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Rex International Holding Ltd

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ECV 2077

18th March 2014

Dear Sirs,

EVALUATION OF SELECTED OIL RESERVES IN South Erin Block, Trinidad, as of 31st December 2013

At the request of Rex International Holding ("RIH"), RPS Energy ("RPS") has prepared an evaluation of selected oil Reserves and Resources and the net present values of those for South Erin Block, onshore Trinidad ("South Erin"), as of 31st December 2013 (the "Services"). The South Erin licence is held by Jasmin Oil and Gas Limited ("Jasmin") which is 100% owned by Caribbean Rex Ltd ("REX") subject to completion of purchase transaction to buy remaining 25% of Jasmin. RIH has 64.17% ownership of REX.

In preparing this report, we relied upon certain factual information and data furnished by RIH, with respect to ownership interests, gas production, historical costs of operation and development, product prices, agreements relating to current and future operations, sales of production, and other relevant data. The extent and character of all factual information and data supplied were relied upon by us in preparing this report and have been accepted as represented without independent verification. We have relied upon representations made by RIH as to the completeness and accuracy of the data provided and that no material changes in the performance of the properties has occurred nor is expected to occur, from that which was projected in this report, between the date that the data was obtained for this evaluation and the date of this report, and that no new data has come to light that may result in a material change to the evaluation of the Reserves presented in this report. No site visit has been undertaken by RPS.

The oil bearing reservoirs at South Erin are the Pliocene Lower Forest and Mid Cruse Sandstones. Lower Forest Fm comprises lenticular delta-top sandstones and this overlies more extensive delta-front turbidites of the Cruse Fm. The majority of production in the licence to date, from some 5 wells, is from the Lower Forest B1 sands.

Some 2D seismic data were provided in digital and scan format but only one line passed near the field. Part of a 3D seismic survey has recently been purchased across the South Erin area. The 3D data are currently being interpreted by AGGO Geoconcepts UG on behalf of RIH but this interpretation is ongoing and has not been integrated into this report. As RPS Reserves and Resources estimates use well performance based rather than volumetric methods this is not considered critical.

RPS volumetric estimates, which were used to confirm STOIIP, have been based on the maps in the 2009 report provided. Although, the 3D seismic data casts doubt on existence of some of the faults in the 2009 report there is evidence of barriers between some wells as a number of updip wells close to the licence are not hydrocarbon bearing, whether these are faults or stratigraphic barriers cannot be determined at this time.

The developed wells are considered representative of the future undrilled wells and (excluding 1ER-102) the average EUR is 82000 barrels per well. A generalised decline curve has been produced that gives an EUR of 82000 barrels with a rate of decline averaging the successful developed wells. The development of the future wells is planned in three phases.

- Phase 1 - Four new wells in the B1 Sand to be brought on stream ~ mid 2014.
- Phase 2- Recompletion of wells 1ER-98 and 1ER-99 into the A2 sands ~ mid 2015.
- Phase 3 - three additional wells to be drilled in late 2015. These three wells are located to the West where the presence of pay is not proven and has been considered to be Contingent Resources.

Economics have been determined for these three phases and allow for Government Royalty, Petrotrin Overriding Royalty (ORR), Supplemental Petroleum Tax (SPT) and Operating Costs.

Reserves and Resources in South Erin attributable to RIH's indirectly owned subsidiary Caribbean Rex Ltd ("REX") as of 31st December 2013 are summarised in the following table. RIH has 64.17% ownership of REX. On completion of an ongoing transaction REX will then own 100% of Jasmin Oil and Gas.

Category	Gross Attributable to Licence (MMstb)	Net Attributable to RIH [1] (MMstb)	Change from Previous Update[2]	Remarks
Reserves				
	Oil Reserves			
1P	0.167	0.114	100%	*1P reserves are uneconomic*
2P	0.374	0.258	100%	*Includes Undeveloped Reserves*
3P	0.646	0.448	100%	*Includes Undeveloped Reserves*
Contingent Resources				
	Oil Contingent Resources			
1C	0.040	0.029	100%	*1C Resources are uneconomic*
2C	0.152	0.108	100%	*2C Resources are uneconomic*
3C	0.265	0.190	100%	*3C Resources are economic*

1. *Net Attributable is the net share of Reserves or Resources after the deduction of Government Royalty and Petrotrin Over-riding Royalty.*
2. *Rex International Holdings Ltd has 64.17% ownership of Caribbean Rex Ltd which has 100% ownership of Jasmin Oil and Gas Limited, subject to completion of purchase of last 25% of the company.*
3. *South Erin Farm-out Block (Sub-Licence) acquired in 2013.*

The cases associated with the Phase 3 development are be classified as sub-marginal Contingent Resources according to Economic Status, The cashflows associated with the nine cases, on a 100% gross WI basis, are presented in Appendix 2 of the main report.

The Services have been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS Energy is not in a position to attest to the property title, financial interest relationships or encumbrances related to South Erin.

The evaluation reflects our informed judgement based on the SPE PRMS 2007 Standards, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The reported hydrocarbon resource volumes are estimates based on professional engineering judgment and are subject to future revisions, upward or downward, as a result of future operations or as additional information become available.

We reserve the right to revise any estimates provided herein if any relevant data existing prior to preparation of this report were not made available, if any data between the effective date of the evaluation and the date of this report were to vary significantly from that forecast, or if any data provided were found to be erroneous.

Yours faithfully

On behalf of RPS Energy Consultants Limited

Gordon Taylor, C.Eng, C.Geol
Director, Head of Subsurface

EVALUATION OF SELECTED OIL RESERVES IN SOUTH ERIN BLOCK, TRINIDAD

AS OF 31st DECEMBER 2013

Prepared for
Rex International Holding

RPS Energy

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1. EXECUTIVE SUMMARY

At the request of Rex International Holding ("RIH" or "Company"), RPS Energy ("RPS") has prepared an evaluation of selected oil Reserves and the net present values of those Reserves for South Erin Block, onshore Trinidad ("South Erin"), as of 31st December 2013.

No site visit has been undertaken by RPS.

The oil bearing reservoirs at South Erin are the Pliocene Lower Forest and Mid Cruse Sandstones. Lower Forest Fm comprises lenticular delta-top sandstones and this overlies more extensive delta-front turbidites of the Cruse Fm. The majority of production in the licence to date, from some 5 wells, is from the Lower Forest B1 sands.

Some 2D seismic data were provided in digital and scan format but only one line passed near the field. Part of a 3D seismic survey has recently been purchased across the South Erin area. The 3D data are currently being interpreted by AGGO Geoconcepts on behalf of RIH but this interpretation is incomplete and has not been integrated into this report. As RPS Reserves estimates use performance-based rather than volumetric methods the is not considered critical.

PS volumetrics estimates, which were used to confirm STOIIP, have been based on the maps in a report from 2009 by M.L. Geotechnical Consultants Limited ("2009 Report") that was provided by RIH [1]. Although, the 3D seismic data casts doubt on existence of some of the faults in the 2009 report, there is evidence of barriers between some wells as a number of updip wells close to the licence are not hydrocarbon bearing, whether these are faults or stratigraphic barriers cannot be determined at this time.

The developed wells are considered representative of the planned undeveloped wells and (excluding 1ER-102) the average EUR is 82,000 barrels. A generalised decline curve has been produced that gives a EUR of 82,000 barrels with a rate of decline averaging the successful developed wells. The drilling of the future wells is planned in three phases.

- Four new wells B1 to be brought on stream mid-2014.
- Following this is the recompletion of wells 1ER-98 and 1ER-99 into the A2 sands in mid 2015
- Final phase is three additional wells to be drilled in 2015. These three well are located to the West where the present of pay is not proven and has been considered to be contingent resources.

Economics have been determined for these three phases which allow for Government Royalty, Petrotrin Overriding Royalty (ORR), Supplemental Petroleum Tax (SPT) and Operating Costs.

The cases associated with a Phase 3 development are classified as sub-marginal Contingent Resources according to their economic status as defined by PRMS [2], and the Resources are summarised below. The cashflows associated with the nine cases, on a 100% gross WI basis, are presented in Appendix 2.

RIH's owns 64.17% of an indirect subsidiary Caribbean Rex Ltd ("REX") which in turn owns 100% of the South Erin Licence after completion of the purchase of the remaining 25% of Jasmin Oil and Gas Limited ("Jasmin"). RIH Reserves in South Erin as of 31st December 2013 are summarised in the following table.

[1] *Updated Geological Review of Jasmin's Farm-out – South Erin Block 1ER98 Area by M.L. Geotechnical Consultants limited. November 2009.*

[2] *Petroleum Resource Management System ("PRMS"), 2007 published by SPE/AAPG/WPC/SPEE*

Field	Gross Reserves (Mstb)[1]			RIH Net WI Reserves (Mstb)[1,2]			RIH Net Reserves Entitlement (Mstb)[1,2,3]		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Developed	10.3	13.8	16.2	10.3	13.8	16.2	6.4	8.6	10.1
Developed plus Undeveloped	166.9	374.0	645.5	166.9	374.0	645.5	113.6	258.5	447.8

1 1P cases have negative Net Present Value at 10% discount rate (NPV10).
2 RIH owns 64.17% of REX which is 100% owner of Jasmin Oil and Gas Limited after completion of the purchase of last 25% of the company.
3 RIH Net Reserves Entitlement is RIH's WI share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

Table 1.1: Reserves as of 31 December 2013

The cases associated with a Phase 3 development can be classified as sub-marginal Contingent Resources according to Economic Status, and the Resources are summarised after economics assessment in the table below.

Field	Gross Contingent Resources (Mstb)			RIH Net WI Resources (Mstb)[1]			RIH Net Resources Entitlement (Mstb)[1,3]		
	1C	2C	3C	1C	2C	3C	1C	2C	3C
South Erin	40.1	151.6	265.3	40.1	151.6	265.3	28.9	107.5	190.1

1 RIH owns 64.17% of REX which is 100% owner of Jasmin Oil and Gas Limited after completion of the purchase of last 25% of the company.
3 RIH Net Reserves Entitlement is RIH WI share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

Table 1.2: Contingent Resources as of 31 December 2013

2. INTRODUCTION

At the request of Rex International Holding ('RIH' or 'Company'), RPS Energy ("RPS") has prepared an evaluation of selected oil Reserves and the net present values of those Reserves for South Erin Block, onshore Trinidad, as of 31st December 2013 (the "Services").

The services comprised preparation of a formal Qualified Persons Report (QPR) report on Reserves and Contingent Resources required for statutory reporting to the Singapore Stock Exchange ("SGX-ST"). The report fulfils the requirements of the SGX-ST. The report has been prepared for inclusion in the RIH's 2013 annual report for public viewing and access.

In preparing this report, we relied upon certain factual information and data furnished by RIH, with respect to ownership interests, gas production, historical costs of operation and development, product prices, agreements relating to current and future operations, sales of production, and other relevant data. The extent and character of all factual information and data supplied were relied upon by us in preparing this report and have been accepted, as represented, without independent verification. We have relied upon representations made by RIH as to the completeness and accuracy of the data provided and that no material changes in the performance of the properties has occurred nor is expected to occur, from that which was projected in this report, between the date that the data was obtained for this evaluation and the date of this report, and that no new data has come to light that may result in a material change to the evaluation of the Reserves presented in this report. As the production and reserves from existing wells is modest and the facilities are mature and of modest scale no site visit has been undertaken by RPS. Site photographs were provided by RIH which appear to be reliable and show facilities commensurate with the levels of production.

The Services have been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS Energy is not in a position to attest to the property title, financial interest relationships or encumbrances related to South Erin.

The evaluation reflects our informed judgement based on the PRMS 2007 Standards [2], but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data.

RPS, operating from its offices at 309 Reading Road, Henley-on-Thames, Oxon, RG9 1EL, UK, is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Mr Gordon Taylor, Director, Subsurface for RPS Energy, has supervised the evaluation. He attended the University of Birmingham and graduated with a Bachelor of Science degree in Geological Sciences in 1978; and a Master of Science degree in Foundation Engineering in 1979. He is a Chartered Geologist and Chartered Engineer in the UK and a Certified Petroleum Geologist (No 5932) through the American Association of Petroleum Geologists (AAPG) with in excess of 35 years' experience in the hydrocarbon exploration and production industry including the conduct of evaluation studies relating to oil and gas fields. Additionally, Mr Gordon Taylor fulfils the following criteria for a qualified person:

a) the qualified person is not a sole practitioner;

b) the qualified person producing the report is a director of RPS Energy

c) the qualified person and RPS's partners, directors, are independent of RIH, RIH directors and substantial shareholders;

d) the qualified person and RPS's partners, directors do not have any interest, direct or indirect, in RIH, its subsidiaries or associated companies and will not receive benefits other than remuneration paid in connection with the qualified person's report; and

e) remuneration paid to RPS in connection with the report is not dependent on the findings of this report.

Table 2.1 summarises the asset and licence details.

Asset Name/Country	RIH's effective Working Interest	Development Status	Licence Expiry Date [2]	Area (acres)	Type of mineral, oil or gas deposit	Remarks
South Erin licence, Trinidad & Tobago	64.17%	On production	31/12/2021	1,350	Oil	Economic limit date is 31/12/26

Table 2.1: Asset Summary & Licence

3. HISTORY OF THE PROPERTY

Prior to October 1998, The Petroleum Company of Trinidad and Tobago Limited was the operator of the 'South Erin' block. Three wells were drilled in the south east part of the block: well TOFO.51 was drilled in 1930 and was plugged and abandoned, ER.91 was drilled in 1988 and was also abandoned, and well ER.14 was located in the block but the producing zone is outside the block (date unknown).

Ten seismic lines were acquired through or close to the block in 1976 and seven of these were reprocessed by Exxon in 1991. Three additional lines were acquired by Exxon in 1990-1991.

In October 1998, Petrotrin farmed-out the block to Jasmin Oil and Gas Limited (Jasmin). The tenure of this agreement was for five years but was extended to September 2006, with two additional renewable terms until September 2016. Under the Agreement Jasmin was obliged to undertake the minimum work programme of six wells.

Wells ER97 and ER97X were drilled in April 1999 to depths of 6,000ft and 5,300ft respectively, and encountered reservoirs but they were dry and the wells were abandoned. Jasmin drilled its third well, IER98, from July to October 2006. This well tested three oil-bearing sands in Lower Forest A2 Sands and B1 Sands, and Mid Cruse Sands. Four other wells were drilled close to each other in the south east part of the block between October to December 2009. These were wells 1ER99, 1ER100, 1ER101 and 1ER102. Oil-bearing intervals were intersected in all these wells.

REX's entitlement to production from the South Erin Block is laid down in the Farmout Agreement (Sub-Licence) of 2nd October 2013 between Petroleum Company of Trinidad and Tobago Limited ("Petrotrin") and Jasmin Oil and Gas Ltd.

RIH holds a 64.17% interest in the Farmout Agreement (sub-Licence) through its 64.17% ownership of REX, after completion of the purchase of remaining 25% of Jasmin.

4. GEOLOGICAL & GEOPHYSICAL SETTING

4.1 Regional

4.1.1 South Erin Licence Location

RPS has put the South Erin field into regional context to try and understand some of the complexities of the geology. There are many aspects of the field that carry uncertainty because of the limited data control, such as trap type and reservoir facies / continuity, that a wider review is relevant.

The South Erin Block is located in the Southern Basin of south Trinidad south west of the large Palo Seco field. The South Erin field (aka as the Jasmin field) lies in the eastern part of the licence (Figure 4.1).

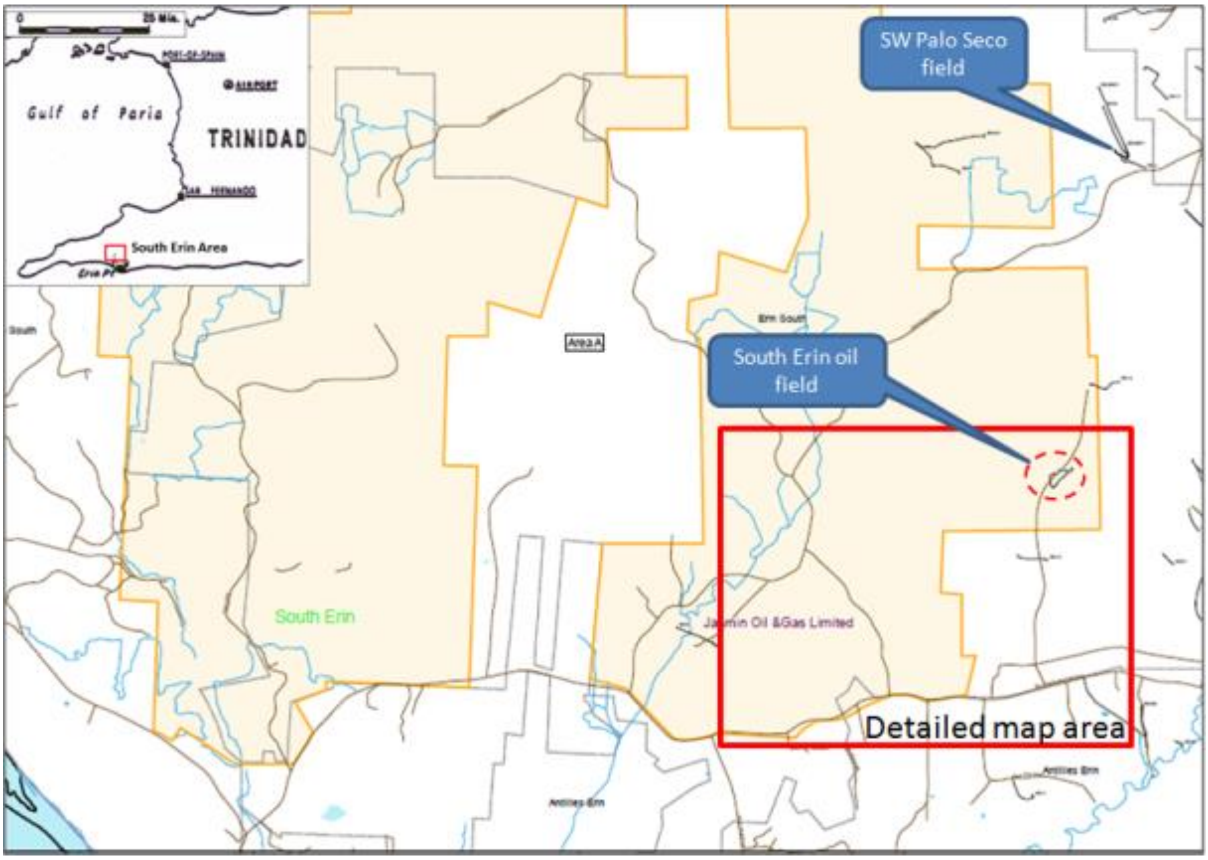

Figure 4.1: South Erin Licence

4.1.2 Palo Seco Field Complex

The Palo Seco field was discovered in 1910 and, according to Gluyas, is considered to be the third largest field in the country. Palo Seco is a complex or group of oil pools rather than a single field and comprises a series of oil fields, including Erin, Los Bajos and Grand Ravine. It covers an area of 22 km^2. According to Gluyas & Swarbrick[3], Palo Seco has estimated STOIIP of 1,691 MMstb. The main producing reservoirs are Pliocene and Miocene sandstones, including the deltaic Lower Forest and Cruse sands. These formations are the oil-bearing sands at South Erin, which is located west of the main Palo Seco field (Figure 4.4). The Erin extension to Palo Seco was discovered in 1963.

[3] *'Case History: Trinidadian Oilfields'. In: Petroleum Geoscience by Gluyas and Swarbrick, Wiley & Son, 2013*

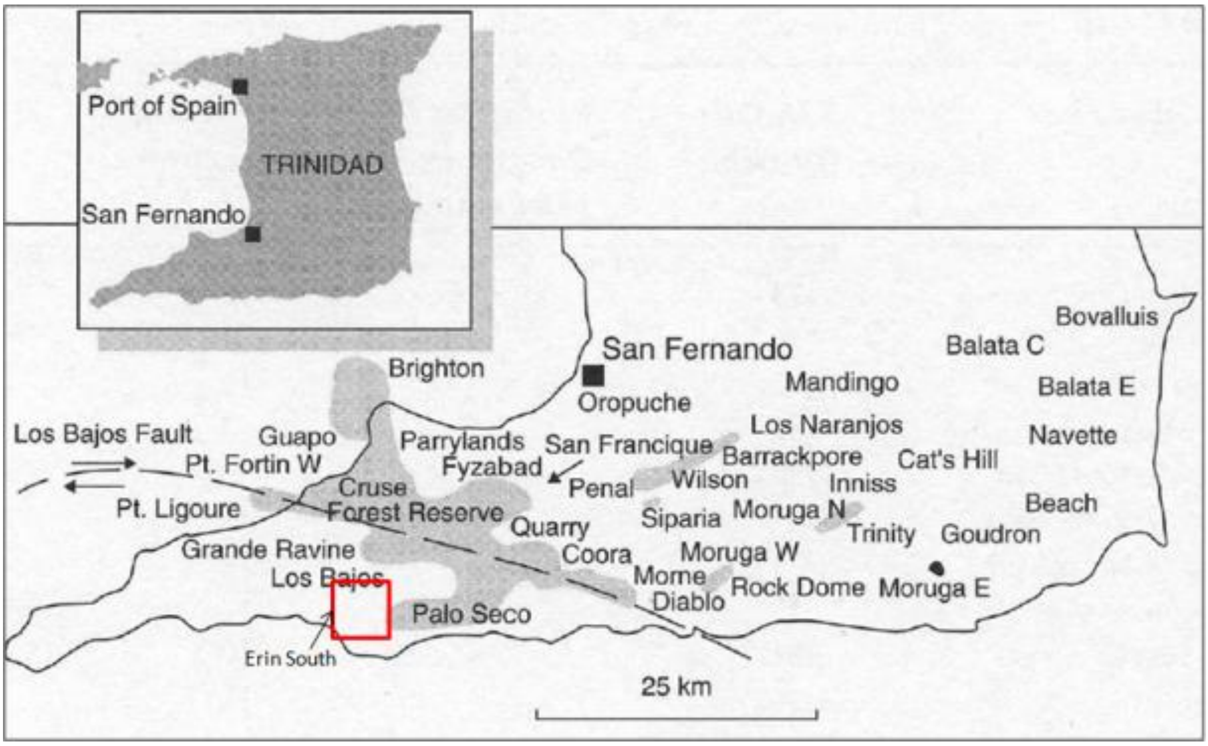

Figure 4.2: South Erin Licence & Other Oil Fields

4.1.3 Regional Structure

Structural elements of the south west part Southern Basin are shown in Figure 4.3. The Palo Seco field has a synclinal structural geometry and is located in the southern limb of the Siparia-Erin Syncline. North-east closure is against the Los Bajos Fault, which is regional right-lateral wrench fault. Closure to the east is against the down-to-the-east normal Santa Flora Fault. Southern and SE closures are created by the Southern Ranges Uplift or Anticline, which is a major west-east compressional feature across south Trinidad. Dip closure is inferred to the north. But closure to the west, towards Erin South, is less clear as it appears to be along-strike. According to Gluyas the '*Skinner Fault completes the triangular shaped trap. This latter fault may be superfluous to the trap, since it is in a downdip position*'. The South Erin field sits west of the Skinner Fault (Figure 4.3).

It is proposed by several authors on the area that there is a significant stratigraphic element to trapping in the Palo Seco field and Woodside[4] states that it is the primary trap type at Palo Seco.

The basin is affected by numerous faults. Normal, reverse, thrust and strike-slip faults are reported from the basin, such is the structural complexity of the area. They can be large scale or sub-seismic in size. The combination of the faulting with the lenticular nature of the reservoir sands and rapid lateral facies changes creates a complex geology. Faults also play a role in facilitating or preventing oil migration into areas, for example the Los Bajos Fault has a major influence on the distribution of hydrocarbons by migration along the fault.

[4] *Woodhouse. P.R. The Petroleum Geology of Trinidad and Tobago. U.S. Geological Survey Open-File Report 81-660*

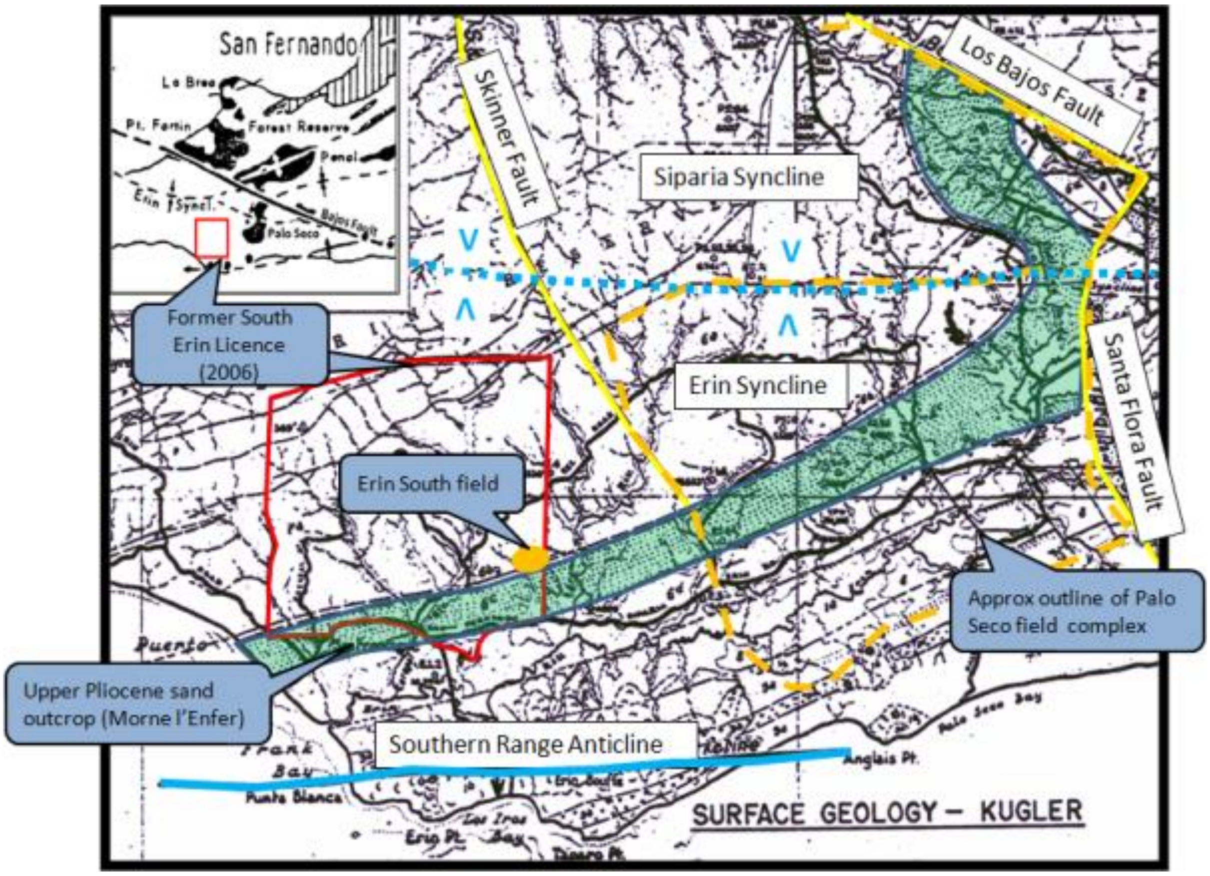

Figure 4.3: Southern Basin Regional Structure

4.1.4 Basin Stratigraphy

The oil bearing reservoirs at South Erin are the Pliocene Lower Forest and Mid Cruse Sandstones (Figure 4.4). Lower Forest Fm comprises lenticular delta-top sandstones and this overlies more extensive delta-front turbidites of the Cruse Fm.

Over 90 percent of cumulative historical onshore oil production from Trinidad has come from lenticular and deltaic sandstones of the Pliocene Lower Forest and Cruse formations, and Moruga Group sands in the south-east. Both the Cruse and Lower Forest sandstones are sourced regionally by rivers from the east and south-east, and thin towards the west. The rivers have been referred to as 'proto-Orinoco' by Gluyas.

Although not specifically documented, it is proposed that the dominant Pliocene depositional system was a deep marine basin during Early Pliocene-Late Miocene Cruse deposition with turbidite sands deposited from the east and SE. At Palo Seco, Cruse Fm depositional setting is interpreted by Hudson *et al*[5] to range from basin floor and slope to marginal marine and inner neritic.

During Mid Pliocene Lower Forest deltaic progradation was towards the west. Delta-top sands were deposited in the Lower Forest Fm and these may comprise distributary and fluvial channel sands, and channel mouth bar sandstones. There is no mention of coals in the stratigraphic sequence.

There is necessity to have a predictive geological model at South Erin in order to optimise field development. The 3D seismic data is an important step in this process but it should be complemented by cores in the reservoirs to gain an understanding of reservoir models and distribution.

[5] *Hudson. D. et al, 1993.Applied sequence stratigraphy analysis of well logs, Cruse Fm, Palo Seco field. Society of Petroleum Engineers (Trinidad and Tobago section) meeting held in June 1993.*

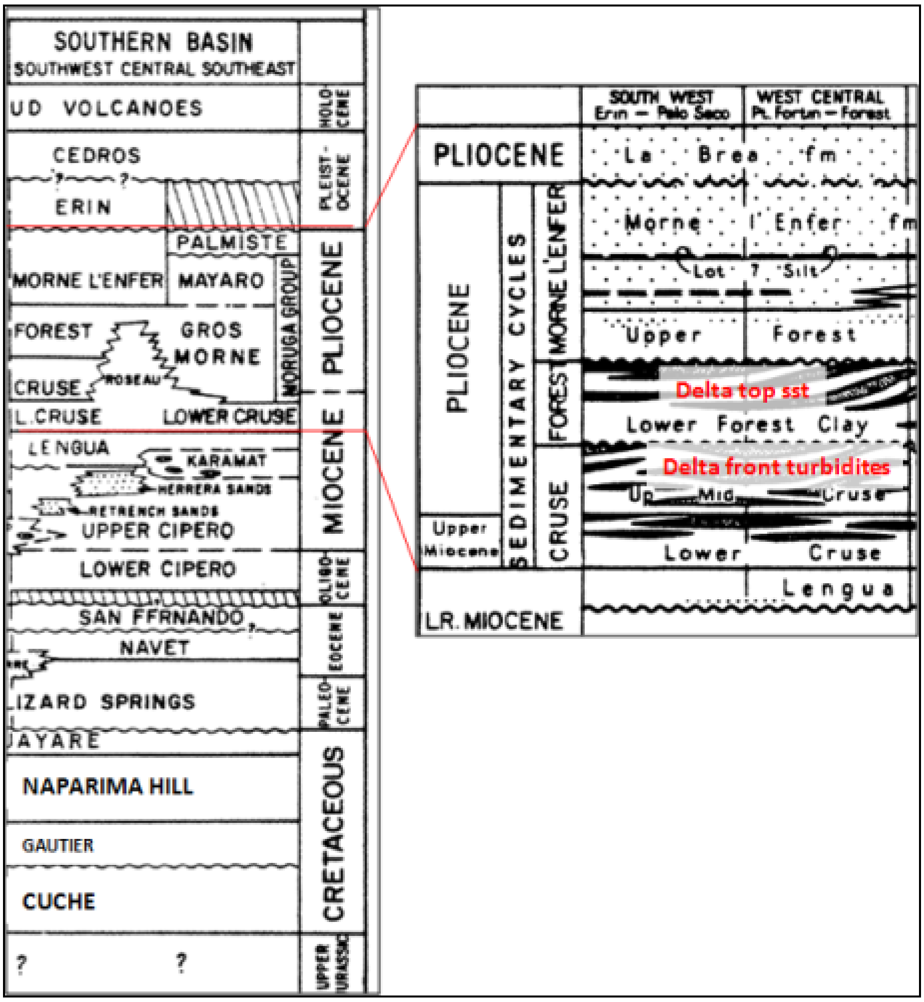

Figure 4.4: Southern Basin Stratigraphy

5. EXPLORATION DATA

At the outset of the study a dataset was provided as the basis for this evaluation.

The geoscience content comprised the 2009 report prepared for Jasmin Oil & Gas Limited by M.L. Geotechnical Consultants Ltd[6]. This report contained analysis of the five oil wells drilled in the South Erin block: 1ER98, 1ER99, 1ER100, 1ER101 & 1ER102. It included depth maps for the Lower Forest B1 Sand and the Mid Cruse Sand based on well data and sparse 2D seismic coverage, and also Gross Sand and Net Oil Sand Isopachs (NOS) for the following sandstones: Lower Forest A1, A2, B1, B2, C Sands, and Mid Cruse Sands.

This was the only set of maps made available for this study.

5.1 Wells

Digital well data were provided for all 5 wells and petrophysical evaluation reports with CPI logs by Schlumberger for all wells except 1ER98.

Locations of the five wells drilled (in green) and the 4 proposed wells (in orange) for 2014 are given in Figure 5.1. The map is the depth structure at Top B1 sand in the Lower Forest Fm. As will be discussed later, the fault pattern shown is somewhat speculative. NB The well locations shown in red in Figure 5.1 were the proposed locations at the time the 2009 report was prepared. RIH advises that different well locations are now being considered and has provided locations for the currently planned wells.

The area of this map is shown approximately as the Detailed Map Area in Figure 4.1.

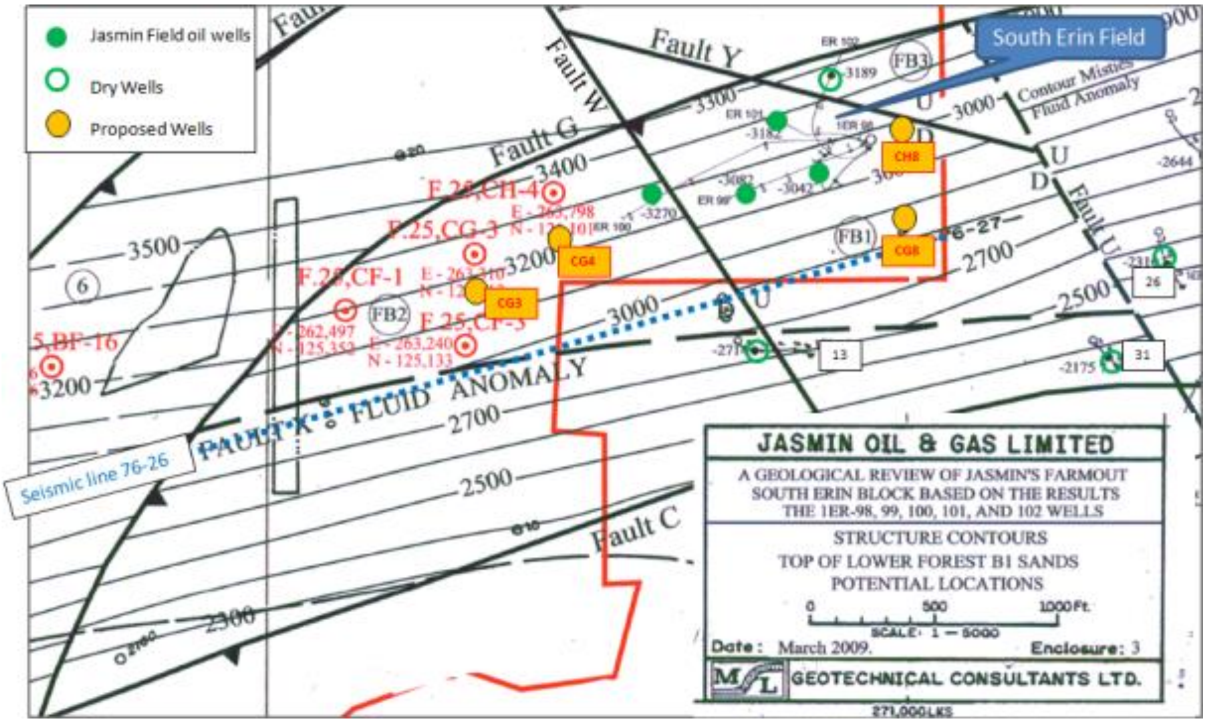

Figure 5.1: South Erin Field – Well Locations on B1 Sand Depth Structure

All wells in the field are deviated but no deviation surveys were provided. Measured depths to formation tops can be read from the logs but not accurate true vertical depths subsea (tvdss). Similarly, along-hole thicknesses (AHT) of drilled sands can be measured but not true vertical thicknesses (TVT).

[6] *Updated Geological Review of Jasmin's Farm-out – South Erin Block 1ER98 Area by M.L. Geotechnical Consultants limited. November 2009.*

5.2 Seismic

Some seismic data were provided in digital and scan format but only one WSW-ENE trending line, 76-27, passed near the field and was of limited value (see Figure 5.1).

Part of a 3D seismic survey has recently been purchased across the South Erin area. This was provided to RPS in early February [2014] and several lines have been viewed across key faults.

The 3D data are currently being interpreted by AGGO Geoconcepts on behalf of REX. Screen-shots of some TWT interpretations were sent to RPS on the 20th February [2014] but these have not been integrated into this report.

Consequently, the only depth maps that were available to estimate In-Place volumes by RPS are those from the 2009 report. The validity of these maps and the faults are considered somewhat questionable as they are based on the 2D seismic data which is of limited coverage. Completed interpretations from the 3D data are needed for an accurate estimation of in-place volumes. However as RPS Reserves and Resources estimates use performance well based methods the absence of such interpreted 3D data are not considered critical.

6. RESOURCE & RESERVES ESTIMATES

6.1 Traps and Reservoirs

The map in Figure 5.1 is from the interpretation in the 2009 report by ML Geotechnical Consultants. It shows the closure at the Erin South Field to be delimited by Fault Y to the north-east and Fault X 'Fluid Anomaly' to the south. This latter 'fault' lies just north of dry wells 13 and 31 that are located updip and south of the oil wells in the field. As with all the 'faults' on this map, their presence and position seem to have been inferred from well data as no useful seismic data existed at the time. All that can be said is that some kind of 'barrier(s)', structural or stratigraphic, separates updip dry wells 13, 31 and 26 from the field to the north and north-west.

No data could be supplied for these dry wells to try and validate this barrier.

The continuation of this barrier, or possibly a separate barrier, to the west is critical to the closure of the compartment to be drilled by wells CG3 and CG4. But clearly there is an updip trap that works for well 1ER100 where oil pays exist in several sands, see Figure 6.1.

'Fault Y' is inferred from well data at 1ER-101, SW of the fault, and 1ER-102 located to the NE. Oil-bearing A1, A2 and B1 sands were found in well 101 (Figure 6.1). Well 102 was interpreted to be on the footwall fault block to the NE and these three sands are largely absent. Although these wells are only 250 ft apart, Schlumberger's CPI analyses for wells 101 and 102 show significant differences. Over a 329 ft interval covering sands A1, A2 and B1, there is 267 ft net sand (0.81 NTG) and 150 ft net oil pay in well 101. An equivalent analysis in well 102 gives 436 ft gross interval and 53 ft net sand (0.12 NTG) and no net pay.

It seems more likely that the barrier between wells 101 and 102 is stratigraphic rather than structural but the 'fault' may approximate the position of any facies change.

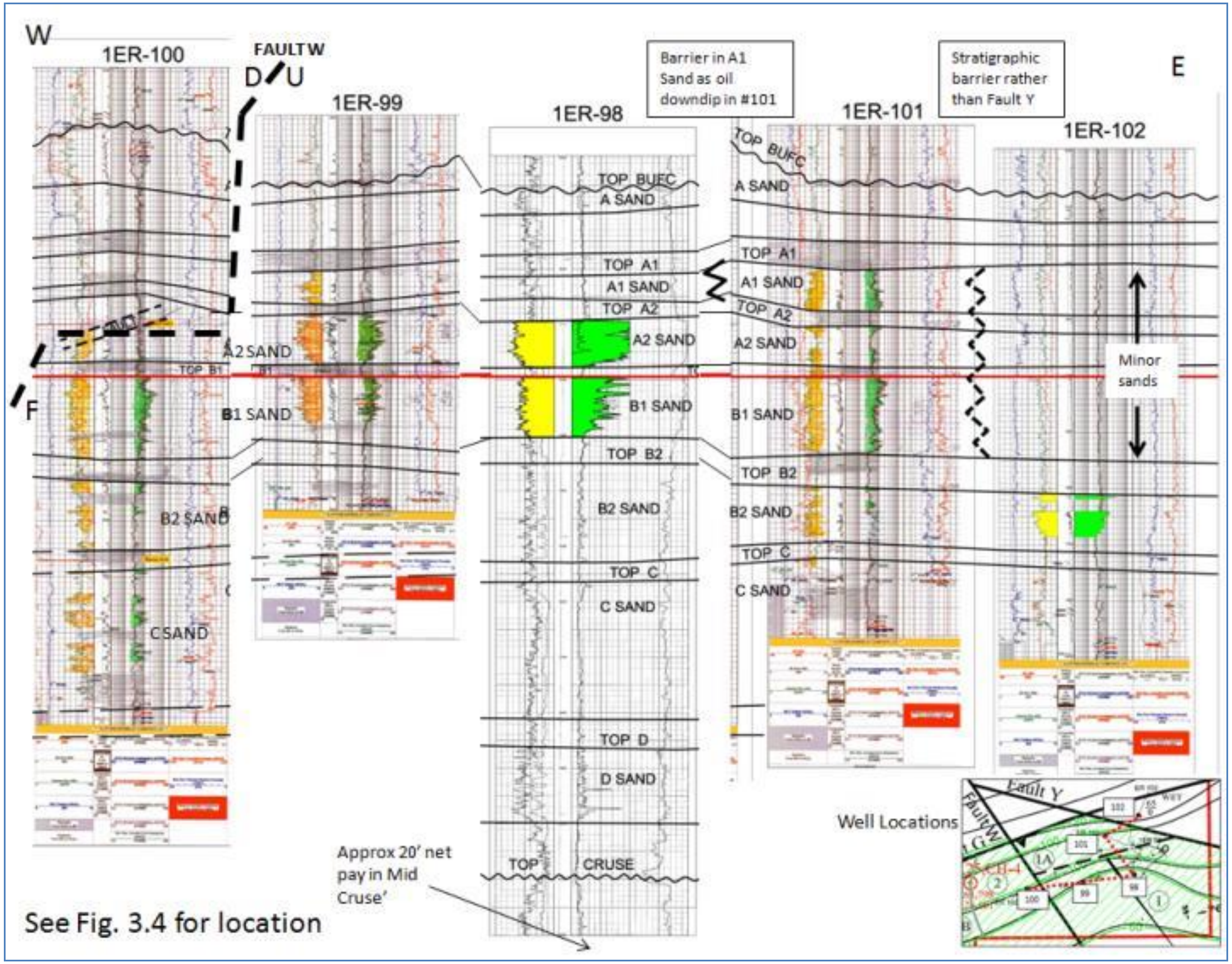

Figure 6.1: Well Correlation of South Erin Wells (based on 2009 Report)

In the 2009 report the field was subdivided into fault bounded areas and the central field area is annotated as FB1 (see Figure 5.1). All three wells (98, 99 and 101) have oil pay intervals in B1 Sands and A2 sands. At the A1 Sand level, well 101 has 36 ft net oil pay but updip wells 98 and 99 have water-bearing A1 Sands. There must be a permeability barrier between wells 98 & 99 and well 101, which is located more than 100 ft down-dip to the north.

Fault W, which is proposed between wells 99 and 100, is equally uncertain (Figure 5.1). The 2009 Report states that well 1ER100 'cut a fault at about 3400 to 3470 feet which affected the A2 sands' but the fault could not be picked on seismic line 76-26. The report continued to state that the fault was 'confirmed by dipmeter log at 3470 ft in 1ER100 as interpreted by Schlumberger'. This dipmeter analysis was not available to RPS and Fault W could not be verified by well data.

RPS reviewed the 3D seismic across this Fault W. A quick-look time structure interpretation at top B1 Sand is shown in Figure 6.2 and confirms the monoclinal bed dip towards the north west. The location of an arbitrary 3D line trending SW- NE is shown in this Figure. RPS' provisional interpretation of this line and a possible position of Fault W is given in Figure 6.3. The fault intersects the well trajectory of 1ER100 at a point where there is a distinct change in bed dip at Top B1 Sand, which supports the fault interpretation. This dip change also seems to occur at Cruse level. It was not part of the work scope to interpret the new 3D data but this appears at this time to confirm a cross fault between wells 100 and 99. Faults of this trend are very common in the Palo Seco field (see Gluyas). Another piece of evidence is that top B1 Sand in well 99 is 170 ft higher than B1 in well 100, although the two wells are only 360 ft apart. A fault down-throwing to the west would explain this.

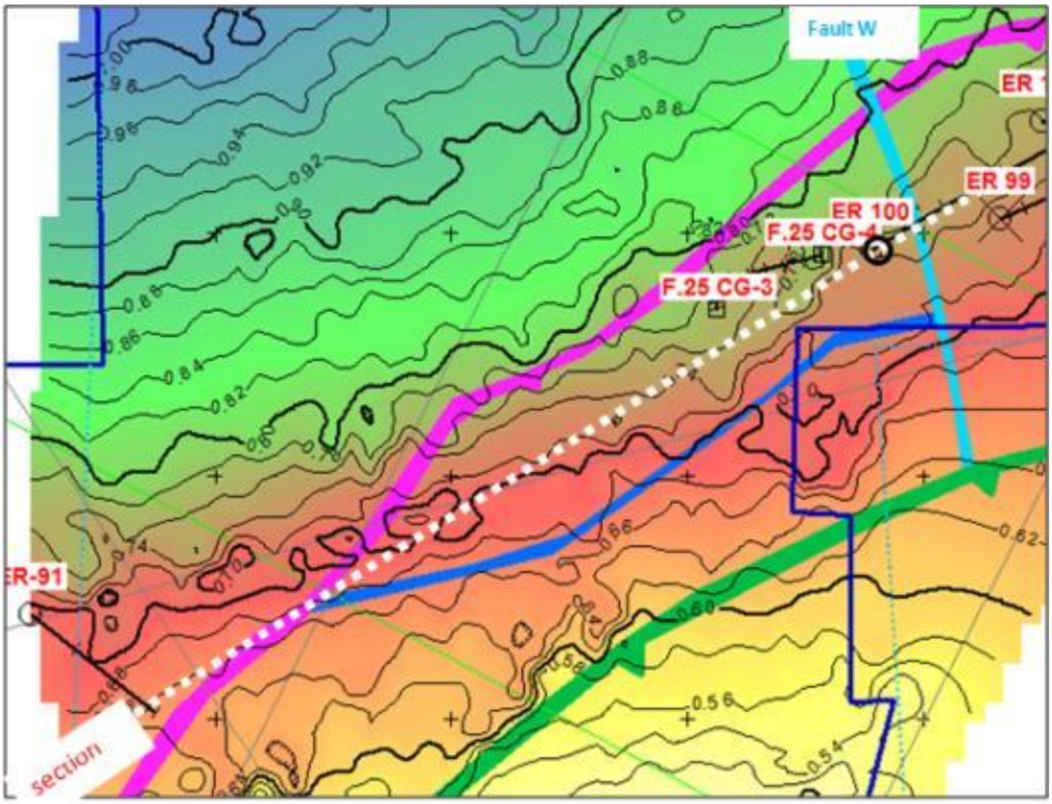

Figure 6.2: Provisional TWT Structure at Top B1 Sand and Seismic Section (RPS)

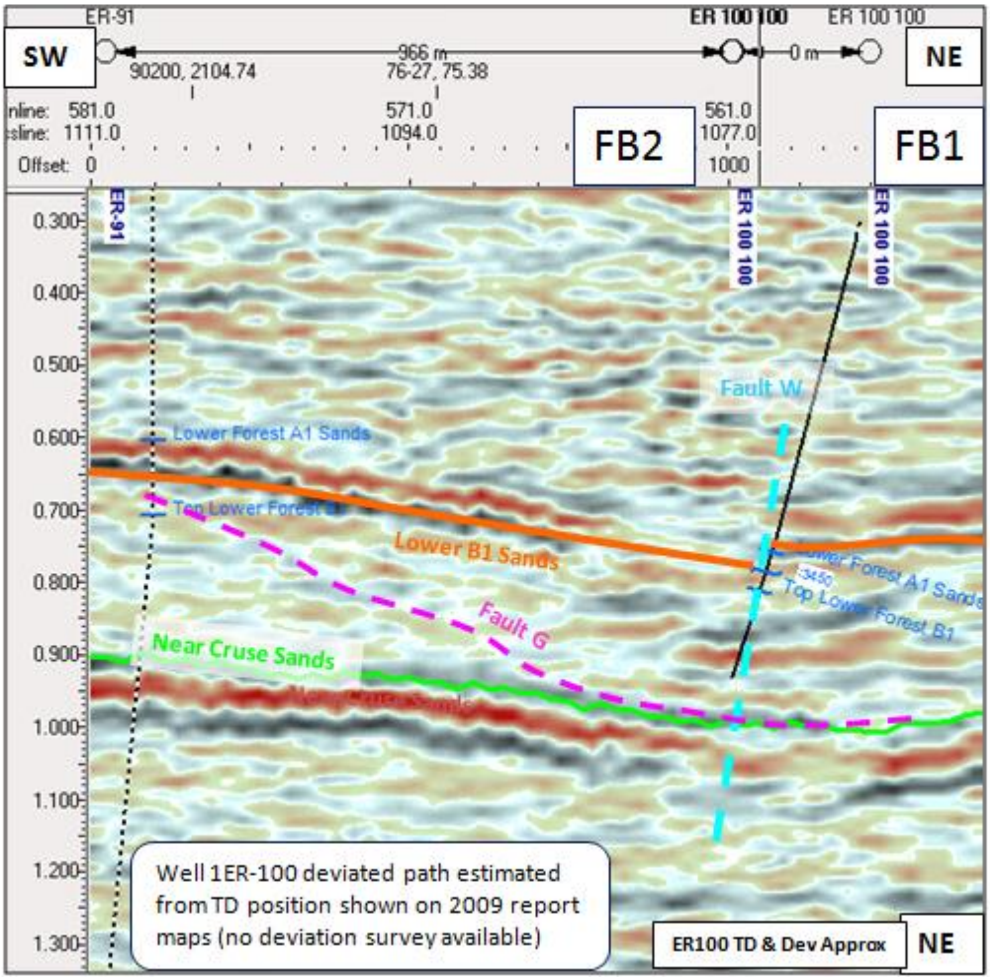

Figure 6.3: Seismic Section Through well 1ER100 (RPS)

With this interpretation, the B1 Sand is oil bearing in well 1ER100 on the west side of Fault W. Oil is also found in B2 Sand and C Sand in this well but there is currently no firm plan to develop these sands. This interpretation enables estimated Reserves to be attributed to the B1 Sand in proposed wells CG3 and CG4, which will be drilled approximately 164 ft (50 m) and 558 ft (170 m) west and updip of well 1ER100 (Figure 6.2 & Figure 6.3).

It is recognised that about 30 ft of oil pay were found in the Mid Cruse Fm in well 1ER98. This is the only well in the field to have drilled to this level. No Reserves have been attributed to this reservoir.

6.2 Petrophysical Review

RPS reviewed the key reservoirs in the field. It carried out an independent petrophysical evaluation of well 1ER100 and the results are given in a section of CPI log and averages for the B1 Sand (Figure 6.4). By comparison the zone averages by Schlumberger are not specific to the B1 Sand but estimates from their CPI log calculate approximately 97 ft net pay in the 148 ft gross sand. Schlumberger calculates averages for net PHIE of 22% and Sw of 37% for the net interval covering the B1 and B2 Sands.

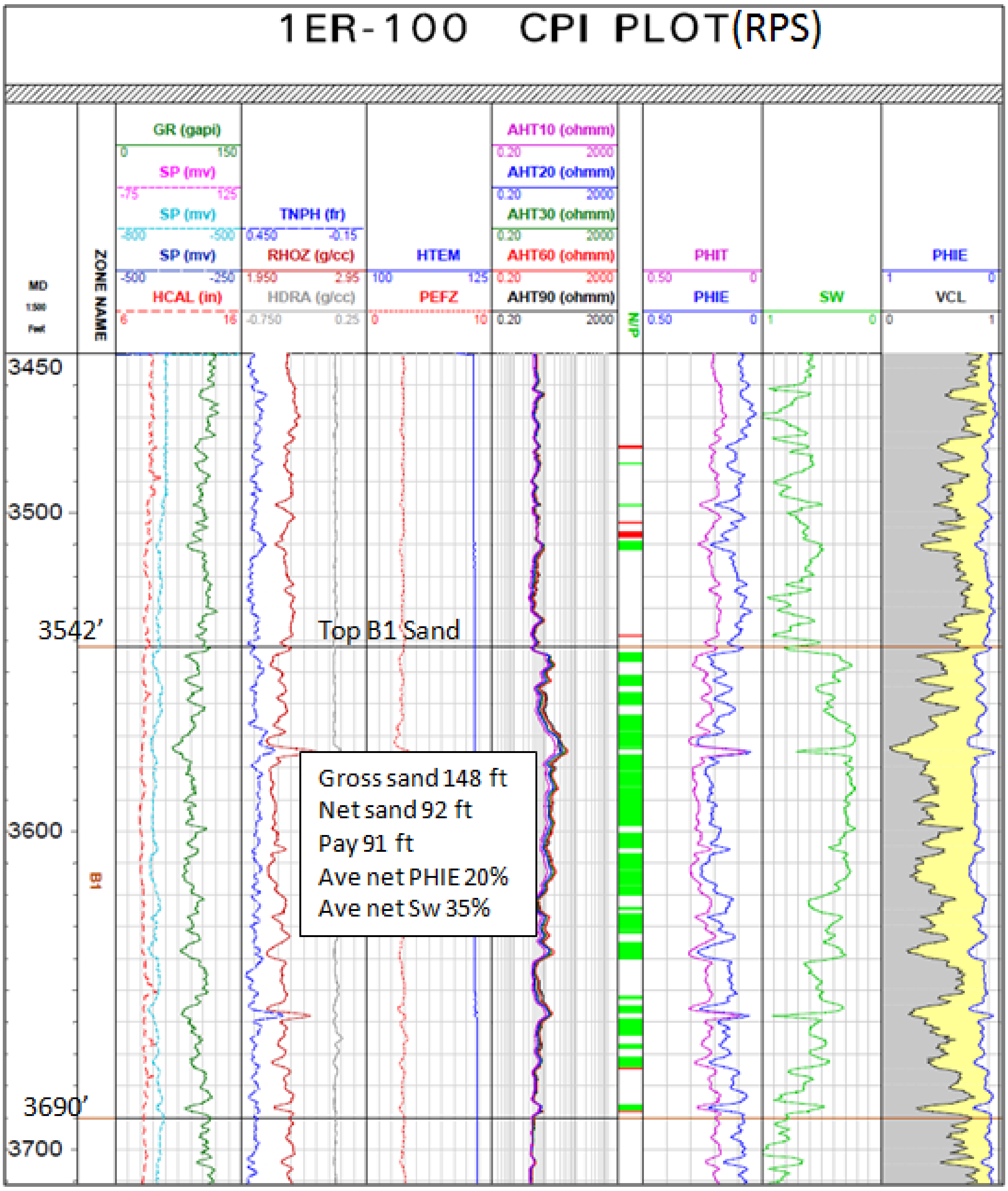

Figure 6.4: Petrophysical CPI Log for Well 1ER100 (RPS)

B1 Sands in wells 1ER98 & 99 provide the basis for STOIIP estimation in the central field area, where wells CH8 and CG8 are proposed. Schlumberger petrophysics is available for well 99 but not well 98. They estimated 71.5 ft net pay in the B1 Sand with average net PHIE of 24% and Sw 32%.

It is recommended that the A2 Sands in well 98 & 99 be recompleted. Schlumberger's CPI log for A2 Sand in well 99 is shown in Figure 6.5 with averages for the 57 ft pay interval. This was the basis of the reservoir parameters used to calculate STOIIP in A2 Sand. Approximately 80 ft gross A2 Sand was found in well 98. Although no petrophysical evaluation is available for this well, the deep resistivity curve shows high oil saturation and no OWC. On the 2009 maps, 74 ft net oil sand (NOS) was estimated for A2 Sand in well 98.

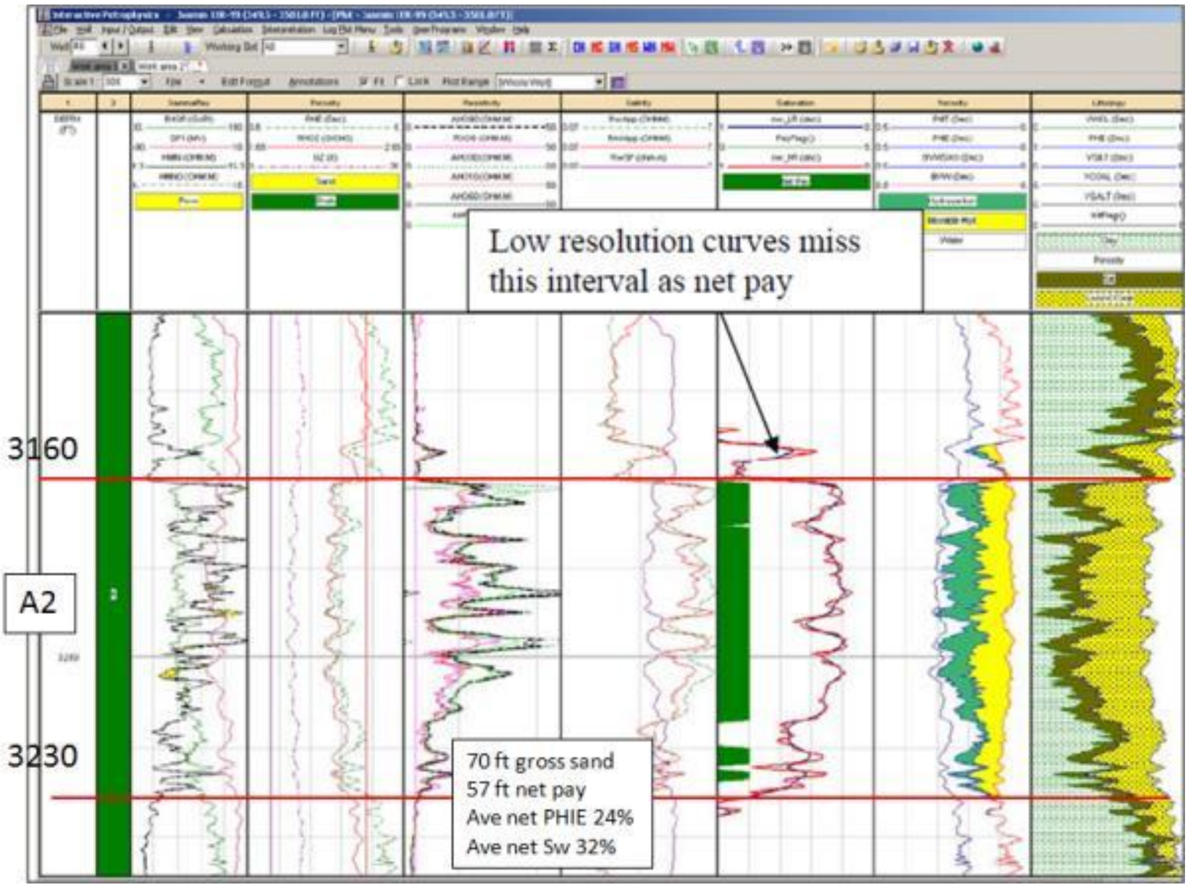

Figure 6.5: Petrophysical CPI Log for Well 1ER99 across A2 Sand (SLB)

6.3 In-Place Volumetrics

In the Erin South field central area, Reserves can be attributed to the B1 Sand in proposed wells CG8 and CH8 (see Figure 5.1 for well locations). In addition, it is proposed to work-over wells and recomplete the A2 Sands in wells 1ER98 and 1ER99 where net oil pay thicknesses of ~70 ft and 57 ft are interpreted. It is understood that initial attempts to test these zones stopped prematurely because of sand production.

In the west part of the field, Reserves are allocated to B1 Sand for proposed wells CG3 and CG4 on the basis of at least 91 ft net oil pay encountered in well 1ER100.

There has been recent notification that 3 further wells may be proposed for 2015 to be drilled from the CG3 & CG4 surface location (Figure 6.6). These wells have been called Forest Target 1, 2 and 3. These may also have possible objectives in the Cruse and Herrera Sandstones. Additional wells are also being considered further to the west for later.

At this time, Reserves cannot be allocated to these wells but their status can be reviewed after the results of wells CG3 and CG4 have been evaluated.

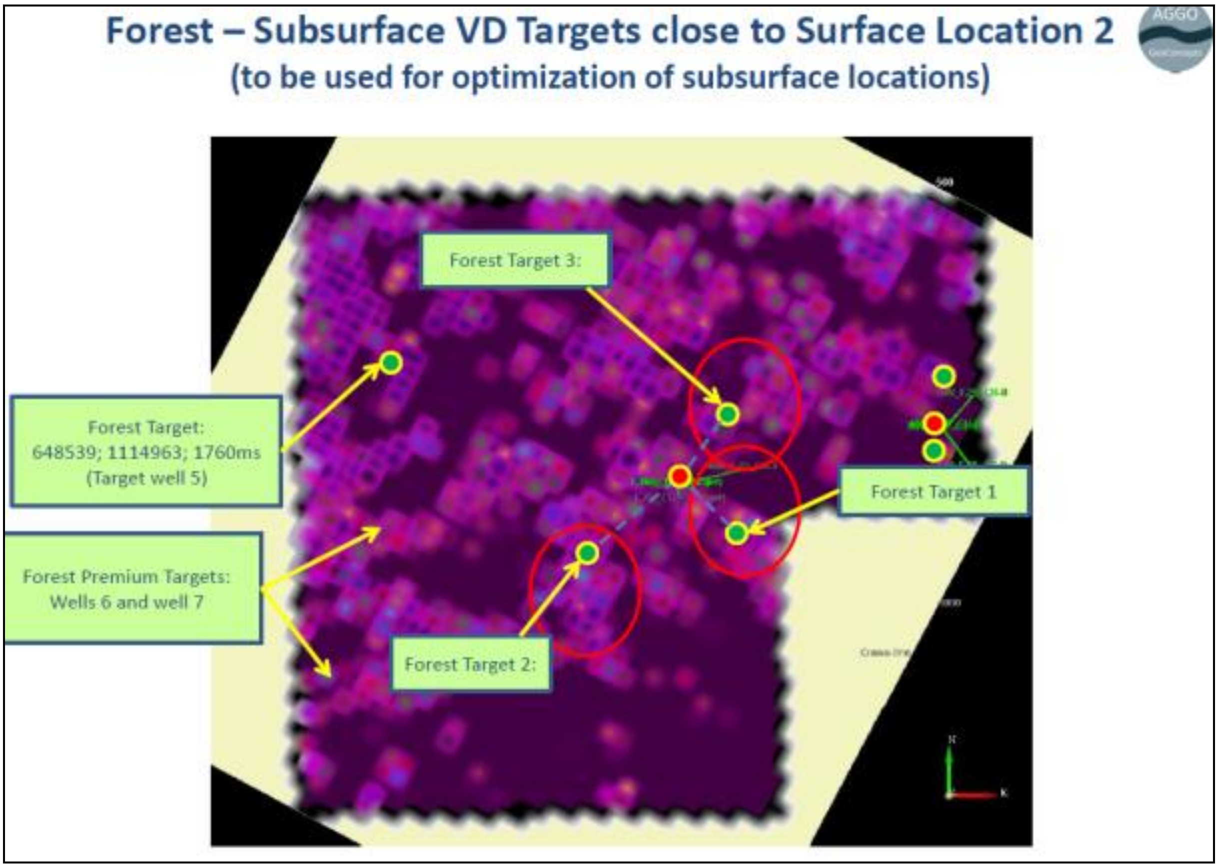

Figure 6.6: Three Proposed Wells for 2015

6.3.1 B1 Sand STOIIP Estimations

Wells CH8 and CG 8 will be located in field area FB1, as shown on the B1 Sand Structure map in Figure 5.1. A general closure area was estimated within the licence boundary to the south and east. No OWC was encountered in the B1 Sand in any of the wells and the deepest ODT is approximately -3317 ft tvdss in well 1ER101, down-dip to the north.

Ranges for B1 Sand gross thickness and reservoir properties were taken from the Schlumberger evaluations for wells 99 and 101 and ranges are shown in Table 6.1. This resulted in a STOIIP estimation of between 0.77 to 1.6 MMstb.

Oil already produced from these three central wells is about 195,000 bbl and EUR is approximately 240,000 bbl. It is estimated that there is sufficient remaining oil in place in this FB1 area for additional wells CH8 and CG8 to produce from the B1 Sand to their maximum capacity.

It must be emphasised that the limits to the FB1 area are very poorly understood and the true closure area is not known. Estimation of STOIIP to the licence boundary does not to account of potential drainage areas beyond the border.

Parameter	Unit	P90	P50	P10
Area	acres	19	19	19
Gross Sand	ft	50	75	100
NTG	%	65	81	98
Porosity	%	21	23	25
Sw	%	40	33	23
FVF	vol/vol	1.22	1.2	1.18
STOIIP	**MMstb**	**0.77**	**1.1**	**1.56**

Table 6.1: B1 Sand in the East Area FB1 – Parameters and STOIIP

Proposed wells CG3 and CG4 will be drilled in field area FB2 to the west, based on the B1 Sand depth map in Figure 5.1. It is proposed to locate these wells respectively about 560 ft (170 m) and 164 ft (50 m) west of well 1ER100 at top B1 Sand. The depth of the B1 Sand was -3,270 ft tvdss in 1ER100 and no OWC was found at base sand at approximately -3,420 ft tvdss. The well had 91 ft of net oil pay in the B1 Sand (Figure 6.4).

The closure area for FB2 is again very poorly understood and requires remapping. But if a closure area of 25 acres and reservoir properties similar to those in Table 6.1 are assumed, a STOIIP range of between1.0 to 1.7 MMstb is estimated for the B1 Sand with a P50 case of 1.3 MMstb.

6.3.2 A2 Sand STOIIP Estimations

The A2 Sand net pay thickness in wells 98 and 99 ranges from 50 ft to 60 ft. There has been no production from this reservoir to date. For the In-Place volumetric calculation for this reservoir, an area of 12 acres was assumed for the FB 1 area. Reservoir properties were used as shown in Figure 6.5 and a STOIIP range of 0.5 to 1.4 MMstb was estimated with a P50 case of 0.9 MMstb.

Again it must be emphasised that closure area for this reservoir is largely unknown and requires revision following the 3D interpretation.

6.4 Developed Reserves

Using the production history provided, production profiles have been produced for each of the five developed wells. Decline curve analysis of these profiles has given estimated recoverable volumes for each well for a P90, P50 and P10 case. For the P90 case exponential decline was assumed, for the P50 hyperbolic decline and for the P10 harmonic decline. The results of this analysis are presented in Table 6.2 below.

Wells	Oil Volume (Barrels)						
	Produced Volume	Expected Ultimate Recoverable (EUR) Volume			Remaining Recoverable Volume		
		P90	P50	P10	P90	P50	P10
1ER-98	108,907	120,357	128,222	138,842	11,450	19,315	29,935
1ER-99	56,278	61,846	72,426	80,378	5,568	16,148	24,100
1ER-100	54,087	73,120	87,240	96,613	19,033	33,153	42,526
1ER-101	29,767	33,572	39,777	44,021	3,805	10,010	14,254
1ER-102	999	1,047	1,131	1,210	48	132	211
TOTAL	250,038	28,9942	328,796	361,064	39,904	78,758	111,026

Note:
1. *These are technical results and do not include an Economic Limit Test.*
Produced Volume as of end 2013 estimated using Production data as of 19th May 2013

Table 6.2: Results of Decline Curve Analysis on the Developed Wells (stb)

The developed wells are considered representative of the planned undeveloped wells. Therefore the results of the decline curve analysis can be used to predict profiles for the undeveloped wells. For the four successful developed wells (excluding 1ER-102) the average EUR is approximately 82,000 barrels. A generalised decline curve has been produced that gives an EUR of 82,000 barrels with a rate of decline averaging the successful developed wells. This decline curve has been applied as the most likely profile for each of the undeveloped wells (Figure 6.7).

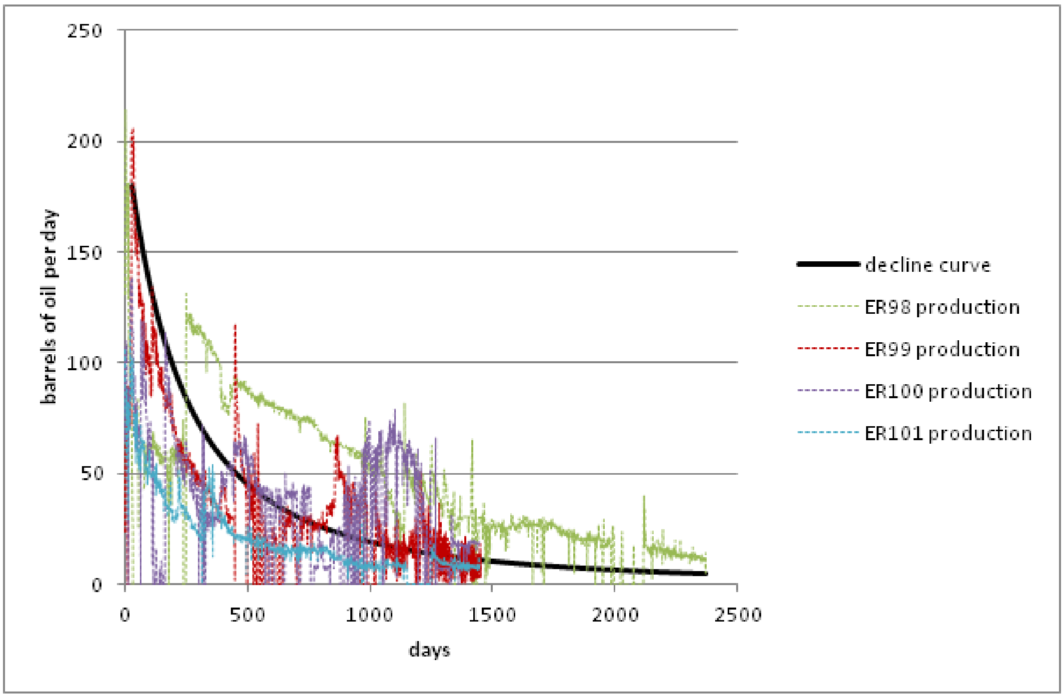

Figure 6.7: A Comparison of the Generalised Decline Curve with Historical Production Data

RPS has investigated the wells in a nearby development on onshore Trinidad which is also producing from the Lower Forest sands. These wells had similar initial production rates to the South Erin wells but the reported EUR per well is lower with a P50 prediction of 38,000 barrels.

The wells investigated have been producing for a similar time period as the South Erin wells. Therefore it is reasonable to compare the cumulative oil production data to give a better idea of how the two fields correspond. This comparison is presented in Figure 3.2. The analysis show similar cumulative oil production from the wells in the two fields with the successful wells in South Erin fitting in the range given by the twelve analogous wells.

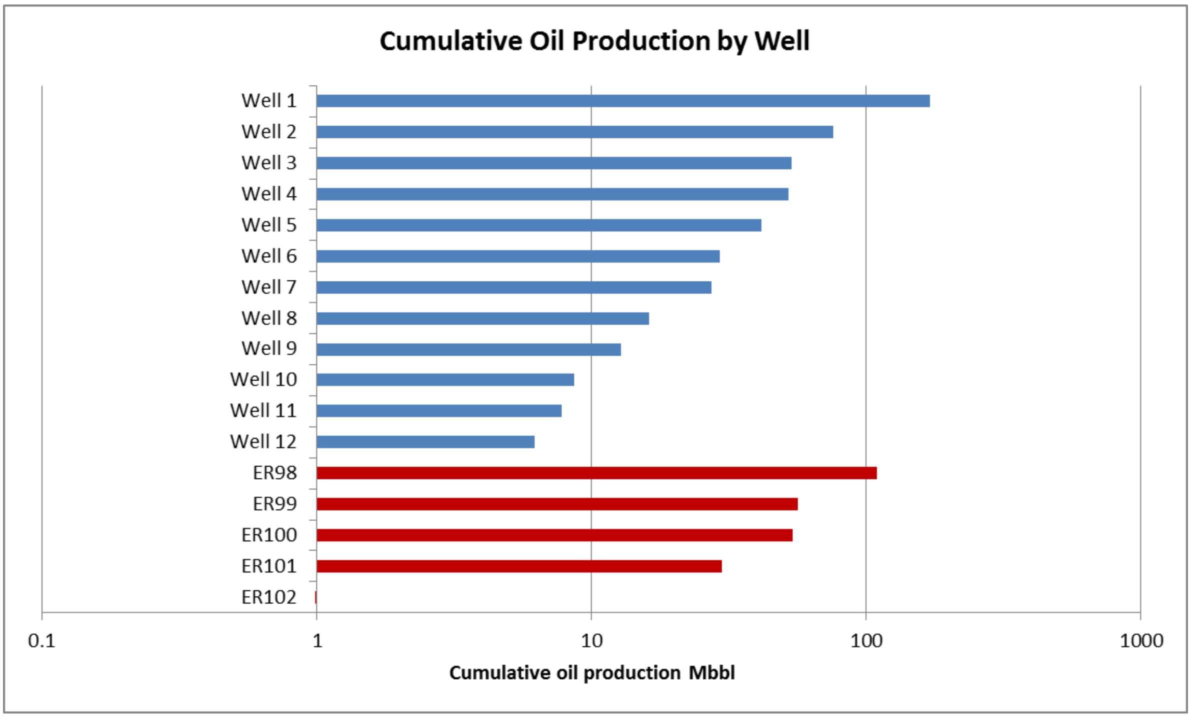

Figure 6.8: Comparison of the Cumulative Oil Production from South Erin and Offset Wells

6.5 Undeveloped Reserves & Resources

The undeveloped wells were considered to be in three phases. The first is the development of four new wells in the B1 Sands to be brought on stream mid 2014. Following this is the recompletion of wells 1ER-98 and 1ER-99 in the A2 sands in mid 2015 after which there would be no further production from these wells in the B1 sands. The final phase is three additional wells to be drilled in 2015 in the B1 Sands. These three well are located to the west where the presence of pay is not proven. Production from these three wells has therefore been considered to be contingent resources. The decline profile for all of these new wells and recompletions will be the same except for the chance of success.

It was assumed that a new well in the first phase had an 85% chance of success and in the second and third phases had a 70% chance of success. The mean production from a successful well in all phases would be 82,000 barrels with a standard deviation of 40,000 barrels. Using @RISK, Monte Carlo methods were performed to estimate P90, P50 and P10 cases based on an equivalent number of wells following the generalised decline curve.

Multiplying these values by the general profile gives three production profiles for the undeveloped wells. The developed and developed + undeveloped profiles up to the end of licence at end 2026 are given in Table 6.3. The remaining amount is the forecasted cumulative production from 2014 onwards. The production for 2013 is estimated based on the performance up to May 2013.

	DEVELOPED (Barrels)		
	P90	P50	P10
2006	4016	4016	4016
2007	26569	26569	26569
2008	29831	29831	29831
2009	67723	67723	67723
2010	54848	54848	54848
2011	32483	32483	32483
2012	27959	27959	27959
2013[1]	17007	17007	17007
2014	10308	13823	16186
2015	6779	11095	13964
2016	4506	9129	12293
2017	3002	7592	10963
2018	2022	6417	9919
2019	1368	5491	9059
2020	928	4759	8360
2021	586	4139	7724
2022	408	3640	7195
2023	130	3220	6735
2024	0	2878	6349
2025	0	2573	5972
2026	0	2321	5652
remaining	30037	77077	120371

[1] *2013 production is estimated.*

	DEVELOPED + PHASE 1 + PHASE 2 (Barrels)				DEVELOPED + PHASE 1 + PHASE 2 + PHASE 3 (Barrels)		
	P90	P50	P10		P90	P50	P10
2014	57624	93000	132217	**2014**	57624	93000	132217
2015	59590	116292	182398	**2015**	59590	116292	182398
2016	31731	69334	113941	**2016**	60478	143627	243860
2017	17910	38600	62371	**2017**	29284	67996	113776
2018	11522	25143	40348	**2018**	17617	40895	67894
2019	8004	17936	28775	**2019**	11803	27754	45944
2020	5902	13660	22006	**2020**	8496	20365	33732
2021	4462	10775	17518	**2021**	6346	15645	26035
2022	3488	8735	14360	**2022**	4919	12433	20827
2023	2678	7251	12082	**2023**	3802	10154	17159
2024	2142	6153	10408	**2024**	3047	8493	14500
2025	1807	5295	9104	**2025**	2552	7222	12472
2026	1535	4601	8052	**2026**	2160	6214	10873
remaining	208396	416774	653580	**remaining**	267719	570089	921688

Table 6.3: Developed and Developed+ Undeveloped Production Profiles

The analysis has shown developed + undeveloped (developed and phases one and two) to be 467,408 barrels in the P90 case, 677,210 barrels in the P50 case and 915,241 barrels in the P10 case. The P50 case corresponds to an ultimate recovery factor of 19.2% for the RPS STOIIPs for the relevant sands and fault blocks.

A production profile is given in Figure 6.9 for the P50 case of the developed+undeveloped (all phases). For phases one and two only production profiles are given for the P90, P50 and P10 cases (Figure 6.10).

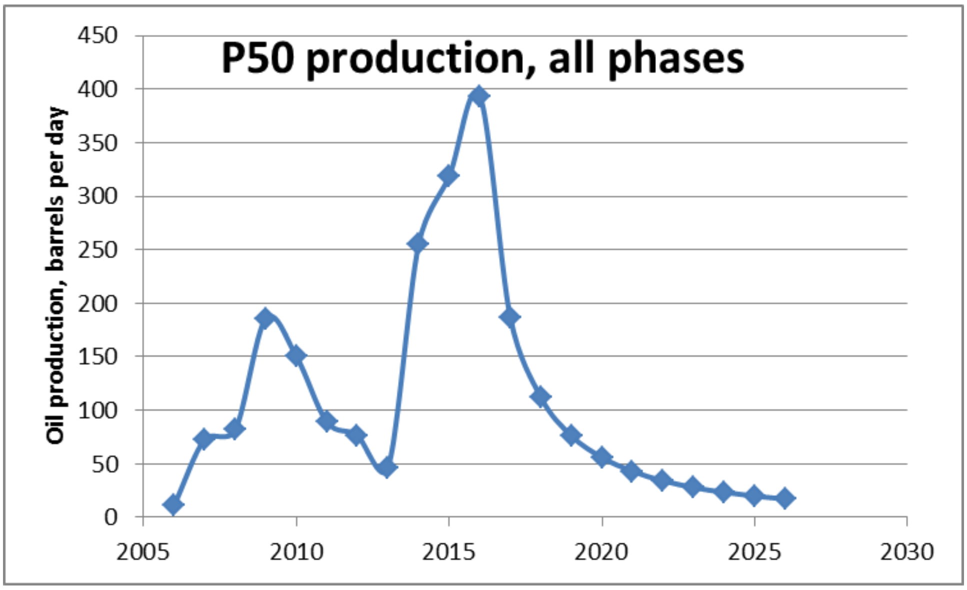

Figure 6.9: P50 Oil Production Forecast for Developed + all Undeveloped Phase

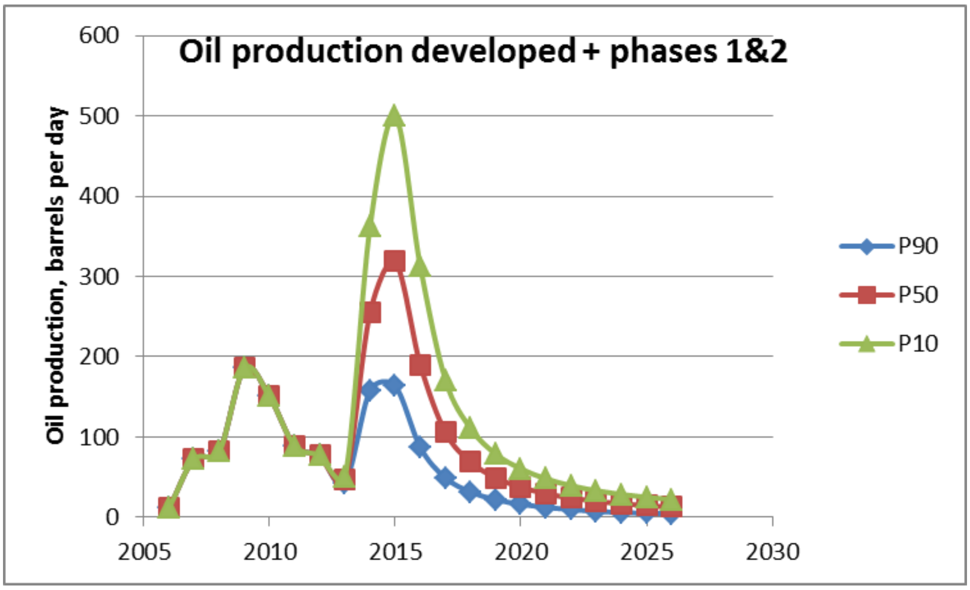

Figure 6.10: P90, P50 and P10 Oil Production Forecast for Developed + Phases 1 & 2

7. CAPITAL & OPERATING COSTS

Three development scenarios were considered for the South Erin resources. RPS cost profiles were created for each scenario based on data provided by REX and RPS regional knowledge. Costs described below are in 2014 real terms. We have assumed there are no significant contingencies to the development such as social, environmental, health and safety factors.

The developed scenario contains production from the existing five wells with no new capital investment. For 2014 the operating costs and general overhead costs were assumed as US$0.675MM.

The developed and undeveloped scenario assumes additional drilling of four planned wells in 2014 at a combined cost of US$7.1MM, which includes small amounts for costs for site, flowlines and storage. This scenario also includes two recompletions in 2015 at a cost of US$0.1MM each. In addition to the operating and G&A costs for the Developed Reserves, an annual opex from mid-2014 of US$0.25MM was assumed for the Undeveloped Reserves.

The third scenario comprises the second scenario plus the drilling of a further three new wells in 2015, at a combined cost of US$5.3MM and includes costs for flowlines and storage. Operating costs for production from these wells was assumed as US$0.2MM per annum.

In each scenario, operating costs have been reduced over the life of the field to reflect the decline in production.

The terms of the licence requires the company to make abandonment provisions of US$0.28/bbl. However, RPS could see no explicit ongoing abandonment provision in the Jasmin Management Report (audited by OFA consultants limited) or in the Jasmin financial statements for the period ended 31st December, 2013. As a result RPS assumed a decommissioning cost at the end of field life for each scenario of US$1.25MM, US$1.85MM and US$2.80MM.

8. FINANCIAL ANALYSIS

8.1 Assumptions

8.1.1 General

Post tax cashflows in US Dollars from 1st January 2014 were calculated for South Erin Licence cases using RPS forecasts of costs and prices. An annual inflation rate of 2% was assumed and applied to both costs and revenues. A constant exchange rate of 6.3Trinidad and Tobago Dollar to 1 US Dollar was assumed.

8.1.2 Oil Prices

The evaluation was based on the RPS long term forecast for West Texas Intermediate (WTI) crude (long term price of US$85/stb in REAL 2014$ from 2016 onwards) as shown in Table 8.1. The 2014 and 2015 WTI price assumptions were based on the WTI market curve. The observed realised sales prices for South Erin relative to WTI prices during the period January 2013 to December 2013 were used as the basis for South Erin oil price assumptions: a constant -4% was applied to the WTI price as seen in Table 8.1.

	WTI Price Case (US$/stb, MOD)	Base South Erin Price Case (US$/stb, MOD)
2014	95.00	91.20
2015	89.49	85.91
2016	88.43	84.90
2017	90.20	86.59
2018	92.01	88.33
2019	93.85	90.09
2020	95.72	91.89
2021	97.64	93.73
2022	99.59	95.61
2023	101.58	97.52
2024	103.61	99.47
2025 onwards	+ 2% p.a.	+ 2% p.a.

Table 8.1: RPS Forecast Oil Prices

8.2 Methodology

The production potential of the South Erin field was assessed with nine forecasts of varying resources and development project assumption. The resource range was provided by three production profiles at P90, P50 and P10 for each of the three development scenarios:

- Scenario 1: Developed, i.e. production from the existing 5 wells
- Scenario 2: Developed + Undeveloped Phase 1 + Undeveloped Phase 2, where Phase 1 is the drilling of four new wells in 2014, and Phase 2 is the recompletion of wells ER98 and ER99 into a different sand in 2015
- Scenario 3: Developed + Undeveloped Phase 1 + Undeveloped Phase 2 + Undeveloped Phase 3, where Phase 3 is the drilling of a further three new wells in 2016.

Scenarios 1 and 2 were considered Reserves cases, and the Phase 3 development considered as Contingent Resources. Resulting volumes are presented as Developed (Scenario 1), Developed plus Undeveloped (Scenario 2) and Contingent Resources (Scenario 3 minus Scenario 2).

A discounted cashflow model was used for the nine cases with RPS's forecast of future production, prices and costs. The model honours the applicable licence terms and Government taxes to provide net REX entitlement Reserves and post-tax cashflows net to REX's share.

8.3 Licence

REX's entitlement to production from the South Erin Block is laid down in the Farmout Agreement (Sub-Licence) of 2nd October 2013 between Petroleum Company of Trinidad and Tobago Limited ("Petrotrin") and Jasmin Oil and Gas Ltd.

RIH has a 64.17% interest in the Farmout Agreement (sub-Licence) through its ownership of REX after completion of the purchase of remaining 25% of Jasmin.

The period of the Farmout Agreement is summarised in Table 8.2.

Field	Working Interest [1] (%)	Current Agreement Expiry Date (d/m/y)	Extension Option	Reserves Limit Date (d/m/y)
South Erin	64.17%	31/12/2021	5 years (to be negotiated) [2]	31/12/2026[1]

1. *Caribbean Rex Ltd ("REX") has rights to explore and extract oil through its 100% ownership of Jasmin Oil and Gas Limited, after completion of the purchase of last 25% of the company. Rex International Holdings Ltd owns 64.17% of Caribbean Rex Ltd.*
2. *RPS has assumed that agreement of the 5 year extension is reasonably certain based on recent history, and assumed on existing terms.*

Table 8.2: Agreement and Reserves Limit Dates

8.3.1 Petrotrin Overriding Royalties

An Over Riding Royalty (ORR) on oil production is payable to Petrotrin that varies according to oil price and oil production. For example, within the oil price band of US$90 to US$130 per barrel, the BASE ORR% rate for Base Production is 25% and the Enhanced ORR% for production above Base Production is 16%, where Base Production is defined in the agreement in barrels of oil per month on an annual basis for the duration of the agreement.

8.3.2 Economic Limit

RPS forecasts of production extend to the term of the licence plus one possible extension, assuming that agreement for the extension occurs. An economic limit has been applied to the RPS production forecasts in accordance with PRMS guidelines: "Economic limit is defined as the production rate beyond which the net operating cash flows (after royalties or share of production owing to others) from a project, which may be an individual well, lease, or entire field, are negative." The economic limit test for each field is therefore based on the operating cashflow calculated as follows:

> Field Revenues less: Government Royalty, Petrotrin Overriding Royalty (ORR), Supplemental Petroleum Tax (SPT) and Operating Costs.

8.4 Fiscal Regime

The applicable fiscal terms exist within a tax and royalty regime. A Government Royalty applies to production and there is a Supplemental Petroleum Tax and a Petroleum Profit Tax, plus further small levies.

8.4.1 Royalty

For the South Erin Farmout Sub-Licence the Royalty rate is 12.5% applicable to oil from the contract area without any deductions.

8.4.2 Supplemental Petroleum Tax

SPT is payable to the Government on revenues after the Government Royalty and the Petrotrin ORR have been deducted, at a rate for onshore licences that varies with oil price as shown in Table 8.3.

Oil Price $/bbl	Onshore SPT Rate
Price ≤ $50.00	0%
$50.00 Price ≤ $90.00	18%
$90.00 Price ≤ $200.00	18% plus 0.2% of (Oil Price less $90.00)
Price >$200.00	40%

Table 8.3: Supplemental Petroleum Tax Rates

An Investment Tax Credit of 20% of capital expenditure (“Capex”) is allowable against the annual SPT charge, and under the Energy incentives in the Government’s proposed 2014 Budget, unused Investment Tax Credits can be carried forward for one year; previously they were lost if unused.

8.4.3 Petroleum Production Levy

The Petroleum Production Levy (PPL) is applied at a rate of 4% of all gross oil revenues if company production is in excess of 3,500 barrels of oil per day. RPS’s forecast of Reserves in REX’s subsidiary company Jasmin Oil and Gas Limited does not exceed this limit so no PPL is expected.

8.4.4 Green Fund Levy and Petroleum Impost

The Green Fund Levy (GFL) is calculated as a percentage (currently 0.1%) of total gross revenues, and these payments are not tax deductible. A small Petroleum Impost is also payable.

8.4.5 Petroleum Profits Tax

The Petroleum Profits Tax (PPT) is applicable to all oil and gas producers and is applied to the net profits from Jasmin Oil and Gas Limited’s operations at the current applicable tax rate of 50%. The net profit is derived by deducting from the gross income all royalties, taxes and levies with the exception of the GFL. Tax losses can be brought forward indefinitely. Balances at 31 December 2013 provided by REX, have been used in the PPT tax calculations.

The capital allowances for PPT are summarised in Table 8.4.

Capex Category	Allowances effective 1 January 2014 (2014 Budget proposals)
Exploration	From 2014 to 2017, 100% of costs to be written off in the year the expenditure is incurred. From 2018, allowances of 50%, 30% and 20% will apply respectively in the first, second and third years of the expenditure.
Tangible and Intangible	Allowances of 50%, 30% and 20% will apply respectively in the first, second and third years of the expenditure.
Workovers and Qualifying Sidetracks	100% of costs to be written off in the year the expenditure is incurred.

Table 8.4: Petroleum Profits Tax Capital Allowances

8.4.6 Unemployment Levy

The applicable rate is 5% of the net taxable income before loss relief.

8.5 Reserves

REX's Reserves in South Erin as of 31 December 2013 are summarised in Table 8.5.

Field	Gross Reserves (Mstb)[1]			RIH Net WI Reserves (Mstb)[1,2]			RIH Net Reserves Entitlement (Mstb)[1,2,3]		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Developed	10.3	13.8	16.2	10.3	13.8	16.2	6.4	8.6	10.1
Developed plus Undeveloped	166.9	374.0	645.5	166.9	374.0	645.5	113.6	258.5	447.8

1 1P cases have negative Net Present Value at 10% discount rate (NPV10).
2 RIH owns 64.17% of REX which is 100% owner of Jasmin Oil and Gas Limited, after completion of the purchase of last 25% of the company.
3 RIH Net Reserves Entitlement is RIH's WI share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

Table 8.5: Reserves as of 31 December 2013

The cases associated with a Phase 3 development can be classified as sub-marginal Contingent Resources according to Economic Status, and the Resources are summarised after economics assessment in Table 8.6.

Field	Gross Contingent Resources (Mstb)			RIH Net WI Resources (Mstb)[1]			RIH Net Resources Entitlement (Mstb)[1,3]		
	1C	2C	3C	1C	2C	3C	1C	2C	3C
South Erin	40.1	151.6	265.3	40.1	151.6	265.3	28.9	107.5	190.1

1 RIH owns 64.17% of REX which is 100% owner of Jasmin Oil and Gas Limited, after completion of the purchase of last 25% of the company.
3 RIH Net Reserves Entitlement is RIH WI share of Reserves after the deduction of Government Royalty and Petrotrin Over-riding Royalty.

Table 8.6: Contingent Resources as of 31 December 2013

The 100 % WI gross field cashflows associated with the nine cases are presented in Appendix 2.

9. INTERPRETATION AND CONCLUSIONS

RPS has estimated Reserves and Contingent Resources for the developed and planned wells in the South Erin Licence.

The developed wells are considered representative of the seven future undeveloped wells and (excluding 1ER-102) the average EUR is 82000 barrels per well. A generalised decline curve has been produced that gives an EUR of 82000 barrels with a rate of decline averaging the successful developed wells. The development of the undeveloped wells is planned in three phases.

- Four new wells in the B1 Sand to be brought on stream mid 2014.
- Recompletion of wells 1ER-98 and 1ER-99 into the A2 sands in mid 2015.
- Final phase is three additional wells to be drilled in 2015. These three wells are located to the West where the presence of pay is not proven and has been considered to be Contingent Resources.

Economics have been determined for these three phases and allow for Government Royalty, Petrotrin Overriding Royalty (ORR), Supplemental Petroleum Tax (SPT) and Operating Costs.

Reserves and Resources in South Erin attributable to RIH's indirectly owned subsidiary Caribbean Rex Ltd ("REX") as of 31st December 2013 are summarised in the following table. RIH has 64.17% ownership of REX.

Category	Gross Attributable to Licence (MMstb)	Net Attributable to RIH[1] (MMstb)	Change from Previous Update[2]	Remarks
Reserves				
	Oil Reserves			
1P	0.167	0.114	100%	*1P reserves are uneconomic*
2P	0.374	0.258	100%	*Includes Undeveloped Reserves*
3P	0.646	0.448	100%	*Includes Undeveloped Reserves*
Contingent Resources				
	Oil Contingent Resources			
1C	0.040	0.029	100%	*1C Resources are uneconomic*
2C	0.152	0.108	100%	*2C Resources are uneconomic*
3C	0.265	0.190	100%	*3C Resources are economic*

1. *Net Attributable is the net share of Reserves or Resources after the deduction of Government Royalty and Petrotrin Over-riding Royalty.*
2. *Rex International Holdings Ltd has 64.17% ownership of Caribbean Rex Ltd which has 100% ownership of Jasmin Oil and Gas Limited, after completion of the purchase of last 25% of the company.*
3. *South Erin Farm-out Block (Sub-Licence) acquired in 2013.*

Table 9.1: Summary of Reserves and Contingent Resources

The cases associated with the Phase 3 development are be classified as sub-marginal Contingent Resources according to Economic Status, The cashflows associated with the nine cases on a 100% gross WI basis are presented in Appendix 2 of the main report.

10. RECOMMENDATIONS

There are no recommendations following this report.

11. DATE AND SIGNATURE

At the request of Rex International Holding ("RIH"), RPS Energy ("RPS") has prepared an evaluation of selected oil Reserves and the net present values of those Reserves for South Erin Block , onshore Trinidad ("South Erin"), as of 31st December 2013.

The report was issued on 18th March 2014 and is signed on behalf of RPS Energy Consultants Limited by Gordon R. Taylor.

Gordon Taylor, C.Eng, C.Geol
Director, Head of Subsurface

APPENDIX 1: GLOSSARY OF TERMS AND ABBREVIATIONS

API	American Petroleum Institute
asl	above sea level
B	Billion
bbl(s)	Barrels
bbls/d	barrels per day
Bcm	billion cubic metres
B_g	gas formation volume factor
B_{gi}	gas formation volume factor (initial)
B_o	oil formation volume factor
B_{oi}	oil formation volume factor (initial)
B_w	water volume factor
bopd	barrels of oil per day
BTU	British Thermal Unit
Bscf	billions of standard cubic feet
bwpd	barrels of water per day
CO_2	Carbon dioxide
condensate	liquid hydrocarbons which are sometimes produced with natural gas and liquids derived from natural gas
cP	Centipoise
C_{ROCK}	rock compressibility
C_w	water compressibility
DBA	Decibels
E_a	areal sweep efficiency
EMV	Expected Monetary Value
EPSA	Exploration and Production Sharing Agreement
ESD	emergency shut down
EUR	Expected ultimate recovery
E_{vert}	vertical sweep efficiency
FBHP	flowing bottom hole pressure
FTHP	flowing tubing head pressure
ft	feet
ftSS	depth in feet below sea level
GDT	Gas Down To
GIP	Gas in Place
GIIP	Gas Initially in Place

GOR	gas/oil ratio
GRV	gross rock volume
GWC	gas water contact
H_2S	Hydrogen sulphide
HIC	hydrogen induced cracking
IRR	internal rate of return
KB	Kelly Bushing
k_a	absolute permeability
k_h	horizontal permeability
km	kilometres
km^2	square kilometres
kPa	kilopascals
k_r	relative permeability
k_{rg}	relative permeability of gas
k_{rgcl}	relative permeability of gas @ connate liquid saturation
k_{rog}	relative permeability of oil-gas
k_{roso}	relative permeability at residual oil saturation
k_{roswi}	relative permeability to oil @ connate water saturation
k_v	vertical permeability
LNG	Liquefied Natural Gases
LPG	Liquefied Petroleum Gases
M	thousand
MM	million
M$	thousand US dollars
MM$	million US dollars
MD	measured depth
mD	permeability in millidarcies
m^3	cubic metres
m^3/d	cubic metres per day
MMscf/d	millions of standard cubic feet per day
m/s	metres per second
msec	milliseconds
mV	millivolts
Mt	thousands of tonnes
MMt	millions of tonnes
MPa	mega pascals
NTG	net to gross ratio
NGL	Natural Gas Liquids

NPV	Net Present Value
OWC	oil water contact
P_b	bubble point pressure
P_c	capillary pressure
petroleum	deposits of oil and/or gas
phi	porosity fraction
p_i	initial reservoir pressure
PI	productivity index
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
p_{wf}	flowing bottom hole pressure
PVT	pressure volume temperature
rb	barrel(s) of oil at reservoir conditions
rcf	reservoir cubic feet
RFT	repeat formation tester
RKB	relative to kelly bushing
rm^3	reservoir cubic metres
SCADA	supervisory control and data acquisition
SCAL	Special Core Analysis
scf	standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	standard cubic feet per day
scf/stb	standard cubic feet per stock tank barrel
SGS	Sequential Gaussion Simulation
SIS	Sequential Indicator Simulation
sm^3	standard cubic metres
S_o	oil saturation
S_{or}	residual oil saturation
S_{orw}	residual oil saturation (waterflood)
S_{wc}	connate water saturation
S_{oi}	irreducible oil saturation
SSCC	sulphur stress corrosion cracking
stb	stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	stock tank barrels per day
STOIIP	stock tank oil initially in place

S_w	water saturation
$	United States Dollars
t	tonnes
THP	tubing head pressure
Tscf	trillion standard cubic feet
TVDSS	true vertical depth (sub-sea)
TVT	true vertical thickness
TWT	two-way time
US$	United States Dollar
V_{sh}	shale volume
W/m/K	watts/metre/° K
WC	water cut
WUT	Water Up To
ϕ	porosity
□	viscosity
□$_{gb}$	viscosity of gas
□$_{ob}$	viscosity of oil
□$_{w}$	viscosity of water

APPENDIX 2: SOUTH ERIN CASH-FLOWS

These cash flows are presented at 100 % gross WI basis

CASH FLOW SUMMARY SOUTH ERIN 1P DEVELOPED REX (Jasmin Oil & Gas Compan 100%

Year	Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
	stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
	0.01	**0.01**	**0**	**0.94**	**0.12**	**0.24**	**0.59**	**0.68**	**-**	**1.28**	**0.11**	**0.00**	**0.00**	**-1.47**	**-**	**-**	**-1.47**
2014	28	18	95.00	0.94	0.12	0.24	0.59	0.68	-	-	0.11	0.00	0.00	-0.20	-	-	-0.20
2015	-	-	89.49	-	-	-	-	-	-	1.28	-	-	-	-1.28	-	-	-1.28
2016	-	-	88.43	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	90.20	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	92.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	93.85	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	95.72	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	97.64	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	99.59	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	101.58	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	103.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	105.69	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	107.80	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub Total	0.01	0.01		0.94	0.12	0.24	0.59	0.68	-	1.28	0.11	0.00	0.00	-1.47	-	-	-1.47
Remaining																	
Total	**0.01**	**0.01**		**0.94**	**0.12**	**0.24**	**0.59**	**0.68**	**-**	**1.28**	**0.11**	**0.00**	**0.00**	**-1.47**	**-**	**-**	**-1.47**

CASH FLOW SUMMARY SOUTH ERIN 2P DEVELOPED REX (Jasmin Oil & Gas Compan 100%

Year	Company Net Production before Royalty & ORR stb/d	Company Net Production after Royalty & ORR stb/d	Oil Price WTI MM$	Company Field Revenues before Royalty & ORR MM$	Royalty MM$	PETROTRIN ORR MM$	Revenue after Royalties MM$	OPEX & G&A MM$	CAPEX MM$	ABEX MM$	SPT MM$	Green Fund Levy MM$	Petroleum Impost MM$	Company's Net Cashflow Before PPT Tax MM$	Petroleum Profits Tax MM$	Unemployment Levy MM$	Company's Net Cashflow After Tax MM$
	0.01	**0.01**	**0**	**1.26**	**0.16**	**0.32**	**0.79**	**0.68**	**-**	**1.28**	**0.14**	**0.00**	**0.00**	**-1.31**	**-**	**-**	**-1.31**
2014	38	24	95.00	1.26	0.16	0.32	0.79	0.68	-	-	0.14	0.00	0.00	-0.03	-	-	-0.03
2015	-	-	89.49	-	-	-	-	-	-	1.28	-	-	-	-1.28	-	-	-1.28
2016	-	-	88.43	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	90.20	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	92.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	93.85	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	95.72	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	97.64	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	99.59	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	101.58	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	103.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	105.69	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	107.80	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub Total	0.01	0.01		1.26	0.16	0.32	0.79	0.68	-	1.28	0.14	0.00	0.00	-1.31	-	-	-1.31
Remaining																	
Total	**0.01**	**0.01**		**1.26**	**0.16**	**0.32**	**0.79**	**0.68**	**-**	**1.28**	**0.14**	**0.00**	**0.00**	**-1.31**	**-**	**-**	**-1.31**

CASH FLOW SUMMARY SOUTH ERIN 3P DEVELOPED REX (Jasmin Oil & Gas Compan) 100%

Year	Company Net Production before Royalty & ORR stb/d	Company Net Production after Royalty & ORR stb/d	Oil Price WTI MM$	Company Field Revenues before Royalty & ORR MM$	Royalty MM$	PETROTRIN ORR MM$	Revenue after Royalties MM$	OPEX & G&A MM$	CAPEX MM$	ABEX MM$	SPT MM$	Green Fund Levy MM$	Petroleum Impost MM$	Company's Net Cashflow Before PPT Tax MM$	Petroleum Profits Tax MM$	Unemployment Levy MM$	Company's Net Cashflow After Tax MM$
	0.02	0.01	0	1.48	0.18	0.37	0.92	0.68	-	1.28	0.17	0.00	0.00	-1.20	-	0.00	-1.20
2014	44	28	95.00	1.48	0.18	0.37	0.92	0.68	-	-	0.17	0.00	0.00	0.08	-	0.00	0.07
2015	-	-	89.49	-	-	-	-	-	-	1.28	-	-	-	-1.28	-	-	-1.28
2016	-	-	88.43	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	90.20	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	92.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	93.85	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	95.72	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	97.64	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	99.59	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	101.58	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	103.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	105.69	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	107.80	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub Total	0.02	0.01		1.48	0.18	0.37	0.92	0.68	-	1.28	0.17	0.00	0.00	-1.20	-	0.00	-1.20
Remaining																	
Total	0.02	0.01		1.48	0.18	0.37	0.92	0.68	-	1.28	0.17	0.00	0.00	-1.20	-	0.00	-1.20

CASH FLOW SUMMARY SOUTH ERIN 1P DEVELOPED & UNDEVELOPED REX (Jasmin Oil & Gas Compan) 100%

Year	Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
	stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
	0.17	**0.11**	**0**	**14.62**	**1.83**	**2.84**	**9.96**	**3.25**	**7.29**	**2.00**	**0.51**	**0.01**	**0.01**	**-3.12**	**-**	**0.02**	**-3.14**
2014	158	108	95.00	5.26	0.66	1.02	3.58	0.80	7.09	-	-	0.01	0.00	-4.31	-	-	-4.31
2015	163	114	89.49	5.12	0.64	0.91	3.57	0.87	0.20	-	-	0.01	0.00	2.48	-	0.02	2.46
2016	87	58	88.43	2.69	0.34	0.55	1.81	0.82	-	-	0.33	0.00	0.00	0.66	-	-	0.66
2017	49	32	90.20	1.55	0.19	0.36	1.00	0.76	-	-	0.18	0.00	0.00	0.05	-	0.00	0.05
2018	-	-	92.01	-	-	-	-	-	-	2.00	-	-	-	-2.00	-	-	-2.00
2019	-	-	93.85	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	95.72	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	97.64	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	99.59	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	101.58	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	103.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	105.69	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	107.80	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub Total	0.17	0.11		14.62	1.83	2.84	9.96	3.25	7.29	2.00	0.51	0.01	0.01	-3.12	-	0.02	-3.14
Remaining																	
Total	**0.17**	**0.11**		**14.62**	**1.83**	**2.84**	**9.96**	**3.25**	**7.29**	**2.00**	**0.51**	**0.01**	**0.01**	**-3.12**	**-**	**0.02**	**-3.14**

CASH FLOW SUMMARY SOUTH ERIN 2P DEVELOPED & UNDEVELOPED REX (Jasmin Oil & Gas Compan) 100%

Year	Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
	stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
	0.37	**0.26**	**0**	**32.79**	**4.10**	**6.04**	**22.65**	**5.21**	**7.29**	**2.13**	**2.64**	**0.03**	**0.02**	**5.34**	**3.34**	**0.38**	**1.62**
2014	255	177	95.00	8.48	1.06	1.54	5.89	0.80	7.09	-	-	0.01	0.00	-2.01	0.36	0.08	-2.45
2015	319	226	89.49	9.99	1.25	1.65	7.10	0.87	0.20	-	0.89	0.01	0.01	5.11	1.55	0.15	3.41
2016	189	133	88.43	5.89	0.74	1.02	4.13	0.82	-	-	0.74	0.01	0.00	2.56	0.54	0.05	1.96
2017	106	72	90.20	3.34	0.42	0.64	2.28	0.76	-	-	0.41	0.00	0.00	1.10	0.53	0.05	0.52
2018	69	46	92.01	2.22	0.28	0.47	1.47	0.71	-	-	0.26	0.00	0.00	0.49	0.25	0.02	0.22
2019	49	31	93.85	1.62	0.20	0.40	1.01	0.65	-	-	0.18	0.00	0.00	0.17	0.09	0.01	0.08
2020	37	23	95.72	1.26	0.16	0.31	0.78	0.59	-	-	0.14	0.00	0.00	0.05	0.02	0.00	0.02
2021	-	-	97.64	-	-	-	-	-	-	2.13	-	-	-	-2.13	-	-	-2.13
2022	-	-	99.59	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	101.58	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	103.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	105.69	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	107.80	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub Total	0.37	0.26		32.79	4.10	6.04	22.65	5.21	7.29	2.13	2.64	0.03	0.02	5.34	3.34	0.38	1.62
Remaining																	
Total	**0.37**	**0.26**		**32.79**	**4.10**	**6.04**	**22.65**	**5.21**	**7.29**	**2.13**	**2.64**	**0.03**	**0.02**	**5.34**	**3.34**	**0.38**	**1.62**

CASH FLOW SUMMARY SOUTH ERIN 3P DEVELOPED & UNDEVELOPED REX (Jasmin Oil & Gas Compan 100%

Year	Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
	stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
	0.65	**0.45**	**0**	**57.13**	**7.14**	**10.42**	**39.57**	**7.57**	**7.29**	**2.35**	**5.74**	**0.06**	**0.03**	**16.54**	**9.06**	**0.95**	**6.53**
2014	362	254	95.00	12.06	1.51	2.11	8.44	0.80	7.09	-	0.12	0.01	0.01	0.42	1.58	0.20	-1.36
2015	500	358	89.49	15.67	1.96	2.50	11.21	0.87	0.20	-	1.98	0.02	0.01	8.14	3.06	0.31	4.77
2016	311	221	88.43	9.67	1.21	1.59	6.87	0.82	-	-	1.24	0.01	0.01	4.80	1.67	0.17	2.97
2017	171	119	90.20	5.40	0.68	0.95	3.77	0.76	-	-	0.68	0.01	0.00	2.32	1.14	0.11	1.06
2018	111	76	92.01	3.56	0.45	0.68	2.44	0.71	-	-	0.44	0.00	0.00	1.29	0.65	0.06	0.58
2019	79	52	93.85	2.59	0.32	0.57	1.69	0.65	-	-	0.31	0.00	0.00	0.73	0.37	0.04	0.33
2020	60	38	95.72	2.02	0.25	0.48	1.29	0.59	-	-	0.24	0.00	0.00	0.45	0.23	0.02	0.20
2021	48	30	97.64	1.64	0.21	0.41	1.03	0.53	-	-	0.19	0.00	0.00	0.30	0.15	0.01	0.13
2022	39	25	99.59	1.37	0.17	0.34	0.86	0.47	-	-	0.16	0.00	0.00	0.22	0.11	0.01	0.10
2023	33	21	101.58	1.18	0.15	0.29	0.74	0.44	-	-	0.14	0.00	0.00	0.15	0.07	0.01	0.07
2024	28	18	103.61	1.04	0.13	0.26	0.65	0.45	-	-	0.13	0.00	0.00	0.07	0.03	0.00	0.03
2025	25	16	105.69	0.92	0.12	0.23	0.58	0.46	-	-	0.12	0.00	0.00	-0.00	-	-	-0.00
2026	-	-	107.80	-	-	-	-	-	-	2.35	-	-	-	-2.35	-	-	-2.35
Sub Total	0.65	0.45		57.13	7.14	10.42	39.57	7.57	7.29	2.35	5.74	0.06	0.03	16.54	9.06	0.95	6.53
Remaining																	
Total	**0.65**	**0.45**		**57.13**	**7.14**	**10.42**	**39.57**	**7.57**	**7.29**	**2.35**	**5.74**	**0.06**	**0.03**	**16.54**	**9.06**	**0.95**	**6.53**

CASH FLOW SUMMARY SOUTH ERIN 1C CONTINGENT RESOURCES REX (Jasmin Oil & Gas Compan) 100%

Year	Company Net Production before Royalty & ORR stb/d	Company Net Production after Royalty & ORR stb/d	Oil Price WTI MM$	Company Field Revenues before Royalty & ORR MM$	Royalty MM$	PETROTRIN ORR MM$	Revenue after Royalties MM$	OPEX & G&A MM$	CAPEX MM$	ABEX MM$	SPT MM$	Green Fund Levy MM$	Petroleum Impost MM$	Company's Net Cashflow Before PPT Tax MM$	Petroleum Profits Tax MM$	Unemployment Levy MM$	Company's Net Cashflow After Tax MM$
	0.04	**0.03**	**0**	**3.43**	**0.43**	**0.53**	**2.47**	**0.40**	**5.42**	**1.03**	**-0.04**	**0.00**	**0.00**	**-4.35**	**-**	**-0.02**	**-4.32**
2014	-	-	95.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	89.49	-	-	-	-	-	5.42	-	-	-	-	-5.42	-	-0.02	-5.40
2016	79	57	88.43	2.44	0.31	0.37	1.77	0.21	-	-	-0.16	0.00	0.00	1.72	-	-	1.72
2017	31	22	90.20	0.98	0.12	0.17	0.70	0.19	-	-	0.13	0.00	0.00	0.38	-	-0.00	0.38
2018	-	-	92.01	-	-	-	-	-	-	1.03	-	-	-	-1.03	-	-	-1.03
2019	-	-	93.85	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	95.72	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	97.64	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	99.59	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	101.58	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	103.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	105.69	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	107.80	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub Total	0.04	0.03		3.43	0.43	0.53	2.47	0.40	5.42	1.03	-0.04	0.00	0.00	-4.35	-	-0.02	-4.32
Remaining																	
Total	**0.04**	**0.03**		**3.43**	**0.43**	**0.53**	**2.47**	**0.40**	**5.42**	**1.03**	**-0.04**	**0.00**	**0.00**	**-4.35**	**-**	**-0.02**	**-4.32**

CASH FLOW SUMMARY SOUTH ERIN 2C CONTINGENT RESOURCES REX (Jasmin Oil & Gas Company 100%

Year	Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
	stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
	0.53	**0.37**	**0**	**13.21**	**1.65**	**2.20**	**9.36**	**1.58**	**5.42**	**1.16**	**0.80**	**0.01**	**0.01**	**0.38**	**0.78**	**0.08**	**-0.47**
2014	-	-	95.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	89.49	-	-	-	-	-	5.42	-	-0.89	-	-	-4.53	-0.91	-0.09	-3.53
2016	203	147	88.43	6.31	0.79	0.95	4.57	0.21	-	-	0.82	0.01	0.00	3.53	0.96	0.10	2.48
2017	81	58	90.20	2.55	0.32	0.38	1.85	0.19	-	-	0.33	0.00	0.00	1.32	0.12	0.01	1.19
2018	43	31	92.01	1.39	0.17	0.21	1.01	0.17	-	-	0.18	0.00	0.00	0.65	0.33	0.03	0.29
2019	27	19	93.85	0.88	0.11	0.16	0.62	0.17	-	-	0.11	0.00	0.00	0.34	0.17	0.02	0.15
2020	18	12	95.72	0.62	0.08	0.14	0.39	0.16	-	-	0.07	0.00	0.00	0.16	0.08	0.01	0.07
2021	43	27	97.64	1.47	0.18	0.37	0.92	0.68	-	-2.13	0.17	0.00	0.00	2.18	0.03	0.00	2.15
2022	-	-	99.59	-	-	-	-	-	-	3.28	-	-	-	-3.28	-	-	-3.28
2023	-	-	101.58	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	103.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	105.69	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	107.80	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sub Total	0.15	0.11		13.21	1.65	2.20	9.36	1.58	5.42	1.16	0.80	0.01	0.01	0.38	0.78	0.08	-0.47
Remaining																	
Total	**0.15**	**0.11**		**13.21**	**1.65**	**2.20**	**9.36**	**1.58**	**5.42**	**1.16**	**0.80**	**0.01**	**0.01**	**0.38**	**0.78**	**0.08**	**-0.47**

CASH FLOW SUMMARY | SOUTH ERIN | 3C CONTINGENT RESOURCES | REX (Jasmin Oil & Gas Compan | 100%

Year	Company Net Production before Royalty & ORR	Company Net Production after Royalty & ORR	Oil Price WTI	Company Field Revenues before Royalty & ORR	Royalty	PETROTRIN ORR	Revenue after Royalties	OPEX & G&A	CAPEX	ABEX	SPT	Green Fund Levy	Petroleum Impost	Company's Net Cashflow Before PPT Tax	Petroleum Profits Tax	Unemployment Levy	Company's Net Cashflow After Tax
	stb/d	stb/d	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$	MM$
	0.27	**0.19**		**23.20**	**2.90**	**3.69**	**16.61**	**1.62**	**5.42**	**1.20**	**1.93**	**0.02**	**0.01**	**6.39**	**3.81**	**0.38**	**2.20**
2014	-	-	95.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	89.49	-	-	-	-	-	5.42	-	-1.08	-	-	-4.34	-0.81	-0.08	-3.44
2016	355	257	88.43	11.03	1.38	1.65	8.00	0.21	-	-	1.44	0.01	0.01	6.33	2.36	0.24	3.74
2017	141	102	90.20	4.45	0.56	0.67	3.23	0.19	-	-	0.58	0.00	0.00	2.45	0.68	0.07	1.70
2018	75	55	92.01	2.43	0.30	0.36	1.76	0.17	-	-	0.32	0.00	0.00	1.27	0.64	0.06	0.57
2019	47	34	93.85	1.55	0.19	0.25	1.11	0.17	-	-	0.20	0.00	0.00	0.74	0.37	0.04	0.33
2020	32	23	95.72	1.08	0.13	0.17	0.77	0.16	-	-	0.14	0.00	0.00	0.47	0.24	0.02	0.21
2021	23	16	97.64	0.80	0.10	0.14	0.56	0.15	-	-	0.10	0.00	0.00	0.30	0.15	0.02	0.14
2022	18	12	99.59	0.62	0.08	0.13	0.41	0.14	-	-	0.08	0.00	0.00	0.19	0.09	0.01	0.08
2023	14	9	101.58	0.50	0.06	0.12	0.31	0.14	-	-	0.06	0.00	0.00	0.10	0.05	0.01	0.05
2024	11	7	103.61	0.41	0.05	0.10	0.25	0.15	-	-	0.05	0.00	0.00	0.06	0.03	0.00	0.03
2025	9	6	105.69	0.34	0.04	0.09	0.21	0.15	-	-	0.04	0.00	0.00	0.02	0.01	0.00	0.01
2026	-	-	107.80	-	-	-	-	-	-	1.20	-	-	-	-1.20	-	-	-1.20
Sub Total	0.27	0.19		23.20	2.90	3.69	16.61	1.62	5.42	1.20	1.93	0.02	0.01	6.39	3.81	0.38	2.20
Remaining																	
Total	**0.27**	**0.19**		**23.20**	**2.90**	**3.69**	**16.61**	**1.62**	**5.42**	**1.20**	**1.93**	**0.02**	**0.01**	**6.39**	**3.81**	**0.38**	**2.20**