01 January – 31 March 2017

Q1 Report

Highlights

- 8 wells drilled offshore Senegal to date with 100% success rate
- SNE oil field appraisal wells SNE-5 and VR-1 successfully completed, under budget and safely
- SNE-6 appraisal well drilled to TD and operations continue including extended flow testing
- Increase on prospective resource estimates for Senegal estimated at 1.5 billion barrels*
- 2016 Annual report to shareholders released
- Farm-in to 80% of blocks A2/A5 offshore The Gambia on trend with SNE Field offshore Senegal
- Area of Mutual interest agreement executed with CNOOC UK
- Cash at 31 March $35.3M
- Fully underwritten placement of shares to raise $80M post end of quarter

Projects update

Offshore Senegal

Drilling commenced on the third drilling campaign offshore Senegal for the Rufisque, Sangomar and Sangomar Deep (RSSD) blocks which house the world class SNE oil field, discovered in November 2014. The Stena DrillMAX deep water drill ship was contracted in the December quarter of 2016 to undertake the new drilling and evaluation program that was planned to consist of two wells (SNE-5 and SNE-6) located in the southern area of the SNE oil field.

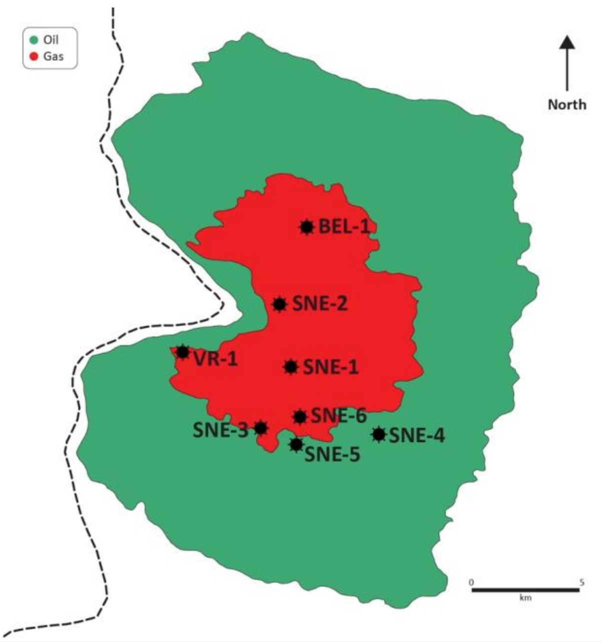

Figure 1: SNE Field wells locations

The SNE-5 well location is shown in Figure 1. The well was successfully drilled, logged and drill stem tested (DST) ahead of budget, within expectations and safely.

The objective of the SNE-5 well was to evaluate and flow oil from two principal units in the upper reservoirs that are within the oil leg at this location.

Oil flow rates recorded from these upper reservoir units were in line with or exceeded expectations. The S460 upper reservoir unit that was identified but not tested in previous wells flowed better than expected in SNE-5.

The SNE-5 well results show a good correlation with previous SNE wells and provide further evidence of the large extent of the SNE field, the material contribution of the upper reservoir units to the SNE oil resource volumes and the ability to produce from the upper reservoir units at commercially viable rates.

The SNE-5 results are consistent with the sand distribution models of the SNE upper reservoirs and give further confidence in the ability to optimally locate and design development wells.

Detailed analysis of the extensive dataset collected from the SNE-5 well is continuing with initial results as follows:

- Two drill stem tests (DST) were conducted within the upper reservoirs, confirming confidence in the deliverability of these units.
    - DST 1a: 18m zone in the S480 reservoir, flowed at a maximum rate 4,500 bopd, stabilized rate 2,500 bopd on 40/64" choke, and 3,000 bopd on 56/64" choke – 24 hour each test. This flow rate was better than the flow rate achieved from the same reservoir in the SNE-3 well.
    - DST 1b: an additional, and previously untested S460 reservoir section of 8.5m was comingled with the 1a DST to deliver a maximum flow rate 4,200 bopd, average stabilised rate 3,900 bopd on 64/64" choke, above expectations for this interval.
- Multiple samples of oil, gas and water were collected from the well which were consistent with samples taken from all other SNE wells
- Depths to the reservoirs, depth to gas oil contact (GOC) and oil water contact (OWC) were on prognosis
- Confirmation of reservoir quality and correlation of the principal reservoir units
- Oil column thickness confirmed at 100m gross, as seen at all other SNE oil field wells to date.

Prior to SNE-5 being plugged and abandoned, pressure gauges were installed over the tested reservoir units in preparation for the planned SNE-6 well and completion of an interference test. The interference test will provide information on the connectivity of the upper reservoirs which will aid with optimising an SNE field development plan and capital expenditure for the development of the field.

Before drilling the SNE-6 well (location as per figures 1 and 2) and completing an interference test, the Stena DrillMAX drillship was moved to the VR-1 location, approximately 5 km to the west of the SNE-1 discovery (as shown in Figures 1 and 2).

Drilling operations on the VR-1 well offshore Senegal reached a depth of 2759m, wireline logging and sampling through the SNE section were completed and the well was deepened into the Aptian carbonate objectives below the SNE field.

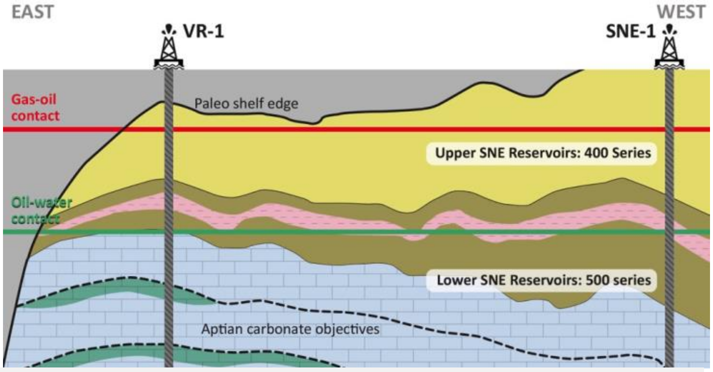

Figure 2: Cross section showing the geological setting for the VR-1 well versus the SNE-1 well

FAR's evaluation of the well results are as follows:

- The SNE reservoir units were in oil as prognosed
- The lower, 500 series 520 reservoir (16m in oil), a key reservoir to the phase 1 development of

* Refer to Cautionary Statement in this report (page 10) relating to estimates of prospective and contingent resources

the SNE field, exhibited excellent reservoir properties, superior to all other reservoirs sampled in the SNE field to date

- The deeper 540 reservoir (11m in oil) has only been seen in the SNE-2 well in oil (2m)
- Samples of oil have been taken
- Along with other appraisal wells, the well confirmed a 97m gross oil column with greater than expected net pay and thickest net pay of all appraisal wells drilled to date
- Hydrocarbon indications, including evidence of oil were encountered after deepening VR-1 to a total depth of 3,899m into a secondary exploration target in the Aptian carbonate section however, this was not of commercial significance

FAR anticipates that the results of the VR-1 well, together with the recent SNE-5 results will lead to a revision of contingent resource estimate for the SNE field and have an impact on design of the development plan in the coming months. The 1C resource is currently 348mmbbls* (gross, unrisked, ref ASX announcement 23 August 2016) compared to the minimum economic field size for the SNE field of 200mmbbls.

SNE-6, the third well in the 2017 campaign was drilled on a back to back basis following the completion of operations in the VR-1 well. In events post the end of the quarter, FAR announced the successful drilling of the well to TD and commencement of wireline logging operations and drill stem testing before the extended flow testing to complete the interference test program aimed at providing important information about the connectivity of the upper 400 series reservoirs across the SNE field. On completion of SNE-6, the joint venture will then drill the FAN South-1 well into the South Fan prospect assessed by FAR to contain 134 mmbbls of recoverable prospective resources*. The FAN South-1 well will be the first pure exploration well to be drilled in the RSSD acreage since the basin opening discovery wells of FAN-1 and SNE-1 in late 2014. The location of the FAN South-1 well can be seen in Figure 3.

Increase in prospective resource inventory

During the quarter, FAR released its assessment of the offshore Senegal prospect inventory following delivery of final 3D seismic products from the 2,400km² survey over the RSSD blocks and the 400km² survey over the Djiffere block in Q4 of 2016.

Four main Senegal exploration plays were identified based in the RSSD Shelf and Basin areas.

- The **Early Cretaceous Albian Shelf Play** houses the SNE oil field. The Sirius and Spica prospects are analogous to the SNE oil field and are located along the shelf edge trend to north of SNE.
- The **Albian Fan Play.**
- The **Late Cretaceous Shelf Play.**
- Central FAN and South Fan are **Late Cretaceous Basin canyon** fed slope plays.

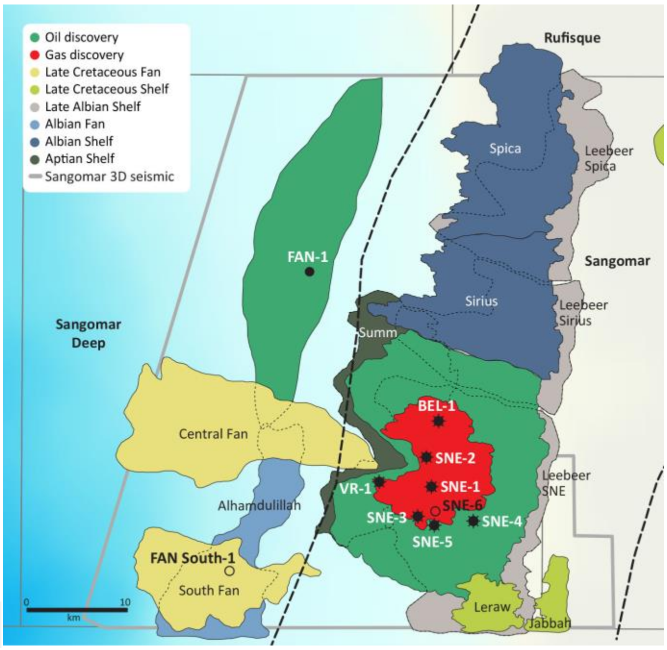

Figure 3. FAR prospect inventory offshore Senegal

* Refer to Cautionary Statement in this report (page 10) relating to estimates of prospective and contingent resources

Figure 3 shows prospect outlines and play types. This figure also highlights several Senegal prospects that are located within tieback range (Operator: 30 – 40km radius) to an SNE production hub and they could have a significant positive impact on the size, scope and future returns generated from the SNE project development.

The prospective resource assessment was completed by RISC Operations Pty Ltd ("RISC") and set out in its Independent Resources Report highlights that FAR has, "a material and robust exploration portfolio, which we expect will be tested in coming years".

The prospective resource estimates detailed in Table 1 are set out in RISC's report and assess the probabilistic resource evaluation carried out by FAR in accordance with industry standard SPE-PRMS definitions.

Table 1: Senegal prospective resources

Prospect name	Play type	Prospective, gross, unrisked recoverable oil resources* Best estimate (P50) mmbbls	Probability of success %
Sirius	Albian shelf edge	294	60%
Spica	Albian shelf edge	199	37%
Leebeer SNE	Late Albian shelf	116	33%
Leebeer Sirius	Late Albian shelf	50	20%
Leebeer Spica	Late Albian shelf	47	20%
Rufisque Onlap	Albian	181	14%
Alhamdulillah	Albian Fan	80	23%
Leraw	Cenomanian	108	23%
Jabbah	Cenomanian	44	25%
Jabbah Deep	Cenomanian	111	16%
South Fan	Cretaceous Fan	134	18%
Central Fan	Cretaceous Fan	96	17%
Total all prospects		1,460	
Suum Lead(1)	Aptian Carbonate Shelf	103	
Total prospects and leads		**1,563**	
Total – net to FAR		**234**	

(i) Not audited by RISC

ConocoPhillips Senegal proposed asset sale

As reported in prior public statements by ConocoPhillips and Woodside, completion of the proposed sale of ConocoPhillips Senegal assets is subject to the rights of partners to pre-empt and Senegal Government approval.

As previously reported, FAR believes a valid pre-emptive rights notice has not been issued to the Senegal joint venture parents by ConocoPhillips, and FAR has invoked its right to resolve this dispute in accordance with the Joint Operating Agreement. At the date of this report, the matter remains unresolved.

* Refer to Cautionary Statement in this report (page 10) relating to estimates of prospective and contingent resources

Rufisque, Sangomar, Sangomar Deep	Participating Interest	Paying Interest
FAR	**15%**	**16.67%**
Cairn Energy	40% Operator	44.44%
ConocoPhillips*	35%	38.89%
Petrosen	10%	-

*The proposed sale to Woodside is subject to the rights of partners to pre-empt and Senegal Government approval

Djiffere block option

No update from previous quarter.

The Gambia

During the quarter, FAR expanded its exploration portfolio in the rapidly emerging offshore Mauritania-Senegal-Guinea-Bissau Basin in West Africa through a farm-in deal with US based oil and gas company, ERIN Energy Corporation.

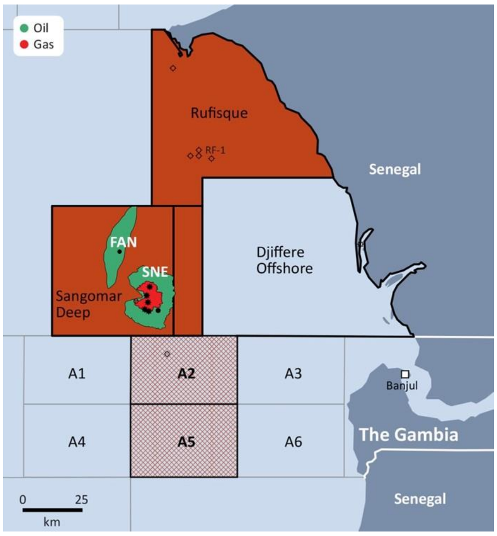

Figure 4: Blocks A2 / A5, The Gambia location

Meridian Minerals Limited ("Meridian"), a wholly owned subsidiary of FAR, will acquire an 80% interest and Operatorship of offshore Blocks A2 and A5 in The Gambia from the New York and Johannesburg Stock Exchange listed ERIN Energy Corporation (location shown in Figure 4).

The farm-in, which remains subject to approval by the Government of The Gambia, requires FAR to fund ERIN up to US$8 million through an exploration well expected to be drilled late in 2018.

Blocks A2 and A5 are adjacent to and on trend with FAR's world class SNE oil field discovery and have significant exploration potential. The blocks cover an area of approximately 2,682km^2 within the rapidly emerging and prolific Mauritania-Senegal-Guinea-Bissau ("MSGB") Basin. The blocks lie approximately 30km offshore in water depths ranging from 50 to 1,200 meters.

In combination, Blocks A2 and A5 have potential to contain prospective resources in excess of one billion barrels of oil (on an unrisked, best estimate, 100% basis*).

From 1,504 km^2 of modern 3D seismic data acquired in the blocks, FAR has identified large prospects similar to the "shelf edge" plays FAR is targeting in Senegal (see Figure 5). FAR has mapped three potentially drillable prospects and leads.

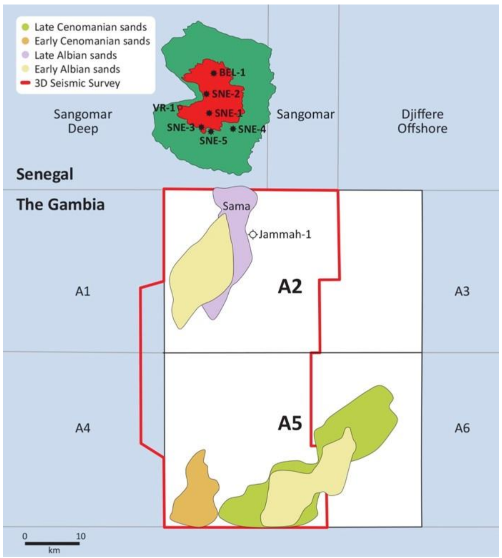

Figure 5: Blocks A2/A5 prospects and leads in relation to SNE field

* Refer to Cautionary Statement in this report (page 10) relating to estimates of prospective and contingent resources

FAR and ERIN expect to undertake 3D seismic reprocessing and interpretation during 2017 in order to mature prospects for drilling in late 2018.

Under the terms of the farm-in agreement, Meridian is to acquire an 80% working interest and become the Operator by making an upfront payment of US$5.18 million and funding up to US$8.0 million of ERIN's share of the cost of an exploration well. If ERIN's share of the exploration well costs is less than US$8.0 million then the balance is to be paid in cash. FAR's share of the cost of the exploration well is expected to be in the order of US$25.0 to US$30.0 million. ERIN will retain a 20% working interest in Blocks A2 and A5.

Under the terms of the agreement, the well to be funded by FAR can be carried out in either Block A2 or Block A5 before 31 December 2018 or such later date if the current licence periods are extended.

Guinea-Bissau

Negotiations have concluded with the National oil company of Guinea-Bissau, Petroguin, to revise the terms of both the Sinapa and Esperanca Licences to which FAR has interests.

Under the revised Licence terms negotiated by FAR and its joint venture partner Svenska Petroleum Exploration AB ("Svenska"), FAR will now have a 21.42% participating and paying interest in the permits, an increase from the 15% participating and 21.42% paying interests as previously reported. These changes reflect the fact that Petroguin will no longer have a participating interest in the joint venture prior to a commercial discovery. Upon making a commercial discovery, Petroguin will have a reduced participating and paying interest of 10% and FAR and Svenska will respectively have interests of 19.28% and 70.71%.

In addition the new Licence terms negotiated include more favourable arrangements for deep water investment including a reduction to production royalty rates payable to Government.

These changes to Licence terms are consistent with the joint venture's new strategy to focus on the shelf edge areas of the Sinapa and Esperanca Licences which display a similar geological setting to offshore Senegal and FAR's enormous SNE field discovery.

In recognition of this new strategy and to provide adequate time to further evaluate the newly acquired 3D seismic data offshore Guinea Bissau, the joint venture has been awarded a three-year extension to the current Licence periods, now ending on 25 November 2020.

During these Licence periods the work obligation is to drill one exploration well on each Licence with a minimum expenditure commitment for each Licence of US$3 million (gross).

These changes in the terms of the Licences have been agreed and signed by Petroguin and remain subject to Government Decree.

Block 2, 4A, and 5A	Participating and Paying Interest
FAR	**21.43%**
Svenska	78.57% Operator

* Refer to Cautionary Statement in this report (page 10) relating to estimates of prospective and contingent resources

Kenya

No update from previous quarter

Kenya Block L6	Participating and Paying Interest Onshore	Participating and Paying Interest Offshore
FAR	**24% Operator**(i)	**60% Operator**
Pancontinental Oil and Gas	16%	40%
Milio Group	60%(i)	

(i) **Subject to the completion of the farm-out agreement with Milio.**

Australia

No update from previous quarter

WA-457-P, WA-458-P	Participating and Paying Interest
FAR	**100% Operator**

Area of Mutual Interest Agreement (AMI) with CNOOC UK

During the quarter, FAR signed an Area of Mutual Interest (AMI) agreement with CNOOC UK Limited ("CNOOC UK"). The AMI covers selected licences offshore Senegal and The Gambia within the designated area (refer to Figure 6).

The AMI provides FAR and CNOOC UK with agreed arrangements to partner in evaluating, bidding, negotiating and managing joint ventures on farm-in and open acreage opportunities for oil and gas licences. The AMI agreement period is for two years.

In combination, FAR and CNOOC UK bring together expertise of the Mauritania-Senegal-Guinea-Bissau (MSGB) offshore basin and the capabilities of an international deep water operator.

FAR and CNOOC UK are committed to building long-term strategic relationships with the host Governments of Senegal and The Gambia and their people. This agreement positions FAR to further expand its portfolio and establish itself as one of the major players in the rapidly emerging MSGB Basin – a basin that is increasingly attracting the attention of the world's oil "majors".

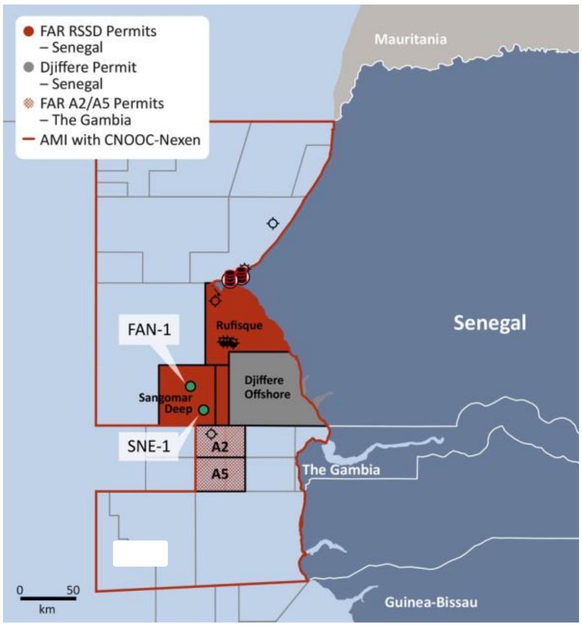

Figure 6: FAR-CNOOC Area of Mutual Interest

CNOOC UK Limited is a subsidiary of CNOOC Limited which (together with its subsidiaries) is the largest producer of offshore crude oil and natural gas in China and one of the largest independent oil and gas exploration and production companies in the world.

* Refer to Cautionary Statement in this report (page 10) relating to estimates of prospective and contingent resources

Management comment and events post end of the quarter

It has been a very eventful first quarter of the year for FAR. A number of initiatives that the Company has been working on for many months have come to fruition and it has been pleasing to bring this good news to our shareholders.

The farm-in to blocks A2 and A5 offshore The Gambia is very important to FAR as we have secured highly prospective acreage adjacent to and on trend with the SNE field offshore Senegal. The significant prospectivity we have identified in Blocks A2 and A5 is in analogous play types to those that FAR has successfully drilled in Senegal.

The 80% working interest and operating rights that FAR has secured by this farm-in provides the company with an exceptional opportunity to add significant shareholder value through near term exploration drilling success with a well to be drilled before the end of 2018. FAR aims to bring in a partner in the coming months to share in these drilling costs.

The AMI with CNOOC UK is also a very important milestone for our company as we aim to grow our portfolio of assets in our strategic area of focus – the MSGB (Mauritania-Senegal-Guinea-Bissau) basin offshore NW Africa, following the discovery of the SNE oil field offshore Senegal.

The complementary skills of both organisations strengthens our collective ability to build acreage positions offshore Senegal and The Gambia and we are very pleased to have secured a strategic partner with the deep technical, operational and financial calibre of CNOOC UK.

The drilling program which began in late January is the latest step in the process to prove that the SNE oil field discovery is one of the world's best discoveries of recent years. The wells drilled to date in this 2017 campaign, the third offshore Senegal, have all been completed successfully, ahead of budget and safely which is an incredible achievement and very pleasing for the joint venture. Because of the drilling efficiencies, the joint venture was able to include an additional well into the 2 planned wells in this campaign. As well as the SNE-5 and SNE-6 appraisal wells, the JV drilled the VR-1 well, an additional appraisal well drilled to the west of the SNE field, which was deepened to examine the Aptian carbonate lead (FAR Suum lead) lying beneath the SNE field. This Suum lead carried a low chance of success and although hydrocarbons were encountered in Suum, the volumes were not commercially significant. Importantly however, the primary objective of the VR-1 well was to evaluate the SNE reservoirs to the west of the field and this was successful. As a result, the JV has now drilled 8 wells offshore Senegal with a 100% success rate and we move closer to completing the appraisal of the SNE field and progressing with development planning.

The wells drilled to date will contribute to a revision of the contingent resource estimates for the SNE Field that FAR looks forward to releasing following the integration of the SNE-5, VR-1 and SNE-6 well results.

As the quarter closed, the SNE-6 well was spudded and subsequently FAR has announced that the well has reached TD and operations are continuing.

In an exciting move, the JV has agreed to drill a fourth well in the campaign and the first pure exploration well to be drilled since the two discovery wells – FAN-1 and SNE-1 – in late 2014. The FAN South-1 well will be drilled on a back to back basis with SNE-6 and will be drilling a 134mmbbl prospect (best estimate, gross, prospective resources).*

FAR finished the quarter with $35.3M in cash and no debt. This balance exceeds our forecast at the end of the last quarter primarily due to the delay in expected start-up of drilling operations and the efficiencies seen in the drilling program.

FAR's cash position has been significantly boosted following the raise of $80M before costs in a fully underwritten placement to institutional and sophisticated investors shortly following the end of the quarter. The placement was heavily oversubscribed with strong support by existing shareholders and the introduction of new institutional investors to FAR's register, one of whom has become a substantial

* Refer to Cautionary Statement in this report (page 10) relating to estimates of prospective and contingent resources

shareholder.

The placement was at 8.0 cents per share which represented a 4.8% discount to FAR's last close share price on 4 April 2017 of 8.4 cents and a 3.5% discount to the volume weighted average share price for the 5 trading days prior to this date.

As announced on Thursday, 6 April 2017, the new shares will be issued in two tranches, the first raised approximately $54M (before costs) and the second tranche for the balance of approximately $26M (before costs) is subject to shareholder approval to be voted on by shareholders at a General Meeting, to be held on Monday, 15 May 2017.

Following the success of this placement, the cash balance after the first tranche is approximately $84M with a further $26M (before fees) anticipated to be received from the second tranche in May subject to shareholder approval at the EGM to be held on 15 May.

Credit Suisse is acting as Financial Adviser to FAR, and the Placement was underwritten by Credit Suisse and RBC Capital Markets as Joint Lead Managers.

The highly successful placement has allowed FAR to focus on continuing to build value for our shareholders as FAR is now in a strong funding position through the balance of the Company's 2017 commitments and through to the final investment decision for the development of the SNE field, expected in early 2019.

FAR is particularly pleased that the offer was substantially oversubscribed especially at the modest discount offered. It is testimony to the value that is yet to be unlocked in FAR that we have been able to raise this quantum of money in what is still a tough market for oil companies.

As at the date of writing, there is no update for shareholders regarding FAR's right to pre-empt the sale of the ConocoPhillips 35% share of the Senegal RSSD project via sale of the ConocoPhillips Senegal BV entity.

FAR looks forward to bringing our shareholders the results of the drilling offshore Senegal in the coming weeks and holding the EGM to approve the second tranche of the placement on 15 May and the AGM on 29 May. Because our AGM is two weeks after the EGM, we do not plan to have a presentation at the EGM but welcome our shareholders to attend the AGM to be held in Melbourne (please revert to our website for further details www.far.com.au).

Disclaimers

***Prospective Resource Estimates Cautionary Statement** - With respect to the prospective resource estimates contained within this report, it should be noted that the estimated quantities of Petroleum that may potentially be recovered by the future application of a development project may relate to undiscovered accumulations. These estimates have an associated risk of discovery and risk of development. Further exploration and appraisal is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.*

***Prospective and Contingent Resources** - All contingent and prospective resource estimates presented in this report are prepared as at 27/2/2013, 11/3/2014, 5/2/2014, 13/04/2015, 13/4/2016, 23/08/2016 and 7/2/2017 (Reference: FAR ASX releases of the same dates). The estimates have been prepared by the Company in accordance with the definitions and guidelines set forth in the Petroleum Resources Management System, 2007 approved by the Society of Petroleum Engineers and have been prepared using probabilistic methods. The contingent resource estimates provided in this report are those quantities of petroleum to be potentially recoverable from known accumulations, but the project is not considered mature enough for commercial development due to one or more contingencies. The prospective resource estimates provided in this report are Best Estimates and represent that there is a 50% probability that the actual resource volume will be in excess of the amounts reported. The estimates are unrisked and have not been adjusted for both an associated chance of discovery and a chance of development. The 100% basis and net to FAR contingent and prospective resource estimates include Government share of production applicable under the Production Sharing Contract.*

***Competent Person Statement Information** - The hydrocarbon resource estimates in this report have been compiled by Peter Nicholls, the FAR Limited exploration manager. Mr Nicholls has over 30 years of experience in petroleum geophysics and geology and is a member of the American Association of Petroleum Geology, the Society of Petroleum Engineers and the Petroleum Exploration Society of Australia. Mr Nicholls consents to the inclusion of the information in this report relating to hydrocarbon Contingent and Prospective Resources in the form and context in which it appears. The Contingent and Prospective Resource estimates contained in this report are in accordance with the standard definitions set out by the Society of Petroleum Engineers, Petroleum Resource Management System.*

***Forward looking statements** - This document may include forward looking statements. Forward looking statements include, are not necessarily limited to, statements concerning FAR's planned operation program and other statements that are not historic facts. When used in this document, the words such as "could", "plan", "estimate", "expect", "intend", "may", "potential", "should" and similar expressions are forward looking statements. Although FAR Ltd believes its expectations reflected in these are reasonable, such statements involve risks and uncertainties, and no assurance can be given that actual results will be consistent with these forward looking statements. The entity confirms that it is not aware of any new information or data that materially affects the information included in this announcement and that all material assumptions and technical parameters underpinning this announcement continue to apply and have not materially changed.*

Top 20 shareholders (as at 27 April 2017)

	Shareholder	Units	%
1.	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED	641,272,704	12.50
2.	CITICORP NOMINEES PTY LIMITED	603,994,909	11.77
3.	FARJOY PTY LTD	451,963,236	8.81
4.	J P MORGAN NOMINEES AUSTRALIA LIMITED	332,113,364	6.47
5.	BNP PARIBAS NOMS PTY LTD	92,687,685	1.81
6.	MR REX SEAGER HARBOUR	77,782,423	1.52
7.	MR OLIVER LENNOX-KING	75,647,869	1.47
8.	TOAD FACILITIES PTY LTD	67,528,589	1.32
9.	NATIONAL NOMINEES LIMITED	64,787,452	1.26
10.	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED - A/C 2	43,533,352	0.85
11.	FOUNTAIN OAKS PTY LTD	34,200,366	0.67
12.	CS FOURTH NOMINEES PTY LIMITED	28,970,147	0.56
13.	FLOTECK CONSULTANTS LIMITED	28,000,000	0.55
14.	RC CAPITAL INVESTMENTS PTY LTD	22,833,760	0.45
15.	MR BENEDICT CLUBE	22,000,000	0.43
16.	MR JOHN DANIEL POWELL	20,046,777	0.39
17.	N & P SUPERANNUATION PTY LIMITED	18,988,839	0.37
18.	MS CATHERINE NORMAN	18,065,883	0.35
19.	KALAN SEVEN PTY LTD	17,300,000	0.34
20.	BNP PARABAS NOMINEES PTY LTDC	15,880,264	0.31
	TOTAL	**2,677,597,619**	**52.19**

+Rule 5.5

Appendix 5B

Mining exploration entity and oil and gas exploration entity quarterly report

Introduced 01/07/96 Origin Appendix 8 Amended 01/07/97, 01/07/98, 30/09/01, 01/06/10, 17/12/10, 01/05/13, 01/09/16

Name of entity

FAR Ltd

ABN	**Quarter ended ("current quarter")**
41 009 117 293	31 March 2017

Consolidated statement of cash flows		**Current quarter $A'000**	**Year to date (3 months) $A'000**
1.	**Cash flows from operating activities**		
1.1	Receipts from customers	-	-
1.2	Payments for		
	(a) exploration & evaluation	(2,910)	(2,910)
	(b) development	-	-
	(c) production	-	-
	(d) staff costs	(867)	(867)
	(e) administration and corporate costs	(383)	(383)
1.3	Dividends received (see note 3)	-	-
1.4	Interest received	27	27
1.5	Interest and other costs of finance paid	-	-
1.6	Income taxes paid	-	-
1.7	Research and development refunds	-	-
1.8	Other (provide details if material)	-	-
1.9	**Net cash from / (used in) operating activities**	**(4,133)**	**(4,133)**

2.	**Cash flows from investing activities**		
2.1	Payments to acquire:		
	(a) property, plant and equipment	(16)	(16)
	(b) tenements (see item 10)	-	-
	(c) investments	-	-
	(d) exploration and evaluation	(5,276)	(5,276)

Consolidated statement of cash flows		**Current quarter $A'000**	**Year to date (3 months) $A'000**
2.2	Proceeds from the disposal of:		
	(a) property, plant and equipment	-	-
	(b) tenements (see item 10)	-	-
	(c) investments	-	-
	(d) other non-current assets	-	-
2.3	Cash flows from loans to other entities	-	-
2.4	Dividends received (see note 3)	-	-
2.5	Other – payment for performance bond	-	-
2.6	**Net cash from / (used in) investing activities**	**(5,292)**	**(5,292)**

3.	**Cash flows from financing activities**		
3.1	Proceeds from issues of shares	-	-
3.2	Proceeds from issue of convertible notes	-	-
3.3	Proceeds from exercise of share options	-	-
3.4	Transaction costs related to issues of shares, convertible notes or options	-	-
3.5	Proceeds from borrowings	-	-
3.6	Repayment of borrowings	-	-
3.7	Transaction costs related to loans and borrowings	-	-
3.8	Dividends paid	-	-
3.9	Other (provide details if material)	-	-
3.10	**Net cash from / (used in) financing activities**	**-**	**-**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	46,978	46,978
4.2	Net cash from / (used in) operating activities (item 1.9 above)	(4,133)	(4,133)
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(5,292)	(5,292)
4.4	Net cash from / (used in) financing activities (item 3.10 above)	-	-
4.5	Effect of movement in exchange rates on cash held	(2,254)	(2,254)
4.6	**Cash and cash equivalents at end of period**	**35,299**	**35,299**

5.	**Reconciliation of cash and cash equivalents** at the end of the quarter (as shown in the consolidated statement of cash flows) to the related items in the accounts	**Current quarter $A'000**	**Previous quarter $A'000**
5.1	Bank balances	31,381	41,036
5.2	Call deposits	18	142
5.3	Bank overdrafts	-	-
5.4	Other – Term deposits	3,900	5,800
5.5	**Cash and cash equivalents at end of quarter (should equal item 4.6 above)**	**35,299**	**46,978**

6.	**Payments to directors of the entity and their associates**	**Current quarter $A'000**
6.1	Aggregate amount of payments to these parties included in item 1.2	412
6.2	Aggregate amount of cash flow from loans to these parties included in item 2.3	

6.3 Include below any explanation necessary to understand the transactions included in items 6.1 and 6.2

7.	**Payments to related entities of the entity and their associates**	**Current quarter $A'000**
7.1	Aggregate amount of payments to these parties included in item 1.2	
7.2	Aggregate amount of cash flow from loans to these parties included in item 2.3	

7.3 Include below any explanation necessary to understand the transactions included in items 7.1 and 7.2

8.	**Financing facilities available** *Add notes as necessary for an understanding of the position*	**Total facility amount at quarter end $A'000**	**Amount drawn at quarter end $A'000**
8.1	Loan facilities	-	-
8.2	Credit standby arrangements	-	-
8.3	Other (please specify)	-	-

8.4 Include below a description of each facility above, including the lender, interest rate and whether it is secured or unsecured. If any additional facilities have been entered into or are proposed to be entered into after quarter end, include details of those facilities as well.

9.	**Estimated cash outflows for next quarter**	**$A'000**
9.1	Exploration and evaluation	33,000
9.2	Development	-
9.3	Production	-
9.4	Staff costs	750
9.5	Administration and corporate costs	250
9.6	Other (provide details if material)	-
9.7	**Total estimated cash outflows**	**34,000**

10.	**Changes in tenements (items 2.1(b) and 2.2(b) above)**	**Tenement reference and location**	**Nature of interest**	**Interest at beginning of quarter**	**Interest at end of quarter**
10.1	Interests in mining tenements and petroleum tenements lapsed, relinquished or reduced				-
10.2	Interests in mining tenements and petroleum tenements acquired or increased			-	-

Compliance statement

1 This statement has been prepared in accordance with accounting standards and policies which comply with Listing Rule 19.11A.

2 This statement gives a true and fair view of the matters disclosed.

Sign here: .... Date: 28 April 2017
(Company secretary)

Print name: Peter Thiessen

Notes

1. The quarterly report provides a basis for informing the market how the entity's activities have been financed for the past quarter and the effect on its cash position. An entity that wishes to disclose additional information is encouraged to do so, in a note or notes included in or attached to this report.
2. If this quarterly report has been prepared in accordance with Australian Accounting Standards, the definitions in, and provisions of, AASB 6: Exploration for and Evaluation of Mineral Resources and AASB 107: Statement of Cash Flows apply to this report. If this quarterly report has been prepared in accordance with other accounting standards agreed by ASX pursuant to Listing Rule 19.11A, the corresponding equivalent standards apply to this report.
3. Dividends received may be classified either as cash flows from operating activities or cash flows from investing activities, depending on the accounting policy of the entity.