.0539	0.0523	0.0507	0.0493
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.66	0.58	0.86	0.76	1.03	0.92	1.18	1.13	1.39	1.27	1.16	1.08	1.00	0.94	0.88	0.83	0.79	0.75	0.71	0.74	0.71
		Recoverable Capex	23.75	26.09	25.51	27.65	26.89	28.86	27.93	29.75	28.62	27.24	25.97	24.81	23.73	22.73	21.79	20.91	20.07	19.29	18.54	17.83	17.09
		Contractor Capex Cost Oil	0.66	0.58	0.86	0.76	1.03	0.92	1.18	1.13	1.39	1.27	1.16	1.08	1.00	0.94	0.88	0.83	0.79	0.75	0.71	0.74	0.71
		Unrecovered Capex	23.09	25.51	24.65	26.89	25.86	27.93	26.75	28.62	27.24	25.97	24.81	23.73	22.73	21.79	20.91	20.07	19.29	18.54	17.83	17.09	16.38
		Total Cost Oil	**0.71**	**0.64**	**0.92**	**0.84**	**1.10**	**1.01**	**1.26**	**1.21**	**1.47**	**1.34**	**1.24**	**1.15**	**1.07**	**1.00**	**0.94**	**0.89**	**0.84**	**0.80**	**0.76**	**0.79**	**0.76**
Profit Share	Norio	Total Profit Oil	0.6564	0.5783	0.8603	0.7650	1.0324	0.9247	1.1813	1.1258	1.3876	1.2654	1.1636	1.0775	1.0034	0.9390	0.8825	0.8324	0.7877	0.7475	0.7112	0.7390	0.7062
		Contractor Profit Oil	0.3282	0.2891	0.4301	0.3825	0.5162	0.4624	0.5907	0.5629	0.6938	0.6327	0.5818	0.5387	0.5017	0.4695	0.4412	0.4162	0.3938	0.3738	0.3556	0.3695	0.3531
		Govt. Profit Oil	0.3282	0.2891	0.4301	0.3825	0.5162	0.4624	0.5907	0.5629	0.6938	0.6327	0.5818	0.5387	0.5017	0.4695	0.4412	0.4162	0.3938	0.3738	0.3556	0.3695	0.3531
		Total Contrctr Cost and Profit Oil, MMBbl	0.0192	0.0173	0.0251	0.0227	0.0300	0.0273	0.0325	0.0313	0.0381	0.0348	0.0320	0.0297	0.0277	0.0259	0.0244	0.0230	0.0218	0.0207	0.0181	0.0188	0.0180
		Evaluated Net Oil, MMBbl	0.0192	0.0173	0.0251	0.0227	0.0300	0.0273	0.0325	0.0313	0.0381	0.0348	0.0320	0.0297	0.0277	0.0259	0.0244	0.0230	0.0218	0.0207	0.0181	0.0188	0.0180
Cash Flow	Norio	Cash Flow	0.98	-2.13	1.29	-1.85	1.55	-1.61	1.77	-1.31	2.08	1.90	1.75	1.62	1.51	1.41	1.32	1.25	1.18	1.12	1.07	1.11	1.06
		DCF @10%	0.85	-1.82	1.09	-1.56	1.29	-1.33	1.45	-1.07	1.68	1.52	1.39	1.27	1.18	1.09	1.02	0.95	0.89	0.84	0.80	0.82	0.78
	Cumulative CF		-2.08	-4.21	-2.92	-4.77	-3.22	-4.83	-3.06	-4.37	-2.29	-0.39	1.35	2.97	4.47	5.88	7.21	8.45	9.64	10.76	11.82	12.93	13.99
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.05	3.06	0.06	3.07	0.07	3.08	0.08	3.09	0.08	0.08	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05
		Cumulative Total Costs, MM$	25.56	28.62	28.68	31.75	31.82	34.90	34.98	38.06	38.15	38.22	38.30	38.37	38.43	38.49	38.55	38.61	38.67	38.72	38.77	38.82	38.87
		Cntrctr's Total Profit from Sales of Oil, MM$	1.03	0.93	1.35	1.22	1.62	1.47	1.85	1.78	2.16	1.98	1.82	1.69	1.57	1.47	1.38	1.31	1.24	1.18	1.12	1.16	1.11
		Cumulative Total Profit, MM$	3.48	4.41	5.76	6.98	8.60	10.07	11.91	13.69	15.86	17.83	19.65	21.33	22.90	24.38	25.76	27.07	28.30	29.48	30.60	31.76	32.87
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Producing Wells + Workovers + Lateral Jetting + Horizontal Wells, Mean Values

Section	Group	Yr-Mo	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
		Oil Volume																					
Production	Norio	Existing Production	313	309	306	303	299	296	293	290	287	284	281	278	275	272	269	266	263	260	258	255	252
		Workovers - SI or BP	93	87	80	75	69	64	59	24	23	21	19	18	17	0	0	0	0	0	0	0	0
		Workovers - RDS	1,016	992	968	946	925	904	884	865	847	830	813	796	781	766	751	737	724	710	698	686	674
		Undeveloped	20,362	19,554	18,806	18,112	17,467	16,865	16,303	15,776	15,282	14,817	14,379	13,965	13,574	13,204	12,853	12,520	12,203	11,901	11,614	11,340	11,078
		Number of Producing Wells	17	17	17	17	17	17	17	15	15	15	15	15	15	14	14	14	14	14	14	14	14
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	3	3	3	3	3	3	3	1	1	1	1	1	1	0	0	0	0	0	0	0	0
		Lateral Jetting	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Undeveloped	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
		Brent Oil Price	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**
Revenue	NORIO	Norio Oil Production	21,785	20,941	20,160	19,435	18,760	18,130	17,540	16,956	16,438	15,951	15,491	15,057	14,646	14,241	13,873	13,523	13,190	12,872	12,570	12,280	12,004
		Daily Production	753	724	697	672	649	627	607	586	568	552	536	521	506	492	480	468	456	445	435	425	415
		Monthly Oil MMbbls	0.0218	0.0209	0.0202	0.0194	0.0188	0.0181	0.0175	0.0170	0.0164	0.0160	0.0155	0.0151	0.0146	0.0142	0.0139	0.0135	0.0132	0.0129	0.0126	0.0123	0.0120
		Norio Revenue	1.40	1.34	1.29	1.24	1.20	1.16	1.12	1.08	1.05	1.01	1.04	1.01	0.98	0.96	0.93	0.90	0.88	0.86	0.84	0.82	0.80
		Total Production	21,785	20,941	20,160	19,435	18,760	18,130	17,540	16,956	16,438	15,951	15,491	15,057	14,646	14,241	13,873	13,523	13,190	12,872	12,570	12,280	12,004
		Total Project Revenue M$	1.40	1.34	1.29	1.24	1.20	1.16	1.12	1.08	1.05	1.01	1.04	1.01	0.98	0.96	0.93	0.90	0.88	0.86	0.84	0.82	0.80
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017
		Floating Opex	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03
		OPEX TOTAL	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03
Cost Recovery	Norio	Recoverable Opex	0.0481	0.0469	0.0458	0.0448	0.0438	0.0430	0.0421	0.0413	0.0406	0.0400	0.0393	0.0387	0.0382	0.0376	0.0371	0.0366	0.0362	0.0358	0.0354	0.0350	0.0346
		Contractor Opex Cost Oil	0.0481	0.0469	0.0458	0.0448	0.0438	0.0430	0.0421	0.0413	0.0406	0.0400	0.0393	0.0387	0.0382	0.0376	0.0371	0.0366	0.0362	0.0358	0.0354	0.0350	0.0346
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.68	0.65	0.62	0.60	0.58	0.56	0.54	0.52	0.50	0.49	0.50	0.49	0.47	0.46	0.45	0.43	0.42	0.41	0.40	0.39	0.38
		Recoverable Capex	16.38	15.70	15.06	14.43	13.83	13.26	12.70	12.16	11.64	11.14	10.65	10.15	9.66	9.19	8.73	8.29	7.85	7.43	7.02	6.62	6.22
		Contractor Capex Cost Oil	0.68	0.65	0.62	0.60	0.58	0.56	0.54	0.52	0.50	0.49	0.50	0.49	0.47	0.46	0.45	0.43	0.42	0.41	0.40	0.39	0.38
		Unrecovered Capex	15.70	15.06	14.43	13.83	13.26	12.70	12.16	11.64	11.14	10.65	10.15	9.66	9.19	8.73	8.29	7.85	7.43	7.02	6.62	6.22	5.84
		Total Cost Oil	**0.72**	**0.70**	**0.67**	**0.64**	**0.62**	**0.60**	**0.58**	**0.56**	**0.54**	**0.53**	**0.54**	**0.52**	**0.51**	**0.50**	**0.48**	**0.47**	**0.46**	**0.45**	**0.44**	**0.43**	**0.42**
Profit Share	Norio	Total Profit Oil	0.6762	0.6486	0.6231	0.5996	0.5777	0.5573	0.5382	0.5204	0.5028	0.4871	0.5006	0.4859	0.4720	0.4589	0.4459	0.4342	0.4230	0.4123	0.4022	0.3925	0.3832
		Contractor Profit Oil	0.3381	0.3243	0.3116	0.2998	0.2888	0.2786	0.2691	0.2082	0.2011	0.1949	0.2002	0.1944	0.1888	0.1836	0.1784	0.1737	0.1692	0.1649	0.1609	0.1570	0.1533
		Govt. Profit Oil	0.3381	0.3243	0.3116	0.2998	0.2888	0.2786	0.2691	0.3123	0.3017	0.2923	0.3004	0.2915	0.2832	0.2753	0.2676	0.2605	0.2538	0.2474	0.2413	0.2355	0.2299
		Total Contrctr Cost and Profit Oil, MMBbl	0.0172	0.0165	0.0159	0.0153	0.0148	0.0142	0.0138	0.0125	0.0121	0.0111	0.0113	0.0110	0.0107	0.0104	0.0101	0.0099	0.0096	0.0094	0.0092	0.0090	0.0088
		Evaluated Net Oil, MMBbl	0.0172	0.0165	0.0159	0.0153	0.0148	0.0142	0.0138	0.0125	0.0121	0.0111	0.0113	0.0110	0.0107	0.0104	0.0101	0.0099	0.0096	0.0094	0.0092	0.0090	0.0088
Cash Flow	Norio	Cash Flow	1.01	0.97	0.93	0.90	0.87	0.84	0.81	0.73	0.70	0.68	0.70	0.68	0.66	0.64	0.62	0.61	0.59	0.58	0.56	0.55	0.54
		DCF @10%	0.74	0.70	0.67	0.64	0.61	0.58	0.56	0.50	0.48	0.46	0.47	0.45	0.44	0.42	0.41	0.39	0.38	0.37	0.36	0.34	0.33
	Cumulative CF		15.01	15.98	16.91	17.81	18.68	19.51	20.32	21.05	21.75	22.44	23.14	23.82	24.48	25.12	25.75	26.35	26.95	27.52	28.09	28.64	29.17
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03
		Cumulative Total Costs, MM$	38.92	38.97	39.01	39.06	39.10	39.15	39.19	39.23	39.27	39.31	39.35	39.39	39.43	39.46	39.50	39.54	39.57	39.61	39.65	39.68	39.71
		Cntrctr's Total Profit from Sales of Oil, MM$	1.06	1.02	0.98	0.94	0.91	0.88	0.85	0.77	0.74	0.72	0.74	0.72	0.70	0.68	0.66	0.64	0.63	0.61	0.60	0.58	0.57
		Cumulative Total Profit, MM$	33.93	34.95	35.93	36.87	37.78	38.66	39.51	40.28	41.02	41.75	42.49	43.21	43.91	44.59	45.25	45.89	46.52	47.13	47.73	48.32	48.89
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
										Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21

Producing Wells + Workovers + Lateral Jetting + Horizontal Wells, Mean Values

Section	Group	Yr-Mo	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24
		Oil Volume																				
Production	**Norio**	**Existing Production**	250	247	244	242	239	237	234	232	230	227	225	222	220	218	216	213	211	209	207	205
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	662	651	640	630	620	610	600	591	582	573	565	556	548	540	533	525	518	511	504	497
		Undeveloped	10,828	10,588	10,359	10,139	9,928	9,725	9,531	9,343	9,163	8,989	8,822	8,660	8,505	8,354	8,209	8,068	7,932	7,801	7,674	7,550
		Number of Producing Wells	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Undeveloped	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
		Brent Oil Price	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**
Revenue	**NORIO**	**Norio Oil Production**	11,740	11,486	11,244	11,011	10,787	10,572	10,365	10,166	9,974	9,789	9,611	9,439	9,273	9,112	8,957	8,807	8,662	8,521	8,384	8,252
		Daily Production	406	397	389	381	373	366	358	352	345	339	332	326	321	315	310	305	300	295	290	285
		Monthly Oil MMbbls	0.0117	0.0115	0.0112	0.0110	0.0108	0.0106	0.0104	0.0102	0.0100	0.0098	0.0096	0.0094	0.0093	0.0091	0.0090	0.0088	0.0087	0.0085	0.0084	0.0083
		Norio Revenue	0.78	0.78	0.76	0.74	0.73	0.71	0.70	0.69	0.67	0.66	0.65	0.64	0.62	0.62	0.61	0.60	0.59	0.58	0.57	0.56
		Total Production	11,740	11,486	11,244	11,011	10,787	10,572	10,365	10,166	9,974	9,789	9,611	9,439	9,273	9,112	8,957	8,807	8,662	8,521	8,384	8,252
		Total Project Revenue M$	0.78	0.78	0.76	0.74	0.73	0.71	0.70	0.69	0.67	0.66	0.65	0.64	0.62	0.62	0.61	0.60	0.59	0.58	0.57	0.56
CAPEX	**Norio**	**Workovers**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	**Norio**	**Fixed Opex+OH**	0.017	0.017	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018
		Floating Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		OPEX TOTAL	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Cost Recovery	**Norio**	**Recoverable Opex**	0.0343	0.0339	0.0336	0.0333	0.0330	0.0327	0.0325	0.0322	0.0320	0.0317	0.0315	0.0313	0.0311	0.0309	0.0307	0.0305	0.0303	0.0302	0.0300	0.0298
		Contractor Opex Cost Oil	0.0343	0.0339	0.0336	0.0333	0.0330	0.0327	0.0325	0.0322	0.0320	0.0317	0.0315	0.0313	0.0311	0.0309	0.0307	0.0305	0.0303	0.0302	0.0300	0.0298
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.37	0.37	0.36	0.36	0.35	0.34	0.33	0.33	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.28	0.28	0.27	0.27
		Recoverable Capex	5.84	5.47	5.09	4.73	4.37	4.03	3.69	3.35	3.02	2.70	2.39	2.08	1.78	1.48	1.19	0.89	0.61	0.33	0.05	0.00
		Contractor Capex Cost Oil	0.37	0.37	0.36	0.36	0.35	0.34	0.33	0.33	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.28	0.28	0.05	0.00
		Unrecovered Capex	5.47	5.09	4.73	4.37	4.03	3.69	3.35	3.02	2.70	2.39	2.08	1.78	1.48	1.19	0.89	0.61	0.33	0.05	0.00	0.00
		Total Cost Oil	**0.41**	**0.41**	**0.40**	**0.39**	**0.38**	**0.37**	**0.37**	**0.36**	**0.35**	**0.35**	**0.34**	**0.33**	**0.33**	**0.33**	**0.32**	**0.32**	**0.31**	**0.31**	**0.08**	**0.03**
Profit Share	**Norio**	**Total Profit Oil**	0.3744	0.3717	0.3634	0.3556	0.3480	0.3407	0.3337	0.3270	0.3206	0.3143	0.3083	0.3025	0.2969	0.2963	0.2910	0.2858	0.2809	0.2761	0.4907	0.5339
		Contractor Profit Oil	0.1498	0.1487	0.1454	0.1422	0.1392	0.1363	0.1335	0.1308	0.1282	0.1257	0.1233	0.1210	0.1188	0.1185	0.1164	0.1143	0.1124	0.1104	0.1963	0.2135
		Govt. Profit Oil	0.2246	0.2230	0.2181	0.2133	0.2088	0.2044	0.2002	0.1962	0.1923	0.1886	0.1850	0.1815	0.1782	0.1778	0.1746	0.1715	0.1685	0.1657	0.2944	0.3203
		Total Contrctr Cost and Profit Oil, MMBbl	0.0084	0.0084	0.0082	0.0080	0.0079	0.0077	0.0075	0.0074	0.0073	0.0071	0.0070	0.0069	0.0066	0.0066	0.0065	0.0064	0.0063	0.0062	0.0041	0.0036
		Evaluated Net Oil, MMBbl	0.0084	0.0084	0.0082	0.0080	0.0079	0.0077	0.0075	0.0074	0.0073	0.0071	0.0070	0.0069	0.0066	0.0066	0.0065	0.0064	0.0063	0.0062	0.0041	0.0036
Cash Flow	**Norio**	**Cash Flow**	0.52	0.52	0.51	0.50	0.49	0.48	0.47	0.46	0.45	0.44	0.43	0.42	0.42	0.41	0.41	0.40	0.39	0.39	0.25	0.21
		DCF @10%	0.32	0.32	0.31	0.30	0.29	0.28	0.27	0.27	0.26	0.25	0.25	0.24	0.23	0.23	0.22	0.22	0.21	0.21	0.13	0.11
		Cumulative CF	29.70	30.22	30.72	31.22	31.71	32.19	32.65	33.11	33.56	34.00	34.43	34.86	35.27	35.69	36.09	36.49	36.89	37.27	37.52	37.74
Payment Date	**Norio**	**Total Costs Incurred for Production, MM$**	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		Cumulative Total Costs, MM$	39.75	39.78	39.82	39.85	39.88	39.92	39.95	39.98	40.01	40.04	40.08	40.11	40.14	40.17	40.20	40.23	40.26	40.29	40.32	40.35
		Cntrctr's Total Profit from Sales of Oil, MM$	0.56	0.55	0.54	0.53	0.52	0.51	0.50	0.49	0.48	0.47	0.46	0.45	0.45	0.45	0.44	0.43	0.42	0.42	0.28	0.24
		Cumulative Total Profit, MM$	49.44	50.00	50.54	51.07	51.59	52.10	52.60	53.09	53.57	54.05	54.51	54.96	55.41	55.86	56.29	56.72	57.15	57.56	57.84	58.09
		Payout? 1=yes, 0=no	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
			Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21

s

Producing Wells + Workovers + Lateral Jetting + Hori

Section		Yr-Mo	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26
		Oil Volume																				
Production	Norio	Existing Production	203	201	199	197	195	193	191	189	187	185	183	181	180	178	176	174	173	171	169	168
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	491	484	478	472	466	460	454	449	443	438	433	428	423	418	413	408	404	399	395	391
		Undeveloped	7,431	7,315	7,202	7,093	6,987	6,884	6,784	6,686	6,592	6,500	6,410	6,323	6,238	6,155	6,074	5,996	5,919	5,844	5,771	5,700
		Number of Producing Wells	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Undeveloped	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
		Brent Oil Price	**76.23**	**76.23**	**76.23**	**76.23**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**78.37**	**78.37**	**78.37**	**78.37**
Revenue	NORIO	Norio Oil Production	8,124	8,000	7,879	7,761	7,647	7,537	7,429	7,324	7,222	7,123	7,026	6,932	6,840	6,751	6,664	6,579	6,496	6,415	6,335	6,258
		Daily Production	281	277	272	268	264	261	257	253	250	246	243	240	237	233	230	228	225	222	219	216
		Monthly Oil MMbbls	0.0081	0.0080	0.0079	0.0078	0.0076	0.0075	0.0074	0.0073	0.0072	0.0071	0.0070	0.0069	0.0068	0.0068	0.0067	0.0066	0.0065	0.0064	0.0063	0.0063
		Norio Revenue	0.55	0.55	0.54	0.53	0.52	0.52	0.51	0.51	0.50	0.49	0.49	0.48	0.47	0.47	0.46	0.45	0.45	0.45	0.44	0.44
		Total Production	8,124	8,000	7,879	7,761	7,647	7,537	7,429	7,324	7,222	7,123	7,026	6,932	6,840	6,751	6,664	6,579	6,496	6,415	6,335	6,258
		Total Project Revenue M$	0.55	0.55	0.54	0.53	0.52	0.52	0.51	0.51	0.50	0.49	0.49	0.48	0.47	0.47	0.46	0.45	0.45	0.45	0.44	0.44
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.019	0.019	0.019	0.019
		Floating Opex	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		OPEX TOTAL	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Cost Recovery	Norio	Recoverable Opex	0.0297	0.0295	0.0294	0.0292	0.0291	0.0290	0.0289	0.0287	0.0286	0.0285	0.0284	0.0283	0.0282	0.0281	0.0280	0.0279	0.0278	0.0277	0.0277	0.0276
		Contractor Opex Cost Oil	0.0297	0.0295	0.0294	0.0292	0.0291	0.0290	0.0289	0.0287	0.0286	0.0285	0.0284	0.0283	0.0282	0.0281	0.0280	0.0279	0.0278	0.0277	0.0277	0.0276
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.26	0.26	0.25	0.25	0.25	0.25	0.24	0.24	0.24	0.23	0.23	0.23	0.22	0.22	0.22	0.21	0.21	0.21	0.21	0.21
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Profit Share	Norio	Total Profit Oil	0.5251	0.5166	0.5084	0.5004	0.4927	0.4930	0.4856	0.4784	0.4713	0.4645	0.4578	0.4513	0.4450	0.4388	0.4328	0.4269	0.4212	0.4228	0.4173	0.4119
		Contractor Profit Oil	0.2100	0.2067	0.2034	0.2002	0.1971	0.1972	0.1942	0.1913	0.1885	0.1858	0.1831	0.1805	0.1780	0.1755	0.1731	0.1708	0.1685	0.1691	0.1669	0.1648
		Govt. Profit Oil	0.3151	0.3100	0.3051	0.3003	0.2956	0.2958	0.2914	0.2870	0.2828	0.2787	0.2747	0.2708	0.2670	0.2633	0.2597	0.2562	0.2527	0.2537	0.2504	0.2471
		Total Contrctr Cost and Profit Oil, MMBbl	0.0036	0.0035	0.0035	0.0034	0.0033	0.0033	0.0033	0.0032	0.0032	0.0031	0.0031	0.0031	0.0030	0.0030	0.0029	0.0029	0.0028	0.0028	0.0028	0.0028
		Evaluated Net Oil, MMBbl	0.0036	0.0035	0.0035	0.0034	0.0033	0.0033	0.0033	0.0032	0.0032	0.0031	0.0031	0.0031	0.0030	0.0030	0.0029	0.0029	0.0028	0.0028	0.0028	0.0028
Cash Flow	Norio	Cash Flow	0.21	0.21	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.18	0.18	0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.16
		DCF @10%	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.07
	Cumulative CF		37.95	38.15	38.36	38.56	38.75	38.95	39.14	39.34	39.52	39.71	39.89	40.07	40.25	40.43	40.60	40.77	40.94	41.11	41.28	41.44
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		Cumulative Total Costs, MM$	40.38	40.41	40.44	40.47	40.50	40.53	40.56	40.58	40.61	40.64	40.67	40.70	40.73	40.75	40.78	40.81	40.84	40.87	40.89	40.92
		Cntrctr's Total Profit from Sales of Oil, MM$	0.24	0.24	0.23	0.23	0.23	0.23	0.22	0.22	0.22	0.21	0.21	0.21	0.21	0.20	0.20	0.20	0.20	0.20	0.19	0.19
		Cumulative Total Profit, MM$	58.33	58.56	58.80	59.02	59.25	59.48	59.70	59.92	60.14	60.35	60.56	60.77	60.98	61.18	61.38	61.58	61.78	61.97	62.17	62.36
		Payout? 1=yes, 0=no	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
			Nov-21	Nov-21	Nov-21	Nov-21	#####	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21

zontal Wells, Mean Values

Producing Wells + Workov

Section		Yr-Mo	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
		Oil Volume																				
Production	Norio	Existing Production	166	164	163	161	159	158	156	155	153	152	150	149	148	131	129	128	126	125	124	123
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	387	382	378	374	371	367	363	359	356	352	349	345	342	339	335	332	329	326	323	320
		Undeveloped	5,630	5,562	5,496	5,431	5,368	5,306	5,245	5,186	5,128	5,071	5,016	4,961	4,908	4,856	4,805	4,755	4,706	4,658	4,611	4,564
		Number of Producing Wells	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	13	13
		Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Undeveloped	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
		Brent Oil Price	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**
Revenue	NORIO	Norio Oil Production	6,183	6,109	6,037	5,967	5,898	5,830	5,765	5,700	5,637	5,575	5,515	5,456	5,398	5,325	5,269	5,215	5,161	5,109	5,058	5,008
		Daily Production	214	211	209	206	204	202	199	197	195	193	191	189	187	184	182	180	178	177	175	173
		Monthly Oil MMbbls	0.0062	0.0061	0.0060	0.0060	0.0059	0.0058	0.0058	0.0057	0.0056	0.0056	0.0055	0.0055	0.0054	0.0053	0.0053	0.0052	0.0052	0.0051	0.0051	0.0050
		Norio Revenue	0.43	0.43	0.42	0.42	0.41	0.41	0.40	0.40	0.40	0.40	0.39	0.39	0.38	0.38	0.38	0.37	0.37	0.36	0.36	0.36
		Total Production	6,183	6,109	6,037	5,967	5,898	5,830	5,765	5,700	5,637	5,575	5,515	5,456	5,398	5,325	5,269	5,215	5,161	5,109	5,058	5,008
		Total Project Revenue M$	0.43	0.43	0.42	0.42	0.41	0.41	0.40	0.40	0.40	0.40	0.39	0.39	0.38	0.38	0.38	0.37	0.37	0.36	0.36	0.36
CAPEX	Norio	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	Norio	Fixed Opex+OH	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
		Floating Opex	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Norio Opex	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		OPEX TOTAL	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Cost Recovery	Norio	Recoverable Opex	0.0275	0.0274	0.0274	0.0273	0.0272	0.0272	0.0271	0.0270	0.0270	0.0269	0.0269	0.0268	0.0268	0.0267	0.0266	0.0266	0.0265	0.0265	0.0265	0.0264
		Contractor Opex Cost Oil	0.0275	0.0274	0.0274	0.0273	0.0272	0.0272	0.0271	0.0270	0.0270	0.0269	0.0269	0.0268	0.0268	0.0267	0.0266	0.0266	0.0265	0.0265	0.0265	0.0264
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.18	0.19	0.18	0.18	0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.16
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Profit Share	Norio	Total Profit Oil	0.4066	0.4015	0.3964	0.3915	0.3867	0.3820	0.3774	0.3729	0.3684	0.3702	0.3659	0.3617	0.3576	0.3536	0.3486	0.3446	0.3409	0.3371	0.3335	0.3299
		Contractor Profit Oil	0.1627	0.1606	0.1586	0.1566	0.1547	0.1528	0.1509	0.1491	0.1474	0.1481	0.1464	0.1447	0.1430	0.1414	0.1394	0.1379	0.1363	0.1349	0.1334	0.1320
		Govt. Profit Oil	0.2440	0.2409	0.2379	0.2349	0.2320	0.2292	0.2264	0.2237	0.2211	0.2221	0.2196	0.2170	0.2146	0.2122	0.2091	0.2068	0.2045	0.2023	0.2001	0.1980
		Total Contrctr Cost and Profit Oil, MMBbl	0.0027	0.0027	0.0027	0.0027	0.0026	0.0026	0.0026	0.0025	0.0025	0.0025	0.0025	0.0024	0.0024	0.0024	0.0024	0.0023	0.0023	0.0023	0.0023	0.0022
		Evaluated Net Oil, MMBbl	0.0027	0.0027	0.0027	0.0027	0.0026	0.0026	0.0026	0.0025	0.0025	0.0025	0.0025	0.0024	0.0024	0.0024	0.0024	0.0023	0.0023	0.0023	0.0023	0.0022
Cash Flow	Norio	Cash Flow	0.16	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13
		DCF @10%	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05
	Cumulative CF		41.60	41.76	41.92	42.08	42.23	42.39	42.54	42.69	42.83	42.98	43.13	43.27	43.42	43.56	43.70	43.84	43.97	44.11	44.24	44.37
Payment Date	Norio	Total Costs Incurred for Production, MM$	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		Cumulative Total Costs, MM$	40.95	40.98	41.00	41.03	41.06	41.08	41.11	41.14	41.17	41.19	41.22	41.25	41.27	41.30	41.33	41.35	41.38	41.41	41.43	41.46
		Cntrctr's Total Profit from Sales of Oil, MM$	0.19	0.19	0.19	0.18	0.18	0.18	0.18	0.18	0.17	0.18	0.17	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16
		Cumulative Total Profit, MM$	62.55	62.74	62.93	63.11	63.29	63.47	63.65	63.83	64.00	64.17	64.35	64.52	64.69	64.86	65.02	65.19	65.35	65.51	65.67	65.83
		Payout? 1=yes, 0=no	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
			Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21	Nov-21

ɾers + Lateral Jetting + Horizontal Wells, Mean Values

Producing Wells + Workovers + Lateral Jetting + Horizontal Wells, Mea

SATSKHENISI

		Yr-Mo	Units	Total	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19
		Oil Volume																			
Production	SKN	Existing Production	Bbl	3,949	103	100	98	95	93	91	88	86	84	82	80	78	76	74	72	71	69
		Workovers - SI or BP	Bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	Bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	Bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	Wells		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Existing Production	Wells		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		SI Wells	Wells		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	Wells		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	$/Bbl		60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	62.81	62.81	62.81	62.81	62.81
Revenue	SKN	SKN Oil Production	BOPM	3,949	103	100	98	95	93	91	88	86	84	82	80	78	76	74	72	71	69
		Daily Production	BOPD		4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2
		Monthly Oil MMbbls	MMBbl	0.0039	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		SKN Revenue	M$	0.2		0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Production	Bbl	3,949	103	100	98	95	93	91	88	86	84	82	80	78	76	74	72	71	69
		Total Project Revenue M$	M$	0.2	0.00	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPEX	SKN	Workovers	MM$	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	MM$	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	MM$	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	MM$	0.3	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	MM$	0.0057	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		Workovers	MM$	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	MM$	0.3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	MM$	0.3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	MM$	0.09	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0027	0.0027	0.0027	0.0027	0.0027
		Contractor Opex Cost Oil	MM$	0.09	0.0000	0.0053	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0027	0.0027	0.0027	0.0027	0.0027
		Unrecovered Opex	MM$		0.0026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	MM$		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	MM$		10.28	10.28	10.28	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.26	10.26	10.26
		Contractor Capex Cost Oil	MM$	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	MM$		10.28	10.28	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.27	10.26	10.26	10.26	10.26
		Total Cost Oil	MM$		0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Profit Share	SKN	Total Profit Oil	MM$	0.0171	0.0000	0.0000	0.0013	0.0012	0.0011	0.0011	0.0010	0.0010	0.0009	0.0009	0.0008	0.0008	0.0007	0.0007	0.0007	0.0006	0.0006
		Contractor Profit Oil	MM$	0.0086	0.0000	0.0000	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	0.0003	0.0004	0.0003	0.0003	0.0003
		Govt. Profit Oil	MM$	0.0086	0.0000	0.0000	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	0.0003	0.0004	0.0003	0.0003	0.0003
		Total Contrctr Cost and Profit Oil, MMBbl	MMBbl	0.0021	0.0000	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		Evaluated Net Oil, MMBbl	MMBbl	0.0019	0.0000	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Cash Flow	SKN	Cash Flow	MM$	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	MM$	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF			0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02
Payment Date	SKN	Total Costs Incurred for Production, MM$	MM$	10.61	10.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	MM$	10.61	10.28	10.28	10.28	10.29	10.29	10.29	10.29	10.30	10.30	10.30	10.30	10.31	10.31	10.31	10.32	10.32	10.32
		Cntrctr's Total Profit from Sales of Oil, MM$	MM$	0.11	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	MM$	0.11	0.00	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.06
		Payout? 1=yes, 0=no			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Section		Yr-Mo	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21
		Oil Volume																				
Production	SKN	Existing Production	67	65	64	62	61	59	58	56	55	54	52	51	50	49	47	46	45	44	43	42
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Existing Production	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**70.70**
Revenue	SKN	SKN Oil Production	67	65	64	62	61	59	58	56	55	54	52	51	50	49	47	46	45	44	43	42
		Daily Production	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1
		Monthly Oil MMbbls	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		SKN Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Production	67	65	64	62	61	59	58	56	55	54	52	51	50	49	47	46	45	44	43	42
		Total Project Revenue M$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPEX	SKN	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0005	0.0005	0.0004	0.0004	0.0003	0.0003	0.0003	0.0002	0.0003	0.0002	0.0002	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0003	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0003	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	SKN	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cumulative CF		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.32	10.33	10.33	10.33	10.33	10.34	10.34	10.34	10.34	10.35	10.35	10.35	10.36	10.36	10.36	10.36	10.37	10.37	10.37	10.37
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		Yr-Mo	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22
		Oil Volume																				
Production	SKN	Existing Production	41	40	39	38	37	36	35	34	34	33	32	31	30	30	29	28	28	27	26	26
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Existing Production	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**
Revenue	SKN	SKN Oil Production	41	40	39	38	37	36	35	34	34	33	32	31	30	30	29	28	28	27	26	26
		Daily Production	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		Monthly Oil MMbbls	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		SKN Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Production	41	40	39	38	37	36	35	34	34	33	32	31	30	30	29	28	28	27	26	26
		Total Project Revenue M$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPEX	SKN	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	SKN	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.38	10.38	10.38	10.39	10.39	10.39	10.39	10.40	10.40	10.40	10.40	10.41	10.41	10.41	10.42	10.42	10.42	10.42	10.43	10.43
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Section	Group	Yr-Mo	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24
		Oil Volume																			
Production	SKN	Existing Production	25	24	24	23	23	22	22	21	21	20	20	19	19	18	18	17	17	16	16
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Existing Production	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**74.23**	**74.23**	**74.23**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**76.23**	**76.23**	**76.23**	**76.23**
Revenue	SKN	SKN Oil Production	25	24	24	23	23	22	22	21	21	20	20	19	19	18	18	17	17	16	16
		Daily Production	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		Monthly Oil MMbbls	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		SKN Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Production	25	24	24	23	23	22	22	21	21	20	20	19	19	18	18	17	17	16	16
		Total Project Revenue M$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPEX	SKN	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	SKN	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.43	10.44	10.44	10.44	10.44	10.45	10.45	10.45	10.45	10.46	10.46	10.46	10.47	10.47	10.47	10.47	10.48	10.48	10.48
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		Yr-Mo	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25
		Oil Volume																			
Production	SKN	Existing Production	16	15	15	15	14	14	14	13	13	13	12	12	12	11	11	11	11	10	10
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Existing Production	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**
Revenue	SKN	SKN Oil Production	16	15	15	15	14	14	14	13	13	13	12	12	12	11	11	11	11	10	10
		Daily Production	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Monthly Oil MMbbls	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		SKN Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Production	16	15	15	15	14	14	14	13	13	13	12	12	12	11	11	11	11	10	10
		Total Project Revenue M$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPEX	SKN	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	SKN	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.49	10.49	10.49	10.49	10.50	10.50	10.50	10.51	10.51	10.51	10.51	10.52	10.52	10.52	10.53	10.53	10.53	10.54	10.54
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		Yr-Mo	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27
		Oil Volume																			
Production	SKN	Existing Production	10	10	9	9	7	7	7	7	7	7	6	6	6	6	6	6	5	5	5
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	5	5	5	5	5	5	5	5	4	4	4	4	4	4	4	4	3	3	3
		Existing Production	5	5	5	5	5	5	5	5	4	4	4	4	4	4	4	4	3	3	3
		SI Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**77.26**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**
Revenue	SKN	SKN Oil Production	10	10	9	9	7	7	7	7	7	7	6	6	6	6	6	6	5	5	5
		Daily Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Monthly Oil MMbbls	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		SKN Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Production	10	10	9	9	7	7	7	7	7	7	6	6	6	6	6	6	5	5	5
		Total Project Revenue M$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPEX	SKN	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	SKN	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.54	10.54	10.55	10.55	10.55	10.56	10.56	10.56	10.56	10.57	10.57	10.57	10.58	10.58	10.58	10.59	10.59	10.59	10.59
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Section	Area	Yr-Mo	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
		Oil Volume						
Production	SKN	Existing Production	5	5	5	5	5	4
		Workovers - SI or BP	0	0	0	0	0	0
		Workovers - RDS	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0
		Number of Producing Wells	3	3	3	3	3	3
		Existing Production	3	3	3	3	3	3
		SI Wells	0	0	0	0	0	0
		Lateral Jetting	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0
		Brent Oil Price	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**
Revenue	SKN	SKN Oil Production	5	5	5	5	5	4
		Daily Production	0	0	0	0	0	0
		Monthly Oil MMbbls	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		SKN Revenue	0.00	0.00	0.00	0.00	0.00	0.00
		Total Production	5	5	5	5	5	4
		Total Project Revenue M$	0.00	0.00	0.00	0.00	0.00	0.00
CAPEX	SKN	Workovers	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	SKN	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00
	Cumulative CF		0.02	0.02	0.02	0.02	0.02	0.02
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.60	10.60	10.60	10.61	10.61	10.61
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	0.11	0.11	0.11	0.11	0.11	0.11
		Payout? 1=yes, 0=no	0	0	0	0	0	0

		Yr-Mo	Units	Total	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19
		Oil Volume																			
Production	SKN	Existing Production	Bbl	1,443	38	37	36	35	34	33	32	32	31	30	29	29	28	27	26	26	25
		Workovers - SI or BP	Bbl	9,177	0	0	245	239	232	227	221	215	210	204	199	194	189	185	180	175	171
		Workovers - RDS	Bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	Bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	Wells		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Existing Production	Wells		5	5	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
		SI Wells	Wells		0	0	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Lateral Jetting			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	Wells		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	$/Bbl		**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**60.56**	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**
Revenue	SKN	SKN Oil Production	BOPM	10,620	38	37	280	273	266	260	253	247	241	234	229	223	217	212	206	201	196
		Daily Production	BOPD		1	1	10	9	9	9	9	9	8	8	8	8	8	7	7	7	7
		Monthly Oil MMbbls	MMBbl	0.0106	0.0000	0.0000	0.0003	0.0003	0.0003	0.0003	0.0003	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
		SKN Revenue	M$	0.6		0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Total Production	Bbl	10,620	38	37	280	273	266	260	253	247	241	234	229	223	217	212	206	201	196
		Total Project Revenue M$	M$	0.6	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CAPEX	SKN	Workovers	MM$	0.0	0	0	0.032	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	MM$	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	MM$	0.0	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	MM$	0.3	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	MM$	0.0152	0.0001	0.0001	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
		Workovers	MM$	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	MM$	0.3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	MM$	0.3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	MM$	0.22	0.0026	0.0026	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0028	0.0028	0.0028	0.0028	0.0029	0.0029	0.0029	0.0029	0.0028
		Contractor Opex Cost Oil	MM$	0.22	0.0000	0.0019	0.0019	0.0071	0.0029	0.0029	0.0029	0.0029	0.0028	0.0028	0.0028	0.0028	0.0029	0.0029	0.0029	0.0029	0.0028
		Unrecovered Opex	MM$		0.0026	0.0032	0.0042	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	MM$		0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	MM$		10.28	10.28	10.31	10.31	10.30	10.30	10.29	10.29	10.28	10.28	10.27	10.27	10.26	10.26	10.26	10.25	10.25
		Contractor Capex Cost Oil	MM$	0.16	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	MM$		10.28	10.28	10.31	10.30	10.30	10.29	10.29	10.28	10.28	10.27	10.27	10.26	10.26	10.26	10.25	10.25	10.24
		Total Cost Oil	MM$		**0.00**	**0.00**	**0.00**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**
Profit Share	SKN	Total Profit Oil	MM$	0.1614	0.0000	0.0000	0.0000	0.0037	0.0056	0.0054	0.0053	0.0051	0.0049	0.0048	0.0046	0.0045	0.0043	0.0044	0.0043	0.0041	0.0040
		Contractor Profit Oil	MM$	0.0807	0.0000	0.0000	0.0000	0.0018	0.0028	0.0027	0.0026	0.0025	0.0025	0.0024	0.0023	0.0022	0.0022	0.0022	0.0021	0.0021	0.0020
		Govt. Profit Oil	MM$	0.0807	0.0000	0.0000	0.0000	0.0018	0.0028	0.0027	0.0026	0.0025	0.0025	0.0024	0.0023	0.0022	0.0022	0.0022	0.0021	0.0021	0.0020
		Total Contrctr Cost and Profit Oil, MMBbl	MMBbl	0.0080	0.0000	0.0000	0.0000	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
		Evaluated Net Oil, MMBbl	MMBbl	0.0072	0.0000	0.0000	0.0000	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001
Cash Flow	SKN	Cash Flow	MM$	0.19	0.00	0.00	-0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		DCF @10%	MM$	0.15	0.00	0.00	-0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
	Cumulative CF				0.00	0.00	-0.04	-0.03	-0.02	-0.01	0.00	0.00	0.01	0.02	0.02	0.03	0.04	0.04	0.05	0.05	0.06
Payment Date	SKN	Total Costs Incurred for Production, MM$	MM$	10.65	10.28	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	MM$	10.65	10.28	10.28	10.32	10.32	10.32	10.32	10.33	10.33	10.33	10.34	10.34	10.34	10.34	10.35	10.35	10.35	10.36
		Cntrctr's Total Profit from Sales of Oil, MM$	MM$	0.46	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Cumulative Total Profit, MM$	MM$	0.46	0.00	0.00	0.00	0.02	0.03	0.04	0.05	0.06	0.07	0.08	0.09	0.10	0.11	0.12	0.13	0.14	0.15
		Payout? 1=yes, 0=no			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		Yr-Mo	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21
		Oil Volume																				
Production	SKN	Existing Production	25	24	23	23	22	22	21	21	20	20	19	19	18	18	17	17	16	16	16	15
		Workovers - SI or BP	167	162	158	154	150	146	143	139	136	132	129	126	122	119	116	113	110	108	105	102
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Existing Production	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
		SI Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**62.81**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**70.70**
Revenue	SKN	SKN Oil Production	191	186	182	177	172	168	164	160	156	152	148	144	141	137	134	130	127	124	121	117
		Daily Production	7	6	6	6	6	6	6	6	5	5	5	5	5	5	5	5	4	4	4	4
		Monthly Oil MMbbls	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		SKN Revenue	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Total Production	191	186	182	177	172	168	164	160	156	152	148	144	141	137	134	130	127	124	121	117
		Total Project Revenue M$	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CAPEX	SKN	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0003	0.0003	0.0003	0.0003	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028
		Contractor Opex Cost Oil	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	10.24	10.24	10.24	10.23	10.23	10.22	10.22	10.22	10.22	10.21	10.21	10.21	10.20	10.20	10.20	10.20	10.19	10.19	10.19	10.19
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	10.24	10.24	10.23	10.23	10.22	10.22	10.22	10.22	10.21	10.21	10.21	10.20	10.20	10.20	10.20	10.19	10.19	10.19	10.19	10.19
		Total Cost Oil	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0039	0.0037	0.0036	0.0035	0.0033	0.0032	0.0031	0.0030	0.0031	0.0030	0.0029	0.0028	0.0027	0.0026	0.0025	0.0024	0.0023	0.0022	0.0021	0.0020
		Contractor Profit Oil	0.0019	0.0019	0.0018	0.0017	0.0017	0.0016	0.0016	0.0015	0.0016	0.0015	0.0014	0.0014	0.0013	0.0013	0.0012	0.0012	0.0011	0.0011	0.0011	0.0010
		Govt. Profit Oil	0.0019	0.0019	0.0018	0.0017	0.0017	0.0016	0.0016	0.0015	0.0016	0.0015	0.0014	0.0014	0.0013	0.0013	0.0012	0.0012	0.0011	0.0011	0.0011	0.0010
		Total Contrctr Cost and Profit Oil, MMBbl	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		Evaluated Net Oil, MMBbl	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Cash Flow	SKN	Cash Flow	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cumulative CF		0.06	0.07	0.07	0.08	0.08	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.14
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.36	10.36	10.36	10.37	10.37	10.37	10.38	10.38	10.38	10.38	10.39	10.39	10.39	10.40	10.40	10.40	10.40	10.41	10.41	10.41
		Cntrctr's Total Profit from Sales of Oil, MM$	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Cumulative Total Profit, MM$	0.15	0.16	0.17	0.18	0.19	0.19	0.20	0.21	0.22	0.22	0.23	0.24	0.25	0.25	0.26	0.26	0.27	0.28	0.28	0.29
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		Yr-Mo	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22
		Oil Volume																				
Production	SKN	Existing Production	15	14	14	14	13	13	13	12	12	12	12	11	11	11	10	10	10	10	9	9
		Workovers - SI or BP	100	97	95	92	90	88	85	83	81	79	77	75	73	71	70	68	66	64	63	61
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Existing Production	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
		SI Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**
Revenue	SKN	SKN Oil Production	115	112	109	106	103	101	98	96	93	91	89	86	84	82	80	78	76	74	72	70
		Daily Production	4	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2
		Monthly Oil MMbbls	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		SKN Revenue	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
		Total Production	115	112	109	106	103	101	98	96	93	91	89	86	84	82	80	78	76	74	72	70
		Total Project Revenue M$	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
CAPEX	SKN	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028
		Contractor Opex Cost Oil	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	10.19	10.18	10.18	10.18	10.18	10.17	10.17	10.17	10.17	10.17	10.17	10.17	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	10.18	10.18	10.18	10.18	10.17	10.17	10.17	10.17	10.17	10.17	10.17	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.15
		Total Cost Oil	**0.01**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0022	0.0021	0.0020	0.0019	0.0019	0.0018	0.0017	0.0016	0.0015	0.0015	0.0014	0.0013	0.0014	0.0013	0.0013	0.0012	0.0011	0.0011	0.0010	0.0009
		Contractor Profit Oil	0.0011	0.0011	0.0010	0.0010	0.0009	0.0009	0.0008	0.0008	0.0008	0.0007	0.0007	0.0007	0.0007	0.0007	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005
		Govt. Profit Oil	0.0011	0.0011	0.0010	0.0010	0.0009	0.0009	0.0008	0.0008	0.0008	0.0007	0.0007	0.0007	0.0007	0.0007	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005
		Total Contrctr Cost and Profit Oil, MMBbl	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		Evaluated Net Oil, MMBbl	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Cash Flow	SKN	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.17	0.17	0.18	0.18	0.18
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.42	10.42	10.42	10.42	10.43	10.43	10.43	10.44	10.44	10.44	10.44	10.45	10.45	10.45	10.45	10.46	10.46	10.46	10.47	10.47
		Cntrctr's Total Profit from Sales of Oil, MM$	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	0.29	0.30	0.31	0.31	0.32	0.32	0.33	0.33	0.34	0.34	0.35	0.35	0.36	0.36	0.37	0.37	0.38	0.38	0.39	0.39
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		Yr-Mo	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24
		Oil Volume																			
Production	SKN	Existing Production	9	9	9	8	8	8	8	8	7	7	7	7	7	7	6	6	6	6	6
		Workovers - SI or BP	60	58	57	55	54	52	51	50	49	47	46	45	44	43	42	41	40	39	38
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Existing Production	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
		SI Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**74.23**	**74.23**	**74.23**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**75.21**	**76.23**	**76.23**	**76.23**	**76.23**
Revenue	SKN	SKN Oil Production	69	67	65	64	62	60	59	57	56	55	53	52	51	49	48	47	46	44	43
		Daily Production	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1
		Monthly Oil MMbbls	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		SKN Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Production	69	67	65	64	62	60	59	57	56	55	53	52	51	49	48	47	46	44	43
		Total Project Revenue M$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPEX	SKN	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0028	0.0028	0.0028	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029
		Contractor Opex Cost Oil	0.0028	0.0028	0.0028	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0009	0.0008	0.0008	0.0007	0.0007	0.0006	0.0006	0.0005	0.0005	0.0004	0.0004	0.0003	0.0003	0.0002	0.0002	0.0001	0.0001	0.0001	0.0000
		Contractor Profit Oil	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000
		Govt. Profit Oil	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	SKN	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.47	10.47	10.48	10.48	10.48	10.49	10.49	10.49	10.49	10.50	10.50	10.50	10.51	10.51	10.51	10.51	10.52	10.52	10.52
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	0.40	0.40	0.40	0.41	0.41	0.41	0.42	0.42	0.43	0.43	0.43	0.44	0.44	0.44	0.45	0.45	0.45	0.45	0.46
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		Yr-Mo	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25
		Oil Volume																			
Production	SKN	Existing Production	6	5	5	5	5	5	5	5	5	4	4	4	4	4	4	4	4	4	4
		Workovers - SI or BP	37	36	35	34	33	32	31	31	30	29	28	28	27	26	26	25	24	24	23
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Existing Production	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
		SI Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**76.23**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**
Revenue	SKN	SKN Oil Production	42	41	40	39	38	37	36	35	34	34	33	32	31	30	30	29	28	27	27
		Daily Production	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		Monthly Oil MMbbls	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		SKN Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Production	42	41	40	39	38	37	36	35	34	34	33	32	31	30	30	29	28	27	27
		Total Project Revenue M$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPEX	SKN	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0029	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0029	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	10.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	10.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	SKN	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative CF	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.53	10.53	10.53	10.54	10.54	10.54	10.54	10.55	10.55	10.55	10.56	10.56	10.56	10.56	10.57	10.57	10.57	10.58	10.58
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		Yr-Mo	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27
		Oil Volume																			
Production	SKN	Existing Production	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2
		Workovers - SI or BP	23	22	21	21	20	20	19	19	18	18	17	17	17	16	14	14	13	13	13
		Workovers - RDS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Number of Producing Wells	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4
		Existing Production	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
		SI Wells	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2
		Lateral Jetting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Brent Oil Price	**77.26**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**
Revenue	SKN	SKN Oil Production	26	25	25	24	23	23	22	22	21	21	20	20	19	19	17	16	16	15	15
		Daily Production	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		Monthly Oil MMbbls	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		SKN Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Production	26	25	25	24	23	23	22	22	21	21	20	20	19	19	17	16	16	15	15
		Total Project Revenue M$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPEX	SKN	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	SKN	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cumulative CF		0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.58	10.59	10.59	10.59	10.59	10.60	10.60	10.60	10.61	10.61	10.61	10.61	10.62	10.62	10.62	10.63	10.63	10.63	10.64
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
		Payout? 1=yes, 0=no	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		Yr-Mo	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
		Oil Volume						
Production	SKN	Existing Production	2	2	2	2	2	2
		Workovers - SI or BP	12	12	12	12	11	11
		Workovers - RDS	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0
		Number of Producing Wells	4	4	4	4	4	4
		Existing Production	2	2	2	2	2	2
		SI Wells	2	2	2	2	2	2
		Lateral Jetting	0	0	0	0	0	0
		Undeveloped	0	0	0	0	0	0
		Brent Oil Price	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**	**79.45**
Revenue	SKN	SKN Oil Production	15	14	14	14	13	13
		Daily Production	1	0	0	0	0	0
		Monthly Oil MMbbls	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		SKN Revenue	0.00	0.00	0.00	0.00	0.00	0.00
		Total Production	15	14	14	14	13	13
		Total Project Revenue M$	0.00	0.00	0.00	0.00	0.00	0.00
CAPEX	SKN	Workovers	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00
Opex	SKN	Fixed Opex+OH	0.003	0.003	0.003	0.003	0.003	0.003
		Floating Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00
		Total SKN Opex	0.00	0.00	0.00	0.00	0.00	0.00
		OPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00
Cost Recovery	SKN	Recoverable Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Opex Cost Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Unrecovered Opex	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Capex recovery Limit	0.00	0.00	0.00	0.00	0.00	0.00
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Profit Share	SKN	Total Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Contractor Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Govt. Profit Oil	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Total Contrctr Cost and Profit Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Evaluated Net Oil, MMBbl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cash Flow	SKN	Cash Flow	0.00	0.00	0.00	0.00	0.00	0.00
		DCF @10%	0.00	0.00	0.00	0.00	0.00	0.00
	Cumulative CF		0.19	0.19	0.19	0.19	0.19	0.19
Payment Date	SKN	Total Costs Incurred for Production, MM$	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Costs, MM$	10.64	10.64	10.65	10.65	10.65	10.65
		Cntrctr's Total Profit from Sales of Oil, MM$	0.00	0.00	0.00	0.00	0.00	0.00
		Cumulative Total Profit, MM$	0.46	0.46	0.46	0.46	0.46	0.46
		Payout? 1=yes, 0=no	0	0	0	0	0	0

WEST RUSTAVI

Yr-Mo			Units	Total	01/18	02/18	03/18	04/18	05/18	06/18	07/18	08/18	09/18	10/18	11/18	12/18	01/19	02/19	03/19	04/19	05/19	06/19	07/19	08/19
		Year			1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2
		Month		Total	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
		Oil Volume																						
Production	W Rustavi	Existing Production	Bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - SI or BP	Bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Sidetracks	Bbl	855,302	0	0	0	0	0	0	0	0	0	0	0	0	0	11,407	10,485	21,075	30,832	39,849	36,798	34,075
		Number of Producing Wells	Wells		0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	2	3	4	4	4
		Existing Production	Wells		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - SI or BP	Wells		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Sidetracks	Wells		0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	2	3	4	4	4
		Brent Oil Price	$/Bbl		60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	60.56	62.81	62.81	62.81	62.81	62.81	62.81	62.81	62.81
Revenue	W Rustavi	W Rustavi Oil Production	BOPM	855,302	0	0	0	0	0	0	0	0	0	0	0	0	0	11,407	10,485	21,075	30,832	39,849	36,798	34,075
		Daily Production	BOPD		0	0	0	0	0	0	0	0	0	0	0	0	0	394	363	729	1,066	1,378	1,273	1,178
		Monthly Oil MMbbls	MMBbl	0.8553	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0114	0.0105	0.0211	0.0308	0.0398	0.0368	0.0341
		W Rustavi Revenue	M$	50.5		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.61	0.56	1.13	1.66	2.14	1.98
		Total Production	Bbl	855,302	0	0	0	0	0	0	0	0	0	0	0	0	0	11,407	10,485	21,075	30,832	39,849	36,798	34,075
		Total Project Revenue M$	M$	50.5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.61	0.56	1.13	1.66	2.14	1.98
CAPEX	W Rustavi	Workovers	MM$	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	MM$	6.0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.5	0	1.5	1.5	1.5	0	0
		CAPEX TOTAL	MM$	6.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.50	0.00	1.50	1.50	1.50	0.00	0.00
Opex	W Rustavi	Fixed Opex+OH	MM$	1.5	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.013	0.013	0.013	0.013	0.013	0.013	0.013
		Floating Opex	MM$	1.2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.03	0.04	0.06	0.05	0.05
		Workovers	MM$	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total W Rustavi Opex	MM$	2.7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.04	0.06	0.07	0.07	0.06
		OPEX TOTAL	MM$	2.7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.04	0.06	0.07	0.07	0.06
Cost Recovery	W Rustavi	Recoverable Opex	MM$	2.71	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.029	0.028	0.043	0.057	0.070	0.066	0.062
		Contractor Opex Cost Oil	MM$	2.71	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.057	0.043	0.057	0.070	0.066	0.062
		Unrecovered Opex	MM$		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.029	0.000	0.000	0.000	0.000	0.000	0.000
		Capex recovery Limit	MM$		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.28	0.26	0.54	0.79	1.04	0.96
		Recoverable Capex	MM$		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.50	1.50	2.72	3.96	4.92	4.13	3.09
		Contractor Capex Cost Oil	MM$	6.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.28	0.26	0.54	0.79	1.04	0.96
		Unrecovered Capex	MM$		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.50	1.22	2.46	3.42	4.13	3.09	2.13
		Total Cost Oil	MM$		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.34	0.30	0.60	0.86	1.10	1.02
Profit Share	W Rustavi	Total Profit Oil	MM$	41.7426	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2785	0.2606	0.5385	0.7946	1.0393	0.9592
		Contractor Profit Oil	MM$	17.1729	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1392	0.1303	0.2693	0.3973	0.5197	0.4796
		Govt. Profit Oil	MM$	24.5697	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1392	0.1303	0.2693	0.3973	0.5197	0.4796
		Total Contrctr Cost and Profit Oil, MMBbl	MMBbl	0.4426	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0088	0.0081	0.0161	0.0234	0.0302	0.0279
		Evaluated Net Oil, MMBbl	MMBbl	0.3319	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0066	0.0060	0.0121	0.0176	0.0226	0.0209
Cash Flow	W Rustavi	Cash Flow	MM$	12.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-1.53	0.45	-1.11	-0.69	-0.31	1.56	1.44
		DCF @10%	MM$	9.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-1.37	0.40	-0.98	-0.60	-0.27	1.34	1.23
		Cumulative CF			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-1.53	-1.08	-2.19	-2.88	-3.19	-1.63	-0.19
Payout Date	W Rustavi	Total Costs Incurred for Production, MM$	MM$	8.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.53	0.03	1.54	1.56	1.57	0.07	0.06
		Cumulative Total Costs, MM$	MM$	8.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.53	1.56	3.10	4.66	6.23	6.29	6.35
		Cntrctr's Total Profit from Sales of Oil, MM$	MM$	25.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.43	0.86	1.26	1.62	1.50
		Cumulative Total Profit, MM$	MM$	25.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.91	1.77	3.03	4.66	6.16
		Payout? 1=yes, 0=no		10/2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Section		Yr-Mo	09/19	10/19	11/19	12/19	01/20	02/20	03/20	04/20	05/20	06/20	07/20	08/20	09/20	10/20	11/20	12/20	01/21	02/21	03/21	04/21	05/21
		Year	**2**	**2**	**2**	**2**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**4**	**4**	**4**	**4**	**4**
		Month	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**
		Oil Volume																					
Production	**W Rustavi**	**Existing Production**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Sidetracks	31,635	29,441	27,462	25,670	24,043	22,561	21,209	19,971	18,836	17,791	16,829	15,941	15,119	14,357	13,650	12,992	12,379	11,807	11,273	10,773	10,305
		Number of Producing Wells	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
		Existing Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Sidetracks	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
		Brent Oil Price	**62.81**	**62.81**	**62.81**	**62.81**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**65.80**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**
Revenue	**W Rustavi**	**W Rustavi Oil Production**	31,635	29,441	27,462	25,670	24,043	22,561	21,209	19,971	18,836	17,791	16,829	15,941	15,119	14,357	13,650	12,992	12,379	11,807	11,273	10,773	10,305
		Daily Production	1,094	1,018	950	888	831	780	733	691	651	615	582	551	523	496	472	449	428	408	390	373	356
		Monthly Oil MMbbls	0.0316	0.0294	0.0275	0.0257	0.0240	0.0226	0.0212	0.0200	0.0188	0.0178	0.0168	0.0159	0.0151	0.0144	0.0136	0.0130	0.0124	0.0118	0.0113	0.0108	0.0103
		W Rustavi Revenue	1.83	1.70	1.58	1.48	1.38	1.37	1.28	1.20	1.13	1.07	1.01	0.96	0.91	0.86	0.82	0.78	0.74	0.76	0.73	0.70	0.66
		Total Production	31,635	29,441	27,462	25,670	24,043	22,561	21,209	19,971	18,836	17,791	16,829	15,941	15,119	14,357	13,650	12,992	12,379	11,807	11,273	10,773	10,305
		Total Project Revenue M$	1.83	1.70	1.58	1.48	1.38	1.37	1.28	1.20	1.13	1.07	1.01	0.96	0.91	0.86	0.82	0.78	0.74	0.76	0.73	0.70	0.66
CAPEX	**W Rustavi**	**Workovers**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	**W Rustavi**	**Fixed Opex+OH**	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
		Floating Opex	0.05	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total W Rustavi Opex	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		OPEX TOTAL	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Cost Recovery	**W Rustavi**	**Recoverable Opex**	0.058	0.055	0.052	0.050	0.047	0.045	0.043	0.042	0.040	0.039	0.037	0.036	0.035	0.034	0.033	0.032	0.031	0.030	0.029	0.029	0.028
		Contractor Opex Cost Oil	0.058	0.055	0.052	0.050	0.047	0.045	0.043	0.042	0.040	0.039	0.037	0.036	0.035	0.034	0.033	0.032	0.031	0.030	0.029	0.029	0.028
		Unrecovered Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
		Capex recovery Limit	0.89	0.82	0.77	0.71	0.67	0.66	0.62	0.58	0.55	0.52	0.49	0.46	0.44	0.41	0.39	0.37	0.35	0.37	0.35	0.33	0.32
		Recoverable Capex	2.13	1.24	0.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.89	0.82	0.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	1.24	0.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.95**	**0.88**	**0.47**	**0.05**	**0.05**	**0.05**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Profit Share	**W Rustavi**	**Total Profit Oil**	0.8877	0.8236	1.1138	1.4279	1.3338	1.3203	1.2381	1.1630	1.0943	1.0313	0.9734	0.9200	0.8706	0.8250	0.7827	0.7435	0.7070	0.7336	0.6991	0.6668	0.6366
		Contractor Profit Oil	0.4438	0.3294	0.4455	0.5712	0.5335	0.5281	0.4952	0.4652	0.4377	0.4125	0.3893	0.3680	0.3483	0.3300	0.3131	0.2974	0.2828	0.2934	0.2796	0.2667	0.2547
		Govt. Profit Oil	0.4438	0.4941	0.6683	0.8568	0.8003	0.7922	0.7429	0.6978	0.6566	0.6188	0.5840	0.5520	0.5224	0.4950	0.4696	0.4461	0.4242	0.4402	0.4195	0.4001	0.3820
		Total Contrctr Cost and Profit Oil, MMBbl	0.0258	0.0225	0.0170	0.0115	0.0102	0.0101	0.0095	0.0089	0.0084	0.0079	0.0075	0.0071	0.0067	0.0064	0.0061	0.0058	0.0051	0.0052	0.0050	0.0048	0.0046
		Evaluated Net Oil, MMBbl	0.0194	0.0168	0.0128	0.0087	0.0077	0.0076	0.0071	0.0067	0.0063	0.0060	0.0056	0.0053	0.0051	0.0048	0.0046	0.0043	0.0038	0.0039	0.0038	0.0036	0.0034
Cash Flow	**W Rustavi**	**Cash Flow**	1.00	0.86	0.65	0.43	0.40	0.40	0.37	0.35	0.33	0.31	0.29	0.28	0.26	0.25	0.23	0.22	0.21	0.22	0.21	0.20	0.19
		DCF @10%	0.85	0.73	0.54	0.35	0.33	0.32	0.30	0.28	0.26	0.24	0.23	0.21	0.20	0.19	0.18	0.17	0.16	0.16	0.15	0.15	0.14
		Cumulative CF	0.80	1.67	2.32	2.75	3.15	3.54	3.91	4.26	4.59	4.90	5.19	5.47	5.73	5.98	6.21	6.43	6.65	6.87	7.08	7.28	7.47
Payout Date	**W Rustavi**	**Total Costs Incurred for Production, MM$**	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		Cumulative Total Costs, MM$	6.41	6.47	6.52	6.57	6.62	6.66	6.71	6.75	6.79	6.83	6.86	6.90	6.93	6.97	7.00	7.03	7.06	7.09	7.12	7.15	7.18
		Cntrctr's Total Profit from Sales of Oil, MM$	1.39	1.21	0.92	0.62	0.58	0.57	0.54	0.51	0.48	0.45	0.43	0.40	0.38	0.36	0.35	0.33	0.31	0.32	0.31	0.30	0.28
		Cumulative Total Profit, MM$	7.55	8.76	9.67	10.29	10.88	11.45	11.99	12.49	12.97	13.42	13.85	14.25	14.64	15.00	15.35	15.68	15.99	16.31	16.62	16.92	17.20
		Payout? 1=yes, 0=no	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

		Yr-Mo	06/21	07/21	08/21	09/21	10/21	11/21	12/21	01/22	02/22	03/22	04/22	05/22	06/22	07/22	08/22	09/22	10/22	11/22	12/22	01/23	02/23
		Year	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**6**	**6**
		Month	**42**	**43**	**44**	**45**	**46**	**47**	**48**	**49**	**50**	**51**	**52**	**53**	**54**	**55**	**56**	**57**	**58**	**59**	**60**	**61**	**62**
		Oil Volume																					
Production	**W Rustavi**	**Existing Production**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Sidetracks	9,866	9,453	9,065	8,699	8,355	8,030	7,723	7,433	7,158	6,898	6,651	6,417	6,195	5,984	5,783	5,591	5,409	5,235	5,069	4,911	4,760
		Number of Producing Wells	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
		Existing Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Sidetracks	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
		Brent Oil Price	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**70.70**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**74.23**	**75.21**	**75.21**
Revenue	**W Rustavi**	**W Rustavi Oil Production**	9,866	9,453	9,065	8,699	8,355	8,030	7,723	7,433	7,158	6,898	6,651	6,417	6,195	5,984	5,783	5,591	5,409	5,235	5,069	4,911	4,760
		Daily Production	341	327	313	301	289	278	267	257	248	239	230	222	214	207	200	193	187	181	175	170	165
		Monthly Oil MMbbls	0.0099	0.0095	0.0091	0.0087	0.0084	0.0080	0.0077	0.0074	0.0072	0.0069	0.0067	0.0064	0.0062	0.0060	0.0058	0.0056	0.0054	0.0052	0.0051	0.0049	0.0048
		W Rustavi Revenue	0.64	0.61	0.58	0.56	0.54	0.52	0.50	0.48	0.48	0.47	0.45	0.43	0.42	0.40	0.39	0.38	0.36	0.35	0.34	0.33	0.33
		Total Production	9,866	9,453	9,065	8,699	8,355	8,030	7,723	7,433	7,158	6,898	6,651	6,417	6,195	5,984	5,783	5,591	5,409	5,235	5,069	4,911	4,760
		Total Project Revenue M$	0.64	0.61	0.58	0.56	0.54	0.52	0.50	0.48	0.48	0.47	0.45	0.43	0.42	0.40	0.39	0.38	0.36	0.35	0.34	0.33	0.33
CAPEX	**W Rustavi**	**Workovers**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	**W Rustavi**	**Fixed Opex+OH**	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
		Floating Opex	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total W Rustavi Opex	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	**W Rustavi**	**Recoverable Opex**	0.027	0.027	0.026	0.026	0.025	0.025	0.025	0.024	0.024	0.023	0.023	0.023	0.022	0.022	0.022	0.022	0.021	0.021	0.021	0.021	0.021
		Contractor Opex Cost Oil	0.027	0.027	0.026	0.026	0.025	0.025	0.025	0.024	0.024	0.023	0.023	0.023	0.022	0.022	0.022	0.022	0.021	0.021	0.021	0.021	0.021
		Unrecovered Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
		Capex recovery Limit	0.30	0.29	0.28	0.27	0.26	0.25	0.24	0.23	0.23	0.22	0.21	0.21	0.20	0.19	0.18	0.18	0.17	0.17	0.16	0.15	0.15
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**
Profit Share	**W Rustavi**	**Total Profit Oil**	0.6083	0.5818	0.5569	0.5334	0.5114	0.4906	0.4709	0.4524	0.4611	0.4436	0.4269	0.4111	0.3962	0.3819	0.3684	0.3556	0.3433	0.3316	0.3205	0.3099	0.3046
		Contractor Profit Oil	0.2433	0.2327	0.2228	0.2134	0.2045	0.1962	0.1884	0.1810	0.1844	0.1774	0.1708	0.1645	0.1585	0.1528	0.1474	0.1422	0.1373	0.1327	0.1282	0.1240	0.1218
		Govt. Profit Oil	0.3650	0.3491	0.3341	0.3201	0.3068	0.2943	0.2826	0.2714	0.2767	0.2661	0.2561	0.2467	0.2377	0.2292	0.2211	0.2133	0.2060	0.1990	0.1923	0.1859	0.1827
		Total Contrctr Cost and Profit Oil, MMBbl	0.0044	0.0042	0.0040	0.0039	0.0037	0.0036	0.0035	0.0031	0.0032	0.0031	0.0030	0.0029	0.0028	0.0027	0.0026	0.0025	0.0024	0.0024	0.0023	0.0022	0.0022
		Evaluated Net Oil, MMBbl	0.0033	0.0032	0.0030	0.0029	0.0028	0.0027	0.0026	0.0024	0.0024	0.0023	0.0022	0.0022	0.0021	0.0020	0.0019	0.0019	0.0018	0.0018	0.0017	0.0016	0.0016
Cash Flow	**W Rustavi**	**Cash Flow**	0.18	0.17	0.17	0.16	0.15	0.15	0.14	0.14	0.14	0.13	0.13	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10	0.09	0.09
		DCF @10%	0.13	0.12	0.12	0.11	0.11	0.10	0.10	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06
		Cumulative CF	7.65	7.82	7.99	8.15	8.30	8.45	8.59	8.73	8.87	9.00	9.13	9.25	9.37	9.49	9.60	9.70	9.81	9.90	10.00	10.09	10.19
Payout Date	**W Rustavi**	**Total Costs Incurred for Production, MM$**	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	7.21	7.23	7.26	7.29	7.31	7.34	7.36	7.38	7.41	7.43	7.45	7.48	7.50	7.52	7.54	7.57	7.59	7.61	7.63	7.65	7.67
		Cntrctr's Total Profit from Sales of Oil, MM$	0.27	0.26	0.25	0.24	0.23	0.22	0.21	0.21	0.21	0.20	0.19	0.19	0.18	0.17	0.17	0.16	0.16	0.15	0.15	0.14	0.14
		Cumulative Total Profit, MM$	17.47	17.73	17.98	18.22	18.45	18.67	18.88	19.09	19.30	19.50	19.69	19.88	20.06	20.23	20.40	20.57	20.73	20.88	21.03	21.17	21.32
		Payout? 1=yes, 0=no	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

		Yr-Mo	03/23	04/23	05/23	06/23	07/23	08/23	09/23	10/23	11/23	12/23	01/24	02/24	03/24	04/24	05/24	06/24	07/24	08/24	09/24	10/24	11/24
		Year	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	7	7	7
		Month	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83
		Oil Volume																					
Production	W Rustavi	Existing Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Sidetracks	4,615	4,477	4,345	4,218	4,096	3,980	3,868	3,761	3,658	3,559	3,464	3,373	3,285	3,200	3,118	3,040	2,964	2,891	2,821	2,753	2,687
		Number of Producing Wells	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
		Existing Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Sidetracks	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
		Brent Oil Price	75.21	75.21	75.21	75.21	75.21	75.21	75.21	75.21	75.21	75.21	76.23	76.23	76.23	76.23	76.23	76.23	76.23	76.23	76.23	76.23	76.23
Revenue	W Rustavi	W Rustavi Oil Production	4,615	4,477	4,345	4,218	4,096	3,980	3,868	3,761	3,658	3,559	3,464	3,373	3,285	3,200	3,118	3,040	2,964	2,891	2,821	2,753	2,687
		Daily Production	160	155	150	146	142	138	134	130	127	123	120	117	114	111	108	105	103	100	98	95	93
		Monthly Oil MMbbls	0.0046	0.0045	0.0043	0.0042	0.0041	0.0040	0.0039	0.0038	0.0037	0.0036	0.0035	0.0034	0.0033	0.0032	0.0031	0.0030	0.0030	0.0029	0.0028	0.0028	0.0027
		W Rustavi Revenue	0.32	0.31	0.30	0.29	0.28	0.27	0.26	0.26	0.25	0.24	0.24	0.23	0.23	0.22	0.22	0.21	0.20	0.20	0.19	0.19	0.19
		Total Production	4,615	4,477	4,345	4,218	4,096	3,980	3,868	3,761	3,658	3,559	3,464	3,373	3,285	3,200	3,118	3,040	2,964	2,891	2,821	2,753	2,687
		Total Project Revenue M$	0.32	0.31	0.30	0.29	0.28	0.27	0.26	0.26	0.25	0.24	0.24	0.23	0.23	0.22	0.22	0.21	0.20	0.20	0.19	0.19	0.19
CAPEX	W Rustavi	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	W Rustavi	Fixed Opex+OH	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
		Floating Opex	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total W Rustavi Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	W Rustavi	Recoverable Opex	0.020	0.020	0.020	0.020	0.020	0.020	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018
		Contractor Opex Cost Oil	0.020	0.020	0.020	0.020	0.020	0.020	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018
		Unrecovered Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
		Capex recovery Limit	0.15	0.14	0.14	0.13	0.13	0.13	0.12	0.12	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.08
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Profit Share	W Rustavi	Total Profit Oil	0.2947	0.2853	0.2764	0.2678	0.2595	0.2516	0.2440	0.2368	0.2298	0.2231	0.2167	0.2140	0.2080	0.2021	0.1965	0.1911	0.1860	0.1809	0.1761	0.1714	0.1669
		Contractor Profit Oil	0.1179	0.1141	0.1105	0.1071	0.1038	0.1006	0.0976	0.0947	0.0919	0.0892	0.0867	0.0856	0.0832	0.0809	0.0786	0.0765	0.0744	0.0724	0.0704	0.0686	0.0668
		Govt. Profit Oil	0.1768	0.1712	0.1658	0.1607	0.1557	0.1510	0.1464	0.1421	0.1379	0.1339	0.1300	0.1284	0.1248	0.1213	0.1179	0.1147	0.1116	0.1086	0.1057	0.1029	0.1002
		Total Contrctr Cost and Profit Oil, MMBbl	0.0021	0.0020	0.0020	0.0019	0.0019	0.0018	0.0018	0.0017	0.0017	0.0016	0.0016	0.0016	0.0015	0.0015	0.0014	0.0014	0.0014	0.0013	0.0013	0.0013	0.0013
		Evaluated Net Oil, MMBbl	0.0016	0.0015	0.0015	0.0014	0.0014	0.0014	0.0013	0.0013	0.0013	0.0012	0.0012	0.0012	0.0011	0.0011	0.0011	0.0011	0.0010	0.0010	0.0010	0.0010	0.0009
Cash Flow	W Rustavi	Cash Flow	0.09	0.09	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05
		DCF @10%	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
		Cumulative CF	10.27	10.36	10.44	10.52	10.60	10.68	10.75	10.82	10.89	10.96	11.02	11.09	11.15	11.21	11.27	11.32	11.38	11.43	11.49	11.54	11.59
Payout Date	W Rustavi	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	7.69	7.71	7.73	7.75	7.77	7.79	7.81	7.83	7.85	7.87	7.89	7.91	7.92	7.94	7.96	7.98	8.00	8.02	8.04	8.05	8.07
		Cntrctr's Total Profit from Sales of Oil, MM$	0.14	0.13	0.13	0.13	0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.09	0.08
		Cumulative Total Profit, MM$	21.45	21.59	21.72	21.85	21.97	22.09	22.21	22.32	22.43	22.54	22.65	22.75	22.85	22.95	23.05	23.14	23.24	23.33	23.42	23.50	23.59
		Payout? 1=yes, 0=no	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Section	Yr-Mo	12/24	01/25	02/25	03/25	04/25	05/25	06/25	07/25	08/25	09/25	10/25	11/25	12/25	01/26	02/26	03/26	04/26	05/26	06/26	07/26	08/26
	Year	**7**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**
	Month	**84**	**85**	**86**	**87**	**88**	**89**	**90**	**91**	**92**	**93**	**94**	**95**	**96**	**97**	**98**	**99**	**100**	**101**	**102**	**103**	**104**
	Oil Volume																					
Production / **W Rustavi**	**Existing Production**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Sidetracks	2,624	2,562	2,503	2,446	2,390	2,337	2,285	2,235	2,186	2,139	2,094	2,049	2,006	1,965	1,925	1,885	1,847	1,810	1,775	1,740	1,706
	Number of Producing Wells	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	Existing Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Sidetracks	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	Brent Oil Price	**76.23**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**77.26**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**	**78.37**
Revenue / **W Rustavi**	**W Rustavi Oil Production**	2,624	2,562	2,503	2,446	2,390	2,337	2,285	2,235	2,186	2,139	2,094	2,049	2,006	1,965	1,925	1,885	1,847	1,810	1,775	1,740	1,706
	Daily Production	91	89	87	85	83	81	79	77	76	74	72	71	69	68	67	65	64	63	61	60	59
	Monthly Oil MMbbls	0.0026	0.0026	0.0025	0.0024	0.0024	0.0023	0.0023	0.0022	0.0022	0.0021	0.0021	0.0020	0.0020	0.0020	0.0019	0.0019	0.0018	0.0018	0.0018	0.0017	0.0017
	W Rustavi Revenue	0.18	0.18	0.17	0.17	0.17	0.16	0.16	0.16	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.12	0.12
	Total Production	2,624	2,562	2,503	2,446	2,390	2,337	2,285	2,235	2,186	2,139	2,094	2,049	2,006	1,965	1,925	1,885	1,847	1,810	1,775	1,740	1,706
	Total Project Revenue M$	0.18	0.18	0.17	0.17	0.17	0.16	0.16	0.16	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.12	0.12
CAPEX / **W Rustavi**	**Workovers**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex / **W Rustavi**	**Fixed Opex+OH**	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
	Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total W Rustavi Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery / **W Rustavi**	**Recoverable Opex**	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017
	Contractor Opex Cost Oil	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017
	Unrecovered Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Capex recovery Limit	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05
	Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total Cost Oil	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**
Profit Share / **W Rustavi**	**Total Profit Oil**	0.1626	0.1584	0.1570	0.1530	0.1491	0.1454	0.1418	0.1383	0.1349	0.1317	0.1285	0.1254	0.1224	0.1196	0.1189	0.1162	0.1135	0.1109	0.1083	0.1059	0.1035
	Contractor Profit Oil	0.0650	0.0634	0.0628	0.0612	0.0597	0.0582	0.0567	0.0553	0.0540	0.0527	0.0514	0.0502	0.0490	0.0478	0.0476	0.0465	0.0454	0.0443	0.0433	0.0423	0.0414
	Govt. Profit Oil	0.0976	0.0950	0.0942	0.0918	0.0895	0.0873	0.0851	0.0830	0.0810	0.0790	0.0771	0.0753	0.0735	0.0717	0.0714	0.0697	0.0681	0.0665	0.0650	0.0635	0.0621
	Total Contrctr Cost and Profit Oil, MMBbl	0.0012	0.0012	0.0012	0.0012	0.0011	0.0011	0.0011	0.0011	0.0010	0.0010	0.0010	0.0010	0.0010	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0008
	Evaluated Net Oil, MMBbl	0.0009	0.0009	0.0009	0.0009	0.0009	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0006	0.0006
Cash Flow / **W Rustavi**	**Cash Flow**	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03
	DCF @10%	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01
	Cumulative CF	11.64	11.69	11.73	11.78	11.82	11.87	11.91	11.95	11.99	12.03	12.07	12.11	12.14	12.18	12.22	12.25	12.28	12.32	12.35	12.38	12.41
Payout Date / **W Rustavi**	**Total Costs Incurred for Production, MM$**	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Cumulative Total Costs, MM$	8.09	8.11	8.13	8.14	8.16	8.18	8.20	8.21	8.23	8.25	8.27	8.28	8.30	8.32	8.34	8.35	8.37	8.39	8.41	8.42	8.44
	Cntrctr's Total Profit from Sales of Oil, MM$	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06
	Cumulative Total Profit, MM$	23.67	23.75	23.83	23.91	23.99	24.07	24.14	24.21	24.28	24.35	24.42	24.49	24.56	24.62	24.69	24.75	24.81	24.88	24.94	25.00	25.06
	Payout? 1=yes, 0=no	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Section	Area	Yr-Mo	09/26	10/26	11/26	12/26	01/27	02/27	03/27	04/27	05/27	06/27	07/27	08/27	09/27	10/27	11/27	12/27
		Year	9	9	9	9	10	10	10	10	10	10	10	10	10	10	10	10
		Month	105	106	107	108	109	110	111	112	113	114	115	116	117	118	119	120
		Oil Volume																
Production	W Rustavi	Existing Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Sidetracks	1,673	1,641	1,610	1,580	1,550	1,521	1,494	1,466	1,440	1,414	1,389	1,365	1,341	1,318	1,295	1,273
		Number of Producing Wells	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
		Existing Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Workovers - SI or BP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Sidetracks	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
		Brent Oil Price	78.37	78.37	78.37	78.37	79.45	79.45	79.45	79.45	79.45	79.45	79.45	79.45	79.45	79.45	79.45	79.45
Revenue	W Rustavi	W Rustavi Oil Production	1,673	1,641	1,610	1,580	1,550	1,521	1,494	1,466	1,440	1,414	1,389	1,365	1,341	1,318	1,295	1,273
		Daily Production	58	57	56	55	54	53	52	51	50	49	48	47	46	46	45	44
		Monthly Oil MMbbls	0.0017	0.0016	0.0016	0.0016	0.0016	0.0015	0.0015	0.0015	0.0014	0.0014	0.0014	0.0014	0.0013	0.0013	0.0013	0.0013
		W Rustavi Revenue	0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.09	0.09	0.09
		Total Production	1,673	1,641	1,610	1,580	1,550	1,521	1,494	1,466	1,440	1,414	1,389	1,365	1,341	1,318	1,295	1,273
		Total Project Revenue M$	0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.09	0.09	0.09
CAPEX	W Rustavi	Workovers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		New Wells	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		CAPEX TOTAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Opex	W Rustavi	Fixed Opex+OH	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
		Floating Opex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Workovers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total W Rustavi Opex	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		OPEX TOTAL	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Cost Recovery	W Rustavi	Recoverable Opex	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017
		Contractor Opex Cost Oil	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017
		Unrecovered Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
		Capex recovery Limit	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
		Recoverable Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Contractor Capex Cost Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Unrecovered Capex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total Cost Oil	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Profit Share	W Rustavi	Total Profit Oil	0.1011	0.0989	0.0967	0.0945	0.0925	0.0921	0.0901	0.0882	0.0863	0.0844	0.0826	0.0809	0.0791	0.0775	0.0758	0.0742
		Contractor Profit Oil	0.0405	0.0396	0.0387	0.0378	0.0370	0.0368	0.0360	0.0353	0.0345	0.0338	0.0330	0.0323	0.0317	0.0310	0.0303	0.0297
		Govt. Profit Oil	0.0607	0.0593	0.0580	0.0567	0.0555	0.0553	0.0541	0.0529	0.0518	0.0506	0.0496	0.0485	0.0475	0.0465	0.0455	0.0445
		Total Contrctr Cost and Profit Oil, MMBbl	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
		Evaluated Net Oil, MMBbl	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Cash Flow	W Rustavi	Cash Flow	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
		DCF @10%	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		Cumulative CF	12.44	12.47	12.50	12.53	12.56	12.59	12.61	12.64	12.66	12.69	12.71	12.74	12.76	12.79	12.81	12.83
Payout Date	W Rustavi	Total Costs Incurred for Production, MM$	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
		Cumulative Total Costs, MM$	8.46	8.47	8.49	8.51	8.53	8.54	8.56	8.58	8.59	8.61	8.63	8.65	8.66	8.68	8.70	8.71
		Cntrctr's Total Profit from Sales of Oil, MM$	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
		Cumulative Total Profit, MM$	25.11	25.17	25.23	25.28	25.33	25.39	25.44	25.49	25.55	25.60	25.65	25.70	25.74	25.79	25.84	25.89
		Payout? 1=yes, 0=no	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

PART IV

HISTORICAL FINANCIAL INFORMATION

Basis of financial information

Part IV of this document contains the following financial information on the Group:

Section A : Accountant's report on the Historic Financial Information on Block Energy plc

Section B : Historical Financial Information for Block Energy plc

Section C : Accountant's report on the unaudited pro forma statement of net assets of Block Energy plc

Section D : Unaudited *pro forma* statement of net assets for the Group

Section A

ACCOUNTANT'S REPORT ON THE HISTORICAL FINANCIAL INFORMATION OF BLOCK ENERGY PLC

PKF Littlejohn LLP

Accountants &
business advisers

The Directors
Block Energy Plc
60 Gracechurch Street,
London EC3V 0HR

The Directors
SPARK Advisory Partners Limited
5 St John's Lane
Farringdon
London EC1M 4BH

4 June 2018

Dear Sirs

Block Energy Plc

Introduction

We report on the historic financial information set out in Section B of Part IV (the "Financial Information") relating to Block Energy Plc. This information has been prepared for inclusion in the AIM admission document dated 4 June 2018 (the "Admission Document") relating to the proposed admission to AIM of Block Energy Plc and on the basis of the accounting policies set out in note 1. This report is given for the purpose of complying with paragraph (a) of Schedule Two of the AIM Rules for Companies and for no other purpose.

Responsibility

The Directors of the Company are responsible for preparing the Financial Information on the basis of preparation set out in the notes to the Financial Information and in accordance with International Financial Reporting Standards ("IFRS") as adopted by the European Union.

It is our responsibility to form an opinion as to whether the Financial Information gives a true and fair view, for the purposes of the Admission Document, and to report our opinion to you.

Save for any responsibility arising under Schedule Two of the AIM Rules for Companies to any person as and to the extent provided, and save for any responsibility that we have expressly agreed in writing to assume, to the fullest extent permitted by law we do not assume responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Schedule Two of the AIM Rules for Companies, consenting to its inclusion in the Admission Document.

Tel: +44 (0)20 7516 2200 • Fax: +44 (0)20 7516 2400 • DX 42660 Isle of Dogs • www.pkf-littlejohn.com
PKF Littlejohn LLP • 1 Westferry Circus • Canary Wharf • London E14 4HD

Basis of opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included an assessment of evidence relevant to the amounts and disclosures in the Financial Information. It also included an assessment of significant estimates and judgements made by those responsible for the preparation of the Financial Information and whether the accounting policies are appropriate to the Company and consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the Financial Information is free from material misstatement whether caused by fraud or other irregularity or error.

Opinion

In our opinion, the Financial Information gives, for the purpose of the Admission Document dated 4 June 2018, a true and fair view of the state of affairs of Block Energy Plc as at 30 June 2015, 2016 and 2017 and of its results, cash flows and changes in equity for the years then ended in accordance with International Financial Reporting Standards as adopted by the European Union.

Declaration

For the purposes of paragraph (a) of Schedule Two of the AIM Rules we are responsible for this report as part of the Admission Document and declare we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the Admission Document in compliance with Schedule Two of the AIM Rules for Companies.

Yours faithfully

PKF Littlejohn LLP
Reporting Accountants

Section B

AUDITED HISTORICAL FINANCIAL INFORMATION ON BLOCK ENERGY PLC

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

AS AT 30 JUNE

	Notes	Continued operations £'000	Discontinued operations £'000	30 June 2017 Group £'000	Continued operations £'000	Discontinued operations £'000	30 June 2016 Group £'000	30 June 2015 Company £'000
Exploration costs		(3)	—	(3)	(19)	—	(19)	(26)
Administrative expenses	**4**	(281)	(30)	(311)	(74)	(3)	(77)	(72)
Finance costs		(6)	—	(6)	(15)	—	(15)	(17)
Gain on disposal		—	39	39	—	—	—	—
Loss before taxation		(290)	9	(281)	(108)	(3)	(111)	(115)
Taxation	**6**	—	—	—	—	—	—	—
Loss and total comprehensive income for the year	**7**	**(290)**	**9**	**(281)**	**(108)**	**(3)**	**(111)**	**(115)**
Earnings per share								
Earnings per share from continuing operations – basic		(0.123)p			(1.289)p			
Earnings per share from discontinued operations – basic			0.004p			(0.036)p		
Earnings per share basic				**(0.119)p**			**(1.325)p**	**(1.372)p**

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

AS AT 30 JUNE 2017

	Notes	2017 Group £	2016 Group £	2015 Company £
Non-current assets				
Intangible assets	**9**	654	329	—
Total non-current assets		654	329	—
Current assets				
Trade and other receivables	**11**	244	2	7
Cash and cash equivalents	**12**	215	12	179
Asset classified as held for sale	**10**	329	—	—
Total current assets		788	14	186
Total assets		**1,442**	**343**	**186**
Current liabilities				
Trade and other payables	**13**	(64)	(122)	(153)
Borrowings	**18**	(247)	(72)	(73)
Total liabilities		(311)	(194)	(226)
Net current assets		**(477)**	**(180)**	**(40)**
Net assets/(liabilities)		**1,131**	**149**	**(40)**
Equity				
Called up share capital	**17**	1,217	1,048	748
Share premium account		1,721	1,628	1,628
Retained earnings		(2,807)	(2,527)	(2,416)
Total equity		**1,131**	**149**	**(40)**

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

AS AT 30 JUNE 2017

	Notes	Share capital £'000	Share premium account £'000	Retained earnings £'000	Total equity £'000
Balance at 1 July 2014		429	1,626	(2,301)	(245)
Loss for the year		—	—	(115)	(115)
Issue of shares		319	34	—	353
Expense of issue		—	(33)	—	(33)
Balance at 1 July 2015 (Company)		**748**	**1,628**	**(2,416)**	**(40)**
Year ended 30 June 2016:					
Loss for the year		—	—	(111)	(111)
Total comprehensive income for the year		—	—	(111)	(111)
Issue of shares	14	300	—	—	300
Total transactions with owners		300	—	—	300
Balance at 30 June 2016		**1,048**	**1,628**	**(2,527)**	**149**
Year ended 30 June 2017:					
Loss for the year		—	—	(281)	(281)
Total comprehensive income for the year		—	—	(281)	(281)
Issue of shares	14	169	1,110	—	1,279
Cost of issue		—	(17)	—	(17)
Total transactions with owners		169	1,093	—	1,262
Balance at 30 June 2017		**1,217**	**2,721**	**(2,807)**	**1,131**

CONSOLIDATED STATEMENT OF CASHFLOWS

AS AT 30 JUNE

	Notes	2017 £'000 (Group)	2016 £'000 (Group)	2015 £'000 (Company)
Cash flows from operating activities				
Loss before taxation	**32**	(290)	(108)	(115)
Profit/(loss) from discontinued operations		9	(3)	—
Adjustment for:				
Finance expense		6	15	17
Non-refundable deposit		(39)	—	—
Net cash flows used in operating activities before changes in working capital		**(314)**	**(96)**	**(98)**
(Decrease)/increase in trade and other receivables		(286)	5	—
Increase/(Decrease) in trade and other payables		291	(32)	2
Decrease in provisions		—	—	(7)
		5	(27)	(5)
Net cashflow from operating activities		**(309)**	**(123)**	**(103)**
Investing activities				
Non-refundable deposit		39	—	—
Purchase of intangible assets		(422)	—	—
Acquisition of subsidiary, net of cash acquired		—	(29)	—
Net cash (used in)/generated from investing activities		**(383)**	**(29)**	**—**
Financing activities				
Convertible loan notes issued		170	—	—
Proceeds from issue of shares		750	—	350
Expense of share issue		(17)	—	(35)
Interest paid		—	(15)	(17)
Proceeds from borrowings		—	—	15
Repayment of borrowings		—	—	(32)
Net cash (used in)/generated from financing activities		**903**	**(15)**	**281**
Net decrease in cash and cash equivalents		**211**	**(167)**	**178**
Cash and cash equivalents at beginning of year		12	179	1
Effect of foreign exchange rate equivalents on cash and cash equivalents		(8)	—	—
Cash and cash equivalents at end of year		**215**	**12**	**179**

CONSOLIDATED STATEMENT OF CASHFLOWS

Non-cash transactions

2017

During 2017, the following shares were issued in settlement of liabilities

	No. of shares / Value £		No. of shares / Value £
Niall Tomlinson	3,200,000 / £8,000	Plutus Strategies Ltd	8,000,000 / £20,000
Ryan Long	2,400,000 / £6,000	Gareth Northam	400,000 / £1,000
Paul Haywood	2,800,000 / £7,000	Timothy Strong	720,000 / £1,800
Gavin Burnell	11,000,000 / £27,500	Hot Rocks Investments Plc	6,000,000 / £15,000
Woodland Capital Ltd	6,000,000 / £15,000		

On 9 May 2017, an additional 500,000 shares were issued to Gareth Northam in settlement of £2,500 accrued debt. On the 9th May 2017, Block Energy issued 46,317,740 shares to Georgian Oil and Gas Ltd to settle consideration of £232,000 in respect of the Norio PSC.

2016

On 18 January 2016, 599,177,916 ordinary shares of £0.0005 were issued as part of the acquisition cost of Taoudeni Resources Limited.

2015

On the 29 April 2015, 1,548,200 Ordinary shares of £0.0005 were issued in the sum of £3,098 in part settlement of a dispute with two former employees

NOTES TO THE CONSOLIDATED FINANCIAL INFORMATION

Corporate information

In line with the Group's change of focus from gold exploration into oil and gas extraction, the Company's name changed on 10 May 2017 to Block Energy Plc from Goldcrest Resources Plc.

The registered office of Block Energy Plc (the Company) is 60 Gracechurch Street, London, EC3V OHR.

1. Significant Accounting policies

IAS 8 requires that management shall use its judgement in developing and applying accounting policies that result in information which is relevant to the economic decision-making needs of users; that are reliable, free from bias, prudent, complete and represent faithfully the financial position, financial performance and cash flows of the entity.

Basis of preparation

The principal accounting policies adopted in the preparation of this consolidated financial information ('Financial Information') are set out below. The policies have been consistently applied to all the years presented, unless otherwise stated. All amounts presented are in '000 GBP unless otherwise stated. This Financial Information does not constitute statutory accounts within the meaning of s434 of the Companies Act.

This Financial Information has been prepared on a historical cost basis in accordance with International Financial Reporting Standards (IFRS) and IFRIC interpretations issued by the International Accounting Standards Board (IASB) adopted by the European Union and in accordance with applicable UK Law. The adoption of all of the new and revised Standards and Interpretations issued by the IASB and the IFRIC of the IASB that are relevant to the operations and effective for annual reporting periods beginning on 1 July 2016 are reflected in this Financial Information.

The preparation of this Financial Information in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of policies and reported amounts of assets and liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and factors that are believed to be reasonable under the circumstances, the results of which form the basis of making judgements about carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Changes in accounting estimates may be necessary if there are changes in the circumstances on which the estimate was based, or as a result of new information or more experience. Such changes are recognised in the period in which the estimate is revised.

Basis of consolidation

Where the Company has control over an investee, it is classified as a subsidiary. The Company controls an investee if all three of the following elements are present: power over the investee, exposure to variable returns from the investee, and the ability of the investor to use its power to affect those variable returns. Control is reassessed whenever facts and circumstances indicate that there may be a change in any of these elements of control. De-facto control exists in situations where the Company has the practical ability to direct the relevant activities of the investee without holding the majority of the voting rights. In determining whether de-facto control exists the Company considers all relevant facts and circumstances, including:

The size of the Company's voting rights relative to both the size and dispersion of other parties who hold voting rights

- Substantive potential voting rights held by the Company and by other parties
- Other contractual arrangements
- Historic patterns in voting attendance.

Business combinations

The Financial Information incorporate the results of business combinations using the purchase method. In the consolidated statement of financial position, the acquiree's identifiable assets, liabilities and contingent liabilities are initially recognised at their fair values at the acquisition date. The difference between the consideration paid and the acquired net assets is recognised as goodwill. The results of acquired operations are included in the consolidated income statement from the date on which control is obtained. Any difference arising between the fair value and the tax base of the aquiree's assets and liabilities that give rise to a deductible difference results in recognition of deferred tax liability. No deferred tax liability is recognised on goodwill.

Going concern

Any consideration of the foreseeable future involves making judgements, at a particular point in time, about future events which are inherently uncertain.

The directors have a reasonable expectation that the Company and the Group has adequate resources to continue in operational existence for the foreseeable future. Thus the directors continue to adopt the going concern basis of accounting in preparing the Financial Information.

New Accounting Standards

(i) New and amended standards adopted by the Group:

No new standards and amendments to standards and interpretations effective for annual periods commencing on or after 1 July 2014 have had a material impact on the Group.

(ii) The following standards, amendments and interpretations, which are effective for reporting periods beginning after 30 June 2017, have not been adopted early:

Standard	**Description**	**Effective date**
IFRS 15	Revenue from Contracts with Customers	1 January 2018
IFRS 9	Financial Instruments	1 January 2018
IFRS 16*	Leases	1 January 2019
Amendments to IAS 7*	Disclosure Initiative	1 January 2017
Clarifications to IFRS 15	Revenue from Contracts with Customers	1 January 2018
Amendments to IFRS 2*	Classification and Measurement of Share-based Payment Transactions	1 January 2018
Annual Improvements 2014-2016 Cycle*	Annual Improvements to IFRS Standards; 2014-2016 Cycle	1 January 2017 / 1 January 2018
IFRIC Interpretation 22*	Foreign Currency Transactions and Advance Consideration	1 January 2018
IFRIC 23*	Uncertainty over Income Tax Treatments	1 January 2019

* Not yet endorsed by the EU

The Group does not expect the new standards and interpretations to have a material impact on the Group's earnings or shareholders' funds. The Group is not currently revenue producing and does not have any contracts in place giving rise to revenue. Revenue is expected once oilfields begin production and the Directors will review the substance of these contracts in order to continue their consideration of the impact of IFRS 15. The Group's first reporting period under IFRS 15 will be for the year ended 30 June 2019.

Intangible Assets

Exploration and evaluation costs

The Group applies the full cost method of accounting for Exploration and Evaluation (E&E) costs, having regard to the requirements of IFRS 6 'Exploration for and Evaluation of Mineral Resources'. Under the full cost method of accounting, costs of exploring and evaluating properties are accumulated and capitalised by reference to appropriate cash generating units ("CGUs"). Such CGU's are based on geographic areas such as a licence area type or a basin and are not larger than an operating segment – as defined by IFRS 8 'Operating segments'. The Group has identified two CGUs, being that of its mineral exploration and oil extraction operations, and Corporate function including unallocated costs.

E&E costs are initially capitalised within 'Intangible assets'. Such E&E costs may include costs of licence acquisition, technical services and studies, seismic acquisition, exploration drilling and testing, but do not include costs incurred prior to having obtained the legal rights to explore an area, which are expensed directly to the statement of comprehensive income as they are incurre

Intangible E&E assets are not amortised and are carried forward until the existence (or otherwise) of commercial reserves has been determined. The Group's definition of commercial reserves for such purpose is proven and probable reserves on an entitlement basis.

If commercial reserves are discovered, the related E&E assets are assessed for impairment, and any impairment loss is recognised in the statement of comprehensive income. The carrying value, after any impairment loss, of the relevant E&E assets is then reclassified to development and production assets within property, plant and equipment and is amortised on a unit of production basis over the life of the commercial reserves of the CGU to which they relate. Intangible E&E assets that relate to E&E activities that are not yet determined to have resulted in the discovery of commercial reserves remain capitalised as intangible E&E assets at cost, subject to impairment assessments as set out below.

Impairment of intangible assets

E&E assets are assessed for impairment when facts and circumstances suggest that the carrying value of the E&E CGU to which they relate may exceed its future recoverable amount. Where the E&E assets concerned fall within the scope of an established CGU, the E&E assets are tested for impairment together with all development and production assets associated with that CGU, as a single cash generating unit. The aggregate carrying value is compared against the expected recoverable amount of the CGU. The recoverable amount is the higher of value in use and the fair value less costs to sell. Where the E&E assets to be tested fall outside the scope of any established CGU, there will generally be no commercial reserves and the E&E assets concerned will generally be written off in full. Any impairment loss is recognised in the statement of comprehensive income.

Fair value of exploration assets acquired

On 25 May 2016, the Group acquired 100% of the share capital of Taoudeni Resources Limited and 100% of the share capital of Taoudeni SARL for £329k. Taoudeni SARL currently does not hold any exploration licenses. Ensign Resources Limited (Taoudeni subsidiary) is registered in the Isle of Man and, via its 100% owned subsidiary Antubia Resources Limited, the Group holds 24.28 sq. km of gold exploration licences in Ghana ("the Asheba asset"). On acquisition the Group was required to assess the fair value of the exploration assets acquired.

The fair value of the exploration assets of £329k was estimated by applying a number of valuation metrics which include; geological upside potential, mineralogy, market benchmarks and the application of local market factors. In the Directors' opinion, the value of the consideration paid to effect the acquisition related primarily to the value of the exploration licences and upside potential representing a price agreed between willing and knowledgeable parties on an arm's length basis. Therefore, the fair value of the consideration transferred, after consideration of tax implications and the removal of the fair value of other identifiable assets acquired, has been used as a basis for valuing the exploration assets acquired.

Asset held for sale

Non-current assets (or disposal groups) are classified as held for sale if their carrying amount will be recovered principally through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset (or disposal group) is available for immediate sale in its present condition subject only to terms that are usual and customary.

Immediately before classification as held for sale, the measurement of the non-current assets (or all the assets and liabilities in a disposal group) is brought up-to-date in accordance with applicable IFRSs. Then, on initial classification as held for sale, noncurrent assets (other than investment properties, deferred tax assets, financial assets and inventories) are measured in accordance with IFRS 5 that is at the lower of carrying value and fair value.

The Asheba asset (£329k) held within the Antubia subsidiary is classed as 'Held for sale' in the year ended 30 June 2017. The classification of this asset is based on a non-refundable deposit being received prior to the year end, Head of Terms agreement signed in the year end 30 June 2017 and the SPA signed in September 2017, therefore meeting the criteria of highly probable sale. The only condition left to satisfy before the sale is completed, is confirmation of the renewal of the licence from the government. The asset at the year-end is available for immediate sale in its present condition.

Taxation and deferred tax

Income tax expense represents the sum of the current tax and deferred tax charge for the year.

The Group's liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the reporting date.

Deferred tax is recognised on differences between the carrying amounts of assets and liabilities in the financial information and the corresponding tax bases, and is accounted for using the balance sheet liability method.

Deferred tax assets are recognised to the extent that it is probable that taxable profits will be available against which deductible temporary differences can be utilised.

Judgement is applied in making assumptions about future taxable income, including oil and gas prices, production, rehabilitation costs and expenditure to determine the extent to which the Group recognises deferred tax assets, as well as the anticipated timing of the utilisation of the losses.

Deferred tax is calculated at the tax rates that have been enacted or substantively enacted and are expected to apply in the period when the liability is settled or the asset realised. Deferred tax is charged or credited to the statement of comprehensive income, except when it relates to items charged or credited directly to equity, in which case the deferred tax is also dealt with in equity.

Foreign currencies

Monetary assets and liabilities denominated in foreign currencies are translated into Sterling GBP at the rates of exchange prevailing at the reporting date. Transactions in foreign currencies are translated at the exchange rate ruling at the date of the transaction. Exchange differences are taken to the statement of comprehensive income.

The presentational and functional currency the Company is Sterling GBP and accordingly the Financial Information have also been prepared in this currency. GOG Norioskhevi Ltd and Ensign Resources Limited currently report in US Dollar ("$USD").

Finance costs

Finance costs are accrued on a time basis, by reference to the principal outstanding and at the effective interest rate applicable.

Borrowings

Borrowings are recorded initially at fair value, net of attributable transaction costs. Borrowings are subsequently carried at their amortised cost and finance charges, including any premium payable on settlement or redemption, are recognised in the profit or loss over the term of the instrument using the effective rate of interest.

Financial instruments

The Group's financial assets consist of cash and cash equivalents at variable interest rates, loans and other receivables. Any interest earned is accrued and classified as interest. Trade and other receivables are stated initially at fair value and subsequently at amortised cost.

The Group's financial liabilities consist of convertible loan notes, trade and other payables. All are non-derivative assets. The trade and other payables are stated initially at fair value and subsequently at amortised cost. Convertible loan notes are treated as described below.

Convertible loan notes

In accordance with IAS 32, the Group has classified the convertible debt in issue as a compound financial instrument. Accordingly, the Group presents the liability and equity component separately on the statement of financial position where material to the Financial Information. In this case, the split is not material and the separation of the liability and equity elements has not been shown.

Share based payments

The fair value of options and warrants granted to directors and others in respect of services provided is recognised as an expense in the statement of comprehensive income with corresponding increase in equity reserves – 'the share option reserve'.

On exercise or cancellation of share options and warrants, the proportion of the share based payment reserve relevant to those options and warrants is transferred to the retained earnings reserve. On exercise, equity is also increased by the amount of the proceeds received.

The fair value is measured at grant date and charged in the accounting period during which the option and warrants becomes unconditional.

The fair value of options and warrants are calculated using the Black-Scholes model, taking into account the terms and conditions upon which the options and warrants were granted. Vesting conditions are non-market and there are no market vesting conditions. These vesting conditions are included in the assumptions about the number of options and warrants that are expected to vest. At the end of each reporting period, the Company revises its estimate of the number of options and warrants that are expected to vest. The exercise price is fixed at the date of grant and no compensation is due at the date of grant.

Where equity instruments are granted to persons other than employees, the statement of comprehensive income is charged with the fair value of the goods and services received.

2. Segmental disclosures

IFRS 8 requires segmental information for the Group on the basis of information reported to the chief operating decision maker for decision making purposes. The Company considers this role as being performed by the Board of Directors. The Group's operations are focused on mineral exploration in Ghana and oil and gas exploration activities in the Georgia with its corporate head office in the UK. Based on risks and returns the Directors consider that there are two operating segments that they use to assess the Group's performance and allocate resources being the Mineral and Oil extraction in Georgia, and Corporate function including unallocated costs. Two operating segments, being the corporate function and the mineral extraction in Ghana, were assessed as appropriate for assessing Group performance for 2016.

The segmental results are as follows:

	Mineral/Oil exploration £	Group Corporate and other £	Total £
Year ended 30 June 2017			
Other Income	—	39	39
Exploration costs	(3)	—	(3)
Administrative costs	—	(311)	(311)
Finance costs	—	(6)	(6)
Loss from operating activities	(3)	(278)	(281)

	Mineral exploration £	Group Corporate and other £	Total £
Year ended 30 June 2016			
Exploration costs	(19)	—	(19)
Administrative costs	—	(77)	(77)
Finance costs	—	(15)	(15)
Loss from operating activities	(19)	(92)	(111)

	Mineral exploration £	Company Corporate and other £	Total £
Year ended 30 June 2015			
Exploration costs	(26)	—	(26)
Administrative costs	—	(72)	(72)
Finance costs	—	(17)	(17)
Loss from operating activities	(26)	(89)	(115)

Segmental asset	Group 30 June 2017 £'000	Group 30 June 2016 £'000	Company 30 June 2015 £'000
Mineral exploration – Ghana	329	329	—
Oil exploration – Georgia	654	—	—
Corporate and other	549	14	186
	1,442	343	186

Segmental liabilities	30 June 2017 £'000	30 June 2016 £'000	30 June 2015 £'000
Mineral exploration	—	—	—
Corporate and other	311	236	226
	311	236	226

In terms of geographical area, the mineral exploration was undertaken in Ghana, the oil development activities undertaken in Georgia, and the corporate and other activities were undertaken in the United Kingdom.

3. Critical accounting judgments, estimates and assumptions

The Group makes estimates and assumptions regarding the future. Estimates and judgements are continually evaluated based on historical experiences and other factors, including expectations of future events that are believed to be reasonable under the circumstances. In the future, actual experience may deviate from these estimates and assumptions. The key assumptions concerning the future and other key sources of estimation uncertainty at the reporting date that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year, are described below.

Recoverable value of Intangible assets

Under the full cost based method of accounting, the Group capitalises exploration and appraisal costs until such times as facts of circumstances indicate that the capitalised E&E costs are not recoverable and an impairment charge may be required to bring the net book values of assets in line with their recoverable amounts.

This assessment involves judgement as to the likely future commerciality of the asset, including geological and commercial chance of success, when such commerciality should be determined as well as future revenues and costs pertaining to the utilisation of the licence rights to which such capitalised costs relate and the discount rate to be applied to such future revenues and costs in order to determine a recoverable value.

Impairment review

The carrying amounts of the Group's intangible assets are reviewed at each reporting date for facts and circumstance which may indicate that an asset may be impaired. If a fact or circumstance indicating impairment is identified, the relevant CGU recoverable amount is estimated. The recoverable amount is the higher of its fair value less costs to sell, and its value in use.

Impairment assessments are also carried out by the Directors at any time during the year, if there has been an event or a change in circumstance that would indicate that the carrying value of the asset may not be recoverable.

When conducting an impairment review of its assets, the Directors exercise judgement in making assumptions about future commodity prices, mineral, oil and gas reserves/resources and future development and production costs. By their nature, impairment reviews include significant estimates regarding future financial resources and commercial and technical feasibility to enable the successful realisation of the exploration and evaluation expenditure. Changes in the estimates used can result in significant charges to the statement of comprehensive income as any impairment loss arising from the review is charged to the statement of comprehensive income whenever the carrying amount of the asset exceeds its recoverable amount.

Convertible loan notes

The fair value of the liability component on initial recognition is the present value of the stream of future cash flows (including both coupon payments and redemption) discounted at the market rate of interest that would have been applied to an instrument of comparable credit quality with substantially the same cash flows, on the same terms, but without the conversion option. The discount rate applied constitutes a significant estimate by using that of a comparable non-convertible instrument. Significant changes in the discount rate used can result in material differences between the equity and liabilities recognised in the statement of financial position.

Share options and warrants

Directors' best estimate of the valuations underlying the share based payments and warrants are based on assumptions made by Directors using updated models previously prepared by external consultants. Those assumptions are described in the Notes to the Financial Information and include, among others, the dividend growth rate, expected volatility, expected life of the options and number of options expected to vest. See note 16 for further details of these assumptions.

4. Expenses by nature

	2017 £'000	2016 £'000	2015 £'000
Loss from operations is stated after charging:			
Employee benefit expense	**99**	42	45
Audit Remuneration – Audit services	**14**	11	7
Fees to auditor for other services	**—**	3	1
NEX fee	**11**	8	8
Corporate adviser fees	**8**	12	12
Other regulatory fees	**13**	3	3
Travel and subsistence	**30**	—	—
Legal and professional fees	**63**	(30)	—
Profit on discontinued operations	**39**	—	—
Other expense	**73**	28	(4)
Reallocated to discontinued operation	**(30)**	(3)	—
	281	74	72

5. Employees

	Year ended 30 June 2017 £'000 Group	Year ended 30 June 2016 £'000 Group	Year ended 30 June 2015 £'000 Company
Employment costs consist of:			
Wages and salaries	73	40	44
Share based payments	24	—	—
Social security costs	2	1	1
	99	41	45

The average monthly number of employees during 2017 was 3 (2016: 3, 2015: 5). The Group does not operate a pension plan for Directors. The share based payments were shares issued for services provided.

Key management and personnel are considered to be the Directors. The Group provides Directors' and Officers' liability insurance at a cost of £1,530 (2016: £1,492, 2015: £1,425). This cost is not included in the above table.

6. Taxation

Based on the results there is no charge to UK or foreign tax. This is reconciled to the accounting loss as follows:

	Year ended 30 June 2017 £	Year ended 30 June 2016 £	Year ended 30 June 2015 £
Loss on ordinary activities	(281)	(111)	(115)
Loss before taxation at the average UK standard rate of 20% (2016:20%, 2015: 20%)	(56)	(22)	(23)
Effect of:			
Tax losses for which no deferred income tax asset was recognised	56	22	23
Current tax	—	—	—

The Company has corporation tax losses available to carry forward against future profits of approximately £861k (2016: £937k, 2015: £784k). A deferred tax asset has not been recognised in the Financial Information as recovery cannot be foreseen with reasonable probability.

Factors that may affect future current and total tax charges

The Group had tax losses carried forward on which no deferred tax asset is recognised. This may affect future tax charges should the Group produce taxable trading profits in future periods. No deferred tax asset is recognised in respect of losses carried forward to future periods due to the uncertainty of the timing of future taxable profits.

7. Earnings per share

	Year ended 30 June 2017	Year ended 30 June 2016	Year ended 30 June 2015
Earnings per share from continuing operations-basic	**(0.123)p**	(1.289)p	(1.372)p
Earnings per share from discontinuing operations-basic	**0.004p**	(0.036)p	—
Earnings per share-basic	**(0.119)p**	(1.325)p	(1.372)p

The basic loss per share is derived by dividing the loss for the period attributable to ordinary shareholders by the weighted average number of shares in issue.

	Year ended 30 June 2017 £'000	Year ended 30 June 2016 £'000	Year ended 30 June 2015 £'000
(Loss) for the year from continuing operations (used in calculation of basic EPS from continuing operations)	(290)	(108)	(115)
Profit/(Loss) for the year from discontinuing operations (used in calculation of basic EPS from discontinuing operations)	9	(3)	—
(Loss) for the year (used in calculation of total basic EPS)	(281)	(111)	(115)
Weighted average number of Ordinary shares of 0.05p in issue	235,479,870	8,380,661	8,380,661

The 2016 and 2015 financial year earnings per shares calculation uses a revised weighted average number of ordinary shares to reflect the share sub-division and consolidation which occurred in December 2016, for comparative purposes, as required under IAS 33. All years also take into account the post year end 5:1 share consolidation, as detailed in note 23 of the Financial Information.

Diluted share earnings per share has not been calculated as the options and warrants have no dilutive effect.

As detailed in note 16, there are warrants outstanding at the year-end which have the potential to dilute basic earnings per share in the future.

8. Acquisition of the Norioskhevi PSA and GOG Norioskhevi Ltd

On the 20 April 2017 the Company reached an agreement for the acquisition of the entire share capital of GOG Norioskhevi Ltd ("Norio"), a BVI registered company.

On acquisition, Block Energy paid USD$1 for the issuance of 1 ordinary Norio share, which is now a wholly owned subsidiary of Block Energy. Norio's principal activity is oil and gas extraction.

Details of the fair value of identifiable assets and liabilities acquired, purchase consideration and goodwill are as follows:

	Fair Values £
Share capital	1
Total net assets acquired	1
Cash paid	1
Goodwill	—

9. Intangible assets

	£'000 Licences	£'000 Exploration and Evaluation cost	£'000 Total
Cost			
At 1 July 2016	329	—	329
Reclass to asset held for sale	(329)	—	(329)
Additions during the year	617	37	654
At 30 June 2017	617	37	654

The additions in the year to 30 June 2017 comprise of the following

- On 11 April 2017, the Company acquire a 38% interest in the Norio onshore oil field Production Sharing Agreement (PSA) for a cash consideration of USD$380k (£306k) and USD$300k (£231k) settled with 46,317,740 ordinary shares of the Company. In accordance with the SPA, the Company is required to recomplete five well recompletions within eighteen months, and two further well recompletions within three years. If the Company does not carry out the planned well recompletions, its working interest in the PSA will be reduced.
- Recognition of the Company's share in the West Rustavi PSA contract £79k.
- Technical Report £37k.

	£'000 Licences	£'000 Exploration and Evaluation cost	£'000 Total
Cost			
At 1 July 2015	—	—	—
Reclassify to asset held for sale	—	—	—
Additions during the year	329	—	329
At 30 June 2016	329	—	329

The addition in the year to 30 June 2016 comprised;

On 25 May 2016 the Company acquired 100% of Taoudeni Resources Limited for a total consideration of £329k, satisfied by £29k in cash and the balance in ordinary shares of the Company.

Company	**£'000** **Licences**	**£'000** **Exploration and Evaluation cost**	**£'000** **Total**
Cost			
At 1 July 2014	—	—	—
Reclassify to asset held for sale	—	—	—
Additions during the year	—	—	—
At 30 June 2015	—	—	—

10. Asset Held for Sale

Details of asset held for sale are as follows

Cost	**2017** **£'000** **Asset held for Sale**
At 1 July 2016	—
Reclassifying from intangible assets	329
At 30 June 2017	**329**

On 8 June 2017 the Antubia Head of Terms was signed and the asset classed as held for sale. The SPA was signed on 6 September 2017. The assets fair value is considered to be its carrying value. No impairment to the value was identified. The consideration receivable under the SPA is $600k, and is conditional on confirmation of licence renewal.

11. Trade and other receivables

	2017 **£'000**	**2016** **£'000**	**2015** **£'000**
Other receivables	213	—	—
Unpaid share capital	25	—	—
Prepayments	6	2	8
	244	2	8

The 2017 year receivable pertains to loan note funds not received by year end, and are due within one year.

All trade and other receivables are denominated in GBP (£) Sterling.

12. Cash

	2017 £'000 Group	2016 £'000 Group	2015 £'000 Company
Cash and cash equivalents	215	12	179
	215	12	179

Cash and cash equivalents consist of balances in bank accounts used for normal operational activities. The bank account is held within an institution with a credit rating of A-1.

All cash and cash equivalents are denominated in GBP (£) Sterling.

13. Trade and Other Payables

	2017 £'000 Group	2016 £'000 Group	2015 £'000 Company
Trade and other payables	14	55	59
Social security and other taxes	—	—	1
Accruals	50	67	94
	64	122	154

Trade and other payables principally comprise amounts outstanding for corporate services.

All trade and other payables are denominated in GBP (£) Sterling.

14. Share capital

	Ordinary Shares	**Deferred Shares**	**Nominal £**
Called up, allotted, issued and fully paid			
As at 30 June 2014	858,075,605	—	429,037
Issued 13 November 2014 at 0.055p per share	181,818,181	—	90,909
Issued 27 November 2014 at 0.55p per share	90,909,090	—	45,455
Issued 10 December 2014 at 0.55p per share	181,818,181	—	90,909
Issued 15 December 2015 at 0.55p per share	90,909,091	—	45,455
Issued 27 March 2015 at 0.55p per share	90,909,091	—	45,455
Issued 29 April 2015 at 0.2p per share	1,548,200	—	773
As at 30 June 2015	**1,495,987,439**	**—**	**747,993**
Issued 18 January 2016 at 0.05p per share	599,177,916	—	299,589
As at 30 June 2016	**2,095,165,355**	**—**	**1,047,582**
Share sub-division at 31 December 2016	—	2,095,165,355	—
Share consolidation at 31 December 2016	(2,053,262,048)	—	—
Issue of equity on 10 January 2017	163,320,001	—	81,660
Issue of equity on 31 March 2017	30,000,000	—	15,000
Issue of equity on 9 May 2017	144,617,740	—	72,309
As at 30 June 2017	**379,841,048**	**2,095,165,355**	**1,216,551**

Subdivision and Consolidation of share capital

A subdivision and consolidation of capital exercise was undertaken at 31 December 2016. Every 50 existing Ordinary Shares of 0.05p were first subdivided into one Ordinary Share of 0.001p and one Deferred Share of 0.049p.

Following this subdivision, each 50 Ordinary shares of 0.001p were consolidated into one Ordinary Share of 0.05p, resulting in a reduction in the number of Ordinary Shares from 2,095,165,355 to 41,903,307 and the creation of 2,095,165,355 Deferred Shares.

The Ordinary Shares consist of full voting, dividend and capital distribution rights and they do not confer any rights for redemption. The Deferred Shares have no entitlement to receive dividends or to participate in any way in the income of profits of the Company, nor is there entitlement to receive notice of, speak at, or vote at any general meeting or annual general meeting.

	Share capital at 01/07/2016	**Share Capital at 31/12/2016 following the share re-organisation**
Ordinary shares of 0.05p	2,095,165,355	41,903,307
Nominal Value (pence)	0.05	0.05
Aggregate nominal value	**£1,047,582**	**£20,951**
Deferred ordinary shares of 0.049p		2,095,165,355
Nominal Value (pence)		0.049
Aggregate nominal value		**£1,026,631**

15. Reserves

The following describes the nature and purpose of each reserve within owners' equity.

Reserve	**Description and purpose**
Called up share capital	Amount subscribed for share capital at nominal value.
Share premium account	Amount subscribed for share capital in excess of nominal value, less attributable costs.
Retained earnings	Cumulative net gains and losses recognised in the income statement.

16. Fundraising incentives and share based payments

	Number of warrants	**30 June 17 Weighted average exercise price**	**Number of warrants**	**30 June 16 Weighted average exercise price**	**Number of warrants**	**30 June 15 Weighted average exercise price**
Outstanding at the beginning of the year	250,000,000	0.05p	250,000,000	0.05p	300,000,000	0.0667p
Additions	2,045,151	2.5p	—	—	—	—
Lapsed	(3,000,000)	2.5p	—	—	(50,000,000)	0.1p
Share capital reorganisation effect	5,000,000	125p	—	—	—	—
Outstanding as the end of the year	4,045,151	125p	250,000,000	0.05p	250,000,000	0.05p

As at 30 June 2017, no warrants were available to exercise. All outstanding warrants have an exercise price of 125p. The weighted average life of the warrants is 10 years. The valuation of the Warrants are not considered material.

As detailed within note 23 of the Financial Information, on 15 November 2017 a further share consolidation of 5:1 Ordinary Shares occurred.

17. Borrowings

	30 June 2017 £'000 Group	30 June 2016 £'000 Group	30 June 2015 £'000 Company
Short term loans – unsecured	247	72	73

All loans are denominated in GBP (£) Sterling.

The majority of the year ended 30 June 2017 loan balance relates to a convertible loan note, (£210k) and carries a flat 10% coupon rate. The loan is convertible into equity of the Company at a 10% discount to any price at which Block Energy's shares will be listed on AIM. The Directors consider it appropriate to classify these loans as current.

18. Financial instruments

The Board of Directors determine, as required, the degree to which it is appropriate to use financial instruments or other hedging contracts or techniques to mitigate risk. The main risk affecting such instruments is foreign currency risk which is discussed below.

There is no material difference between the book value and fair value of the Group cash balances, and the short-term receivables and payables because of their short maturities.

Credit risk

Financial assets which potentially subject the holder to concentrations of credit risk consist principally of cash balances. These balances are all held at a recognised financial institution. The maximum exposure to credit risk is £215k (2016: £12k). The Company and Group does not hold any collateral as security.

Market risk

Market risk arises from the Group's use of interest bearing and foreign currency financial instruments. It is the risk that future cash flows of a financial instrument will fluctuate because of changes in interest rates (interest rate risk), and foreign exchange rates (currency risk).

Currency risk

The Group has potential currency exposures in respect of items denominated in foreign currencies comprising transactional exposure in respect of operating costs and capital expenditure incurred in currencies other than the functional currency of operations.

Liquidity risk

Liquidity risk arises from the possibility that the Group and its subsidiaries might encounter difficulty in settling its debts or otherwise meeting its obligations related to financial liabilities. In addition to equity funding, additional borrowings have been secured to finance operations. The Company manages this risk by monitoring its financial resources and carefully plans its expenditure programmes.

Capital

The Company considers its capital to comprise its share capital, share premium and retained deficit. In managing its capital, the directors's primary objective is to maintain a sufficient funding base to enable the Group to meet its working capital and strategic investment needs. In making decisions to adjust its capital structure to achieve these aims, through new share issues, the Group considers not only their short-term position but also their long term operational and strategic objectives.

	2017 £'000	2016 £'000	2015 £'000
Capital and reserves attributable to shareholders			
Share capital	1,217	1,048	748
Share premium	2,721	1,628	1,628
Retained deficit	(2,807)	(2,527)	(2,416)
Total equity	1,131	149	(40)

Other than the share subdivision and consolidation on 31 December 2016, there have been no significant changes to the Company's capital management objectives, policies and processes nor has there been any change in what the Company considers to be its capital.

See note 23 for details of a post 30 June 2017 share consolidation.

19. Categories of financial instruments

The Company and Group has no category of financial assets which require separate disclosure.

In terms of financial liabilities, these solely comprise of those measured at amortised cost and are as follows:

	30 June 2017 £'000	30 June 2016 £'000	30 June 2015 £'000
Liabilities at amortised cost	14	55	59
Loans and receivables	247	73	73
	261	132	132
Cash and cash equivalents at amortised cost	215	12	179
Trade receivables at amortised cost	244	2	8
	459	14	187

No collateral has been pledged in relation thereto.

20. Subsidiaries

At 30 June 2017, the Group consists of the following subsidiaries, which are wholly owned by the Company.

Company	**Country of Incorporation**	**Proportion of voting rights and equity interest** 2017	2016
GOG Norioskhevi Ltd	British Virgin Islands	100%	0%
Taoudeni Resources SARL	Mauritania	100%	100%
Taoudeni Resources UK Ltd**	UK	100%	100%
Ensign Resources Ltd***	Isle of Man	100%	100%
Goldcrest Resources Ltd	UK	100%	100%

** in the process of liquidation
*** holds Antubia Resources Ltd – held for sale

Registered Office

The registered office of GOG Norioskhevi Ltd is the same as the Parent Company.

The registered office of Taoudeni Resources SARL is International House, 1-6 Yarmouth place, London W1J 7BU.

The registered office of Ensign Resources Ltd is Falcon Cliff, Palace road, Douglas, Isle of Man, IM2 4LB

The registered office of Goldcrest Resources Ltd 6^{th} Floor, 60 Gracechurch Street, London EC3V OHR

21. Commitments

There were no commitments at any of the reporting dates.

22. Related party transactions

Year ended 30 June 2017

In March 2017, Plutus Strategies Limited were paid consultancy fees of £2,500. In January 2017 they were issued £20,000 of shares in settlement of broker fees. Both Niall Tomlinson and Paul Haywood are directors of Plutus Strategies Limited.

As part of the consideration for Taoudeni Resources, Plutus Strategies Limited were issued 658,234 warrants at a subscription price of 2.5p on 21 December 2016.

Year ended 30 June 2016

Gavin Burnell, a former non-executive director and shareholder:

- Loans granted to the Company with no fixed repayment term and with interest at the rate of 20% per annum as follows:

	£
Balance at 1 July 2015	21,000
Balance at 30 June 2016	21,000
Interest paid in year	4,200
Interest accrued and unpaid	4,200

- Taoudeni Resources Limited was acquired during the period when Gavin Burnell (a former director and shareholder) was a significant shareholder in Taoudeni Resources Limited.

Starvest plc, a company of which John Watkins is a director and shareholder:

- Loans granted to the Company with no fixed repayment term and with interest at the rate of 20% per annum as follows:

	£
Balance at 1 July 2015	27,500
Balance at 30 June 2016	27,500
Interest paid in year	5,500
Interest accrued and unpaid	5,500

Hot Rocks Investments plc, a company of which Gavin Burnell is a director and shareholder:

- Loans granted to the Company with no fixed repayment term and with interest at 20% per annum as follows:

	£
Balance at 1 July 2015	13,750
Balance at 30 June 2016	13,750
Interest paid in year	2,750
Interest accrued and unpaid	2,750

Woodland Capital Limited, a company of which Gavin Burnell is a director and shareholder:

- Loan granted to the Company with no fixed repayment term and with interest at 20% per annum.

	£
Balance at 1 July 2015	10,500
Balance at 30 June 2016	10,500
Interest paid in year	2,100
Interest accrued and unpaid	2,100

Directors fees

Directors fees of £7,000 per person are due to be settled at a future date by shares in the company to Niall Tomlinson and Paul Haywood.

Year ended 30 June 2015

Gavin Burnell, non-executive director and shareholder:

- Loans granted to the Company with no fixed repayment term and with interest at the rate of 20% per annum as follows:

	£
Balance at 1 July 2014	29,500
Repayment 2 January 2015	(8,500)
Balance at 30 June 2015	21,000
Interest paid in year	5,547
Interest accrued and unpaid	2,100

Starvest plc, a company of which John Watkins is a director and shareholder:

- Loans granted to the Company with no fixed repayment term and with interest at the rate of 20% per annum as follows:

	£
Balance at 1 July 2014	30,000
Advances	
28 July 2014	5,000
15 October 2014	5,000
Repayment	
2 January 2015	(12,500)
Balance at 30 June 2015	27,500
Interest paid in year	5,732
Interest accrued and unpaid	2,750

Hot Rocks Investments plc, a company of which Gavin Burnell is a director and shareholder:

- Loans granted to the Company with no fixed repayment term and with interest at 20% per annum as follows:

	£
Balance at 1 July 2014	15,000
Advance- 28 July 2014	5,000
Repayment- 28 July 2014	(6,250)
Balance at 30 June 2015	13,750
Interest paid in year	2,945
Interest accrued and unpaid	1,375

Woodland Capital Limited, a company of which Gavin Burnell is a director and shareholder:

- Loan granted to the Company with no fixed repayment term and with interest at 20% per annum.

	£
Balance at 1 July 2014	5,000
Repayment 2 January 2015	(4,500)
Balance at 30 June 2016	10,500
Interest paid in year	2,523
Interest accrued and unpaid	1,050

Directors fees

Directors fees of £5,000 per person are due to be settled at a future date by shares in the Company to Messrs Callum Baxter, Gavin Burnell, Shaun Dowling and John Watkins.

23. Subsequent events

On 17 July 2017, Block Energy increased its ownership in the Norio PSA to 69% from 38% by making a further payment of USD$310k in cash to Georgia Oil and Gas Ltd. On 25 September 2017, Block Energy acquired the remaining interest through payment of USD 310k, and now owns 100% of the PSA.

On 25 July 2017 Block Energy acquired Satskhenisi Ltd, a Marshall Islands incorporated company. This subsidiary holds the Satskhenisi PSA.

On 1 August 2017, Block Energy secured a 90% working interest in the Satskhenisi Production Sharing Agreement (SKN PSA) via the acquisition of 100% of the share capital of Satskhenisi Ltd, a Marshall Islands registered company.

Between 3 July 2017 and 31 August 2017, Block Energy raised £250,000 via the placing of 29,411,765 new ordinary shares at an issue price of 0.85p per new share. The proceeds will be used to execute the planned AIM listing and to provide working capital.

On 12 September 2017 the Group purchased Georgia New Ventures Inc, a Bahamas incorporated company.

On 12 September 2017, Block Energy reached final agreement for the disposal of the entire issued and to be issued share capital of Antubia Resources Limited for USD600,000 in cash through the signing of the Sale and Purchase Agreement (SPA) with Star Goldfields Limited ("the Antubia SPA").

On 25 September 2017, Block Energy acquired 100% of the Norio PSA, changing its status to operator in these fields as well as the Satskhenisi area.

On 8 November 2017, an SPA was signed for the sale of Taoudeni Resources SARL for £40,000 payable in cash or shares of the acquirer. The consideration is payable on the earlier of 30 days from the date of First Production or the date falling on the fifth anniversary of the agreement.

On 15 November 2017, Block Energy performed a share consolidation exercise whereby 1 new share of 0.25p nominal value was issued to replace every 5 shares of 0.05p nominal value.

On 13 December 2017 the Company issued a further £150,000 of Convertible Loan Notes.

On 26 February 2018, the Company varied the Antubia SPA and paid the sum of USD150,000 to satisfy any obligation that may arise under the Antubia SPA.

On 28 March 2018, the West Rustavi Production Services Contract was ratified by the Georgian government.

24. Auditors

The financial information presented to the members of the Company as prepared under IFRS in respect of the years ended 30 June 2017 and 2016 were audited by PKF Littlejohn LLP and carried an unqualified audit report. PKF Littlejohn LLP's address is 1 Westferry Circus, Canary Wharf, London E14 4HD. PKF Littlejohn LLP are registered auditors in the UK and are members of The Institute of Chartered Accountants in England and Wales.

The financial statements presented to the members of the Company as prepared under IFRS as adopted by the European Union in respect of the year ended 30 June 2015 were audited by Fryza Bannister and carried an unqualified audit report. Fryza Bannister are registered auditors in the UK and are members of the Institute of Chartered Accountants in England and Wales.

SECTION C

UNAUDITED INTERIM FINANCIAL INFORMATION ON BLOCK ENERGY PLC FOR THE SIX MONTHS ENDED 31 DECEMBER 2017

The Directors have prepared the Consolidated Interim Financial Statements for the six months ended 31 December 2017 on the basis set out in note 2 to the Consolidated Interim Financial Statements. The Consolidated Interim Financial Statements contained in this Part VI, Section C, which have been prepared by the Directors and are unaudited. The Directors are responsible for the Consolidated Interim Financial Statements contained in this Part VI, Section C.

Condensed Consolidated Interim Statement of Comprehensive Income

For the period ended 31 December 2017

	6 months to 31 December 2017 Unaudited Group £'000	6 months to 31 December 2016 Unaudited Group £'000	Year ended 30 June 2017 Audited Group £'000
Continuing operations			
Revenue	58	—	—
Cost of sale	(2)	—	—
Gross Profit	56	—	—
Exploration costs	(92)	(2)	(3)
Administrative expenses	(285)	(65)	(281)
Operating loss before exceptional items	(321)	(67)	(284)
AIM admission preparation costs	(43)	—	—
Finance costs	(11)	—	(6)
Total finance cost	(54)	—	(6)
Loss for the period/ year before taxation	**(375)**	**(67)**	**(290)**
Taxation	—	—	—
Loss for the period/ year from continuing operations (attributable to the equity holders of the parent)	(375)	(67)	(290)
Discontinued operations			
Gain on disposal from discontinued operations	—	—	39
Administrative expenses	(41)	—	(30)
Profit/ (loss) for the period/ year from discontinued operations (attributable to the equity holders of the parent)	(41)	—	(9)
Loss for the period/ year	**(416)**	**—**	**(281)**
Earnings per share from continuing operations – basic	(0.10)p	(0.067)p	(0.123)p
Earnings per share from discontinued operations – basic	(0.01)p	—	0.004p
Earnings/ (loss) per share basic	(0.11)p	(0.067)p	(0.119)p

Condensed Consolidated Statement of financial position
As at 31 December 2017

	At 31 December 2017 Unaudited Group £000	At 31 December 2016 Unaudited Group £000	At 30 June 2017 Audited Group £000
Non-current assets			
Intangible assets	1,381	329	654
Property, plant and equipment	275	—	—
	1,656	329	654
Current assets			
Cash and cash equivalents	81	40	215
Restricted cash	197	—	—
Trade and other receivables	113	1	244
Inventory	160	—	—
Asset held for sale	329	—	329
Total current assets	880	41	788
Total assets	2,536	370	1,442
Equity and liabilities			
Capital and reserves			
Called up share capital	1,274	1,048	1,217
Share premium account	3,619	1,628	2,721
Other reserve	55	—	—
Profit and loss account	(3,223)	(2,594)	(2,807)
Total Equity	1,725	82	1,131
Current liabilities			
Trade and other payables	458	133	64
Borrowings	353	155	247
Total current liabilities	811	288	311
Total equity and liabilities	2,536	370	1,442

Consolidated Statement of changes in equity
As at 31 December 2017

	Share capital £'000	Share premium £'000	Retained deficit £'000	Other reserve £'000	Total equity £'000
Balance at 30 June 2016	**1,048**	**1,628**	**(2,527)**	**—**	**149**
Loss for the period	—	—	(66)	—	(66)
Shares issued	—	—	—	—	
Balance at 30 December 2016	**1,048**	**1,628**	**(2,593)**	**—**	**83**
Loss for the period	—	—	(214)	—	(214)
Shares issued	169	1,110	—	—	1,279
Cost of issue	—	(17)	—	—	(17)
Balance at 30 June 2017	**1,217**	**2,721**	**(2,807)**	**—**	**1,131**
Loss for the period	—	—	(416)	—	(416)
Shares issued	22	341	—	—	363
cost of issue		(3)	—	—	(3)
Acquisition of subsidiary	35	560	—	—	595
Equity component of convertible loan note	—	—	—	55	55
Balance at 31 December 2017	**1,274**	**3,619**	**(3,223)**	**55**	**1,725**

Condensed Consolidated Interim Statement of Cash Flows
for the 6 months ended 31 December 2017

	6 months ended 31 December 2017 Unaudited Group £'000	6 months ended 31 December 2016 Unaudited Group £'000	Year ended 30 June 2017 Audited Group £'000
Cash flows from Operating activities			
Loss for the period before income tax	(375)	(67)	(290)
Profit/(loss) from discontinued operations	(41)	—	9
Adjustments for:			
Non-refundable deposit	(39)	—	(39)
Finance expense	11	—	6
Net cash flows used in operating activities before changes in working capital	**(444)**	**(67)**	**(314)**
(Increase)/ Decrease in trade and other receivables	(60)	1	(286)
Increase/(decrease) in trade and other payables	265	24	291
Net cashflows used in operating activities	**(239)**	**25**	**(309)**
Cash flows from investing activities			
Non-refundable deposit	30	—	39
Expenditure in respect of intangible assets	(454)	—	(422)
Restricted cash	(197)	—	—
Proceeds from borrowings	—	70	—
Cash used in investing activities	**(612)**	**70**	**(383)**
Cash inflows from financing activities			
Convertible loan notes issued	360	—	170
Issue of ordinary share capital	361	—	750
Costs of issue of ordinary share capital	(3)	—	(17)
Net cash flows from financing activities	**718**	**—**	**903**
Net increase/(decrease) in cash and cash equivalents	**(133)**	**28**	**211**
Cash and cash equivalents at the beginning of period	215	12	12
Effects of foreign exchange rate changes on cash and cash equivalents	(1)	—	(8)
Cash and cash equivalents at end of period	**81**	**40**	**215**

Notes to the Condensed Consolidated Interim Financial Statements

1. Interim Financial Statements

The information relates to the 6 month period from 1 July 2017 to 31 December 2017. The Company's name changed to Block Energy Plc from Goldcrest Resources Plc on 10 May 2017.

The Group's trading symbol is BLOK.

The Condensed Consolidated Interim Financial Statements comprise of the Company and its subsidiaries and were approved by the Directors on 29 March 2018.

The Condensed Consolidated Interim Financial Statements have not been reviewed by the Group's auditors.

2. Basis of accounting

The report has been prepared using accounting policies that the Group has adopted and were used for the accounting period to 30 June 2017. The information does not constitute statutory accounts within the meaning of section 435 of the Companies Act 2006.

The financial statements are prepared under the historical cost convention.

The Group will report again for the full year to 30 June 2018.

3. Significant accounting policies

The accounting policies applied by the Group in this consolidated interim financial report are the same as those applied by the Group in its consolidated financial statements for the period ended 30 June 2017, with the exception of the following policies;

Revenue

Revenue from the production of oil is recognised at the point at which oil is delivered to the customer.

The total revenue for the Group for the period was derived from its principal activity, being the development and enhancement of oil and gas production assets.

Property, Plant and Equipment

The PPE were acquired through the acquisition of the PSA interests in Norioskhevi and Satskhenisi licence areas. These assets are stated at cost less accumulated depreciation and accumulated impairment losses.

Inventories

Inventories were acquired through the acquisition of the PSA interests in Norioskhevi and Satskhenisi licence areas. Costs comprises of all costs of purchase, costs of conversion and other costs incurred in bringing the inventories to their present location and condition.

Financial instruments

The Group's financial assets consist of current bank account, loans and other receivables. Trade and other receivables are stated initially at fair value and subsequently at amortised cost.

The Group's financial liabilities consist of convertible loan notes, trade and other payables. All are non derivative assets. The trade and other payables are stated initially at fair value and subsequently at amortised cost. Convertible loan notes are treated as described below.

Convertible loan notes

In accordance with IAS 32, the Group has classified the convertible debt in issue as a compound financial instrument. Accordingly, the Group presents the liability and equity component separately on the statement of financial position. The classification of the liability and equity component is not reversed as a result of a change in the likelihood that the conversion option will be exercised. No gain or loss arises from initially recognising the components of the instrument separately. Interest on the debt element of the loan is accreted over the term of the loan at the effective interest rate. In the event of conversion the equity component relating to the conversion rights will be transferred to share capital and share premium (for any amount over the nominal value of each share).

4. Operating segments

The Group manages a group involved in Oil resources development and exploration in the country of Georgia, and, is therefore considered to operate in a single geographical and business segment.

5. Acquisition of Satskhenisi Ltd

On 25 July 2017, Block Energy secured a 90% working interest in the Satskhenisi Production sharing agreement ("PSA") via the acquisition of 100% of the share capital of Satskhenisi Ltd, a (Marshall Islands registered company) for £595k satisfied by the issue of share capital in Block Energy Plc.

	£'000
Fair Value of consideration – shares issued	595
Fair value of Inventory & PPE acquired	322
Fair value of PSA acquired	273
	595

6. Basic and diluted loss per share

The calculation of loss per share for the six months to 31 December 2017 is based on the loss for the period attributable to ordinary shareholders of £416K (31 December 2016 – £67k) is 0.10p (continued operations) and 0.01 (discontinued operations) , (31 December 2016 -loss of 0.067p).

The weighted average number of ordinary shares has been impacted by the share consolidation which took place on November 15th, 2017. The consolidation of capital exercise replaced five ordinary shares in the company with one.

In the opinion of the directors, all the outstanding share options and warrants are anti-dilutive and hence, basic and fully diluted loss per share are the same.

7. Investments & Intangibles

	£'000 Licences	**£'000 Exploration and Evaluation cost**	**£'000 Total**
Cost			
At 1 July 2017	617	37	654
Additions during the year	727	—	727
At 31 Dec 2017	1,344	37	1,381

The main additions in the current period comprise of the following

- £273k fair value of the Satskhenisi PSA.
- $620k USD in cash to increase the Companies ownership in the Norio PSA from 38% to 100%.

8. Plant, Property and equipment

	£'000 Equipment	£'000 Total
Cost		
At 1 July 2017	—	—
Additions during the year	275	275
At 31 December 2017	275	275
Depreciation		
At 1 July 2017	—	—
Disposals in the year	—	—
Charge for the year	—	—
At 31 December 2017	—	—
Net book value		
At 31 December 2017	275	275

9. Inventory

	£'000
At 1 July 2017	—
Additions	160
Written off during the period	—
At 31 December 2017	160

10. Share capital

A consolidation of capital exercise was undertaken on the 15th November 2017. The existing 489,841,048 Ordinary shares of GBP0.005 in issue were consolidated into 97,968,209 Ordinary shares of GBP0.0025, in a five for one share consolidation.

11. Subsequent events

Subsequent to the end of this reporting period, the Group received total cash funds of $600k, from the completion of sale of the entire issued and to be issued share capital of Antubia Resources Ltd subsidiary which held the Asheba mining asset in Ghana.

Section D

ACCOUNTANT'S REPORT ON THE UNAUDITED PRO FORMA STATEMENT OF NET ASSETS OF BLOCK ENERGY PLC

PKF Littlejohn LLP

Accountants & business advisers

The Directors
Block Energy Plc
60 Gracechurch Street,
London EC3V 0HR

The Directors
SPARK Advisory Partners Limited
5 St John's Lane
Farringdon
London EC1M 4BH

4 June 2018

Dear Sirs

Report on the unaudited *pro forma* statement of net assets

We report on the unaudited *pro forma* statement net assets (the ''Unaudited Statement of Pro forma Net assets'') set out in Section E of Part IV, of the Admission Document dated 4 June 2018, which has been prepared on the basis described in notes 1 to 5, for illustrative purposes only, to provide information about how the Placing might have affected the financial information presented on the basis of the accounting policies to be adopted by Block Energy Plc.

This report is required by guidance issued by the London Stock Exchange with respect to AIM and is given for the purpose of complying with the guidance issued by the London Stock Exchange and for no other purpose.

Responsibilities

It is the responsibility solely of the Directors of Block Energy Plc to prepare the Unaudited Statement of Pro forma Net assets.

It is our responsibility to form an opinion as to the proper compilation of the Unaudited Statement of Pro forma Net assets and to report that opinion to you.

In providing this opinion we are not updating or refreshing any reports or opinions previously made by us on any financial information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed by us at the dates of their issue.

Tel: +44 (0)20 7516 2200 • Fax: +44 (0)20 7516 2400 • DX 42660 Isle of Dogs • www.pkf-littlejohn.com
PKF Littlejohn LLP • 1 Westferry Circus • Canary Wharf • London E14 4HD

Basis of opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. The work that we performed for the purposes of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering evidence supporting the adjustments and discussing the Unaudited Statement of Pro forma Net assets with the Directors of Block Energy Plc.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with reasonable assurance that the Unaudited Statement of Pro forma Net assets has been properly compiled on the basis stated and as such is consistent with the accounting policies of Block Energy Plc.

Opinion

In our opinion:

- The Unaudited Statement of Pro forma Net assets has been properly compiled on the basis set out therein;
- Such bases are consistent with the accounting policies of Block Energy Plc; and
- The adjustments are appropriate for the purposes of the Unaudited Statement of Pro forma Net assets as disclosed.

Declaration

For the purposes of guidance issued by the London Stock Exchange we are responsible for this report as part of the Admission Document and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included within the Admission Document in compliance with guidance issued by the London Stock Exchange.

Yours faithfully

PKF Littlejohn LLP
Reporting Accountants

SECTION E

UNAUDITED PRO FORMA STATEMENT OF NET ASSETS FOR THE GROUP

Set out below is an unaudited *pro forma* statement of net assets of Block Energy Plc (''the Company'' or ''Block) which has been prepared for illustrative purposes only to show the effect of the Placing and Subscription and admission of the Company on the London Stock Exchange as if it had occurred on 31 December 2017. The unaudited *pro forma* statement of net assets has been prepared for illustrative purposes only, and because of its nature, it may not give a true reflection of the Enlarged Group's financial position or results.

The Company

	Net assets as at 31 December 2017 (Note 1) £'000	Conversion of Convertible Loan Notes (Note 2) £'000	GOG shares issued pursuant to Norio and GNV SPA (note 3) £'000	Placing and Subscription (Note 4) £'000	Pro forma net assets at 31 December 2017 £'000
Assets					
Non-current assets					
Intangible assets	1,381	—	939	—	2,320
Property, plant and equipment	275	—	—	—	275
	1,656	—	939	—	2,595
Current assets					
Inventory	160	—	—	—	160
Trade and other receivables	113	—	—	—	113
Asset held for sale	329	—	—	—	329
Cash and cash equivalents	81	—	—	4,270	4,351
Restricted cash	197	—	—	—	197
Current assets	880	—	—	4,270	5,150
Total assets	2,536	—	939	4,270	7,745
Liabilities					
Current liabilities					
Trade and other payables	(458)	11	—	—	(447)
Borrowings	(353)	353	—	—	—
Current liabilities	(811)	364	—	—	(447)
Total assets less total liabilities	1,725	364	939	4,270	7,298

Notes

The unaudited *pro forma* statement of net assets has been prepared on the following basis:

1. The unaudited net assets of Block as at 31 December 2017 have been extracted without adjustment from the Historic Financial Information included in Section C of Part IV of this document;
2. An adjustment has been made to reflect the issue, in aggregate of 10,759,132 New Ordinary Shares in relation to the conversion of the Convertible Loan Notes totalling £352,625 and accrued interest of £10,500 in respect of the CLN as at 31 December 2017;
3. An adjustment has been made to reflect the issue of New Ordinary Shares in relation to Consideration due under the Norio SPA totalling \$250,000 and the GNV SPA totalling \$1,000,000, both converted at £1/\$1.331, being the closing rate on 31 May 2018.
4. An adjustment has been made to reflect the proceeds of 125,000,000 Placing Shares and Subscription Shares issued at 4 pence each net of an adjustment to reflect the payment in cash of admission costs estimated at approximately £730,000 inclusive of any non-recoverable sales taxes;
5. No adjustments have been made to reflect the trading or other transactions, other than described above, of the Company since 31 December 2017; and
6. The *pro forma* statement of net assets does not constitute financial statements.

PART V

ADDITIONAL INFORMATION

1. Responsibility

The Directors and Proposed Directors, whose names appear on page 6 of this document, and the Company, accept responsibility, both individually and collectively, for the information contained in this document and compliance with the AIM Rules for Companies. To the best of the knowledge and belief of the Directors, the Proposed Directors and the Company (having taken all reasonable care to ensure that such is the case) the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information.

2. The Company

i. The Company was incorporated and registered on 8 February 2005 as a public limited company with the name Lisungwe Plc and with registration number 05356303. On 15 December 2010, the Company changed its name to Rare Earths and Metals Plc. On 21 May 2013, the Company changed its name to Goldcrest Resources Plc. On 5 May 2017 the Company changed its name to Block Energy plc.

ii. The Company was incorporated in England and Wales.

iii. The Company is a public limited company and accordingly the liability of its members is limited.

iv. The Company is domiciled in England and Wales and its registered office is at 6th Floor, 60 Gracechurch Street, London, United Kingdom, EC3V 0HR. The Company's business address is at 3 St Michael's Alley, London EC3V 9DS The Company's telephone number is +44 (0)20 7236 1177.

v. The ISIN (International Security Identification Number) for the Ordinary Shares is GB00BF3TBT48.

vi. The Company's legal Entity Identifier (LEI) code is 213800E2J8QA1J6KN415.

vii. The principal legislation under which the Company operates, and under which the New Ordinary Shares will be issued, is the Companies Act and the regulations made thereunder.

viii. The Company's principal activity is that of a holding company as well as performing all administrative, strategic and governance functions for the Group.

ix. As at the date of this document, the Company has the following significant subsidiaries:

Name	Country of incorporation	Registration number	Ownership interest
GOG Norioskhevi Ltd	British Virgin Islands	1849997	100%
Georgia New Ventures Inc	Bahamas	167542	100%
Satskhenisi Ltd	Marshall Islands	91733	100%

x. The Company also has two additional subsidiary companies – Taoudeni Resources Limited and Ensign Resources Limited. Taoudeni Resources Limited is a limited liability company incorporated in England and Wales with company number 09084718, which entered members' voluntary liquidation on 25 May 2016. Ensign Resources Limited is a limited liability company incorporated in the Isle of Man with company number 36799, which is now dormant after disposing of Antubia Resources Limited (details set out in paragraph 13x) and which will be imminently placed into members voluntary liquidation. Each of Taoudeni Resources Limited and Ensign Resources Limited were no longer required by the Company after selling their assets and accordingly, both are being wound up with no loss to creditors.

3. Share capital of the Company

i. Upon incorporation, the Company's share capital comprised two ordinary shares of £1.00 each, both of which were fully paid up.

ii. Immediately following incorporation, the Company sub-divided each of the ordinary shares of £1.00 each into 2,000 ordinary shares of £0.0005 each, immediately following which the Company had a share capital of 4,000 ordinary shares of £0.0005 each.

iii. Immediately prior to 31 December 2016, the Company had an issued share capital of 2,095,165,355 Ordinary Shares. On 31 December 2016, the Company reorganised its share capital by sub-dividing each Ordinary Share into one ordinary share of £0.00001 each and one deferred share of £0.00049 each. The Company then consolidated every 50 ordinary shares of £0.00001 each into one ordinary share of £0.0005 each.

iv. The Deferred Shares created do not carry any voting or dividend rights and carry a right to participate in a return on capital, only when each holder of Ordinary Shares has been distributed £100,000,000 per Ordinary Share held by them.

v. Immediately prior to 15 November 2017, the Company had an issued ordinary share capital of 489,841,048 ordinary shares of £0.0005 each. On 15 November 2017, the Company carried out a consolidation of its ordinary share capital, pursuant to which every five ordinary shares of £0.0005 each were converted into one ordinary share of £0.0025 each.

vi. At the date of publication of this document, the Company has an issued share capital comprising 97,968,209 Ordinary Shares and 2,095,165,354 Deferred Shares, all of which are fully paid up.

vii. Since 1 July 2014, there have been the following changes to the issued share capital of the Company:-

Date of Issue / Exercise	Description	No. of Shares	Nominal value per share (£)	Subscription price paid per Share (£)	Total No. of Shares
13.11.2014	Ordinary Shares	181,818,181	0.0005	0.00055	1,039,893,786
27.11.2014 – 15.12.2014	Ordinary Shares	90,909,090	0.0005	0.00055	1,130,802,876
27.11.2014 – 15.12.2014	Ordinary Shares	181,818,181	0.0005	0.00055	1,312,621,057
27.11.2014 – 15.12.2014	Ordinary Shares	90,909,091	0.0005	0.00055	1,403,530,148
27.03.2015	Ordinary Shares	90,909,091	0.0005	0.00055	1,494,439,239
29.04.2015	Ordinary Shares	1,548,200	0.0005	0.002	1,495,987,439
18.01.2016	Ordinary Shares	599,177,916	0.0005	0.0005	2,095,165,355
31.12.2016	Sub-division of each ordinary share of £0.0005 each into 1 ordinary share of £0.00001 each and 1 deferred share of £0.00049 each	2,095,165,355 ordinary shares 2,095,165,354 deferred shares	0.00001 0.00049	0.0001 0.00049	2,095,165,355 ordinary shares 2,095,165,354 deferred shares
31.12.2016	Share consolidation of every 50 ordinary shares of £0.00001 each in to 1 ordinary share of £0.0005 each	41,903,307 ordinary shares	0.0005	0.0005	41,903,307 ordinary shares 2,095,165,354 deferred shares
10.01.2017	Ordinary Shares	163,320,001	0.0005	0.0025	205,223,308 ordinary shares 2,095,165,354 deferred shares
31.03.2017	Ordinary Shares	30,000,000	0.0005	0.005	235,223,308 ordinary shares 2,095,165,354 deferred shares
09.05.2017	Ordinary Shares	144,617,740	0.0005	0.005	379,841,048 ordinary shares 2,095,165,354 deferred shares
03.07.2017	Ordinary Shares	10,588,235	0.0005	0.0085	390,429,283 ordinary shares 2,095,165,354 deferred shares
02.08.2017	Ordinary Shares	70,000,000	0.0005	0.0085	460,429,283 ordinary shares 2,095,165,354 deferred shares
31.08.2017	Ordinary Shares	29,411,765	0.0005	0.0085	489,841,048 ordinary shares 2,095,165,354 deferred shares
15.11.2017	Share consolidation of every 5 ordinary shares of £0.0005 each in to 1 ordinary share of £0.0025 each	97,968,209	0.0025	0.0025	97,968,209 ordinary shares 2,095,165,354 deferred shares

viii. Immediately following Admission, the Company will have:

– an issued share capital comprising 258,547,601 Ordinary Shares and 2,095,165,354 Deferred Shares, all of which will be fully paid up on or before Admission;

– outstanding warrants to subscribe for 11,017,116 Ordinary Shares; and

– no outstanding options to subscribe for Ordinary Shares (although the Company has agreed to grant 5,600,000 options to Paul Haywood and Roger McMechan under their respective service agreements).

ix. Pursuant to the Companies Act, with effect from 1 October 2009, the concept of authorised share capital was abolished and accordingly there is no limit on the maximum number of shares that may be allotted by the Company save as otherwise set out in the Company's articles of association or as may be approved by shareholder resolution from time to time.

x. At a general meeting of the Company held on 5 May 2017, a resolution of the Company was approved that the Directors are generally and unconditionally authorised pursuant to section 551 of the Companies Act to allot shares and grant rights to subscribe for or to convert any security into shares (such shares and rights to subscribe for or to convert any security into shares being ''relevant securities'') up to an aggregate nominal amount of £1,000,000, such authority to expire on 28 April 2021, except that the Directors can during such period make offers or arrangements which could or might require the allotment of relevant securities after the expiry of such period.

xi. At an annual general meeting of the Company held on 29 December 2017, resolutions of the Company were approved that:

(A) the Directors are generally and unconditionally authorised pursuant to section 551 of the Companies Act to allot shares and grant rights to subscribe for or to convert any security into shares (such shares and rights to subscribe for or to convert any security into shares being ''relevant securities'') up to an aggregate nominal amount of £180,833, such authority to expire on the conclusion of the annual general meeting of the Company to be held in 2018, except that the Directors can during such period make offers or arrangements which could or might require the allotment of relevant securities after the expiry of such period; and

(B) the Directors are empowered pursuant to section 570(1) of the Companies Act to allot equity securities (as defined in section 560(1) of the Companies Act) of the Company wholly for cash pursuant to the authority of the Directors under section 551 of the Companies Act referred to in paragraph 3(xi)(A) above, as if the provisions of section 561 of the Companies Act did not apply to such allotment provided that this power is limited to the allotment of equity securities up to an aggregate nominal value equal to £54,250, such authority to expire upon the conclusion of the next annual general meeting of the Company, except that the Directors can during such period make offers or arrangements which could or might require the allotment of equity securities after the expiry of such period.

xii. At a general meeting of the Company held on 29 May 2018, resolutions of the Company were approved that:

(A) the Directors are generally and unconditionally authorised pursuant to section 551 of the Companies Act to allot shares and grant rights to subscribe for or to convert any security into shares (such shares and rights to subscribe for or to convert any security into shares being ''relevant securities'') up to an aggregate nominal amount of £1,000,000, such authority to expire on the conclusion of the annual general meeting of the Company, except that the Directors can during such period make offers or arrangements which could or might require the allotment of relevant securities after the expiry of such period; and

(B) the Directors are empowered pursuant to section 570(1) of the Companies Act to allot equity securities (as defined in section 560(1) of the Companies Act) of the Company wholly for cash pursuant to the authority of the Directors under section 551 of the Companies Act referred to in paragraph 3(xii)(A) above, as if the provisions of section 561 of the Companies Act did not apply to such allotment provided that this power is limited to the allotment of equity securities up to an aggregate nominal value equal to £1,000,000, such authority to expire upon the conclusion of the next annual general meeting of the Company, except that the Directors can during such period make offers or arrangements which could or might require the allotment of equity securities after the expiry of such period.

xiii. Save as disclosed in this Part V, since 1 July 2014:

– no share or loan capital of the Company has been proposed to be issued or is under option or agreed, conditionally or unconditionally, to be put under option;

- no share or loan capital of the Company has been issued, or is now proposed to be issued, fully or partly paid, either for cash or other consideration to any person;
- no person has preferential subscription rights in respect of any share or loan capital of the Company;
- no commissions, discounts, brokerages or other special terms, have been granted by the Company in connection with the issue or sale of any share or loan capital of the Company;
- neither the Company nor any of its subsidiaries holds any Ordinary Shares or Deferred Shares;
- the Company has no convertible securities, exchangeable securities or securities with warrants in issue; and
- there are no acquisition rights or obligations over the unissued share capital of the Company and there is no undertaking to increase the share capital of the Company.

xiv. The Company has no issued Ordinary Shares that are not fully paid up.

xv. The Ordinary Shares have no redemption or conversion rights.

xvi. The Ordinary Shares are in registered form and may be held either in certificated form or in uncertificated form. The Articles permit the Company to issue shares in uncertificated form. Application has been made to Euroclear for the Ordinary Shares to be enabled for dealings through CREST as a participating security.

4. Articles

The Articles, by a special resolution of the Company passed on 31 August 2016, contain, *inter alia*, provisions to the following effect:

i. Objects

Section 31 of the Companies Act provides that the objects of a company are unrestricted unless any restrictions are set out in its articles.

The Articles do not contain any restrictions on the objects of the Company.

ii. Voting rights

Subject to paragraph 4 ix below, and to any special terms as to voting upon which any shares may for the time being, be held, on a show of hands every member holding Ordinary Shares who (being an individual) is present (or by proxy) in person or (being a corporation) is present by its duly appointed representative shall have one vote and on a poll every member present in person or by representative or proxy shall have one vote for every Ordinary Share in the capital of the Company held by him. A proxy need not be a member of the Company.

The Deferred Shares do not carry any right to receive notice of or to attend any general meeting of the Company or to vote on any resolution proposed thereat.

iii. Alteration of capital

Subject to, and in accordance with the provisions of the Companies Act, and to any rights for the time being attached to any shares, the Company may purchase its own shares (including any redeemable shares), provided that the Company shall not purchase any of its shares unless such purchase has been sanctioned by an resolution passed at a separate meeting of the holders of any class of shares convertible into equity share capital of the Company.

The rights attaching to the Company's shares are set out in its Articles and summarised in this paragraph 4. The alterations or change of these rights would require the passing of a special resolution passed at a general meeting of the holders of that class of shares.

iv. Variation of rights

If at any time the capital of the Company is divided into different classes of shares, all or any of the rights or privileges attached to any class of shares in the Company may be varied or abrogated with the consent in writing of the holders of three-quarters in nominal value of the issued shares of that class or with the sanction of a special resolution passed at a separate general meeting of the holders of that class of shares. At every such separate general meeting (except an adjourned meeting), the quorum shall be two persons holding or representing by proxy one-third in nominal value of the issued shares of that class.

v. Return of capital

Subject to any preferred, deferred or other special rights, or subject to such conditions or restrictions to which any shares in the capital of the Company may be issued, on a winding-up or other return of capital, the holders of Ordinary Shares are entitled to share in any surplus assets remaining after the distribution of the Company's liabilities *pro rata* to the amount paid up or deemed to be paid up on their Ordinary Shares. A liquidator may, with the sanction of a special resolution of the Company and any other sanction required by the Companies Act, divide amongst the members in specie or in kind the whole or any part of the assets of the Company, those assets to be set at such value as he deems fair. A liquidator may also vest the whole or any part of the assets of the Company in trustees on trusts for the benefit of the members.

The holders of Deferred Shares shall have the right to the amount paid up on their shares in the event of a distribution of assets on a winding up of the Company only after there shall have been distributed to the holders of Ordinary Shares the amount of £100,000,0000 in respect of each Ordinary Share held by them.

vi. Transfer of shares

A member may transfer all or any of his shares:

(1) in the case of certificated shares by instrument in writing in any usual or common form or in such other form as may be approved by the directors; and

(2) in the case of uncertificated shares, through a relevant system in accordance with the facilities and requirements of the relevant system concerned.

The instrument of transfer of a certificated share shall be executed by or on behalf of the transferor and, if the share is not fully paid, by or behalf of the transferee. The directors may in their absolute discretion refuse to register a transfer of any share which is not fully paid, or on which the Company as a lien provided that dealings in the shares are not prevented from taking place on an open and proper basis. Subject to paragraph 4 (ix) below, the Articles contain no restrictions on the free transferability of fully paid shares provided that the transfer is in respect of only one class of share and is accompanied by the share certificate and any other evidence of title required by the directors and that the provisions in the Articles relating to the deposit of instruments for transfer have been complied with.

The directors may also refuse to register the transfer of a share which is in favour of more than four transferees or as provided under paragraph 4 vi If the directors refuse to register a transfer, they shall within two months of the date on which the instrument of transfer was lodged with the Company (or in the case of uncertified shares the operator instrument was received by the Company) send to the transferee notice of refusal.

vii. Dividends and other distributions

The Company may (subject to the provisions of the Companies Act) by ordinary resolution declare dividends to be paid to members in accordance with their respective rights and their respective interests provided that no dividend shall be paid otherwise than out of profits of the Company available for distribution and no dividend shall exceed the amount recommended by the directors. The directors may from time to time pay such interim dividends as appear to the directors to be justified.

Subject to the rights of persons, if any, holding shares with special dividend rights, and subject to paragraph 4 ix below, all dividends shall be apportioned and paid *pro rata* according to the amounts paid or credited as paid on the shares during any portion or portions of the period in respect of which the dividend is paid. No amount paid or credited as paid in advance of calls shall be regarded as paid on shares for this purpose.

The holders of Deferred Shares shall not be entitled to receive any dividend out of the profits of the Company.

All dividends unclaimed for a period of 12 years after the payment date for such dividend shall if the directors so resolve be forfeited and shall revert to the Company.

The Company may deduct from any dividend payable all sums of money (if any) due to the Company by the member on account of calls or alterations and use such monies to satisfy such amount payable.

All dividends unclaimed for a period of 12 years after having been declared shall if the directors so resolve be forfeited and shall revert to the Company and the Company shall not be constituted a trustee thereof. All dividends unclaimed for a period of 12 months shall be invested or otherwise made use of by the directors for the benefit of the Company until claimed.

The Board may if authorised by an ordinary resolution of the Company and subject to such terms and conditions as the Board may determine, offer any holder of ordinary shares the right to elect to receive additional ordinary shares, credited as fully paid, in lieu of cash in respect of any dividend or any part of any dividend specified by the ordinary resolution.

viii. Pre-emption rights

There are no rights of pre-emption under the Articles in respect of transfers of issued ordinary shares.

In certain circumstances, the Company's shareholders have statutory pre-emption rights under the Companies Act in respect of the allotment of new shares in capital of the Company. These statutory pre-emption rights require the Company to offer new shares for allotment by existing shareholders on a *pro rata* basis before allotment to other persons.

ix. Restrictions on shares

If a member or any other person appearing to be interested in shares held by such shareholder has been duly served with notice under section 793 of the Companies Act and is in default in supplying to the Company within 14 days (or such longer period as may be specified in such notice) the information thereby, required, then (if the directors so resolve) such member shall not be entitled to vote or to exercise any right conferred by membership in relation to meetings of the Company in respect of the shares which are the subject of such notice. Where the holding represents more than 0.25 per cent. of the issued shares of that class, the payment of dividends may be withheld, and such member shall not be entitled to transfer such shares otherwise than by an arm's length sale.

x. Meetings of members

Annual general meetings are called on 21 days' notice in writing, exclusive of the day of which it is served or deemed to be served and of the day on which the meeting is to be held, and is to be given to all members on the register at the close of business on a day determined by the Company, such day being not more than 21 days before the day that the notice of meeting is sent.

An annual general meeting may be called on shorter notice providing all members entitled to attend and vote thereat agree. The Company must specify in the notice of meeting a time, not more than 48 hours before the time fixed for the meeting, by which a person must be entered into the register in order to have the right to attend or vote at the meeting. Notice of a general meeting may be validly given when sent in electronic form or made available on the Company's website.

All other general meetings may be called whenever the directors think fit or when a meeting has been requisitioned in accordance with the Companies Act. General meetings are called on 14 days' notice in writing exclusive of the day on which it is served or deemed to be served and the day on which it is to be held. A general meeting can be called on shorter notice if a majority in number of the members having a right to attend and vote at the general meeting, being a majority together holding not less than 95 per cent. in nominal value of the shares giving that right, consent. Two members present in person or by proxy and entitled to vote shall be a quorum for all purposes.

Shareholders need not attend a meeting of the Company in person but can do so by way of a validly appointed proxy. Proxies are appointed in accordance with the Articles. In order to be validly appointed, details of the proxy must be lodged with the Company no later than 48 hours before the commencement of the relevant meeting (although a later time may be specified by notice of the meeting) or in the case of a poll which is not taken at or on the same day as the meeting, not less than 24 hours prior to the taking of the poll. Failure to lodge details of the appointed proxy in accordance with Articles will result in the proxy not being treated as valid.

xi. Directors

Save as provided in the Articles, a director shall not vote as a director in respect of any contract, transaction or arrangement or proposed contract, transaction or arrangement or any other proposal in which he has any interest which conflicts or which may conflict with the interests of the Company. He will not be counted in the quorum present at the meeting, and if he does vote, his vote shall not be counted.

A director shall (in the absence of any other interest than is indicated below) be entitled to vote (and be counted in the quorum) in respect of any resolution relating to any of the following matters namely:

(a) the giving of any security, guarantee or indemnity in respect of money lent or obligations incurred by him or by any other person at the request of or for the benefit of the Company or any of its subsidiary undertakings;

(b) the giving of any security, guarantee or indemnity in respect of a debt or obligation of the Company or any of its subsidiary undertakings for which the director himself has assumed responsibility in whole or in part under a guarantee or indemnity or by the giving of security;

(c) the granting of any indemnity or provision of funding unless the terms of such arrangement confer upon such director a benefit not generally available to any other director;

(d) an offer of shares or debentures or other securities of or by the Company or any of its subsidiary undertakings for subscription or purchase in which offer he is or is to be or may be entitled to participate as a holder of securities or as an underwriter or sub-underwriter;

(e) any matter involving any other company in which he or any person connected with him is interested, directly or indirectly, and whether as an officer or shareholder or otherwise howsoever, provided that he and any persons connected with him are not to his knowledge the holder (otherwise than as a nominee for the Company or any of its subsidiary undertakings) of or beneficially interested in one per cent, or more of any class of the equity share capital of such company (or of any third company through which his interest is derived) or of the voting rights available to members of the relevant company (any such interest being deemed for this purpose to be a material interest in all circumstances);

(f) an arrangement for the benefit of the employees of the Company or any of its subsidiary undertakings which does not award him any privilege or benefit not generally awarded to the employees to whom such arrangement relates; and

(g) the purchase and/or maintenance of any insurance policy for the benefit of directors or for the benefit of persons including directors.

The directors may, subject to the Articles, authorise a director to be involved in a situation in which he may have an interest which conflicts with the interests of the Company, provided that the director shall not vote in connection with the authorisation, and the authorisation may be given subject to such terms and conditions as are thought fit.

Fees may be paid out of the funds of the Company to directors who are not managing or executive directors at such rates as the directors may from time to time determine.

Any director who devotes special attention to the business of the Company, or otherwise performs services which in the opinion of the directors are outside the scope of the ordinary duties of a director, may be paid such additional remuneration as the directors or any committee authorised by the directors may determine.

The directors (including alternate directors) shall be entitled to be paid out of the funds of the Company all their travelling, hotel and other expenses properly incurred by them in connection with the business of the Company, including their expenses of travelling to and from meetings of the directors, committee meetings or general meetings.

Any director may hold any other office or place of profit under the Company (except that of Auditor) in conjunction with his office of director and, subject to Section 188 of the Companies Act, on such terms as to remuneration and otherwise as the Board shall arrange.

No shareholding qualification is required by a director. Unless otherwise determined by ordinary resolution of the Company, the number of directors (other than alternate Directors) shall not be less than two. At each annual general meeting, one-third of the directors shall retire from office provided that if their number is more than three, but not a multiple thereof, then the number nearest to but not exceeding one-third shall retire, if their number is two, one of such directors shall retire, and if their number is one that director shall retire. The directors to retire by rotation in each year shall be those who have been longest in office since their last appointment or reappointment.

The members of the Company may pass an ordinary resolution to fill the vacancy of a retiring director either by electing the retiring director or by appointing some other eligible person.

A director need not be a member of the Company but shall be entitled to receive notice of and attend and speak at all general meeting of the Company and all separate meetings of the holders of any class of securities of the Company.

The directors may from time to time appoint any one of their number to an executive office on such terms as they think fit. Such a director may receive such remuneration as the directors may determine.

The directors may appoint any person to be a director, either to fill a casual vacancy or by way of addition of their number, but the total number of directors shall not exceed the maximum number fixed by or in accordance with the Articles. Any director so appointed shall retire from office at the next annual general meeting of the Company but shall then be eligible for re-appointment. Such a director shall not be taken into account when determining which directors shall retire by rotation at an annual general meeting.

At each annual general meeting any director bound to retire shall retire from office. A retiring director shall retain office until the close of the meeting at which he retires. Any director who was not elected or re-elected at either of the two preceding annual general meetings shall retire by rotation. The directors to retire at each annual general meeting will, first, be the directors who have been longest in office since their last appointment. As between directors who have been in office an equal length of time, the directors to retire shall, unless they shall otherwise agree among themselves, be selected from among them by lot. The retiring directors shall be eligible for re-appointment.

No other director other than a director retiring at the meeting shall be appointed or re-appointed unless not less than twenty eight and no more than thirty five days before the date appointed for the meeting, notice executed by a member entitled to vote at the meeting (and not the person being proposed) has been given to the Company of the intention for that person to be appointed or reappointed, which must state the particular which would be added to the Company's register of directors, together with notice executed by the person being proposed of his willingness to be appointed.

xii. Borrowing Powers

The directors may exercise all the powers of the Company to borrow or raise money to mortgage or charge all or any of its undertaking, property, assets (present and future) and uncalled capital to issue debentures and other securities, and to give security whether outright or as collateral security for any debt, liabilities or obligations of the Company, any subsidiary of the Company or any third party.

5. Directors

i. The business address of each of the Directors and Proposed Directors is 3 St Michael's Alley, London, EC3V 9DS.

ii. Details of the length of service of each of the Directors to date in their current office are set out below:

Name	Age	Commencement date in office
Philip Dimmock	71	Date of Admission
Paul Haywood	36	8 June 2016
Niall Tomlinson	36	19 January 2016
Roger McMechan	59	Date of Admission
Timothy Parson	60	9 May 2017
Serina Bierer	37	Date of Admission

iii. Other than in relation to the Company, details of any directorship that is, or was in the last five years, held by each of the Directors, and any partnership of which each of the Directors is, or was in the last five years, a member, are set out below:

Director	Current directorships and partnerships	Past directorships and partnerships
Philip Anthony Dimmock	Gulf Keystone Petroleum Limited Georgian Energy Limited (Australian Company)	Africa Oil Exploration Limited Nor Energy AS
Paul Haywood	Wheal Consulting Limited Plutus Strategies Limited* Eagle Gas Limited Spur Resources Limited (dissolved) Tamar Oil Limited (dissolved) Ekeh Petroleum Limited Oilex Petroleum plc TPH Oil and Gas Limited	Taoudeni Resources Ltd (in liquidation) Streamline Resources Limited (dissolved)
Niall Tomlinson	Plutus Strategies Limited Goldcrest Resources Limited Wheal Investments Limited TAIEX Limited Wheal Jane Consulting Limited (UK) Every Brand New Day Limited Ensign Resources Ltd (in liquidation) Wheal Jane Ltd (BVI)	Georgian Minerals Ltd Cligga Ltd Antubia Resources Limited (Ghana) Taoudeni Resources Ltd (in liquidation)
Roger George McMechan	Iskander Energy Corp.	Huntington Exploration Inc.
Timothy Richard Beresford Parson	Lakeside Resources Limited TPH Oil & Gas Ltd TRBP Ltd	
Serina Vera Emanuela Bierer	Bierer Resources Limited 143-155 Gloucester Terrace Limited	Bierer Associates Ltd

*Paul Haywood has not been formally appointed as a director of Plutus Strategies Limited, but acts as a shadow director

Save as set out above, as at the date of this document, none of the Directors has:

– any unspent convictions in relation to indictable offences; or

– been declared or made any individual voluntary arrangement; or

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

– been a partner of a partnership at the time of or within the 12 months preceding the partnership being subject to a compulsory liquidation, administration or partnership voluntary arrangement; or

– had any asset subject to receivership or been a partner of any partnership at the time of, or within the 12 months preceding, any asset of such partnership being subject to a receivership; or

– been subject to any public criticism by statutory or regulatory authorities (including recognised professional bodies), nor 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.

6. Directors' and other interests

i. The interests in Ordinary Shares of the Directors, their respective immediate families and (so far as is known to the Directors or could, with reasonable diligence, be ascertained by them) the persons connected with them (within the meaning of section 252 of the Companies Act) (all of which are beneficial, save where otherwise stated) as at the date of this document, and as they are expected to be immediately following Admission, are as follows:

Name	Number of Ordinary Shares at the date of this document	Percentage of Ordinary Share Capital (%)	Number of Ordinary Shares at Admission	Percentage of Enlarged Issued Ordinary Share Capital (%)	Number of Options to be granted following Admission
Philip Dimmock	—	—	312,500	0.12%	—
Paul Haywood†	2,749,454	2.81	2,749,454	1.06%	4,400,000‡
Niall Tomlinson†	2,829,454	2.89	2,829,454	1.09%	—
Roger McMechan*	—*	—	—*	—	1,200,000‡
Timothy Parson	—	—	325,000	0.13%	—
Serina Bierer	—	—	420,000	0.16%	—

† This total includes 2,189,454 Ordinary Shares held by Plutus Strategies Limited, in which each of Mr Haywood and Mr Tomlinson have an interest. In addition, Plutus Strategies Limited owns warrants over 131,664 Ordinary Shares, with an exercise price of 12.5p, and an expiry date of 11 June 2028 and is due to be issued 1,566,838 Ordinary Shares on the earlier of the Company's second placing on AIM and the date 12 months after Admission.

‡ see paragraph 7(iv) of Part V of this document for details.

* Mr McMechan is a director of Iskander Energy Corporation, which holds 14,000,000 Ordinary Shares. An agreement is in place whereby Iskander will transfer 3,401,260 Ordinary Shares to Mr McMechan.

Other than as set out in the table above, at Admission there will be no options and/or warrants over Ordinary Shares held by the Directors.

ii. Save as disclosed in paragraphs 6 (i) of this Part V, none of the Directors or any member of their respective immediate families, nor any person connected with the Directors within the meaning of section 252 of the Companies Act has any interest, beneficial or non-beneficial, in any shares or options to subscribe for, or securities convertible into, shares of the Company or any of its subsidiaries.

iii. No Director nor any member of his immediate family nor any person connected with him (within the meaning of section 252 of the Companies Act) has a Related Financial Product (as defined in the AIM Rules for Companies) referenced to Ordinary Shares.

7. Options and Warrants

The following Warrants and Options are outstanding in relation to the Ordinary Shares as at the date of this document and as at Admission.

i. Existing Warrants

At present there are 2,279,616 Warrants in issue:

Number	Exercise price	Expiry date
809,028	12.5p	11 June 2028
1,470,588	15p	31 August 2018

ii. New Warrants

In total, new Warrants over 8,737,500 Ordinary Shares will be issued at Admission as follows:

Warrantholder	Number of Ordinary Shares	Exercise price	Expiry date
SPARK Advisory Partners Limited	1,250,000	4p	11 June 2023
Novum	1,875,000	4p	11 December 2019
Northland	3,775,000	4p	11 December 2019
Gneiss Energy Limited	1,837,500	4p	11 December 2019

iii. Existing Options

At present there are no Options outstanding.

iv. New Options

The Company is in the process of establishing two EMI share option schemes:

a) A scheme specifically for the issue of options over 4,400,000 Ordinary Shares to be awarded to Paul Haywood at an exercise price of 2.5p per share; and

b) A scheme for the issue of options to Directors and employees. It is intended that a maximum of 10 per cent of the Enlarged Issued Share Ordinary Capital will be subject to option grants under this scheme.

In addition, the Company has agreed to issue options to Roger McMechan over 1,200,000 Ordinary Shares at an exercise price of 2.5 pence per share.

8. Directors' letters of appointment, service agreements and agreement for services

i. Mr Philip Dimmock is appointed as Non-Executive Chairman (and Chairman of the Audit Committee and Disclosure Committee) pursuant to the terms of a letter of appointment with the Company entered into on 1 December 2017 and with effect from Admission. The agreement is terminable by either party on not less than 3 months' written notice. In addition, Mr Dimmock is entitled to a payment of £12,500 upon Admission, which will be satisfied by the issue of Ordinary Shares at the Issue Price. Mr Dimmock is paid an annual fee of £30,000. His fee is subject to annual review by the Remuneration Committee but there is no obligation to increase Mr Dimmock's fee. The agreement is governed by English law.

ii. Mr Paul Haywood is employed as Chief Executive Director pursuant to the terms of a service agreement with the Company to be entered into on Admission. The agreement is terminable by either party on not less than 12 months' written notice. Mr Haywood is paid an annual salary of £120,000 and may be entitled to receive a discretionary bonus as the Remuneration Committee determines from time to time and is entitled to participate in bonus and share incentive schemes. His basic salary is subject to annual review by the Remuneration Committee but there is no obligation to increase Mr Haywood's basic salary. In the event of a change of control of the Company and Mr Haywood's employment is terminated, Mr Haywood shall be entitled to receive compensation for loss of office in an amount of 2x basic salary. Mr Haywood is subject to certain non-competition and non-solicitation covenants for a period of 6 months following the termination of his employment. The agreement is governed by English law.

iii. Mr Niall Tomlinson is employed as Executive Director of Business Development pursuant to the terms of a service agreement with the Company to be entered into on Admission. The agreement is terminable by either party on not less than 6 months' written notice.

Mr Tomlinson is paid an annual salary of £120,000 and may be entitled to receive a discretionary bonus as the Remuneration Committee determines from time to time and is entitled to participate in bonus and share incentive schemes. His basic salary is subject to annual review by the Remuneration Committee but there is no obligation to increase Mr Tomlinson's basic salary. In the event of a change of control of the Company and Mr Tomlinson's employment is terminated, Mr Tomlinson shall be entitled to receive compensation for loss of office in an amount of 2x basic salary. Mr Tomlinson is subject to certain non-competition and non-solicitation covenants for a period of 6 months following the termination of his employment. The agreement is governed by English law.

iv. Prior to Admission, Ms Serina Bierer has been engaged as Chief Finance Officer pursuant to the terms of a consultancy agreement entered into between the Company and Bierer Resources Ltd, pursuant to which Bierer Resources Ltd makes available the services of Ms. Bierer to the Company. Bierer Resources Ltd was paid a monthly fee of £4,500, such amounts being satisfied by a payment of £3,000 and the issue to Bierer Resources Ltd of Ordinary Shares with a value of £1,500. The cash payment of £3,000 was payable monthly in arrears, with the Ordinary Shares to be issued to Bierer Resources Ltd on Admission.

On Admission, Ms Serina Bierer will be appointed as a director of the Company and will be employed as Financial Director pursuant to the terms of a service agreement with the Company to be entered into on Admission. The agreement is terminable by either party on not less than 6 months' written notice. Ms Bierer works on a part-time basis for 3-4.5 days a week and is paid an annual salary of £80,000 based on full time employment, (being £48,000 *pro-rata*) and may be entitled to receive a discretionary bonus as the Remuneration Committee determines from time to time and is entitled to participate in bonus and share incentive schemes. Her basic salary is subject to annual review by the Remuneration Committee but there is no obligation to increase Ms Bierer's basic salary. Ms Bierer is subject to certain non-competition and non-solicitation covenants for a period of 6 months following the termination of his employment. The agreement is governed by English law.

v. Mr Roger McMechan is employed as Technical Director pursuant to the terms of a service agreement with the Company to be entered into on Admission. The agreement is terminable by either party on not less than 6 months' written notice. Mr McMechan is paid an annual salary of £120,000 and may be entitled to receive a discretionary bonus as the Remuneration Committee determines from time to time and is entitled to participate in bonus and share incentive schemes . His basic salary is subject to annual review by the Remuneration Committee but there is no obligation to increase Mr McMechan's basic salary. In the event of a change of control of the Company and Mr McMechan's employment is terminated, Mr McMechan shall be entitled to receive compensation for loss of office in an amount of 2x basic salary. Mr McMechan is subject to certain non-competition and non-solicitation covenants for a period of 6 months following the termination of his employment. The agreement is governed by English law.

vi. Pursuant to the terms of the letter of appointment with the Company to be entered into on Admission, Timothy Parson has agreed to serve as a Non-executive Director (and Chairman of the Remuneration Committee and Nominations Committee) for an annual fee of £24,000. In addition, Mr Parson is entitled to £1,000 for every month for which he has been a Director prior to the Company's listing on AIM, which will be satisfied by the issue of Ordinary Shares at the Issue Price. This appointment is for an initial term of 2 years terminable by either party by giving not less than three month's notice in writing, but will terminate automatically if Mr Parson is removed from office by a resolution of the Shareholders or is not re-elected to office.

vii. Save as disclosed in this document, there are no service agreements or agreements for the provision of services existing or proposed between the Directors and the Company or the Group.

viii. No loans made or guarantees granted or provided by the Company or any member of the Group to or for the benefit of any Director are outstanding.

ix. The aggregate remuneration (including any contingent or deferred compensation) payable and benefits in kind granted to Directors is estimated to be approximately £379,000 for the financial period ending 30 June 2018 under arrangements in force at the date of this document.

9. Significant shareholders

i. As at the date of this document and at Admission, save for the interests of the Directors which are set out in paragraph 6 above, the Company is aware of the following persons who are or will hold, directly or indirectly, voting rights representing three per cent. or more of the issued share capital of the Company to which voting rights are attached:

Name	Number of Ordinary Shares at the date of this document	Percentage of Ordinary Share capital (%)	Number of Ordinary Shares at Admission	Percentage of Enlarged Issued Ordinary Share Capital (%)
Iskander Energy Corporation†	14,000,000	14.29%	14,000,000	5.41%
Pershing Nominees Limited *	19,176,470	19.57%	19,176,470	7.42%
Lynchwood Nominees Limited **	9,663,548	9.88%	33,162,415	12.83%
Pershing Nominees Limited	9,545,206	9.74%	9,545,206	3.69%
JIM Nominees Limited	5,660,835	5.78%	5,660,835	<3%
Nomura Custody Nominees Limited	5,370,588	5.48%	5,370,588	<3%
Fiske Nominees Limited	3,588,235	3.66%	3,588,235	<3%
JIM Nominees Limited	3,475,294	3.55%	3,475,294	<3%
Mr Jeremy Edelman	3,000,000	3.06%	3,000,000	<3%
Mayan Energy Limited	2,117,647	2.15%	8,510,341	3.29%
Amati Global Investors	—	—	37,500,000	14.50%
Miton Asset Management Limited	—	—	22,500,000	8.70%

† An agreement is in place whereby Iskander will transfer 3,401,260 Ordinary Shares to Mr Roger McMechan.

* the underlying shareholder of these shares is Pelamis Investments Limited;

** the underlying shareholder of 9,263,548 of these shares (at the date of this document) and 32,762,415, (at Admission) is GOG; ;

ii. All Shareholders have the same voting rights.

iii. To the best of the Directors' knowledge, the Company is not directly or indirectly owned or controlled by any Shareholder.

10. United Kingdom Taxation

10.1 The following paragraphs are intended as a general guide only and are based on current United Kingdom legislation and HMRC published practice as at the date of this document. Such law and practice (including, without limitation, rates of tax) is in principle subject to change at any time, possibly with retrospective effect. Except where the position of non-United Kingdom resident Shareholders is expressly referred to, these comments deal only with the position of Shareholders who are resident and, in the case of individuals, domiciled in the United Kingdom for tax purposes, who are the beneficial owners of their Ordinary Shares and who hold their Ordinary Shares as an investment. They do not deal with the position of certain classes of Shareholders such as officers or employees of the Company, dealers in securities, broker-dealers, insurance companies, collective investment schemes, financial institutions, tax exempt organisations and holders that hold (either directly or indirectly) 10 per cent. or more of the shares in the Company. The following paragraphs are not exhaustive and are intended as a general guide only.

10.2 Any person who is in any doubt as to his or her own tax position, or is subject to taxation in a jurisdiction other than the United Kingdom, is strongly recommended to consult their professional tax adviser. The position of non-UK resident and non-UK domiciled Shareholders are not considered in this section and such Shareholders should consult their own tax advisers.

10.3 Taxation of Chargeable Gains

(A) For the purpose of UK tax on chargeable gains, the purchase of Ordinary Shares on a placing will be regarded as an acquisition of a new holding in the share capital of the Company. To the extent that a Shareholder acquires Ordinary Shares allotted to him, the Ordinary Shares so acquired will, for the purpose of tax on chargeable gains, be treated as acquired on the date of the purchase becoming unconditional.

(B) The amount paid for the Ordinary Shares will constitute the base cost of a Shareholder's holding.

(C) A disposal of all or any of the Ordinary Shares may, depending on the circumstances of the relevant Shareholder give rise to a liability to UK taxation on chargeable gains. Shareholders will normally be subject to UK taxation of chargeable gains, unless such holders are not UK tax resident.

Individuals

Where an individual Shareholder disposes of Ordinary Shares at a gain, capital gains tax will be levied to the extent that the gain exceeds the annual exemption (£11,700 for 2018/19) and after taking account of any exemptions and reliefs available to the individual.

For individuals, the starting rate for capital gains tax is 10 per cent. This rate applies where the individual's income and gains are less than the upper limit of the income tax basic rate band after taking into account the individual's personal allowance. To the extent that any chargeable gains, or part of any chargeable gain, aggregated with income arising in a tax year exceed the upper limit of the income tax basic rate band, capital gains tax will be charged at 20 per cent.

For trustees and personal representatives of deceased persons, capital gains tax on gains in excess of the current annual exempt amount (for 2018/19, £11,800 for personal representative of deceased persons and trustees for disabled persons and £5,850 for other trustees) will be charged at a flat rate of 20 per cent.

Where an individual Shareholder disposes of the Ordinary Shares at a loss, the loss may be available to offset against other current year chargeable gains or carried forward to offset against future chargeable gains.

Companies

Where a Shareholder is within the charge to UK corporation tax, a disposal of Ordinary Shares may give rise to corporation tax on 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. Corporation tax is charged on chargeable gains at the rate applicable to that company which is currently 19 per cent. indexation allowance may reduce the amount of chargeable gain that is subject to corporation tax but may not create or increase any allowable loss. In the Autumn 2017 budget it was announced that Indexation Allowance will no longer arise to UK Corporate Shareholders. Pursuant to the Finance Act 2018, indexation allowance ceased to accrue from 1 January 2018.

10.4 Taxation of Dividends

No tax is required to be withheld from dividend payments made by the Company.

Individuals

An individual Shareholder receiving a dividend from the Company whose total income from dividends in the relevant financial year does not exceed £2,000 (the "Tax Free Dividend Allowance") will not pay any income tax on such dividend.

Based on current law at the date of this Admission Document, an individual Shareholder receiving a dividend from the Company whose total income from dividends in the relevant tax year does exceed £2,000 will be taxed as follows:

(a) the individual Shareholders will not pay income tax on the first £2,000 of dividend income in any tax year;

(b) to the extent that the individual's Total Income (as defined below) exceeds the personal allowance but does not exceed the basic rate tax band for that tax year, the individual will be liable to income tax on the Excess Dividend (as defined below) at the rate of 7.5 per cent.;

(c) to the extent that the individual's Total Income (as defined below) exceeds the basic rate band but does not exceed the higher rate tax band for that tax year, the individual will be liable to income tax on the Excess Dividend (as defined below) at the rate of 32.5 per cent.;

(d) to the extent that the individual's Total Income (as defined below) falls within the additional rate band for that tax year, the individual will be liable to income tax on the Excess Dividend (as defined below) at the rate of 38.1 per cent.;

(e) "Total Income" means the total of the individual's dividend income and other taxable income for a tax year; and

(f) "Excess Dividend" means the total of that individual's dividend income in that tax year less £2,000.

For the year 2018/19 in England and Wales, the basic rate band is the first £34,500 of income in excess of any personal allowance, the higher rate band is income between £34,500 and £150,000 in excess of any available personal allowance and the additional rate band applies to income in excess of £150,000 (these bands differ slightly in Scotland).

Where an individual's taxable income exceeds £100,000, their personal allowance is abated by £1 for every £2 of income such that individuals with income in excess of £123,000 will have no personal allowance.

Trustees of interest in possession trusts and representatives of deceased persons receiving dividends from shares are also liable to account for income tax at a rate of 7.5 per cent., unless the dividends are mandated directly to beneficiaries, in which case only the beneficiaries need to account for the income. In either case, the beneficiaries will be taxable at the rates detailed above. Trustees and personal representatives do not qualify for the £2,000 dividend allowance available to individuals.

Companies

Shareholders within the charge to UK corporation tax which are "small companies" (for the purposes of UK taxation of dividends) will not generally expect to be subject to tax on dividends from the Company.

Other Shareholders within the charge to UK corporation tax will not be subject to tax on dividends (including dividends from the Company) so long as the dividends fall within an exempt class and certain conditions are met. In general, dividends paid on shares that are "ordinary share capital" for UK tax purposes and are not redeemable, and dividends paid to a person holding less than 10 per cent. of the issued share capital of the payer (or any class of that share capital) are examples of dividends that generally fall within an exempt class.

10.5 Stamp Duty and Stamp Duty Reserve Tax ("SDRT")

No stamp duty or SDRT will be levied on the issue of Ordinary Shares in registered form.

The transfer of shares quoted on the small companies markets, such as AIM are not subject to SDRT or stamp duty. Accordingly, so long as the Ordinary Shares are admitted to trading on AIM and are not also listed on a recognised stock market, no stamp duty or SDRT will be payable on their transfer.

10.6 Inheritance Tax

Individual and trustee Shareholders domiciled or deemed to be domiciled in any part of the UK may be liable on occasions to inheritance tax ("IHT") on the value of any Ordinary Shares held by them. IHT may also apply to individual Shareholders who are not domiciled in the UK although relief under a double tax convention may apply to those in this position.

Under current law, the chief occasions on which IHT is charged are on the death of the Shareholder, on any gifts made during the seven years prior to the death of the Shareholder and on certain lifetime transfers, including transfers to trusts or appointments out of trusts to beneficiaries, save in very limited and exceptional circumstances.

However, a relief from IHT known as business property relief ("BPR") may apply to the Ordinary Shares once these have been held for two years, provided that all the relevant conditions for the relief are satisfied at the appropriate time. This relief applies notwithstanding that the Company's Ordinary Shares will be admitted to trading on AIM. BPR operates by reducing the value of shares by 100 per cent. for IHT purposes.

Any person who is in any doubt as to his tax position or who may be subject to tax in any other jurisdiction should consult his professional adviser.

10.7 *VCTs*

The Company anticipates that the Placing Shares and Subscription Shares will be eligible shares for the purposes of the investment by VCTs. The status of the Placing Shares and Subscription Shares as a qualifying holding for VCTs will be conditional, *inter alia*, upon the Company satisfying the relevant requirements. It is the Directors' intention that the Company will meet the Venture Capital Scheme provisions so that it is a qualifying company for these purposes. However, the Directors cannot give any warranty or undertaking that the Company will continue to meet the conditions, including in the event that the Directors believe that the interests of the Company are not best served by preserving the VCT qualifying status, or as a result of changes in legislation.

10.8 *EIS*

The Company has received provisional assurance from HMRC that the subscription for the Placing Shares and Subscription Shares will be eligible for EIS purposes, subject to the submission of the relevant claim form in due course. The obtaining of such provisional assurance and submission of such a claim by the Company does not guarantee EIS qualification for an individual, whose claim for relief will be conditional upon his or her own circumstances and is subject to holding the shares throughout the relevant three year period.

In addition, for EIS relief not to be withdrawn, the Company must comply with a number of conditions throughout the qualifying period relating to those shares.

The following provides an outline of the EIS tax reliefs available to individuals and trustee investors. Any potential investor should obtain independent advice from a professional advisor in relation to their own particular set of personal circumstances.

In summary, EIS relief may be available where a qualifying company issues new shares, the purpose of which is to raise money for a qualifying business activity. The EIS shares must be subscribed for in cash and be fully paid up at the date of issue and must be held, broadly, for three years after they were issued.

EIS income tax relief is available to individuals only – the current relief is 30 per cent. of the amount subscribed for EIS shares to be set against the individual's income tax liability for the tax year in which the EIS investment is made, and is available up to a maximum of

£1,000,000 in EIS subscriptions per tax year. This relief can be 'carried back' one tax year. This relief is only available to individuals who are not connected with the Company in the period of two years prior to and three years after the subscription.

Very broadly, an individual is connected with the issuing company if, *inter alia*, he or his associates are employees or directors or have an interest in more than 30 per cent. of the Company's ordinary share capital.

Where EIS income tax relief has been given and has not been withdrawn, any gain on the subsequent disposal of the shares in qualifying circumstances is generally free from capital gains tax. If the shares are disposed of at a loss, capital gains tax relief will generally be available for that loss net of any income tax relief previously given. Alternatively, an election can be made to set that loss (less any income tax relief already given) against income of that year.

Individuals and trustees who have realised gains on other assets within one year before or up to three years after the EIS shares are issued, are able to defer a capital gains tax liability arising on those gains by making a claim to reinvest an amount of those gains against the cost of the EIS share subscription. Deferred gains will become chargeable on a disposal or deemed disposal of the EIS shares. The investor can be connected with the Company (as outlined above) and obtain such capital gains tax deferral relief.

11. Other relevant laws and regulations

i. Takeovers

As a public limited company incorporated and centrally managed and controlled in the UK, the Company is subject to the Takeover Code. Following the implementation of Part 28 of the Companies Act, the Takeover Panel has statutory powers to enforce the

Takeover Code in respect of companies whose shares are admitted to trading on AIM. Since the date of incorporation of the Company, there has been no takeover offer (within the meaning of Part 28 of the Companies Act) for any Ordinary Shares.

ii. Mandatory bid

Under Rule 9 of the Takeover Code when (i) a person acquires an interest in shares which (taken together with shares in which he and persons acting in concert with him are interested) carry 30 per cent. or more of the voting rights of a company subject to the Takeover Code; or (ii) a person who, together with persons acting in concert with him, is interested in shares which in the aggregate carry not less than 30 per cent. and no more than 50 per cent. of the voting rights of a company subject to the Takeover Code, and such person, or any persons acting in concert with him, acquires an interest in any other shares which increases the percentage of shares carrying voting rights in which he is interested, then in either case, that person together with the persons acting in concert with him, is normally required to extend a general offer in cash, at the highest price paid by him (or any persons acting in concert with him) for shares in the company within the preceding 12 months, to the holders of any class of equity share capital whether voting or non-voting and also to the holders of any other class of transferable securities carrying voting rights not already held by them.

iii. Squeeze-out

Under the Companies Act, an offeror which makes a takeover offer for the Company has the right to buy out minority Shareholders where it has acquired (or unconditionally contracted to acquire) not less than 90 per cent. in value of the shares to which the offer relates and not less than 90 per cent. of the voting rights in the Company. It would do so by sending a notice to the outstanding minority Shareholders telling them that it will compulsorily acquire their shares. Such notice must be sent within three months of the last day on which the offer can be accepted. The notice must be made in the prescribed manner. The squeeze-out of the minority Shareholders can be completed at the end of six weeks from the date the notice has been given, following which the offeror can execute a transfer of the outstanding shares in its favour and pay the consideration to the Company, which would hold the consideration on trust for the outstanding minority Shareholders. The consideration offered to the outstanding minority Shareholders whose shares are compulsorily acquired under the Companies Act must, in general, be the same as the consideration that was available under the takeover offer.

iv. Sell-out

The Companies Act also gives minority Shareholders a right to be bought out in certain circumstances by an offeror who has made a takeover offer for the Company, provided that at any time before the end of the period within which the offer can be accepted, the offeror has acquired (or unconditionally contracted to acquire) not less than 90 per cent. in value of the shares to which the offer relates and not less than 90 per cent. of the voting rights in the Company. A minority Shareholder can exercise this right by a written communication to the offeror at any time until three months after the period within which the offer can be accepted or a later date specified in the notice given by the offeror. An offeror would be required to give the remaining Shareholders notice of their rights to be bought out within the one month from the end of the period in which the offer can be accepted. The offeror may impose a time limit on the rights of the minority Shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period. If a Shareholder exercises his/her rights, the offeror is bound to acquire those shares on the terms of the offer or on such other terms as may be agreed.

12. Employees

As at 30 June 2017, the employees of the Group were employed as follows:

Management	2
Consulting directors	4
Total	6

13. Material contracts

The following contracts, not being contracts entered into in the ordinary course of business, have been entered into by any member of the Group in the two years immediately preceding the date of this document and are, or may be, material or contain provisions under which any member of the Group has any obligation or entitlement which is, or may be, material to the Group:

Block Energy

i. Share Purchase Agreement – Satskhenisi Ltd

On 25 July 2017, the Company entered into a Share Purchase Agreement with Iskander Energy Corporation for the purchase of the entire share capital of Satskhenisi Ltd (the "Satskhenisi SPA"). Pursuant to an assignment agreement dated 14 July 2017, Satskhenisi Ltd acquired a 90% participating interest in the Satskhenisi PSA (as defined below). The closing date of the Satskhenisi SPA was 31 July 2017.

The consideration paid by the Company to Iskander Energy Corporation was the issue of 70,000,000 (seventy million) ordinary shares of 0.05p each in the capital of the Company.

Iskander Energy Corporation has undertaken to the Company that it will not, and shall use its reasonable endeavours to procure that its associates will not, dispose of or encumber its interest in the consideration shares at any time prior to the earlier of the admission of the Company to AIM and the first anniversary of completion of the Satskhenisi SPA.

Subject to the matters set out below, Iskander Energy Corporation has undertaken to the Company that it will not, and shall use its reasonable endeavours to procure that its associates will not deal or otherwise dispose of the consideration shares in the 12 month period commencing on the first anniversary of completion of the Satskhenisi SPA unless such the Company gives its prior written consent to such dealing or disposal acting reasonably and brokered through the Company's corporate or nominated advisor.

Under the terms of the Satskhenisi SPA, if, after 12 (twelve) months following completion, the Company's entire issued share capital remains admitted to trading on the NEX Exchange and has not commenced trading on AIM, Iskander Energy Corporation shall have the option to either sell the shares in the Company provided as consideration under the Satskhenisi SPA, or return the shares in the Company to the Company in return for the shares transferred to the Company in Satskhenisi. Under AIM Rule 7 Iskander Energy Corporation will be required to enter into a lock in agreement.

The Company agreed that it shall not sell or transfer any or all of its interest in the Satskhenisi PSA during the 12 month period following completion of the Satskhenisi SPA or, if earlier, the date on which Iskander Energy Corporation ceases to be entitled to the claw back right set out in above.

ii. Production Sharing Agreement – Satskhenisi Block

On 12 December 2000, the State and Georgian Oil, and CanArgo (Norio) Ltd. entered into the production Sharing Contract on Block XIC and North Kumisi Licence Area (the "2000 PSA"). On 6 March 2008, CanArgo (Norio) Ltd. and Norio Oil Company Ltd. ("NOCL") entered into a Partial Assignment Agreement, whereby CanArgo (Norio) Ltd. assigned and transferred all of its rights and responsibility under the 2000 PSA relating to the Norio Block and the Satskhenisi Block to Norio Oil Company Ltd. and retained all rights to conduct Oil and Gas Operations below 1,300m from the sea level in the assigned area. On 7 March 2011, NOCL transferred its rights and obligations under the 2000 PSA to an affiliated company, GOG.

Under a Farmout Agreement dated 14 June 2013, GOG and Iskander Energy (Georgia) Limited ("Iskander") agreed to split the 2000 PSA (as amended above) into two separate blocks, the Norio Block and the Satskhenisi Block, with rights and obligations for the Satskhenisi Block in respect to 50% of GOG's stake being transferred from GOG to Iskander. On 24 October 2013, the remaining 50% stake retained by GOG was transferred to an affiliated Company, GNV, from GOG. The Satskhenisi PSA was entered into by GNV, Iskander, Georgian Oil and The State to effect the Farmout

Agreement dated 14 June 2013 and the transfers that followed. This restated the terms of the 2000 PSA and set out the relationship between the parties in regard to the Satskhenisi Block (''the Satskhenisi PSA''). Following entry into the Satskhenisi PSA, Iskander acquired an additional 40% participating interest in the Satskhenisi PSA from GNV on the terms and conditions of a purchase and sale agreement dated 23 April 2015, taking its participating interest to 90% and leaving GNV with a participating interest of 10%. On 8 June 2017 Iskander assigned its 90% interest in the Satskhenisi PSA to Iskander Energy Corporation, following which Iskander Energy Corporation assigned it to Satskhenisi Ltd on the terms and conditions of an assignment agreement dated 14 July 2017.

Under the terms of the Satskhenisi PSA, Satskhenisi Ltd is the contractor of the Satskhenisi Block and is responsible for providing all financial and technical requirements relating to the exploration and exploitation of petroleum in that area. In addition, Satskhenisi Ltd has established a branch office in Georgia named ''Satskhenisi Georgia'' which shall be the operator under the Satskhenisi PSA and shall be responsible for performing petroleum operations in the Satskhenisi Block. Prior to the Company acquiring its interests in Satskhenisi, the operator under the Satskhenisi PSA was NOC, a company owned by GOG. For the time being, NOC shall continue to act as operator under the Satskhenisi PSA, pursuant to which the Company shall pay to NOC a fee of US$5,555 per calendar month.

The Satskhenisi PSA has an initial term of 25 years from 9 April 2001 to 9 April 2026. Should commercial production remain possible beyond the initial term, an extension request may be made to the State no later than one year prior to the end of the initial term, for a period of 5 years, or the producing life of the development, whichever is lesser. Such approval shall not be unreasonably withheld. There shall be no relinquishments for the remainder of the term.

The parties to the Satskhenisi PSA shall not be compensated for their services in cash, but shall be reimbursed by receipt of their share in the petroleum produced in the Satskhenisi Block. Firstly, operation expenses (including production, processing, transportation, training and administration expenses) shall be recovered from all available petroleum (''Available Oil''). Secondly, capital expenditure (including drilling costs and development expenditures and exploration expenditures) shall be recovered from a maximum of 50% of remaining petroleum (''Cost Oil'') following the recovery of operation expenses. Such capital expenditure is recoverable according to the date it was incurred, earliest first. Thirdly, following the recovery of operation expenses and capital expenditure, the remaining petroleum (''Profit Oil'') shall be allocated between Georgian Oil and Satskhenisi Ltd as to 50% each (if such split occurs prior to the date on which the profits from the sale of all petroleum produced are equal to Satskhenisi Ltd's costs and expenses. Fourthly, following the date on which the profits from the sale of oil and gas produced are equal to Satskhenisi Ltd's costs and expenses, then the Profit Petroleum shall be allocated between Georgian Oil and Satskhenisi Ltd as to 60% to Georgian Oil and 40% to Satskhenisi Ltd. If outstanding recoverable operation expenses and capital expenditure exceed Cost Oil in any Calendar Year, the excess shall be carried forward year on year up until the termination of the 2013 Satskhenisi PSA (following which no such costs and expenses will be recoverable).

The State may charge an administration fee assistance provided in connection with assistance provided to Satskhenisi Ltd, such administration fee to be reasonable as may be customary for such services (but not in excess of what a third party would charge for such services). Such fees may be included in the recoverable costs and expenses of Satskhenisi Ltd.

Double Tax Treaties shall have effect for Satskhenisi Ltd, foreign employees and contractors. Satskhenisi Ltd shall be liable for Profit Tax at the applicable rate in any calendar year and Mineral Usage Tax at the rate of 5%. Foreign employees shall be responsible for Georgian personal income tax. With regard to foreign subcontracts, tax shall be withheld by any legal entity making revenue payments to a foreign subcontractor. VAT exemptions apply, however the Contractor shall charge VAT at on petroleum sold locally within Georgia that is not intended to be exported. Otherwise, Satskhenisi Ltd, any foreign employees and the operating company shall have full and complete exemption from taxes.

Georgian Oil shall assume, pay and discharge, in the name of and on behalf of Satskhenisi Ltd, the profit tax and mineral usage tax liability referred to above on behalf of Satskhenisi Ltd, such amounts to be paid out of Georgian Oil's share of Profit Petroleum for that calendar year. In the event that a loss is made in any calendar year, that loss may be carried forward to subsequent calendar years until such time as a loss is wholly offset in determining the taxes payable as set out above.

Where assets (whether fixed or moveable) have been acquired by Satskhenisi Ltd, such assets shall vest in the State without consideration if (i) both the costs of such asset have been recovered by Satskhenisi Ltd and (ii) either the 2013 Satskhenisi PSA has come to an end or such asset is no longer required in connection with petroleum operations being carried out by Satskhenisi Ltd under the Satskhenisi PSA.

The Satskhenisi PSA also contains standard indemnities from Satskhenisi Ltd to the State and Georgian Oil in relation to liabilities arising out of losses arising as a result of Satskhenisi Ltd carrying out actions under the PSA in breach of applicable laws, rules, regulations and good oilfield practices.

iii. Operator Letter – Satskhenisi Block

Since Satskhenisi acquired its interests in the Satskhenisi PSA, NOC has been acting as operator for and on behalf of Satskhenisi and GOG. On 10 November 2017, Satskhenisi, GOG and NOC signed a letter recording the terms of NOC's acting as operator. Satskhenisi and GOG shall pay NOC a monthly payment of US$5,555 in aggregate for the monthly fixed costs under the Satskhenisi PSA, such amounts being split between Satskhenisi and GOG on a pro-rata basis in line with their participating interest. The Company has informed us that they pay US$5,000 of these amounts, whilst GOG are responsible for the remaining US$555. The appointment of NOC as operator may be terminated by either Satskhenisi and GOG, or NOC giving not less than 30 days' notice to the other parties.

iv. Share Purchase Agreement – GOG Norioskhevi Ltd

On 7 April 2017, the Company entered into the Norio SPA with GOG for the purchase of the entire share capital of GOG Norioskhevi. Immediately before entering into the Norio SPA, GOG directly held 62% of the participating interest in the Norio PSA and GOG Norioskhevi held the remaining 38% of the participating interest in the Norio PSA. Closing of the Norio SPA occurred on 7 April 2017.

The consideration paid by the Company to GOG was (i) US$380,000 payable on completion of the Norio SPA (ii) shares in the capital of the Company equalling a price of US$300,000 and (iii) a commitment by the Company to recomplete a minimum 5 wells in Norio acreage within 18 months from closing, requiring an expenditure of around US$ 600,000 in aggregate for all 5 wells. In the event that the commitment to recomplete 5 wells in Norio acreage is not duly fulfilled, the participating interest in the Norio PSA held by GOG Norioskhevi will be reduced by 15% (and such interest be reassigned to GOG). In the event that that the recompletion of 5 wells leads to increased production, shares will be issued by the Company to GOG worth either US$250,000 and US$750,000 if production reaches an average of 350 or 500 barrels per day in any 60 day period.

The Norio SPA contained an option that the Company could acquire the remaining 62% participating interest in the Norio PSA from GOG. The consideration payable to exercise this option consisted of a cash payment of US$620,000, shares in the capital of the Company equalling a price of US$250,000 and that the Company will drill 2 horizontal wells in Norio within 3 years of the exercise of the option requiring capital expenditure of around US$6,000,000. In the event that the drilling of 2 horizontal wells in Norio is not duly fulfilled in the 3 year time period provided for, GOG Norioskhevi Ltd's participating interest in the Norio PSA will be reduced by 15%. In the event that the commitment to drill 2 horizontal wells in Norio results in increase of production, shares will be issued by the Company to GOG worth either US$250,000 and US$750,000 if production reaches an average of 550 or 750 barrels per day in any 60 day period. This option was exercised in two tranches on 13 July 2017 and 8 September 2017. Accordingly, GOG Norioskhevi Ltd now holds a 100% participating interest in the Norio PSA.

No shares issued to GOG pursuant to the Norio SPA shall be subject to lock-in provisions.

v. Norio Option Documents

Amendment No 1

Pursuant to Amendment No 1 to the Norio SPA dated 20 July 2017 ("Amendment No 1) entered into between GOG, GOG Norioskhevi and the Company, the parties agreed to amend the terms of the Norio Option contained in the Norio SPA as follows:-

- The end date of the option period was extended from 31 August 2017 to 16 September 2017; and
- The consideration payable for the Norio Option was amended to $620,000 in cash and $250,000 shares in the Company to be issued on Admission, thus removing the commitment to drill 2 new horizontal wells and potential reassignment of a 15% interest in the Norio PSA should the Company fail to do so. (albeit that if such horizontal wells are drilled, the performance shares payable in connection with these under the Norio SPA shall still be issued to GOG).

Option SPA

Under the terms of a sale and purchase agreement dated 8 September 2017 ("Option SPA") between GOG, GOG Norioskhevi and the Company, Norioskhevi acquired the remaining 62% interest in the Norio PSA from GOG. The Option SPA reflected changes to the terms of the Norio Option contained in Amendment No 1.

In consideration for the services provided under the Option SPA, a monthly fee of US$12,500 is payable to GOG by the Company or GOG Norioskhevi, such amounts to also cover any fixed costs incurred by NOC. These arrangements are terminable by either party giving to the other 60 days' notice.

Assignment Agreement

In order to complete the exercise of the Norio Option, GOG, GOG Norioskhevi and the Company entered into an Assignment Agreement dated 9 November 2017 in order to confirm the assignment of the remaining 62% interest in the Norio PSA from GOG to GOG Norioskhevi.

vi. Production Sharing Agreement – Norio Block

On 12 December 2000, the State, Georgian Oil, and CanArgo (Norio) Ltd. entered into the 2000 PSA. On 6 March 2008, CanArgo (Norio) Ltd. and NOCL entered into a partial assignment agreement, whereby CanArgo (Norio) Ltd. assigned and transferred all of its rights and responsibility under the 2000 PSA relating to the Norio Block and the Satskhenisi Block to Norio Oil Company Ltd. and retained all rights to conduct Oil and Gas Operations below 1,300m from the sea level in the assigned area. On 7 March 2011, NOCL transferred its rights and obligations under the 2000 PSA to an affiliated company, GOG. Under a Farmout Agreement dated 14 June 2013, GOG and Iskander agreed to split the 2000 PSA into two separate blocks, the Norio Block and the Satskhenisi Block. Consequently, the Satskhenisi PSA was entered into in respect of the Satskhenisi Block and the 2000 PSA continues to govern the relationship between the parties in regard to the Norio Block (hereinafter referred to as the "Norio PSA").

Under the terms of the Norio PSA, GOG Norioskhevi is the contractor of the Norio Block and is responsible for providing all financial and technical requirements relating to the exploration and exploitation of petroleum in that area. At present, GOG acts as GOG Norioskhevi's representative to the state for a fee of US$12,500 per month. However, GOG Norioskhevi Ltd has established a branch office in Georgia named "Norioskhevi Georgia" which shall become the operator under the Norio PSA and shall be responsible for performing petroleum operations in the Norio Block. Prior to the Company acquiring its interests in Norio, the operator under the Norio PSA was NOC, a company owned by

GOG. For the time being, NOC shall continue to act as operator under the Norio PSA, pursuant to which the Company shall pay to NOC a fee of US$12,500 per calendar month.

The Norio PSA has an initial term of 25 years from 9 April 2001 to 9 April 2026. Should commercial production remain possible beyond the initial term, an extension request may be made to the State no later than one year prior to the end of the initial term, for a period of 5 years, or the producing life of the development, whichever is lesser. Such approval shall not be unreasonably withheld. There shall be no relinquishments for the remainder of the term.

The parties to the Norio PSA shall not be compensated for their services in cash, but shall be reimbursed by receipt of their share in the petroleum produced in the Norio Block. Firstly, operation expenses (including production, processing, transportation, training and administration expenses) shall be recovered from all Available Oil. Secondly, capital expenditure (including drilling costs and development expenditures and exploration expenditures) shall be recovered from Cost Oil following the recovery of operation expenses. Such capital expenditure is recoverable according to the date it was incurred, earliest first. Thirdly, following the recovery of operation expenses and capital expenditure, the remaining petroleum (''Profit Petroleum'') shall be allocated between Georgian Oil and GOG Norioskhevi as to 50% each (if such split occurs prior to the date on which the profits from the sale of all petroleum produced are equal to GOG Norioskhevi's costs and expenses. Fourthly, following the date on which the profits from the sale of oil and gas produced are equal to GOG Norioskhevi's costs and expenses, then the Profit Petroleum shall be allocated between Georgian Oil and GOG Norioskhevi as to 60% to Georgian Oil and 40% to GOG Norioskhevi. If outstanding recoverable operation expenses and capital expenditure exceed Cost Oil in any calendar year, the excess shall be carried forward year on year up until the termination of the Norio PSA (following which no such costs and expenses will be recoverable).

The State may charge an administration fee assistance provided in connection with assistance provided to GOG Norioskhevi, such administration fee to be reasonable as may be customary for such services (but not in excess of what a third party would charge for such services). Such fees may be included in the recoverable costs and expenses of GOG Norioskhevi.

Double Tax Treaties shall have effect for GOG Norioskhevi, foreign employees and contractors. GOG Norioskhevi shall be liable for Profit Tax at the applicable rate in any calendar year and Mineral Usage Tax at the rate of 5%. Foreign employees shall be responsible for Georgian personal income tax. With regard to foreign subcontracts, tax shall be withheld by any legal entity making revenue payments to a foreign subcontractor. VAT exemptions apply, however the Contractor shall charge VAT at on petroleum sold locally within Georgia that is not intended to be exported. Otherwise, GOG Norioskhevi, any foreign employees and the operating company shall have full and complete exemption from taxes.

Georgian Oil shall assume, pay and discharge, in the name of and on behalf of GOG Norioskhevi, the profit tax and mineral usage tax liability referred to above on behalf of GOG Norioskhevi, such amounts to be paid out of Georgian Oil's share of Profit Petroleum for that calendar year. In the event that a loss is made in any calendar year, that loss may be carried forward to subsequent calendar years until such time as a loss is wholly offset in determining the taxes payable as set out above.

Where assets (whether fixed or moveable) have been acquired by GOG Norioskhevi, such assets shall vest in the State without consideration if (i) both the costs of such asset have been recovered by GOG Norioskhevi and (ii) either the Norio PSA has come to an end or such asset is no longer required in connection with petroleum operations being carried out by GOG Norioskhevi under the Norio PSA.

The Norio PSA also contains standard indemnities from GOG Norioskhevi to the State and Georgian Oil in relation to liabilities arising out of losses arising as a result of GOG Norioskhevi carrying out actions under the Norio PSA in breach of applicable laws, rules, regulations and good oilfield practices.

vii. Agreement on Operatorship – Norio Block

On 9 November 2017 Norioskhevi entered into an agreement on operatorship (the "Agreement on Operatorship") with NOC, pursuant to which NOC acts as operator under the Norio PSA for and on behalf of Norioskhevi. The term of the Agreement on Operatorship is 18 months from 09 November 2017. NOC shall act as an operating company for operations within the Norio Block in accordance with approved work programs and budgets. NOC shall have the rights, functions and duties of operating company under the Norio PSA but in performing such duties shall act for and on behalf of, and at the cost of GOG Norioskhevi from time to time, at all times in accordance with the express instructions given by GOG Norioskhevi to NOC. and any right and obligation/liability arising out of the performance of NOC will inure to GOG Norioskhevi.

The Agreement on Operatorship contains usual provisions relating to the obligations of NOC, including a requirement to conduct operations in a diligent, safe and efficient manner in accordance with good and prudent petroleum industry practices. In consideration for the provision of services by NOC to Norioskhevi under the Agreement on Operatorship, Norioskhevi shall pay a monthly fee of US$12,500 which shall cover all fixed costs associated with the routine/daily operations under the Norio PSA. Prior to incurring any expenditure estimated to be in excess of US$50,000 for exploration work or development work, or US$25,000 in connection with production work, NOC shall require the consent of Norioskhevi. NOC is required to procure and maintain all insurance policies required under the Norio PSA. Within one month of Admission, GOG Norioskhevi shall be required to transfer an amount of US$50,000 to NOC to be kept on account of costs incurred by NOC pursuant to the Agreement on Operatorship. Norioskhevi has indemnified NOC, together with its affiliates, for all damage, loss, cost, expense or liability arising from the performance or non-performance of the operations under the Agreement on Operatorship by NOC. Accordingly, NOC shall have no liability under the Agreement on Operatorship, howsoever arising.

viii. Share Purchase Agreement – Georgian New Ventures Inc ("GNV")

On 21 June 2017, the Company entered into GNV SPA for the purchase of the entire share capital of GNV. As at the date of the GNV SPA, GNV held a proposed 5% interest in the production sharing agreement to be entered into in connection with Licence Block XIF (as defined below). Closing of the GNV SPA occurred on 21 June 2017.

The GNV SPA provides that the Company has the option (the "West Rustavi Option") to increase GNV's participating interest in the West Rustavi PSA from 5% up to 75%. The option is subject to the Company being admitted to AIM on or before the later of 31 October 2017 and the date falling 3 months after the date on which the West Rustavi PSA is entered into. The option is exercisable in the following 3 stages:-

Stage 1 – (to be exercised and fulfilled within 10 days of the Company being admitted to AIM) GNV may acquire an additional 20% participating interest in the West Rustavi PSA from GOG in consideration for which either the Company or GNV shall pay to GOG either (i) US$1,500,000 or (ii) US$500,000 + shares in the Company equalling a price of US$1,000,000;

Stage 2 – (to be exercised and fulfilled within 3 months of the Company being admitted to AIM, and GNV has acquired a 25% participating interest by exercising Stage 1 of the West Rustavi Option) GNV may acquire an additional 25% participating interest in the West Rustavi PSA from GOG if by such time (i) GNV has conducted work overs or prepared wells for side-tracks in Block XIF, and (ii) paid an amount to of US$ 1,000,000 to LLC Norio Operating Company in connection with these works in aggregate US$1,000,000, such amounts to be paid in 3 tranches prior to exercise of stage 2 of the West Rustavi Option; and

Stage 3 – (to be exercised and fulfilled within 6 months of the Company being admitted to AIM, and GNV has acquired up to a 50% participating interest by exercising Stages 1 and 2 (which may be partially exercised) of the West Rustavi Option) GNV may acquire an additional 25% participating interest in the West Rustavi PSA from GOG in consideration for which either the Company or GNV shall (i) perform a side-track in each of two wells and for these purposes transfer to LLC Norio Operating Company no less than US$ 3,000,000 in aggregate (ii) purchase production facilities up to a maximum amount of US$ 1,000,000 for use in connection with the West Rustavi PSA. If these obligations of GNV are only partially satisfied, the additional interest in the West Rustavi PSA shall be increased by a proportionate amount to which the obligations have been satisfied.

In the event that daily average production from a single side track under the West Rustavi PSA during any period of 60 days reaches over 200 barrels, GOG shall be paid US$ 150,000, such amount to be satisfied either by way of cash or the issue of shares in the Company. In the event that daily average production from a single side track under the West Rustavi PSA during any period of 60 days reaches over 300 barrels, GOG shall be paid US$ 250,000, such amount to be satisfied either by way of cash or the issue of shares in the Company. In the event that daily average production from a single side track under the West Rustavi PSA during any period of 60 days reaches over 400 barrels, GOG shall be paid US$ 350,000, such amount to be satisfied either by way of cash or the issue of shares in the Company. In the event that daily average production from a single side track under the West Rustavi PSA during any period of 60 days reaches over 500 barrels, GOG shall be paid US$ 500,000, such amount to be satisfied either by way of cash or the issue of shares in the Company. Only one of the bonus amounts set out above shall be triggered in respect of each of the two proposed side tracks, and accordingly where production level would trigger a bonus payment, the highest bonus shall be paid and the meeting of a higher threshold at a later date shall not trigger any further bonus payment.

For so long as GOG holds a majority participating interest in the West Rustavi PSA, GOG will be the contractor's representative to the State. For so long as GOG holds a 35% participating interest in the West Rustavi PSA, LLC Norio Operating Company will be the Operator. In the event that GNV increases its interest under the West Rustavi PSA to 75% pursuant to the West Rustavi Option, GNV will be allowed to replace the Operator.

ix. Production Sharing Agreement – West Rustavi Block

On 28 March 2018 GNV entered into a production sharing agreement in relation to Block XIF – West Rustavi (the ''West Rustavi PSA'') with the State, Georgian Oil and GOG which governs the relationship between the parties in regard to West Rustavi.

Under the terms of the West Rustavi PSA, GOG and GNV together as contractors, have the exclusive right to conduct petroleum operations in West Rustavi and are required to provide all financial and technical requirements in accordance with standards generally accepted in the international petroleum industry. For so long as GOG holds a majority participating interest in the West Rustavi PSA, GOG will be the contractor's representative to the State.

Georgian Oil shall act as the national oil company on behalf of the state for the purposes of the West Rustavi PSA until such time as the State ceases to hold at least 50% of its shares. Georgian Oil shall be responsible for disposing of the State's share of oil and gas produced thereunder.

GOG and GNV shall designate the operating company and shall submit this designation, along with the charter of the operating company to the State and Georgian Oil. The operating company shall have the responsibility of performing the petroleum operations in accordance with the directions received from the Coordination Committee and implement the work programmes and budgets approved by the Coordination Committee. At present, LLC Norio Operating Company is the operator under the West Rustavi PSA in accordance with the terms of the GNV SPA. In the event that GNV increases its interest under the West Rustavi PSA to 75% pursuant to the West Rustavi Option, GNV will be allowed to replace the Operator.

The West Rustavi PSA becoming effective is subject to certain conditions precedent being satisfied, of which only one remains outstanding. In order for the West Rustavi PSA to become effective, the State must receive the consent or confirmation of the

Ministry of Finance of Georgia, following whereto, the State is reassigned the obligation to pay and cover the Profit Tax liabilities of each contractor under the West Rustavi PSA in accordance with the applicable Georgian Law.

The West Rustavi PSA has an initial term of 25 years from the date on which it becomes effective. Should commercial production remain possible beyond the initial term, an extension request may be made to the State no later than six months prior to the end of the initial term, for a period of up to 5 years, or the producing life of the development, whichever is lesser. Such approval shall not be unreasonably withheld.

The following relinquishments are required over the duration of the West Rustavi PSA: After 5 years of the initial term, at least 25% of the original agreement area (less any development areas containing a commercial discovery); after 10 years of the initial term, at least 25% of the remaining agreement area following the prior relinquishments (less any development areas containing a commercial discovery); after 15 years of the initial term, at least 50% of the remaining agreement area following the prior relinquishments (less any development areas containing a commercial discovery); after 20 years of the initial term, the remainder of the remaining agreement area following the prior relinquishments (less any development areas containing a commercial discovery).

In addition to the above relinquishments, GOG and GNV shall be entitled to relinquish voluntarily all or any part of the agreement area. Following any relinquishments, GOG and GNV shall have the continuing right to use so much of the surface of the relinquished area as is reasonably necessary to carry out operations on the remaining parts of the contract area.

Georgian Oil, GOG and GNV shall establish a coordination committee within 45 days of the effective date of the West Rustavi PSA for the purposes of acceptance and control over the implementation of the plans, work programs and budgets. In particular, the coordination committee is empowered to (amongst other things) review and approve any work plan and budget, consider, approve or confirm a purchase contract of any item within the budget with a unit price exceeding US$250,000, any single purchase order exceeding US$750,000 or any lease of equipment, or service contract within budget worth more than US$500,000. The coordination committee shall be comprised of six members, three shall be representatives of Georgian Oil and three shall be representatives of GOG and GNV. Meetings of the coordination committee shall be held on a quarterly basis. Decisions made by the coordination committee shall be unanimous. and should the coordination committee not come to a decision and Georgian Oil be deems its objections to GOG and/or GNV to be justified, the matter shall be passed on to an internationally recognised independent expert, whose decision shall be final .

GOG and GNV are required to carry out the minimum work program set out in the West Rustavi PSA and failure to do so shall result in the automatic termination of the West Rustavi PSA. The minimum work program is split into the following 3 stages :-

i. Stage 1 – Within 6 months from the effective date of the West Rustavi PSA, to procure, reprocess and interpret all necessary data and to carry out the environmental assessment of the agreement area and elaborate on recommendations due to oil and gas operations;

ii. Stage 2 – Within the first 2 years of the term re-enter one deep well for field geophysical works and testing or side-track drilling to produce hydrocarbons

iii. Stage 3 – Within 2 years of completion of, an in accordance from date acquired from, stage 2 drill one deep well sufficient to test the deepest prospective horizon.

iv. The first two stages constitute the mandatory minimum of works to be completed. If GOG and GNV fail to fulfil the second stage of the minimum work program a penalty of US$1,000,000 shall be payable and if they fail to fulfil the third stage of the minimum work program a penalty of US$1,500,000 shall be payable (save that if GOG and GNV decline to proceed with further work following stage two, no penalty shall be payable).

Within 45 days after the effective date of the West Rustavi PSA, the Contractor shall submit a draft work program and draft budget proposal for the current calendar year to the coordination committee. Before 1 October of each calendar year, GOG and GNV shall submit to the coordination committee an annual work programme and budget.

The parties to the West Rustavi PSA shall not be compensated for their services in cash, but shall be reimbursed by receipt of their share in the petroleum produced as follows: GOG and GNV shall be entitled to recover all recoverable expenses incurred in respect of operations carried out from a maximum of 50% of total available oil and gas. Such expenses are recoverable according to the date it was incurred, earliest first. If outstanding recoverable expenses exceed Cost Oil in any quarter, the excess shall be carried forward quarter on quarter up until the termination of the West Rustavi PSA (following which no such costs and expenses will be recoverable). Following recovery of expenses from Cost Oil, the remaining oil shall be allocated in each quarter between Georgian Oil on the one part and GOG and GNV on the other part as to 50% each if such split occurs prior to the date on which the profits from the sale of all petroleum produced and delivered to GOG and GNV are equal to its recoverable expenses, and from and following such date, profit oil shall be split as to 60% for Georgian Oil and 40% for GOG and GNV.

The State shall be obliged to assist GOG and GNV by providing any necessary approvals or permits needed to conduct petroleum operations, arrange for the conversion of foreign exchange, use office space, assist with custom formalities, provide entry and exit visas as required, provide permits to send documents, data and samples abroad, provide permits and approvals for the construction of bases, facilities and installations and to provide data and samples in connection with the agreement area. The State may charge an administration fee for the assistance referred to above, such administration fee to be reasonable as may be customary for such services (but not in excess of what a third party would charge for such services). Such fees may be included in the recoverable costs and expenses of GOG and GNV.

GOG and GNV are required to establish a reserve fund for future abandonment and site restoration costs and to make regular contributions thereto, such contributions to be approved by the coordination committee.

The State has an option to take a participating interest in the West Rustavi PSA up to 20% of the rights and obligations of the contractors, such option being exercisable up until the date falling 12 months after the approval of any development plan. If the nominee of the state acquiring an interest under this option fails to enter into (or, if applicable, join) a joint operating agreement within two months as of the exercise date of the option, the State's right of exercisability shall be automatically cancelled.

Prior to the issuance of a licence to GOG and GNV, a licence fee of US$50,000 was payable to the State within 30 days of signing the West Rustavi PSA. In addition, GOG and GNV shall be required to pay the State a bonus of US$1,200,000 on the occurrence of a commercial discovery, being a discovery of one or several yet unknown accumulations of oil and gas. The bonus will only be payable once and not on each commercial discovery made.

Double Tax Treaties shall have effect for GNV, foreign employees and contractors. GNV shall be liable for Profit Tax and Mineral Usage Tax at the applicable rate in any calendar year. Foreign employees shall be responsible for Georgian personal income tax. With regard to foreign subcontracts, tax shall be withheld by any legal entity making revenue payments to a foreign subcontractor. VAT exemptions apply, however the Contractor shall charge VAT at on petroleum sold locally within Georgia that is not intended to be exported. Otherwise, GNV, any foreign employees and the operating company shall have full and complete exemption from taxes. In the event that a loss is made in any calendar year, that loss may be carried forward to subsequent calendar years until such time as a loss is wholly offset in determining the taxes payable as set out above. Georgian Oil shall assume, pay and discharge, in the name of and on behalf of GNV, the profit tax and mineral usage tax liability referred to above on behalf of Satskhenisi, such amounts to be paid out of Georgian Oil's share of Profit Oil for that calendar year.

GNV shall be subject to a regulatory fee established in Georgia under Order No1 at the rate in force on the signing date of the West Rustavi SPA, being 24.19 Laris per ton of oil.

Where assets (whether fixed or moveable) have been acquired by GNV, such assets shall vest in the State without consideration if (i) both the costs of such asset have been recovered by GNV and (ii) either the West Rustavi PSA has come to an end or such asset is no longer required in connection with petroleum operations being carried out by GNV under the West Rustavi PSA.

An indemnity has been given by GOG and GNV to the State and Georgian Oil in respect of all losses, damages and liability arising from any claim made by any employee of GOG, GNV or any subcontractor in relation to personal injury suffered by such employees in connection with the West Rustavi PSA save for any such losses, damages and liability arising as a result of the performance or non-performance of the West Rustavi PSA by the State or Georgian Oil, in respect of which a cross-indemnity has been given by the State and Georgian Oil to GOG and GNV.

An indemnity has been given by GOG and GNV for all loss or damage suffered by the State or Georgian Oil arising out of the petroleum operations where such operations are not conducted in accordance with good oilfield practices or applicable laws, rules and regulations. Carved out of this indemnity are losses and damages arising out of a breach of the West Rustavi PSA or of duty by the State or Georgian Oil. In addition, there shall be no liability of GOG or GNV in respect of any punitive or exemplary damages or any other indirect or consequential damages.

x. Share Purchase Agreement – Antubia Resources Limited

On the terms of a share purchase agreement between Ensign Resources Limited ("Ensign"), a wholly owned subsidiary of the Company, and Star Goldfields Limited ("Star Goldfields") dated 7 September 2017 Ensign agreed to sell and Star Goldfields agreed to purchase the entire issued share capital of Antubia Resources Limited (the "Antubia SPA").

The Antubia SPA was conditional on (i) Ensign obtaining a no objection notice from the minister for Lands and Natural Resources in Ghana and (ii) Ensign renewing the licence held over the Asheba Concession (being a gold concession in Kadedwen, Western Region of Ghana). These conditions have been satisfied and the completion date of the Antubia SPA was 26 February 2018.

The consideration payable by Star Goldfields to Ensign was USD 600,000, which comprised a payment of US$50,000 which was payable on the execution of heads of terms (prior to entering into the Antubia SPA) and US$550,000 payable to Ensign on completion of the Antubia SPA.

At completion, all intragroup amounts owing by Antubia Resources Limited to Ensign were written off.

Ensign gave usual warranties to Star Goldfields as would be expected in a transaction of this nature. The warranties are not subject to a limitation period and have not been limited by knowledge/awareness. In the event of any warranty claim being made, Ensign Resources has the opportunity to put Star Goldfields in the same position it had been in would the warranty have been complied with. If such action is not effected, Ensign has indemnified Star Goldfields for any direct losses incurred (but not for indirect losses, loss of profit).

The Antubia SPA is governed by the Laws of Ghana and the parties have agreed that the courts of Ghana shall have exclusive jurisdiction in respect of any disputes.

xi. Deed of Variation – Antubia SPA

On 26 February 2018 Ensign and Star Goldfields entered into a deed of variation in respect of the Antubia SPA pursuant to which they agreed that Star Goldfields shall no longer be liable for the Deferred Consideration (defined below) in consideration for which they agreed to pay an amount of S$150,000 to the Company on completion of the

Antubia SPA. In consideration for this payment, the Company indemnified Star Goldfields in respect of any liability arising in connection with the Deferred Consideration following completion of the Antubia SPA.

xii. Framework Agreement – Centrebind

Taoudeni Resources Limited (a company wholly owned by the Company and now in liquidation) ("Taoudeni") entered into a share purchase agreement with Centrebind on 23 April 2015 pursuant to which Taoudeni acquired the entire issued share capital of Ensign from Centrebind (the "Centrebind SPA").

Under the terms of the Centrebind SPA, Taoudeni agreed to pay Centrebind deferred consideration of a total amount of up to US$4,500,000 to be satisfied in cash or by 4,500,000 ounces of gold (whichever is capable of being realised at each milestone of the deferred consideration referred to in the Centrebind SPA) (the "Deferred Consideration").

Centrebind, Ensign and the Company (replacing Taoudeni following its liquidation) entered into a framework agreement ("Framework Agreement") on 17 November 2017 pursuant to which the Centrebind SPA was to be terminated in its entirety and the parties would be released from their obligations under the Centrebind SPA, including any obligation of the Company to pay the Deferred Consideration. As consideration for the release, the Company agreed to pay a fixed sum of US$100,000 to be paid on the date in which Antubia Resourses Limited notified the Company that the licence held by it over the Ashaba concession in Ghana was renewed and consequently the shares of Antubia Resources Limited were sold by Ensign Resources Limited to Star Goldfields Limited or any similar or alternative or related award or transaction.

The release was only to be effective on the date in which the fixed sum of US$100,000 was paid by the Company to Centrebind.

xiii. Deed of Variation – Framework Agreement

On 26 February 2018 the Company, Ensign and Star Goldfields entered into a deed of variation in respect of the Framework Agreement pursuant to which they agreed that the consideration to be paid to Centrebind in connection with the Framework Agreement would be increased to US$150,000. On 26 February 2018 (being the completion date of the Antubia SPA), the Company received the consideration due to it under the Antubia SPA (as varied) and accordingly settled the consideration due to Centrebind pursuant to the Framework Agreement (as varied).

By entering into the Framework Agreement (and subsequent deed of variation), the Company has ensured that it has no residual liabilities owing under the Centrebind SPA. Following the completion of the Ensign SPA and the payment of the consideration due to Centrebind pursuant to the Framework Agreement, Centrebind provided a written confirmation of receipt of the consideration due to it and of the release of Block and Ensign from any liability in respect of the Deferred Consideration. Accordingly, the Company no longer has any liability in respect of its previous interests in Ghana save for any liabilities arising under the Antubia SPA or the Framework Agreement.

xiv. Share Purchase Agreement – Taoudeni Resources SARL

On the terms of a share purchase agreement between the Company and Safi Minerals Ltd dated 8 November 2017, the Company agreed to sell and Safi Minerals Ltd agreed to purchase the entire issued share capital of Taoudeni Resources SARL (the "Taoudeni SPA"). The Taoudeni SPA was completed on 8 November 2017.

The consideration payable by Safi Minerals Ltd to the Company will be either £40,000 or £40,000 shares in the capital of Safi Minerals Ltd. The price per share being determined by the 30 day volume weighted average price (if listed) or the share price of the most recent share transaction of Safi Minerals Ltd., such consideration to be satisfied on the earlier of (i) 30 days from the date of first production under the licence held by Taoudeni Resources SARL and (ii) 5 years from the date of the Taoudeni SPA.

The Company has given usual warranties in respect of title to the shares of Taoudeni and its capacity to sell them but has not given any warranties relating to its business or assets.

Following the completion of the Taoudeni SPA, the Company no longer has any liability in respect of its previous interests in Mauritania save for any liabilities that may arise pursuant to the Taoudeni SPA.

xv. Share Purchase Agreement – Taoudeni Resources Limited

The Company acquired its previously owned interests in Ghana and Mauritania on the terms and conditions of a share purchase agreement entered into on 18 January 2016 between the Company as buyer and Hot Rocks Investments Plc and Others as sellers (the "TRL SPA") pursuant to which the Company acquired the entire issued share capital of Taoudeni Resources Ltd (who at the time was the parent company of Ensign and Taoudeni). We are informed by the Company that the following Ordinary Shares in the Company are to be issued by the Company pursuant to the TRL SPA:-

On Admission, the following Ordinary Shares shall be issued:-

- Ryan Long – 24,040 Ordinary Shares;
- Charles Vaughan – 24,040 Ordinary Shares;
- Brian Rowbotham – 24,040 Ordinary Shares.
- On the earlier of the Company's second placing on AIM and the date falling 12 months after Admission, 1,566,838 Ordinary Shares and 113,909 Ordinary Shares respectively shall be issued to Plutus Strategies Ltd and Geoffrey Tomlinson.

xvi. Placing Agreement between: (1) the Company, (2) the Directors, (3) SPARK Advisory Partners (4) Novum and (5) Northland

Pursuant to the Placing Agreement dated 4 June 2018, SPARK Advisory Partners, as the Company's nominated adviser, has been granted certain powers and authorities in connection with the application for Admission. Under the terms of the Placing Agreement, the Company and the Directors have given certain customary warranties to SPARK Advisory Partners, Novum and Northland. The Company has given certain customary indemnities and undertakings to SPARK Advisory Partners, Novum and Northland in connection with Admission and other matters relating to the Group and its affairs. SPARK Advisory Partners, Novum and Northland may terminate the Placing Agreement in certain specified circumstances prior to Admission, principally if any of the warranties has ceased to be true and accurate in any material respect or shall have become misleading in any respect or in the event of circumstances existing which make it impracticable or inadvisable to proceed with Admission. The liability of the Directors in respect of a breach of the warranties given in the Placing Agreement is limited in time and amount.

The Placing Agreement is subject to the satisfaction or waiver of a number of conditions, including Admission. Such conditions must be satisfied (or, where possible, waived) by 11 June 2018 (or such later time as may be agreed by the Company, SPARK Advisory Partners, Novum and Northland, being not later than 30 June 2018).

xvii Engagement letter between (1) the Company and (2) Novum Securities Limited

Pursuant to an engagement letter dated 25 April 2018, the Company appointed Novum to act as broker to the Company. The Company has agreed a) to pay Novum placing commission of 7.5% on all funds introduced by Novum, and b) to grant warrants representing 7.5% of all funds introduced by Novum. The Company has also agreed to pay Novum a fee of £30,000 (plus VAT) per annum for its services as broker under this agreement. The appointment was for an initial 12 month period and is then terminable by either party giving six months' notice.

xviii. Convertible Loan Note Instrument ("CLN") (June 2017)

On 27 June 2017 the Company adopted a convertible loan note instrument. Notes issued under the CLN ("Notes") accrue interest at a rate of 10% per annum. If conversion of the Notes occurs prior to the date 12 calendar months after issue of the Notes, the interest accrued to that date shall be paid by the Company to the holder of the Notes. The nominal amount of each Note is £1 and may be issued up to an aggregate of £210,000. Any shares issued on conversion of the Notes shall be subject to such lock in provisions as are strictly required by NEX or AIM, as the case may be on a Qualifying IPO (defined below). The Notes may not be assigned without the express written consent of the Company.

If the Notes have not been converted, the Notes shall be redeemable on the earlier of (i) the 2nd anniversary of the CLN and (ii) the date falling 14 days after written request for redemption has been submitted to the Company by the holder of the Notes (such request not being issuable prior to the 1st anniversary of the CLN). The Notes shall also be redeemable in an event of default, being standard insolvency events;

The Notes shall be convertible as follows:-

(a) At any time following the 1st anniversary of the CLN, a holder of the Notes shall be entitled to have all or part of the Notes converted into ordinary shares in the capital of the Company, provided that if such notice is given prior to a Qualifying IPO (defined below), the Company may redeem the Notes in cash, rather than by issued shares;

(b) Upon a Qualifying IPO, the Notes will be automatically redeemed by the Company issuing ordinary shares in the Company equal to the value of the amounts outstanding under the CLN (such value to be at the conversion price set out below);

(c) Whilst the Company's shares are admitted to NEX, the Company may convert the Notes into ordinary shares in the capital of the Company.

The conversion price for the Notes shall be:-

(i) If the Company is admitted to a recognised investment exchange (including AIM, but not NEX) (a "Qualifying IPO") within 12 months of the date of the CLN, the conversion price shall be the share price at the time of the admission (but subject to a 10% discount);

(ii) If no Qualifying IPO occurs within 12 months of the date of the CLN or the Notes are converted pursuant to (c) above, the conversion price shall be the 10 day volume weighted average price of the shares of the Company immediately prior to conversion (but subject to a 10% discount);

As at the date of this Report £210,000 of Notes has been subscribed for by Mayan Energy Ltd. The Company shall not be entitled to dispose of any of its interests acquired in oil and gas licences in Georgia without the consent of the holders of 75% of the Notes;

xix. Convertible Loan Note Instrument (December 2017)

On 13 December 2017 the Company adopted a second convertible loan note instrument. Notes issued under the CLN ("Notes") accrue interest at a rate of 10% per annum. If conversion of the Notes occurs prior to the date 12 calendar months after issue of the Notes, the interest accrued to that date shall be paid by the Company to the holder of the Notes. The nominal amount of each Note is £1 and may be issued up to an aggregate of £150,000. Any shares issued on conversion of the Notes shall be subject to such lock in provisions as are strictly required AIM on a Qualifying IPO (defined below). The Notes may not be assigned without the express written consent of the Company.

If the Notes have not been converted, the Notes shall be redeemable on any date up to the 2nd anniversary of the CLN. The Notes shall also be redeemable in an event of default, being standard insolvency events.

If the Notes have not been converted, the Notes shall be redeemable on any date up to the 2nd anniversary of the CLN. The Notes shall also be redeemable in an event of default, being standard insolvency events.

At any time prior to the final date of redemption of the Notes, the Company shall be entitled to have all or part of the Notes (including any accrued interest) converted into ordinary shares in the capital of the Company. The conversion price for the Notes shall be:-

(i) if the Company is admitted to a recognised investment exchange (including AIM, but not NEX) (a "Qualifying IPO") within 12 months of the date of the CLN, the conversion price shall be the share price at the time of the admission (but subject to a 10% discount); or

(ii) if no Qualifying IPO occurs within 12 months of the date of the CLN or the Notes are converted pursuant to (c) above, the conversion price shall be the 10 day volume weighted average price of the shares of the Company immediately prior to conversion (but subject to a 10% discount).

As at the date of this Report £150,000 of Notes has been subscribed for by the following parties:-

Noteholder	Amount of Notes subscribed for
Croesus Mining Pty Ltd	£50,000
Bespoke Capital Solutions Ltd	£20,000
Charles Richard Topham	£80,000
Total	**£150,000**

xx. Debenture

The Notes issued to Mayan Energy Ltd pursuant to the CLN are secured by way of debenture entered into by the Company and Mayan Energy Ltd on 27 June 2017. The Company has covenanted to pay on demand in writing all amounts owing pursuant to the CLN. The Debenture contains full fixed and floating charges over all of the assets of the Company in favour of Mayan Energy Ltd. The Company has assigned all right, title and interest in agreements to which the Company is a party to Mayan Energy Ltd (including any interest rate hedging agreement entered into by the Company). The Company may not, without the prior written consent of Mayan Energy Ltd, create any encumbrance over its assets, sell or dispose of any of its assets other than those secured by a floating charge only on arms-length terms in the ordinary course of trading, or dispose of the equity of redemption of any asset, save that the Company shall not be prevented from disposing of its interests in Mauritania and Ghana. The Company has given usual undertakings to Mayan Energy Ltd in connection with the operation of its business for so long as the Debenture remains in place. The Debenture shall become enforceable if the Company fails to pay any amounts under the CLN when they become due or upon any insolvency event of the Company.

xxi. Warrant instruments dated 4 June 2018 created by the Company

a) On 4 June 2018, the Company entered into a warrant instrument constituting New Warrants to subscribe for, in aggregate, 1,250,000 Ordinary Shares which will, subject to Admission, be granted to SPARK Advisory Partners. The Warrants are exercisable at the Issue Price at any time during the period of five years from Admission.

b) On 4 June 2018, the Company entered into a warrant instrument constituting New Warrants to subscribe for, in aggregate, 1,875,000 Ordinary Shares which will, subject to Admission, be granted to Novum. The Warrants are exercisable at the Issue Price at any time during the period of eighteen months from Admission.

c) On 4 June 2018, the Company entered into a warrant instrument constituting New Warrants to subscribe for, in aggregate, 3,775,000 Ordinary Shares which will, subject to Admission, be granted to Northland. The Warrants are exercisable at the Issue Price at any time during the period of eighteen months from Admission.

d) On 4 June 2018, the Company entered into a warrant instrument constituting New Warrants to subscribe for, in aggregate, 1,837,500 Ordinary Shares which will, subject to Admission, be granted to Gneiss Energy Limited. The Warrants are exercisable at the Issue Price at any time up until 11 December 2019.

xxii. SPARK Advisory Partners engagement letter dated 4 August 2017 between (1) SPARK Advisory Partners and (2) the Company

On 4 August 2017, the Company and SPARK entered into an agreement to appoint SPARK to act as its financial adviser, in relation to the Admission to trading on AIM of the Company. Under this agreement, SPARK will receive from the Company £25,000 on commencement of work (plus VAT) ("Work Fee") and a success fee of £150,000 together with the issue of warrants equivalent to 1% of the Placing Shares and Subscription Shares.

xxiii. Nominated adviser agreement dated 1 June 2018 between (1) SPARK Advisory Partners and (2) the Company

On 1 June 2018, the Company appointed SPARK to act as nominated adviser to the Company on an ongoing basis as required by the AIM Rules for Companies with effect from Admission. The Company has agreed to pay SPARK a fee of £50,000 per annum (plus VAT) for retaining its services as Nominated adviser. The agreement contains certain undertakings and indemnities given by the Company in respect of, *inter alia*, compliance with all applicable laws and regulations. The Company agreed to comply with its legal obligations and those of AIM and the London Stock Exchange and to consult and discuss with SPARK all of its announcements and statements and to provide SPARK with any information SPARK believes is necessary to enable it to carry out its obligations to the Company or the London Stock Exchange as Nominated adviser. Pursuant to these arrangements, SPARK has agreed, *inter alia*, to provide such independent advice and guidance to the Directors as they may require to ensure compliance by the Company on a continuing basis with the AIM Rules for Companies. These arrangements contain certain undertakings and indemnities given by the Company in respect of, *inter alia*, compliance with all applicable laws and regulations. These arrangements continue for an initial period of 12 months from Admission unless terminated for reason prior to such date in accordance with the terms of the Agreement and thereafter until terminated in accordance with the terms thereof.

xxiv. Lock-in and Orderly Market Agreements between (1) the Company, (2) SPARK Advisory Partners (3) Novum (4) Northland, and (5) each of the Locked-in Persons

Pursuant to the Lock-in and Orderly Market Agreements dated 4 June 2018, each of the Locked-in Persons has undertaken to the Company, SPARK Advisory Partners, Northland and Novum that, subject to certain limited exceptions permitted by Rule 7 of the AIM Rules for Companies (and which includes acceptance of a takeover offer for the Company which is open to all shareholders) , they will not dispose of Ordinary Shares held by them for a period of 12 months from the date of Admission.

Each Locked-in Person has also undertaken that for the period of 12 months following the anniversary of the date of Admission, they will only dispose of Ordinary Shares held by them on an orderly market basis through the Company's broker from time to time.

xxv Engagement letter between (1) the Company and (2) Northland

Pursuant to the engagement letter dated 5 January 2018, the Company has appointed Northland to act as joint broker to the Company in relation to the Placing. The Company has agreed a) to pay Northland a placing commission of 5% on all funds introduced by Northland, and b) to grant warrants representing 5% of all funds introduced by Northland.

xxvi Engagement letter between (1) the Company and (2) Gneiss Energy Limited ("Gneiss")

Pursuant to the engagement letter dated 14 May 2018, the Company agreed to pay Gneiss a placing commission of 7.5% on all funds introduced by Gneiss, and b) to grant warrants representing 7.5% of all funds introduced by Gneiss.

14. Related party transactions

During the period from 1 July 2014 to the date of this document, other than the transactions set out in paragraph 22 of Part IV Section B of this document, the Company has not entered into any related party transactions of the kind set out in the Standards adopted according to Regulation (EC) No1606/2002).

15. Litigation

Save as set out below, there are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened by or against the Group of which the Company is aware) during the 12 months immediately preceding the date of this document which may have, or have had in the recent past, significant effects on the Company's and/or the Group's financial position or profitability.

16. No significant change

Save as disclosed in this document, there has been no significant change in the financial or trading position of the Group since 31 December 2017, being the end of the last financial period included in the most recently published financial information (as set out in Part IV of this document).

17. Working capital

The Directors are of the opinion, having made due and careful enquiry, that the working capital available to the Group will be sufficient for its present requirements, that is for at least 12 months from the date of Admission.

18. Third party information

i. The Company confirms that the information in this document which has been sourced from third parties has been accurately reproduced and that as far as it is aware and able to ascertain from information published by each of those parties, no facts have been omitted which would render the information reproduced inaccurate or misleading.

ii. The source of the third party information is indicated on the relevant pages.

19. General

i. The financial information relating to the Company contained in Part IV (B) and (C) of this document has been prepared to 31 December 2017.

ii. The accounting reference date of the Company is 30 June each year. The Company will publish its audited accounts for year ending 30 June 2018 by 31 December 2018.

iii. The auditors of the Company are PKF Littlejohn LLP. PKF Littlejohn LLP is registered to carry out audit work by the Institute of Chartered Accountants in England and Wales, and were appointed for the financial periods ended 30 June 2016 and 30 June 2017.

For the period ended 30 June 2015, the auditors of the Company were Fryza Bannister Financials Limited. Fryza Bannister Financials Limited is registered to carry out audit work by the Institute of Chartered Accountants in England and Wales.

iv. The total costs and expenses payable by the Company in connection with or incidental to Admission, including registration and London Stock Exchange fees, corporate finance, accountancy and legal fees, commissions due to certain introducers for procuring placees, and the costs of printing and despatching this document, are estimated to be approximately £730,000 (including VAT), all of which will be payable by the Company.

v. Save as disclosed in this document no person (excluding professional advisers otherwise disclosed in this document and trade suppliers) has:

– received, directly or indirectly, from the Company within 12 months preceding the date of this document; or

– entered into contractual arrangements (not otherwise disclosed in this document) to receive, directly or indirectly, from the Company on or after Admission any of the following:

 (a) fees totalling £10,000 or more; or

 (b) securities in the Company with a value of £10,000 or more; or

 (c) any other benefit with a value of £10,000 or more at the date of Admission.

vi. The Directors are not aware of any exceptional factors that have influenced the Company's activities.

vii. Other than in relation to the Placing Agreement in paragraph 13 xiv of this document, no commission is payable by the Company to any person in consideration of his agreeing to subscribe for securities to which this document relates or of his procuring or agreeing to procure subscriptions for such securities.

viii. No payment (including commissions) or other benefit has been or is to be paid or given to any promoter of the Company.

ix. Save as disclosed in this document, there are no patents or licences, industrial commercial or financial contracts which are, or may be, of fundamental importance to the business of the Company.

x. Save as disclosed in this document, the Directors are unaware of any environmental issues that may affect the Company's utilisation of its tangible fixed assets.

xi. Save as disclosed in this document there are no investments in progress or future investments on which the Directors have already made firm commitments which are significant.

xii. The Directors are not aware of any known trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Company's prospects for at least the current financial year.

xiii. PKF Littlejohn LLP has given and has not withdrawn its written consent to the issue of this document with the inclusion of its name and references to it in the form and context in which they appear and to the inclusion of its reports in this document and has authorised the contents of its accountants' report for the purposes of Schedule Two of the AIM Rules for Companies.

xiv. SPARK Advisory Partners has given and has not withdrawn its written consent to the issue of this document with the inclusion of its name and the references to it in the form and context in which they appear.

xv. Novum has given and has not withdrawn its written consent to the issue of this document with the inclusion in it of references to its name in the form and context in which they appear.

xvi Baden Hill has given and not withdrawn its written consent to the issue of this document with the inclusion in it of references to its name in the form and context in which they appear.

xvii. Gustavson Associates, LLC has given and not withdrawn its consent to the issue of this document with the inclusion of its name and the references to it in the form and context in which they appear.

20. Availability of this document

A copy of this document is available in electronic form at the Company's website, www.block energy.co.uk.

Date: 4 June 2018