SHAMARAN PETROLEUM CORP.

MANAGEMENT DISCUSSION AND ANALYSIS

For the three and six months ended June 30, 2018

Management's discussion and analysis ("MD&A") of the financial and operating results of ShaMaran Petroleum Corp. (together with its subsidiaries, "ShaMaran" or the "Company") is prepared with an effective date of August 8, 2018. The MD&A should be read in conjunction with the unaudited condensed interim consolidated financial statements for the three and six months ended June 30, 2018 together with the accompanying notes.

The financial statements of the Company have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. Unless otherwise stated herein all currency amounts indicated as "$" in this MD&A are expressed in thousands of United States dollars ("USD").

OVERVIEW

ShaMaran Petroleum Corp. is a Canadian oil and gas company listed on the TSX Venture Exchange and the NASDAQ First North Exchange (Stockholm) under the symbol "SNM". ShaMaran has a 20.1% direct interest in the Atrush Block production sharing contract ("Atrush PSC") located. The Atrush Block is in the Kurdistan Region of Iraq ("Kurdistan"), approximately 85 kilometres northwest of Erbil, the capital of Kurdistan. The Atrush Block is 269 square kilometres in area and has oil proven in Jurassic fractured carbonates in the Chiya Khere structure.

Oil production from Atrush commenced in July 2017. Installed production facilities have a capacity of 30,000 barrels of oil per day ("bopd"). Six production wells have been drilled to date. Five wells are currently producing.

Atrush is continuously being appraised and further phases of development, including further drilling and possible facilities expansion will be defined based on production data, appraisal information and economic circumstances.

HIGHLIGHTS AND DEVELOPMENTS

- ShaMaran entered into an agreement on June 4, 2018 to acquire a further 15% interest in Atrush from Marathon Oil KDV BV ("Marathon") for $60 million before closing adjustments ("the Marathon Acquisition").
- Company issued new $240 million senior unsecured bonds on July 5, 2018 with 5-year term and 12% semi-annual coupon interest. Retired existing bonds set to mature in November 2018.
- Current Atrush production is approximately 28,000 barrels of oil per day with production from five wells: AT-2, CK-5, CK-7, CK-8 and CK-10. It is planned to further increase production gradually.
- Atrush oil production in three and six months ended June 30, 2018 was 15,800 bopd and 19,700 bopd which compares to 23,600 reported in the first quarter of 2018. The production was impacted by the need to reduce well flow rates to manage higher than expected volumes of salt produced from some wells. Fresh water is now being injected to remove salt during processing of the crude for sales. Average lifting cost per barrel in the second quarter was $7.97 and $6.83 in the first six months.
- CK-7 completed in Q2 2018 and tested 27.5 API oil at 7,040 bopd at only 14 psi drawdown. CK-7 was tied into the production facility in July 2018 and came on line on July 23, 2018.
- CK-10 drilled on time and within budget during May and June 2018, and flow tested approximately 4,400 bopd at a low drawdown. CK-10 was tied into the production facility in July 2018 and came on line on July 25, 2018.
- The CK-9 water disposal well was spudded on July 20, 2018 with planned well depth of 3,000 metres 70-day drill time. The main objective is to target deep horizons below the oil reservoir to allow for disposal of produced water that is expected as production continues. The well will also be used to dispose of water injected in to the process as part of the salt management strategy.

- Principal cash inflows in the six months ended June 30, 2018:
  - $40.4 million for entitlement share of Atrush PSC profit oil and cost oil for October 2017 through March 2018 oil deliveries. A further $4.4 million was received in July relating to April 2018 oil sales.
  - $1.2 million of Atrush Exploration Costs receivable[1] on October 2017 through March 2018 oil sales. A further $0.1 million was received in July relating to April 2018 oil sales.
  - $7.8 million in payments of principal plus interest on the Atrush Development Cost Loan and the Atrush Feeder Pipeline Cost loans for invoices from January to June 2018. A further $1.3 million was received in July relating to the July 2018 KRG Loan invoice.
- A new sales agreement was concluded in February 2018 between Atrush co-venturers and the KRG for the sale of Atrush oil. The KRG buys oil exported from the Atrush field by pipeline at the Atrush block boundary based upon the Dated Brent oil price minus $15.73 for quality discount and all local and international transportation costs.
- On February 15, 2018 the Company reported estimated reserves and contingent resources for the Atrush field as at December 31, 2017. Total Field Proven plus Probable ("2P") Reserves on a property gross basis for Atrush increased from 85.1 MMbbl reported as at December 31, 2016 to 102.7 MMbbl which, when 2017 Atrush production of 3.4 MMbbl is included, represents an increase of 25 percent. Total Field Unrisked Best Estimate Contingent Oil Resources ("2C")[2] on a property gross basis for Atrush was approximately the same as the 2016 estimate at 296 MMbbl. Total discovered oil in place in the Atrush Block is a low estimate of 1.5 billion barrels, a best estimate of 2.1 billion barrels and a high estimate of 2.9 billion barrels.

OPERATIONS

Atrush oil production

Oil production on the Atrush Block commenced on July 3, 2017. Cumulative production exported from Atrush from July 2017 to June 30, 2018 was 6.9 million barrels of oil.

	Q2.2018	Q1.2018	Q2.2017
Average daily oil production (bopd)	15,767	23,639	-
Oil produced and sold – gross field (Mbbls)	1,435	2,127	-
ShaMaran production entitlement (Mbbls)	260	518	-

From start up, production in Atrush steadily increased to approximately 26,000 bopd in January 2018. In March 2018 production dropped to approximately 20,300 bopd because of a partial blockage of the heat exchanger by sediments. In early April 2018 Atrush production was temporarily suspended to address the partial blockage of the heat exchanger. The sediments were successfully removed during a plant shut down. It was confirmed that the blockage was caused by salt the source of which is likely to be drilling fluid losses during drilling of the Chiya Khere-5 ("CK-5") and Atrush-2 ("AT-2") wells which is now being back-produced with the oil. Trials with injecting fresh water at the CK-5 wellhead and separating salt water out at the separator have significantly reduced the amount of salt going through the rest of the system. Water injection at the wellhead will continue and it is the intention to gradually increase production while carefully monitoring the facilities. Water injection is currently limited due to limited disposal capacity, which will be increased following the drilling and completion of the Chiya Khere 9 water disposal well in the second half of 2018.

Currently Atrush oil production is approximately 28,000 bopd. Following the successful tie-in of the Chiya Khere-7 ("CK-7") and Chiya Khere-10 ("CK-10") wells in July 2018, five Atrush wells, (which include previous producers: AT-2, CK-5 and Chiya Khere-8 ("CK-8")) are currently supplying this production. The Atrush-4 ("AT-4") production well was drilled in a steeply dipping part of the reservoir and appears to be not connected to the full reservoir sequence. AT-4 is currently shut in and awaits a work-over at a future date to be determined by the Atrush co-venturers.

[1] The Exploration Costs Receivable is related to the repayment of certain development costs that ShaMaran paid on behalf of the KRG which, for purposes of repayment, are governed under the Atrush PSC and the related Facilitation Agreement and deemed to be Exploration Costs.

[2] This estimate of remaining recoverable resources (unrisked) includes contingent resources that have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be recovered.

Drilling, testing and facilities

The CK-7 well was drilled in Q4 2017 and the reservoir section was encountered 114 meters shallower than prognosis. In March and April 2018 three intervals were successfully tested: the Mus formation tested 20.1 API oil at a rate of 830 bopd, with a final productivity of 13 bopd/psi of drawdown; the Alan formation tested 27.1 API oil at a rate of 930 bopd, with a final productivity of 6 bopd/psi of drawdown; and the main Lower Sargelu formation tested 26.4 API oil at 1040 bopd at a drawdown of only 2 psi, yielding a final productivity of 446 bopd/psi of drawdown. No water was produced at the end of the test.

CK-7 is now completed on the Alan and Lower Sargelu formation with an electric submersible pump. During the final completion test the well produced 7,040 bopd at only 14 psi drawdown. Based on the test results the well is expected to be capable of producing over 10,000 bopd

The CK-10 well was spudded on May 15, 2018 was drilled to a total depth of 1,985 metres, which was reached on time and within budget on June 16, 2018. The well was encountered some 60 meters shallow to prognosis. The well flow tested approximately 4,400 bopd at a low drawdown, yielding a final productivity index of 313 bopd/psi. The well is now completed on the Lower Sargalu formation

After installation of flowlines CK-7 and CK-10 were successfully tied-in and began producing near the end of July 2018. It is planned to gradually increase production and to start testing the limits of the 30,000 bopd production facilities which will allow for defining a de-bottlenecking strategy.

A further two appraisal wells have previously been drilled and tested in the eastern part of the field. Good reservoir communication has been proven between the east part and the west part of the field. It is planned to conduct an extended well test in one of the two eastern appraisal wells, Atrush-3 (“AT-3”). This will provide important production information on the heavier part of the oil column. Together with production data from the five development wells this will allow for defining the next phases of development

Following encouraging production results from the Atrush field after the start of production in July 2017, as well as the positive drilling results of CK-7 well, the Company’s independent reserves and resources evaluator, McDaniel & Associates Consultants Ltd (“McDaniel”) increased the 2P oil reserves estimate to 102.7MMbbl at the end of the year 2017. This estimate assumes that four extra production wells will be drilled to further develop the medium gravity oil in the reserves area of the field increasing medium oil recovery. Reserves associated with the heavy oil extended well test planned in 2018 for the CK-3 well have also been included. Reserves which were included in McDaniel’s previous estimate for heavy oil production from the wells currently producing have now been transferred to contingent resources because production to date has shown no indication of heavy oil.

The contingent oil resources represent the likely recoverable oil volumes associated with further phases of development after Phase 1. McDaniel has estimated gross 2C best estimate contingent oil resources of 296 MMbbl. These are contingent oil resources rather than reserves due to the uncertainty over the future development plan which will depend in part on Phase 1 production performance and the heavy oil extended well test planned for the second half of 2018. McDaniel estimates the chance of developing the 2C contingent oil resources at 80 percent.

OUTLOOK

Operations

- Production guidance for the second half of 2018 is 25,000-30,000 bopd. Guidance for 2018 lifting costs remains unchanged at $6.80/bbl in light of higher expected production for the rest of 2018.
- Capital expenditure guidance has been lowered from previous estimate of $19.6 million to $17.0 million (20.1% working interest in Atrush), principally due to lower than planned drilling and testing costs on CK-7 and CK-10. Remaining planned capital expenditure includes:
  - identify and install additional heat sources ahead of the next winter months;
  - continue with program to identify debottleneck opportunities to further increase production capacity beyond 30,000 bopd;
  - drilling and completion of Chiya Khere (“CK-9”), a dedicated water disposal well; and
  - conducting extended testing of the AT-3 well which is located on the eastern side of the Atrush Block and which is outside the 2P reserve area of Atrush. This would involve the installation of temporary production facilities near the Chamanke–C well pad and the delivery by truck of oil to the main Phase 1 Production Facilities.

- Following the results of the CK-7 and CK-10 wells, the extended well testing in AT-3 and sustained production from the Phase 1 Production Facilities the Company expects to further assess the significant undeveloped Atrush resource base with the potential to grow organically to approximately 100,000 bopd production.

Financing and corporate

- A cash payment is due to Marathon upon close of the Marathon Acquisition for $60 million less the $2 million deposit and less all other final closing adjustments which will include net Atrush cash flows received by Marathon after January 1, 2018, the effective date of the acquisition.
- Two cash payments of $14.4 million each to be made by the Company into the Debt Service Retention Account. The payments are due on December 31, 2018 and June 30, 2019. Refer to the discussion under "The ShaMaran Bonds" section below.
- The first semi-annual coupon interest payment of $14.4 million under the Company's $240 million bonds is due January 5, 2019.

OWNERSHIP, PRINCIPAL TERMS OF THE ATRUSH PSC

ShaMaran, through its wholly owned subsidiary, GEP, holds a 20.1% direct interest in the Atrush PSC. TAQA Atrush B.V. ("TAQA" a subsidiary of Abu Dhabi National Energy Company PJSC, and the "Operator" of the Atrush Block) with a 39.9% direct interest, the KRG holds a 25% direct interest and Marathon Oil KDV B.V. ("MOKDV") holds a 15% direct interest. TAQA, GEP, and MOKDV together are the "Non-Government Contractors" to the Atrush PSC. The Non-Government Contractors and the KRG together are the "Contractors" to the Atrush PSC.

The Company announced on June 4, 2018 that it had signed an agreement with Marathon Oil KDV B.V. to acquire its 15% interest in the Atrush Block. At the date of this MD&A certain closing conditions remained outstanding.

The Atrush field was discovered in 2011 and a Phase 1 development plan was approved in October 2013, which consists of installing and commissioning production facilities with 30,000 bopd capacity and the drilling and completion of production wells which supply the Production Facility. In August 2010 the Company acquired a 33.5% shareholding in GEP which then held an 80% working interest in the Atrush PSC, with the remaining 20% third party interest ("TPI") being held by the KRG. In October 2010 MOKDV was assigned the 20% TPI in the Atrush PSC. On December 31, 2012 GEP sold a 53.2% direct interest in the Atrush Block to TAQA, who also assumed from GEP the Operatorship of the Block, and repurchased the entire 66.5% shareholding which Aspect Energy International LLC ("Aspect") held in GEP, leaving the Company with a 100% shareholding interest in GEP and, at that time, a 26.8% direct interest in the Atrush PSC.

On November 7, 2016 the Assignment, Novation and Fourth Amendment Agreement to the Atrush PSC (the "4th PSC Amendment") and Atrush Facilitation Agreement were concluded between Non-Government Contractors and the KRG, in which the KRG acquired a 25% interest in the Atrush PSC effective November 7, 2012, resulting in GEP reducing its interest in the Atrush PSC to 20.1%.

Under the terms of the Atrush PSC the development period is for 20 years after the declaration of commerciality (November 7, 2012) with an automatic right to a five-year extension and the possibility to extend for an additional five years. All qualifying petroleum costs incurred by the Contractors shall be recovered from a portion of available petroleum production, defined under the terms of the Atrush PSC. All modifications to the Atrush PSC are subject to the approval of the KRG.

Fiscal terms under the Atrush PSC include a 10% royalty and a variable profit split based on a percentage share to the KRG. GEP has the right to recover costs using up to 40% of the available oil (produced oil less royalty oil) and 55% of the produced gas. The Contractors are entitled to cost recovery in respect of all costs and expenditures incurred for exploration, development, production and decommissioning operations, as well as certain other allowable direct and indirect costs.

The portion of profit oil available to the Contractors is based on a sliding scale from 32% to 16% depending on the "R-Factor", which is a ratio of cumulative revenues to cumulative costs. When the ratio is below one, the Contractors are entitled to 32% of profit oil, with a reducing scale to 16% when the ratio is greater than 2.75. In respect of gas, the sliding scale is from 40% to 22%.

SELECTED QUARTERLY FINANCIAL INFORMATION

The following is a summary of selected quarterly financial information for the Company:

(In $000, except per share data)	For the quarter ended							
	Jun-30 2018	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**	**Sep 30 2016**
Continuing operations								
Revenues	15,328	26,501	13,907	3,782	-	-	-	-
Cost of goods sold	(6,990)	(12,168)	(9,426)	(4,583)	-	-	-	-
Service fee income	-	-	-	-	-	-	-	90
General and admin. expense	(941)	(925)	(966)	(1,637)	(818)	(1,090)	(805)	(695)
Share based payments expense	-	-	-	-	-	(11)	(57)	(58)
Depreciation and amortisation	(2)	(4)	-	(8)	(8)	(10)	(11)	(12)
Finance cost	(3,016)	(4,230)	(5,802)	(3,436)	(1,482)	(1,503)	(1,422)	(1,393)
Finance income	444	443	361	525	439	352	509	16
Income tax expense	(11)	(16)	(14)	(36)	(14)	(21)	(14)	(14)
Net income / (loss)	4,812	9,601	(1,940)	(5,393)	(1,883)	(2,283)	(1,800)	(2,066)
Basic and diluted net inc. / (loss) in $ per share	0.002	0.004	(0.001)	(0.002)	(0.001)	(0.001)	(0.001)	(0.001)

Summary of Principal Changes in the Second Quarter Financial Information

In the second quarter of 2018 production from the Atrush Block and work on the Atrush development program continued. The net income was primarily driven by the gross margin on Atrush oil sales and interest income on Atrush cost loans to the KRG and was reduced by general and administrative expenses and finance cost, the substantial portion of which were expensed borrowing costs on the Company's Senior Bonds and Super Senior Bonds.

The Company's operations are comprised of the Phase 1 development program on the Atrush Block petroleum property which commenced production on July 3, 2017. The expenses and income items of operations are explained in detail as follows:

Gross margin on oil sales

In $000	---------Three month period---------			-----Six month period-----	
	Q2.2018	**Q1.2018**	**Q2.2017**	**Q2.2018**	**Q2.2017**
Revenues from Atrush oil sales	15,328	26,501	-	41,829	-
Other costs of production	119	(202)	-	(83)	-
Lifting costs	(2,463)	(2,426)	-	(4,889)	-
Depletion costs	(4,646)	(9,540)	-	(14,186)	-
Cost of goods sold	(6,990)	(12,168)	-	(19,158)	-
Gross margin on oil sales	8,338	14,333	-	22,671	-

Revenues relate to the Company's entitlement share of oil sales from Atrush. Revenue for sales of oil is recognised when the significant risks and rewards of ownership are deemed to have been transferred to the KRG, the amount can be measured reliably and it is assessed as probable that economic benefit associated with the sale will flow to the Company. This occurs when oil reaches the delivery point at the Atrush Block boundary in route to the KRG's main export pipeline.

Revenue is recognised at fair value. The fair value is comprised of the Company's entitlement production due under the terms of the Atrush Joint Operating Agreement ("Atrush JOA") and the Atrush PSC which have two principal components: cost oil, which is the mechanism by which the Company recovers qualifying costs it has incurred on an asset, and profit oil, which is the mechanism through which profits are shared between the Company, the Atrush co-venturers and the KRG. The Company pays capacity building payments on profit oil, which are due for payment once the Company has received the related profit oil proceeds. Profit oil revenue is reported net of any related capacity building payments.

The Company's oil sales are made to the KRG under the terms of a sales agreement which allows for Atrush oil volumes to be sold to the KRG at the Atrush block boundary at a discount to the Dated Brent oil price for estimated oil quality adjustments and all local and international transportation costs.

Income tax arising from the Company's activities under production sharing contracts is settled by the KRG at no cost and on behalf of the Company. However, the Company is not able to measure the tax that has been paid on its behalf and consequently revenue is not reported gross of income tax paid.

Production from the Atrush field was delivered to the KRG's Feeder Pipeline at the Atrush block boundary for onward export through Ceyhan, Turkey. In the second quarter and the first half of 2018 the respective gross exported oil volumes from Atrush were 1.4 MMbbls and 3.6 MMbbls, and the Company's entitlement shares were approximately 260 Mbbls and 779Mbbls which were sold with average netback prices of $58.88 and $53.73 per barrel. ShaMaran's oil entitlement share is based on PSC terms covering allocation of profit oil and cost oil, capacity building bonuses owed to the KRG and a priority arrangement with TAQA for sharing initial exploration cost oil and on export prices which are based on Dated Brent oil price with an agreed discount throughout year to date 2018 of $15.73 per barrel for estimated oil quality adjustments and all local and international transportation costs.

Second quarter revenues were down from the amount reported in the first quarter because of lower production and a lower entitlement allocation from TAQA. 2018 Atrush production was 15,767 bopd in the second quarter and was 19,681 bopd in the first half of the year compared with 23,639 bopd in the first quarter. The decreased production in the second quarter was caused by a partial blockage of the heat exchanger by sediments due to back producing salt drilling fluids lost during the drilling of CK5 and AT-2 wells. The heat exchanger has now been successfully cleaned. Fresh water is now injected at the CK-5 wellhead which has significantly reduced the amount of salt going through the system. During Q1 the Company exceptionally received a full allocation of TAQA's exploration cost oil entitlement under the terms of the Atrush JOA. The allocation from TAQA to the Company was completed within Q2 and therefore resulted in a lower level of entitlement oil incremental to the Company's 20.1% entitlement.[3]

Lifting costs are comprised of the Company's share of expenses related to the production of oil from the Atrush Block including operation and maintenance of wells and production facilities, insurances, and the operator's related support costs. The average lifting cost per barrel of oil produced from Atrush was respectively $7.97 and $6.83 in the three and six months ended June 30, 2018. The increase in average lifting cost per barrel in the second quarter was principally attributable to lower production as most production costs are fixed and the additional costs related to managing the increased volume of salt in the production which began in the first quarter of 2018. Other costs of production include the Company's share of other costs prescribed under the Atrush PSC. In the three months ended June 30, 2018 an amount of $164 thousand was reclassed from other costs of production to lifting costs which has resulted in net recovery during this period of $119 thousand.

Oil and gas assets are depleted using the unit of production method based on proved and probable reserves using estimated future prices and costs and accounting for future development expenditures necessary to bring those reserves into production. The reserves correspond to the Company's entitlement to oil under the terms of the PSC. The depletion cost per entitlement barrel was $18.22 and $17.84, respectively for the six and three months ended June 30, 2018. Changes to depletion rates resulting from changes in reserve quantities and estimates of future development expenditure are reflected prospectively.

[3] The Company's entitlement share includes an adjustment for the exploration cost sharing arrangement between TAQA and GEP. TAQA and GEP have under the Atrush JOA agreed a priority arrangement for sharing their combined initial $49.9 million share of exploration cost oil revenues such that TAQA receives the initial $10.8 million and GEP receives the next $39.1 million, thereafter cost oil revenues for these two parties is determined by their relative participating interests in the Atrush PSC. The Company's entitlement share of oil sold up to June 30, 2018 reflects a full recovery of the $39.1 million.

General and administrative expense

In $000	---------Three month period---------			----Six month period----	
	Q2.2018	**Q1.2018**	**Q2.2017**	**Q2.2018**	**Q2.2017**
Salaries and benefits	500	496	523	996	1,228
Listing costs and investor relations	121	79	82	200	157
Management and consulting fees	79	114	65	193	167
Legal, accounting and audit fees	36	134	21	170	128
General and other office expenses	80	82	75	162	148
Travel expenses	125	20	52	145	80
General and administrative expense	941	925	818	1,866	1,908

The overall lower general and administrative expense incurred in the first half of 2018 was principally due to lower payroll costs relating to salary bonuses incurred by the Company's Swiss subsidiary in the comparable period of last year. The additional costs associated with the Company's efforts to refinance its bonds and acquire an additional 15% interest in Atrush has resulted in an increase in all other G&A costs relative to the amounts reported for the six months ended June 30, 2017.

Share based payments expense

In $000	---------Three month period---------			----Six month period----	
	Q2.2018	**Q1.2018**	**Q2.2017**	**Q2.2018**	**Q2.2017**
Share based payments expense	-	-	-	-	11

The Company uses the fair value method of accounting for stock options granted to directors, officers, employees and consultants whereby the fair value of all stock options granted is recorded as a charge to operations. The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model. Share based payments expense results from the vesting of stock options granted over the vesting period which is normally two years after the grant date. The last stock option grant of January 19, 2015 is now fully vested and was fully expensed at the end of the first quarter of 2017.

Depreciation and amortisation expense

In $000	---------Three month period---------			----Six month period----	
	Q2.2018	**Q1.2018**	**Q2.2017**	**Q2.2018**	**Q2.2017**
Depreciation and amortisation expense	2	4	8	6	18

Depreciation and amortisation expense corresponds to cost of use of the furniture and IT equipment at the Company's technical and administrative offices located in Switzerland and Kurdistan.

Finance income

In $000	---------Three month period---------			----Six month period----	
	Q2.2018	**Q1.2018**	**Q2.2017**	**Q2.2018**	**Q2.2017**
Interest on Atrush Development Cost Loan	227	268	252	495	484
Interest on Atrush Feeder Pipeline Cost Loan	147	167	127	314	221
Interest on deposits	10	8	39	18	65
Total interest income	384	443	418	827	770
Foreign exchange gain	60	-	21	-	-
Total finance income	444	443	439	827	770

Under the terms of the 4th PSC Amendment and the Atrush Facilitation Agreement the Non-Government Contractors have agreed to pay their pro-rata share of the Feeder Pipeline costs and of the KRG's share of Atrush development costs up to October 31, 2017. Thereafter these costs will be reimbursed to the Non-Government Contractors. The loan interest amounts reported in the first six months of 2018 represent 7% per annum interest on the principal balances outstanding over this period. For further information on the loans refer to the discussion under the "Loans and receivables" section below.

Interest on deposits represents bank interest earned on cash and investments held in interest bearing funds. The decrease in interest income reported in the six months ended June 30, 2018 relative to the amount reported in 2017 is due to a lower level of interest bearing funds held in 2018.

The foreign exchange gain recorded in the three months ended June 30, 2018 resulted primarily from holding in the Company's Swiss subsidiary net assets denominated in United States dollars while the USD strengthened during the period against the Swiss Franc, the functional currency of the Swiss subsidiary. Over the first six months of 2018 the Company recorded a foreign exchange loss (refer to discussion below under finance cost).

Finance cost

In $000	---------Three month period---------			----Six month period----	
	Q2.2018	**Q1.2018**	**Q2.2017**	**Q2.2018**	**Q2.2017**
Interest charges on bonds at coupon rate	5,359	5,360	4,883	10,719	9,729
Amortisation of bond transaction costs	210	210	210	420	420
Interest expense on borrowings	5,569	5,570	5,093	11,139	10,149
Unwinding discount on decommissioning provision	(11)	5	3	(6)	(7)
Foreign exchange loss	-	70	-	10	26
Total finance costs before borrowing costs capitalised	5,558	5,645	5,096	11,143	10,168
Borrowing costs capitalised as E&E and PP&E assets	(2,542)	(1,415)	(3,614)	(3,957)	(7,204)
Finance cost	3,016	4,230	1,482	7,186	2,964

General and specific borrowing costs directly attributable to the acquisition, exploration and development of Atrush have been capitalised together with the related Atrush oil and gas assets. All other borrowing costs are recognised in profit or loss in the period in which they are incurred.

During the six months ended June 30, 2018 the Company incurred interest expense relating to its Senior Bonds and Super Senior Bonds which both carry an 11.5% fixed semi-annual coupon interest rate. Interest expense on borrowings increased over the amount reported in 2017 due to the additional bonds outstanding in the period resulting from the issuance of PIK bonds in May and November 2017. Refer also to the discussion in the section below entitled "Borrowings".

The foreign exchange loss recorded in the first half of 2018 resulted primarily from holding in the Company's Swiss subsidiary net liabilities denominated in United States dollars while the USD strengthened during the period against the Swiss Franc, the functional currency of the Swiss subsidiary.

Income tax expense

In $000	---------Three month period---------			----Six month period----	
	Q2.2018	**Q1.2018**	**Q2.2017**	**Q2.2018**	**Q2.2017**
Income tax expense	11	16	14	27	35

Income tax expense relates to provisions for income taxes on service income generated in Switzerland which is based on costs incurred in procuring the services. The decrease in tax expense reported in the six months ended June 30, 2018 is primarily due to lower taxable income in the Company's Swiss subsidiary which decreased compared to 2017 because of lower costs of service.

Capital Expenditures on Property Plant & Equipment ("PP&E")

The net book value of PP&E is principally comprised of development costs related to the Company's share of Atrush PSC proved and probable reserves as estimated by McDaniel less the cumulative depletion costs corresponding to commercial production which commenced in July 2017. The movements in PP&E are explained as follows:

In $000	Six months ended June 30, 2018			Year ended December 31, 2017		
	Oil and gas assets	Office equipment	Total	Oil and gas assets	Office equipment	Total
Opening net book value	184,918	3	184,921	174,642	16	174,658
Additions	10,296	4	10,300	17,903	3	17,906
Reclass from Intangibles	498	-	498	-	-	-
Depletion and depreciation expense	(14,186)	(1)	(14,187)	(7,627)	(16)	(7,643)
Net book value	181,526	6	181,532	184,918	3	184,921

During the first six months of 2018 movements in PP&E were comprised of additions of $10.3 million (year 2017: $17.9 million), which included borrowing costs totalling $3.8 million (year 2017: $8.8 million), depletion of $14.2 million (year 2017: $7.6 million) and a one-time cost reclass to PP&E from E&E of $0.5 million (year 2017: nil) which resulted in a net decrease to PP&E assets of $3.4 million.

Capital Expenditures on Intangible Assets

The net book value of Intangible assets is principally comprised of exploration and evaluation ("E&E") assets which represent the Atrush Block exploration and appraisal costs related to the Company's share of Atrush Block contingent resources as estimated by McDaniel. The movements in Intangible assets are explained as follows:

In $000	Six months ended June 30, 2018			Year ended December 31, 2017		
	E&E assets	Software & Licences	Total	E&E assets	Software & Licences	Total
Opening net book value	89,113	6	89,119	88,972	35	89,007
Additions	307	-	307	141	2	143
Reclass to PP&E	(498)	-	(498)	-	-	-
Disposals	-	-	-	-	(21)	(21)
Amortisation expense	-	(4)	(4)	-	(10)	(10)
Net book value	88,922	2	88,924	89,113	6	89,119

During the six months of 2018 movements in E&E were comprised of additions of $307 thousand (year 2017: $143 thousand), which included borrowing costs of $175 thousand (year 2017: $16 thousand), and a one-time cost reclass of $498 thousand from E&E to PP&E resulting in a net decrease to E&E assets of $191 thousand.

Loans and receivables

On November 7, 2016, the 4th PSC Amendment and Atrush Facilitation Agreement were concluded between the Non-Government Contractors and the KRG. On the same day TAQA entered into an Engineering, Procurement and Construction ("EPC") contract with KAR Company for the construction of the feeder pipeline from the Atrush block boundary to the tie-in point with the main Kurdistan export pipeline (the "Feeder Pipeline").

Under the terms of the 4th PSC Amendment and Atrush Facilitation Agreement:

- The KRG acquires a 25% interest in the Atrush PSC effective November 7, 2012, the date of declaration of commerciality ("DOC date"). Consequently, the respective participating interests in the Atrush PSC are TAQA at 39.9%, the KRG at 25%, GEP at 20.1% and MOKDV at 15%;
- All Atrush petroleum costs from the DOC date through the commencement of oil exports from Atrush are paid by the Non-Government Contractors and a defined portion of the KRG's share of these costs are deemed Exploration Costs as defined in the Atrush PSC and repaid through an accelerated petroleum cost recovery arrangement from the sale of future oil production from Atrush. This arrangement has resulted in the Atrush Exploration Cost receivable at year end as reported in the table below; and
- The Non-Government Contractors will fund the cost of constructing the Feeder Pipeline which will be novated to the KRG following the commencement of oil exports from Atrush. The Feeder Pipeline costs and the balance of the Atrush petroleum costs incurred by the Non-Government Contractors on behalf of the KRG excluding the portion deemed as Exploration Costs will be repaid with interest at 7% per annum by the KRG within 2 years from October 31, 2017 (respectively, the "Atrush Feeder Pipeline Cost Loan" and the "Atrush Development Cost Loan"). These arrangements have resulted in loan balances at year end as reported in the table below.

In $000	For the six months ended June 30, 2018	For the year ended December 31, 2017
Atrush Exploration Costs receivable	36,077	37,247
Accounts receivable on Atrush oil sales	15,329	13,957
Atrush Development Cost Loan	11,623	16,018
Atrush Feeder Pipeline Cost Loan	7,468	9,751
Total loans and receivables	70,497	76,973

The Company funded Feeder Pipeline costs of $394 thousand in the first half of 2018. This concludes the Company's funding obligations for both the Atrush Feeder Pipeline and Atrush Development Cost loans. In the first six months of 2018 the Company has received principal plus interest payments totalling $4.8 million for Atrush Development Cost Loan and $3.0 million for the Atrush Feeder Pipeline Cost Loan.

In the period from the balance sheet date up to when these financial statements were approved the Company received $5.8 million in total payments for loans and receivables balances outstanding at June 30, 2018 comprised of $4.4 million in total payments for its entitlement share of oil sales for April 2018, $1.3 million for Atrush Development Cost Loan and Atrush Feeder Pipeline Cost Loan balances outstanding at end of July 2018 and $0.1 million in reimbursements of the Atrush Exploration Costs receivable.

Borrowings

At June 30, 2018 General Exploration Partners, Inc. had outstanding $166.3 million of senior secured bonds ("Senior Bonds") and $20.2 million of super senior secured bonds ("Super Senior Bonds"). had outstanding $166.3 million of senior secured bonds ("Senior Bonds") and $20.2 million of super senior secured bonds ("Super Senior Bonds"). Both the Senior Bonds and the Super Senior Bonds carried an 11.5% fixed semi-annual coupon and were used to fund capital expenditures related to the development of the Atrush Block.

After the balance sheet date, on July 5, 2018, the Company issued additional bonds of $240 million ("the ShaMaran bonds"). A portion of the proceeds of the ShaMaran bonds were used after the balance sheet date on August 1, 2018 to retire all GEP's outstanding bonds and related accrued coupon interest.

All the movements in borrowings during the first six months of 2018 are explained as follows:

In $000

	For the six months ended June 30, 2018	For the year ended December 31, 2017
Opening balance	188,491	167,632
Interest charges at coupon rate	10,719	20,018
Amortisation of bond transaction costs	420	841
Bonds issued	-	19,721
Interest payments to bondholders	(10,719)	(19,721)
Ending balance	188,911	188,491
- Current portion: accrued bond interest expense	2,799	2,799
- Current portion: borrowings	186,112	185,692

The ShaMaran Bonds

On July 5, 2018 the Company announced that it issued $240 million senior unsecured bonds. The ShaMaran bonds have a five-year maturity without amortization and carry 12% fixed semi-annual coupon. A portion of the proceeds of the ShaMaran bonds have been used to retire the existing bonds of GEP and related accrued interest and $53 million of bond proceeds are currently being held in escrow, pending the closing of the purchase by the Company of an additional 15% of the Atrush asset as announced by the Company on June 4, 2018. In case the Company is unable to conclude the purchase these funds would be used to repurchase $50 million of the ShaMaran bonds plus related accrued interest.

In connection with the bond issue, Nemesia S.à.r.l. ("Nemesia"), a company controlled by a trust settled by the estate of the late Adolf H. Lundin, has agreed to undertake a guarantee of the Company's obligation to fund, on or before July 5, 2019, 12 month's bond coupon interest in a debt service retention account pledged to the bond trustee (the "Liquidity Guarantee"). In exchange for the Liquidity Guarantee the Company has agreed, subject to obtaining all requisite regulatory body approvals, to issue to Nemesia 2,000,000 common shares of ShaMaran as fully paid shares and, in case of a draw down on the Liquidity Guarantee, a further 50,000 shares of ShaMaran for each $500 thousand drawn down per month until the drawn amount is repaid.

Under the terms of the Company's bond agreement the Company is required to place in a Debt Service Retention Account ("DSRA") two cash instalments each in the amount $14.4 million, which corresponds to one year of 12% coupon interest on $240 million of bonds. The DSRA is pledged to the bondholders as security and the Company can only use these funds to pay coupon interest on the bonds six months before maturity and at maturity on July 5, 2023. The DSRA payments are due on December 31, 2018 and June 30, 2019.

LIQUIDITY AND CAPITAL RESOURCES

Working capital at June 30, 2018 was negative $124.0 million compared to positive $19.7 million at June 30, 2017. The decrease in working capital since June 30, 2017 is principally due to the approaching maturity of the Company's bonds in November 2018. These bonds were retired after the balance sheet date on August 1, 2018. Refer also to the discussion above under "Borrowings".

The overall cash position of the Company increased by $22.0 million during the first six months of 2018 compared to an increase in cash of $10.3 million during the same period of 2017. The main components of the movement in funds are discussed in the following paragraphs.

The operating activities of the Company during the first half of 2018 resulted in an increase in the cash position of $29.3 million compared to a decrease of $2.2 million in the cash position during the comparable period of 2017. The increase in the cash position is explained by net income of $14.4 million plus $14.9 million of net positive cash adjustments from working capital items and non-cash expenses.

Net cash inflows from investing activities in the first six months of 2018 were $3.4 million compared to cash outflows of $13.8 million during the same period in 2017. Cash inflows from investing activities in the first half of 2018 were comprised of cash inflows of $9 million in payments by the KRG of principal plus interest on Atrush Development Cost and Atrush Feeder Pipeline Cost loans net of cash outflows of $5.7 million on investments in the Atrush Block development work program.

Net cash outflows to financing activities in the first six months of 2018 were $ 10.7 million compared to $26.4 million of cash inflows in the comparable period in 2017. The 2018 cash outflows were entirely comprised of $10.7 million of coupon interest payments made to bondholders.

The condensed interim consolidated financial statements were prepared on the going concern basis which assumes that the Company will be able to realise into the foreseeable future its assets and liabilities in the normal course of business as they come due in the foreseeable future. Management has applied judgment in preparing forecasts supporting the going concern assumption. Specifically, management has made assumptions regarding projected oil sale volumes and pricing, and the timing and extent of capital, operating, and general and administrative expenditures. Should production be materially less than anticipated or in case there are extended delays to the forecasted receipt of cash from the sale of oil exports or in the magnitude of those cash receipts, which are under the control of the KRG, and the Company was unable to defer certain planned cost activities, the Company could require additional liquidity to fund the forecasted Atrush operating and development costs and its commitments under the bond agreement in the next 12 months. Failure to meet development commitments could put the Atrush PSC and the Company's bond agreements at risk of forfeiture.

OUTSTANDING SHARE DATA AND STOCK OPTIONS

The Company had 2,158,631,534 outstanding shares at June 30, 2018 and at the date of this MD&A. Refer also to the discussion under *New ShaMaran Bond Issue* in the *Borrowings* section above.

At June 30, 2018 there were 26,000,000 stock options outstanding under the Company's employee incentive stock option plan. In the first half of 2018, 2,165,000 stock options have been expired from December 31, 2017 (2017: nil). No stock options were forfeited or exercised in the first six months of 2018 (2017: nil). There has been no further change in the number of stock options outstanding from June 30, 2018 to the date of this MD&A.

The Company has no warrants outstanding.

OFF BALANCE SHEET ARRANGEMENTS

The Company has no off-balance sheet arrangements.

RELATED PARTY TRANSACTIONS

In $000	Purchases of services for periods ended June 30, three months		six months		Amounts owing at the balance sheet dates	
	2018	2017	2018	2017	June 30, 2018	December 31, 2017
Lundin Petroleum AB	52	53	104	104	41	18
Namdo Management Services Ltd.	13	13	26	25	-	-
Bennett-Jones	5	13	11	25	-	-
Total	**70**	**79**	**141**	**154**	**41**	**18**

The Company received services from various subsidiary companies of Lundin Petroleum AB ("Lundin"), a shareholder of the Company until June 21, 2018 when Lundin sold its ShaMaran shares. Lundin charges during the three and six months ended June 30, 2018 of $52 (2017: $53) and $104 (2017: $104) were comprised of office rental, administrative and building services of $43 (2017: $47) and $88 (2017: $91) and investor relations services of $9 (2017: $6) and $16 (2017: $13).

Namdo Management Services Ltd. is a private corporation affiliated with a shareholder of the Company and has provided corporate administrative support and investor relations services to the Company.

Bennett-Jones is a law firm in which an officer of the Company is a partner and has provided legal services to the Company. Amounts reported under Bennett Jones are inclusive of services provided to the Company by McCullough O'Connor Irwin LLP, which merged with Bennett Jones on June 1, 2018, where the same officer of the Company was previously a partner.

All transactions with related parties are in the normal course of business and are made on the same terms and conditions as with parties at arm's length.

Also refer to the discussion under the "Outstanding Share Data and Stock Options" section above.

COMMITMENTS AND CONTINGENCIES

Atrush Block Production Sharing Contract

Under the terms of the Atrush PSC the development period is for 20 years after declaration of commerciality (November 7, 2012) with an automatic right to a five-year extension and the possibility to extend for an additional five years. All qualifying petroleum costs incurred by the Contractors shall be recovered from a portion of available petroleum production, defined under the terms of the Atrush PSC. All modifications to the Atrush PSC are subject to the approval of the KRG. The Company is responsible for its pro-rata share of the costs incurred in executing the development work program on the Atrush Block which commenced on October 1, 2013.The Company is responsible for its pro-rata share of the costs incurred in executing the development work program on the Atrush Block which commenced on October 1, 2013.

As at June 30, 2018 the outstanding commitments of the Company were as follows:

In $000	For the three months ended June 30,				
	2019	2020	2021	Thereafter	Total
Atrush Block development	22,551	120	120	1,448	24,239
Office and other	22	-	-	-	22
Total commitments	**22,573**	**120**	**120**	**1,448**	**24,261**

Amounts relating to Atrush Block development represent the Company's unfunded paying interest share of the approved 2018 work program and other obligations under the Atrush PSC.

Under the terms of the Atrush PSC the Company will owe a share of production bonuses payable to the KRG when cumulative oil production from Atrush reaches production milestones defined in the Atrush PSC as follows: $8.3 million at 10 million barrels (ShaMaran share: $2.2 million); $13.3 million at 25 million barrels (ShaMaran share: $3.6 million); and $23.3 million at 50 million barrels (ShaMaran share: $6.2 million).

PROPOSED TRANSACTIONS

On June 4, 2018 the Company entered into an agreement to acquire a further 15% working interest in the Atrush PSC and certain other assets from Marathon Oil KDV B.V. for $60 million, subject to final closing adjustments. Under the terms of the agreement the Company paid to Marathon in June 2018 a deposit of $2.0 million on the total purchase value. At the date of this MD&A certain closing conditions remained outstanding.

The Company continues to evaluate new opportunities.

CRITICAL ACCOUNTING ESTIMATES AND ACCOUNTING POLICIES

Accounting Estimates

The consolidated financial statements of the Company have been prepared by management using IFRS. In preparing financial statements, management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the period. Specifically, estimates are utilised in calculating depletion, asset retirement obligations, fair values of assets on acquisition of control, share-based payments, amortisation and impairment write-downs as required. Actual results could differ from these estimates and differences could be material.

Significant Accounting Policies

The Company adopted IFRS 15, Revenue from Contracts with Customers and IFRS 9, Financial Instruments effective January 1, 2018. Refer to Note 2 "Basis of Presentation, Going Concern and Significant Accounting Policies" in the Company's Condensed Interim Consolidated Financial Statements for the period ended June 30, 2018 for further discussion.

New Accounting Standards Issued But Not Yet Applied

Standards and interpretations issued but not yet effective up to the date of issuance of the financial statements are listed below.

IFRS 16: Leases will replace *IAS 17 Leases* and requires assets and liabilities arising from all leases, with some exceptions, to be recognized on the balance sheet. The new standard will be effective for annual periods beginning on or after January 1, 2019. The Company currently has no outstanding leases.

Accounting for Oil and Gas Operations

The Company follows the successful efforts method of accounting for its oil and gas operations. Under this method acquisition costs of oil and gas properties, costs to drill and equip exploratory and appraisal wells that are likely to result in proved reserves and costs of drilling and equipping development wells are capitalised and subject to annual impairment assessment.

Exploration well costs are initially capitalised and, if subsequently determined to have not found sufficient reserves to justify commercial production, are charged to exploration expense. Exploration well costs that have found sufficient reserves to justify commercial production, but whose reserves cannot be classified as proved, continue to be capitalised if sufficient progress is being made to assess the reserves and economic viability of the well and or related project.

Capitalised costs of proved oil and gas properties are depleted using the unit of production method based on estimated gross proved and probable reserves of petroleum and natural gas as determined by independent engineers. Successful exploratory wells and development costs and acquired resource properties are depleted over proved and probable reserves. Acquisition costs of unproved reserves are not depleted or amortised while under active evaluation for commercial reserves. Costs associated with significant development projects are depleted once commercial production commences. A revision to the estimate of proved and probable reserves can have a significant impact on earnings as they are a key component in the calculation of depreciation, depletion and accretion.

Producing properties and significant unproved properties are assessed annually, or more frequently as economic events dictate, for potential indicators of impairment. Economic events which would indicate impairment include:

- The period for which the Company has the right to explore in the specific area has expired during the period or will expire in the near future and is not expected to be renewed.
- Substantive expenditure on further exploration for and evaluation of mineral resources in the specific area is neither budgeted nor planned.

- Exploration for and evaluation of resources in the specific area have not led to the discovery of commercially viable quantities of mineral resources and the Company has decided to discontinue such activities in the specific area.
- Sufficient data exists to indicate that, although a development in the specific area is likely to proceed, the carrying amounts of E&E and oil and gas assets is unlikely to be recovered in full from successful development or by sale.
- Extended decreases in prices or margins for oil and gas commodities or products.
- A significant downwards revision in estimated volumes or an upward revision in future development costs.

For impairment testing the assets are aggregated into cash generating unit ("CGU") cost pools based on their ability to generate largely independent cash flows. The recoverable amount of a CGU is the greater of its fair value less costs to sell and its value in use. Fair value is determined to be the amount for which the asset could be sold in an arm's length transaction. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU.

Where conditions giving rise to the impairment subsequently reverse the effect of the impairment charge is also reversed as a credit to the statement of comprehensive income net of any depreciation that would have been charged since the impairment.

A substantial portion of the Company's exploration and development activities are conducted jointly with others.

There have been no evaluations of the Company's reserves and resource estimates since the report as at December 31, 2017 provided by McDaniel in February 2018.

Risks in estimating resources

There are a number of uncertainties inherent in estimating the quantities of reserves and resources including factors which are beyond the control of the Company. Estimating reserves and resources is a subjective process and the results of drilling, testing, production and other new data after the date of an estimate may result in revisions to original estimates.

Reservoir parameters may vary within reservoir sections. The degree of uncertainty in reservoir parameters used to estimate the volume of hydrocarbons, such as porosity, net pay and water saturation, may vary. The type of formation within a reservoir section, including rock type and proportion of matrix and or fracture porosity, may vary laterally and the degree of reliability of these parameters as representative of the whole reservoir may be proportional to the overall number of data points (wells) and the quality of the data collected. Reservoir parameters such as permeability and effectiveness of pressure support may affect the recovery process. Recovery of reserves and resources may also be affected by the availability and quality of water, fuel gas, technical services and support, local operating conditions, security, performance of the operating company and the continued operation of well and plant equipment.

Additional risks associated with estimates of reserves and resources include risks associated with the oil and gas industry in general which include normal operational risks during drilling activity, development and production; delays or changes in plans for development projects or capital expenditures; the uncertainty of estimates and projections related to production, costs and expenses; health, safety, security and environmental risks; drilling equipment availability and efficiency; the ability to attract and retain key personnel; the risk of commodity price and foreign exchange rate fluctuations; the uncertainty associated with dealing with governments and obtaining regulatory approvals; performance and conduct of the Operator; and risks associated with international operations.

The Company's project is in the appraisal and development stages and, as such, additional information must be obtained by further appraisal drilling and testing to ultimately determine the economic viability of developing any of the contingent or prospective resources. There is no certainty that the Company will be able to commercially produce any portion of its contingent or prospective resources. Any significant change, in particular, if the volumetric resource estimates were to be materially revised downwards in the future, could negatively impact investor confidence and ultimately impact the Company's performance, share price and total market capitalisation.

The Company has engaged professional geologists and engineers to evaluate reservoir and development plans; however, process implementation risk remains. The Company's reserves and resource estimations are based on data obtained by the Company which has been independently evaluated by McDaniel.

FINANCIAL INSTRUMENTS

The Company's financial instruments currently consist of cash, cash equivalents, advances to joint operations, other receivables, borrowings, accounts payable and accrued expenses, accrued interest on bonds, provisions for decommissioning costs, and current tax liabilities. The Company classifies its financial assets and liabilities at initial recognition in the following categories:

- Financial assets and liabilities at fair value through profit or loss are those assets and liabilities acquired principally to sell or repurchase in the short-term and are recognised at fair value. Transaction costs are expensed in the statement of comprehensive income and gains or losses arising from changes in fair value are also presented in the statement of comprehensive income within other gains and losses in the period in which they arise. Financial assets and liabilities at fair value through profit or loss are classified as current except for the portion expected to be realised or paid beyond twelve months of the balance sheet date, which is classified as non-current.
- Loans and receivables comprise of other receivables and cash and cash equivalents with fixed or determinable payments that are not quoted on an active market and are generally included within current assets due to their short-term nature and are classified as financial assets when the Company has a right to cash collection. If collection of the amounts is expected in one year or less they are classified as current assets. If not, they are presented as non-current assets. Loans and receivables are initially recognised at fair value and are subsequently measured at amortised cost using the effective interest method less any provision for impairment.
- Financial liabilities at amortised cost comprise of trade and other payables and are initially recognised at the fair value of the amount expected to be paid and are subsequently measured at amortised cost using the effective interest rate method. Financial liabilities are classified as current liabilities unless the Company has an unconditional right to defer settlement for at least 12 months after the balance sheet date.

With the exception of borrowings, accrued interest on bonds and provisions for decommissioning costs, which have fair value measurements based on valuation models and techniques where the significant inputs are derived from quoted prices or indices, the fair values of the Company's other financial instruments did not require valuation techniques to establish fair values as the instrument was either cash and cash equivalents or, due to the short term nature, readily convertible to or settled with cash and cash equivalents.

The Company is exposed in varying degrees to a variety of financial instrument related risks which are discussed in the following sections:

Financial Risk Management Objectives

The Company's management monitors and manages the Company's exposure to financial risks facing the operations. These financial risks include market risk (including commodity price, foreign currency and interest rate risks), credit risk and liquidity risk.

The Company does not presently hedge against these risks as the benefits of entering into such agreements is not considered to be significant enough as to outweigh the significant cost and administrative burden associated with such hedging contracts.

Commodity price risk: The prices that the Company receives for its oil and gas production may have a significant impact on the Company's revenues and cash flows provided by operations. World prices for oil and gas are characterised by significant fluctuations that are determined by the global balance of supply and demand and worldwide political developments and, in particular, the price received for the Company's oil and gas production in Kurdistan is dependent upon the Kurdistan government and its ability to export production outside of Iraq. A decline in the price of ICE Brent Crude oil, a reference in determining the price at which the Company can sell future oil production, could adversely affect the amount of funds available for capital reinvestment purposes as well as the Company's value in use calculations for impairment test purposes.

The Company does not hedge against commodity price risk.

Foreign currency risk: The substantial portion of the Company's operations require purchases denominated in USD, which is the functional and reporting currency of the Company and the currency in which the Company maintains the substantial portion of its cash and cash equivalents. Certain of its operations require the Company to make purchases denominated in foreign currencies, which are currencies other than USD and correspond to the various countries in which the Company conducts its business, most notably, Swiss Francs ("CHF") and Canadian dollars ("CAD"). As a result, the Company holds some cash and cash equivalents in foreign currencies and is therefore exposed to foreign currency risk due to exchange rate fluctuations between the foreign currencies and the USD. The Company considers its foreign currency risk is limited because it holds relatively insignificant amounts of foreign currencies at any point in time and since its volume of transactions in foreign currencies is currently relatively low. The Company has elected not to hedge its exposure to the risk of changes in foreign currency exchange rates.

Interest rate risk: The Company earns interest income at variable rates on its cash and cash equivalents and is therefore exposed to interest rate risk due to a fluctuation in short-term interest rates.

The Company's policy on interest rate management is to maintain a certain amount of funds in the form of cash and cash equivalents for short-term liabilities and to have the remainder held on relatively short-term deposits.

The Group is highly leveraged though financing at the project level, for the continuation of Atrush project, and at the corporate level due to GEP's outstanding Senior Bonds and Super Senior Bonds. However, the Company is not exposed to interest rate risks associated with the bonds as the interest rate is fixed over the next five years.

Credit risk: Credit risk is the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Company. The Company is primarily exposed to credit risk on its cash and cash equivalents, loans and receivables and other receivables.

The Company manages credit risk by monitoring counterparty ratings and credit limits and by maintaining excess cash and cash equivalents on account in instruments having a minimum credit rating of R-1 (mid) or better (as measured by Dominion Bond Rate Services) or the equivalent thereof according to a recognised bond rating service.

The carrying amounts of the Company's financial assets recorded in the consolidated financial statements represent the Company's maximum exposure to credit risk.

Liquidity risk: Liquidity risk is the risk that the Company will have difficulties meeting its financial obligations as they become due. In common with many oil and gas exploration companies, the Company raises financing for its exploration and development activities in discrete tranches to finance its activities for limited periods. The Company seeks to acquire additional funding as and when required. The Company anticipates making substantial capital expenditures in the future for the acquisition, exploration, development and production of oil and gas reserves and as the Company's project moves further into the development stage, specific financing, including the possibility of additional debt, may be required to enable future development to take place. The financial results of the Company will impact its access to the capital markets necessary to undertake or complete future drilling and development programs. There can be no assurance that debt or equity financing, or future cash generated by operations, would be available or sufficient to meet these requirements or, if debt or equity financing is available, that it will be on terms acceptable to the Company.

The Company manages liquidity risk by maintaining adequate cash reserves and by continuously monitoring forecast and actual cash flows. Annual capital expenditure budgets are prepared, which are regularly monitored and updated as considered necessary. In addition, the Company requires authorisations for expenditure on both operating and non-operating projects to further manage capital expenditures.

RISKS AND UNCERTAINTIES

ShaMaran Petroleum Corp. is engaged in the exploration, development and production of crude oil and natural gas and its operations are subject to various risks and uncertainties which include but are not limited to political and regional risks in the Kurdistan Region of Iraq, industry and market risks such as fluctuation in the price of oil, and business risks such as the potential for significant delays in the receipt of cash for its entitlement share of future oil exports and other risks discussed in this MD&A. For a complete discussion on risk factors which may affect the Company's business refer to the "Risk Factors" section of the Company's Annual Information Form, which is available for viewing both on the Company's web-site at www.shamaranpetroleum.com and on SEDAR at www.sedar.com, under the Company's profile.

ADDITIONAL INFORMATION

Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com and on the Company's web-site at www.shamaranpetroleum.com .