MANAGEMENT'S DISCUSSION AND ANALYSIS

SECOND QUARTER 2017 FINANCIAL AND OPERATING HIGHLIGHTS

- Successfully brought on production three light oil horizontal Banff wells drilled in the first quarter 2017 at Michichi;

- Production averaged 3,024 boe/d (44% liquids) in the second quarter of 2017, up 545 boe/d (22%) from the previous quarter;

- Closed a $30 million, 5-year subordinated term loan with Crown Capital Fund IV, LP, an investment fund managed by Crown Capital Partners Inc. (CRWN-TSX) and obtained a $12 million credit facility with National Bank of Canada to improve financial liquidity on May 30, 2017;

- Funds flows from operations were $2.4 million in the second quarter, an increase of $1.3 million from the previous quarter; and

- Operating netbacks averaged $15.79/boe in Q2 2017, a 21% increase from the previous quarter.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(thousands of Canadian dollars, except per share and per boe amounts)	Three months ended June 30, **2017**	2016	Six months ended June 30, **2017**	2016
Financial				
Oil and natural gas sales [1]	**$ 8,989**	$ 8,344	**$ 16,412**	$ 16,093
Funds flow from operations [2]	**$ 2,384**	$ 31	**$ 3,489**	$ 1,353
Per share - basic and diluted	**$ 0.01**	$ -	**$ 0.01**	$ 0.01
Per boe	**$ 8.66**	$ 0.09	**$ 7.00**	$ 1.81
Net income (loss)	**$ (1,956)**	$ 1,043	**$ (5,618)**	$ (6,875)
Per share - basic and diluted	**$ 0.00**	$ 0.01	**$ (0.01)**	$ (0.03)
Capital expenditures	**$ 1,246**	$ 377	**$ 7,486**	$ 477
Net debt [2]			**$ 22,914**	$ 44,275
Total Assets			**$ 175,458**	$ 182,647
Weighted average basic shares outstanding	**435,772,196**	205,686,639	**435,772,196**	205,686,639
Weighted average diluted shares outstanding	**435,772,196**	205,686,639	**435,772,196**	205,686,639
Operational				
Net wells drilled	**-**	-	**3**	-
Daily sales volumes				
Oil (bbls per day)	**1,174**	1,265	**1,088**	1,361
Heavy Oil (bbls per day)	**-**	261	**-**	334
NGL's (bbls per day)	**159**	136	**146**	147
Natural Gas (mcf per day)	**10,141**	12,864	**9,117**	13,657
Total (boe per day)	**3,024**	3,806	**2,754**	4,118
% Oil and NGL's	**44%**	44%	**45%**	45%
Average realized prices				
Light Oil ($/bbl)	**$ 52.11**	$ 46.92	**$ 52.36**	$ 38.45
Heavy Oil ($/bbl)	**$ -**	$ 35.03	**$ -**	$ 24.43
NGL's ($/bbl)	**$ 40.71**	$ 36.52	**$ 41.02**	$ 29.75
Natural Gas ($/mcf)	**$ 3.07**	$ 1.42	**$ 3.04**	$ 1.72
Netback				
Revenue ($/boe)	**$ 32.66**	$ 24.09	**$ 32.93**	$ 21.47
Royalties ($/boe)	**$ (1.90)**	$ (3.27)	**$ (2.24)**	$ (2.23)
Operating and transportation costs ($/boe)	**$ (16.18)**	$ (14.21)	**$ (16.79)**	$ (15.42)
Operating netback prior to hedging [2]	**$ 14.58**	$ 6.61	**$ 13.90**	$ 3.82
Realized hedging gain (loss) ($/boe)	**$ 1.21**	$ (0.13)	**$ 0.67**	$ 3.11
Operating netback ($/boe) [2]	**$ 15.79**	$ 6.48	**$ 14.57**	$ 6.94

(1) Before royalties
(2) Non-IFRS Measure. See Non-IFRS Measures advisory.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations for Marquee Energy Ltd. ("Marquee", "we", "our" or the "Company") as at and for the three and six months ended June 30, 2017. This MD&A is dated August 23, 2017 and should be read in conjunction with the Company's unaudited condensed interim Financial Statements and related notes thereto for the three and six months ended June 30, 2017, as well as the audited Financial Statements and related notes thereto for the years ended December 31, 2016. The Company's condensed interim Financial Statements have been prepared in accordance with International Accounting Standard ("IAS") 34, Interim Financial Reporting within International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All figures provided herein are reported in thousands of Canadian dollars unless otherwise stated. The reader should be aware that historical results are not necessarily indicative of future performance.

Additional information relating to Marquee, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com. Marquee is listed on the TSX Venture Exchange (TSX-V) under the symbol "MQL-V", and on the United States OTC Market ("OTCQX") under the symbol "MQLXF".

DESCRIPTION OF BUSINESS

Marquee Energy Ltd. is a publicly traded, Calgary-based, oil and natural gas company focused on high rate of return oil development and production. Marquee is committed to growing the Company through exploitation of existing opportunities and continued consolidation within its core area at Michichi, Alberta which includes are large contiguous land base.

RESULTS OF OPERATIONS

Production

	Three months ended June 30,			Six months ended June 30,		
	2017	2016	Change	**2017**	2016	Change
Light oil (bbls/d)	**1,174**	1,265	-7%	**1,088**	1,361	-20%
Heavy oil (bbls/d)	**-**	261	-100%	**-**	334	-100%
NGLs (bbls/d)	**159**	136	17%	**146**	147	-1%
Natural gas (mcf/d)	**10,141**	12,864	-21%	**9,117**	13,657	-33%
Total boe/d (6:1)	**3,024**	3,806	-21%	**2,754**	4,118	-33%
Production split (%)						
Crude oil and NGL	**44%**	44%	0%	**45%**	45%	0%
Natural gas	**56%**	56%	0%	**55%**	55%	0%
Total	**100%**	100%		**100%**	100%	

Marquee's second quarter sales decreased 21% to 3,024 boe/d compared to the second quarter of 2016. During the second quarter of 2016, the Company disposed of non-core shallow gas assets with average daily production of approximately 5,700 mcf/day, and 350 bbl/d of heavy oil production at Lloydminster for total sold production of 1,300 boe/day. During Q1 2017, the Company drilled and tied-in three wells which increased production in the second quarter by 595 boe/day to 3,024 boe/day as compared to 2,479 boe/day in the first quarter, a 22% increase.

Production for the six months was 2,754 boe/day, a 33% decrease from the 4,118 boe/day of 2016. Production declines year over year are a result of property dispositions, and the natural decline of existing light oil wells which was partially offset by the production from the wells drilled in the first quarter of 2017.

Average Realized Sales Prices

	Three months ended June 30,						Six months ended June 30,				
		2017		2016	Change		**2017**		2016	Change
Benchmark prices										
WTI ($US/bbl)	**$**	**48.29**	$	45.59	6%	**$**	**50.10**	$	39.52	27%
$CDN/$US foreign exchange rate	**$**	**0.74**	$	0.78	-5%	**$**	**0.75**	$	0.75	0%
WTI ($CDN/bbl)	**$**	**64.95**	$	58.76	11%	**$**	**66.81**	$	52.32	28%
MSW ($CDN/bbl)	**$**	**61.84**	$	54.68	13%	**$**	**62.85**	$	47.67	32%
AECO -5A (CDN$/mcf)	**$**	**2.79**	$	1.40	99%	**$**	**2.74**	$	1.62	69%
Average sales prices										
Light oil ($/bbl)	**$**	**52.11**	$	46.92	11%	**$**	**52.36**	$	38.45	36%
Heavy oil ($/bbl)	**$**	**-**	$	35.03	-100%	**$**	**-**	$	24.43	-100%
NGL ($/bbl)	**$**	**40.71**	$	36.52	11%	**$**	**41.02**	$	29.75	38%
Natural gas ($/mcf)	**$**	**3.07**	$	1.42	116%	**$**	**3.04**	$	1.72	77%
Combined ($/boe)	**$**	**32.66**	$	24.09	36%	**$**	**32.91**	$	21.47	53%

During the three months ended June 30, 2017, the WTI crude oil price benchmark averaged US$48.29/bbl as compared to US$45.59/bbl in the comparable 2016 period representing a 6% increase. Marquee's realized price for the quarter increased 11% to $52.11 from $46.92 in the prior year. The improvement in the realized price for the quarter was a result of the lower price differential between the Edmonton price (MSW) and WTI, and the difference in the exchange rate of the Canadian to US dollar.

For the six months ended June 30, 2017 WTI increased by 27% to $US 50.10/bbl compared to $US 39.52 for the comparable 2016 period. Marquee's realised price increased 36% to $52.36 from $38.45bbl. The improvement in the realized price for the six months is due to the improvement in the differential between the Edmonton (MSW) price and WTI.

Alberta AECO natural gas benchmark pricing increased 99% to $2.79 for the three months ended June 30, 2017, as compared to $1.40 for the same period in 2016. Consequently, Marquee's average realized price for the second quarter of 2017, increased to $3.07 per mcf as compared to $1.42 per mcf in the second quarter of 2016. For the six months ended June 30, 2017, AECO-5A increased by 69% from $1.62 in 2016 to $2.74. Marquee's realized gas price increased to $3.04 from $1.72, a 77% increase. Marquee produces natural gas with a higher heating value therefore receives a premium to the AECO price.

Oil and Natural Gas Revenue

	Three months ended June 30,			Six months ended June 30,		
(thousands of Canadian dollars)	**2017**	2016	Change	**2017**	2016	Change
Light oil	**5,568**	5,401	3%	**10,311**	9,525	8%
Heavy oil	**-**	832	-100%	**-**	1,485	-100%
NGLs	**589**	452	30%	**1,084**	796	36%
Natural gas	**2,832**	1,659	71%	**5,017**	4,287	17%
Total revenue	**8,989**	8,344	8%	**16,412**	16,093	2%

Total revenue for the second quarter of 2017 increased by 8% to $9.0 million compared to $8.3 million in the second quarter of 2016 and increased to $16.4 million for the six months as compared to $16.1 million for the comparable period in 2016, a 2% increase. The increase in revenue for the quarter and for the six months is attributable to strengthening prices which more than offset properties sold during Q2 2016 and lower volumes due to natural declines.

Royalties

(thousands of Canadian dollars, except per boe amounts)	Three months ended June 30, 2017	2016	Change	Six months ended June 30, 2017	2016	Change
Royalties	**524**	1,133	-54%	**1,115**	1,674	-33%
As a percentage of revenue	**6%**	14%	-57%	**7%**	10%	-35%
$/boe	**1.90**	3.27	-42%	**2.24**	2.23	0%

Royalties for the three months ended June 30, 2017, decreased to $0.5 million compared to $1.1 million for the same period in 2016. For the six months ending June 30, 2017 royalties decreased to $1.1 million compared to $1.7 million the previous year. As a percentage of sales, royalties decreased year over year due to the disposition of higher royalty rate properties in 2016 as well as lower royalty rates on the three wells drilled in 2017. The new wells qualify under the modernized Alberta provincial royalty framework in which the royalty is lower until the average drilling and completion costs are recovered after which higher royalty rates are applicable.

Commodity Price Contracts and Risk Management

The Company's financial results will be dependent on the prices received for crude oil and natural gas production. North American crude oil prices have sharply increased due primarily to global production quota reductions and reduced exploration and development drilling. Natural gas benchmark prices have also increased and are determined by supply and demand factors, including weather, and general economic conditions in natural gas consuming and producing regions. Management has been proactive in entering into derivatives for the purpose of hedging and has partially mitigated commodity price risk by entering into crude oil hedging contracts extending to June 30, 2019. Marquee's current commodity contract position as at the date of this MD&A is as follows:

Type of Instrument	Notional Volumes	Price	Index	Term
Crude Oil Swap	250 bbl/day	US$55.00/bbl	WTI-Fixed	July 1, 2017 to September 30, 2017
Crude Oil Collar	200 bbl/day	US$40.00 - $54.10/bbl	WTI-Fixed	July 1, 2017 to September 30, 2017
Crude Oil Collar	400 bbl/day	US$40.00 - $56.25/bbl	WTI-Fixed	October 1, 2017 to June 30, 2018
Crude Oil Put	400 bbl/day	US$45.00 Strike, $4.95 Premium	WTI-Fixed	July 1, 2018 to June 30, 2019
Natural Gas Swap	3,000 GJ/day	Cdn$3.05/GJ	AECO-Fixed	January 1, 2018 to March 31 ,2018
Natural Gas Swap	3,000 GJ/day	Cdn$2.48/GJ	AECO-Fixed	July 1, 2017 to September 30, 2017
Natural Gas Swap	3,000 GJ/day	Cdn$3.00/GJ	AECO-Fixed	October 1, 2017 to December 31, 2017
Natural Gas Swap	1,500 GJ/day	Cdn$2.80/GJ	AECO-Fixed	July 1, 2017 to September 30, 2017
Natural Gas Collar	3,000 GJ/day	Cdn$2.00 to $2.53/GJ	AECO-Fixed	April 1, 2018 to September 30, 2018
Natural Gas Collar	3,000 GJ/day	Cdn$2.20 to $2.72/GJ	AECO-Fixed	October 1, 2018 to December 31, 2018
Natural Gas Collar	3,000 GJ/day	Cdn$2.40 to $2.92/GJ	AECO-Fixed	January 1, 2019 to March 31, 2019
Natural Gas Collar	3,000 GJ/day	Cdn$1.90 to $2.14/GJ	AECO-Fixed	April 1, 2019 to June 30, 2019

A summary of realized and unrealized commodity contract gains and losses for the three and six months ended June 30, 2017 and 2016 are as follows:

(thousands of Canadian dollars)	Three months ended June 30, **2017**	2016	Change	Six months ended June 30, **2017**	2016	Change
Realized gain (loss) on commodity contracts	**334**	(45)	-842%	**334**	2,329	-86%
Unrealized gain (loss) on commodity contracts	**875**	(1,483)	-159%	**613**	(2,527)	-124%
	1,209	(1,528)	-179%	**947**	(198)	578%

Marquee realized a commodity contract gain for the three and six months ended June 30, 2017 of $0.3 million (2016 - $0.1 million loss and $2.4 million gain, respectively). For the six months ended June 30, 2017, an unrealized gain of $0.6 million (2016 - $2.5 million loss) was recognized. The fair value of the net commodity contract asset or liability is the estimated value to settle the outstanding contracts as at a point in time. As such, unrealized derivative gains and losses are not cash and the actual gains or losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices as compared to the valuation assumptions.

Operating and Transportation Expenses

(thousands of Canadian dollars, except per boe amounts)	Three months ended June 30, **2017**	2016	Change	Six months ended June 30, **2017**	2016	Change
Operating costs	**4,141**	4,455	-7%	**7,799**	10,555	-26%
Transportation costs	**311**	465	-33%	**571**	1,000	-43%
	4,452	4,920	-10%	**8,370**	11,555	-28%
$/boe	**16.18**	14.21	14%	**16.79**	15.42	9%

Production and transportation costs for the quarter were $4.5 million or $16.18 per boe compared to $4.9 million or $14.21 per boe for the second quarter of 2016. On a year to date basis production and operating costs were $8.4 million for 2017 compared to $11.6 million for 2016, a 28% decrease. The overall decrease in operating costs are due to reductions in field expenses due to management's cost containment strategy and reduced operational activity due to the sale of the Lloydminster and shallow gas assets in Q2 2016. Due to higher fixed costs on older wells, operating costs are not declining at the same rate as production.

General and Administrative Expenses

(thousands of Canadian dollars, except per boe amounts)	Three months ended June 30, **2017**	2016	Change	Six months ended June 30, **2017**	2016	Change
G&A expense, gross	**1,640**	1,525	8%	**2,988**	2,871	4%
Recovered and capitalized	**(150)**	(369)	-59%	**(332)**	(650)	-49%
G&A expense, net	**1,490**	1,156	29%	**2,656**	2,221	20%
$/boe, net	**5.41**	3.34	62%	**5.33**	2.96	80%

During the second quarter of 2017, general and administrative expense "G&A", net of capitalized and overhead recovery costs was $1.5 million or $5.41 per boe as compared to the quarter ended June 30, 2016 where G&A expenses were $1.2 million or $3.34 per boe. Gross G&A expenses prior to the effects of capitalized and overhead recoveries amounts were $1.6 million compared to $1.5 million for 2016. G&A expenses for both the three and six months ended June 30, 2017 were higher due to a lower overhead recovery as a result of the property dispositions in 2016 and severance costs in the current year. On a per barrel basis G&A for the second quarter and year to date 2017 is higher than 2016 due to lower sales volumes as a result of property sales in 2016.

Share-based Compensation

The Company records share-based compensation expense ("SBC") related to employee stock options with the offsetting amount recorded in contributed surplus. The Company capitalizes a portion of SBC which is directly attributable to personnel involved in exploration and development capital investment activities. Marquee uses a Black-Scholes option pricing model to calculate the fair value of stock option grants where the corresponding expense is recognized over the option vesting period.

As at June 30, 2017, the Company had 23,440,000 stock options which were outstanding at an average exercise price of $0.13 per option. For the three months and six months ended June 30, 2017 and 2016, the following is recorded related to SBC:

	Three months ended June 30,			**Six months ended June 30,**		
(thousands of Canadian dollars)	**2017**	2016	Change	**2017**	2016	Change
Gross costs	**64**	118	-46%	**183**	312	-41%
Capitalized costs	**(11)**	(11)	0%	**(12)**	(21)	-43%
Total shared-based compensation	**53**	107	-50%	**171**	291	-41%

Finance Expenses

	Three months ended June 30,			**Six months ended June 30,**		
(thousands of Canadian dollars, except per boe amounts)	**2017**	2016	Change	**2017**	2016	Change
Interest per boe	**1.45**	1.78	-19%	**1.63**	1.49	10%
Interest on debt	**400**	620	-36%	**815**	1,109	-27%
Amortization of debt issue costs	**34**	-	100%	**34**	-	100%
Accretion of decommissioning liabilities	**254**	258	-1%	**513**	588	-13%
Total Finance Expense	**688**	878	-22%	**1,362**	1,697	-20%

For the three and six months ended June 30, 2017, finance expenses decreased by approximately 20% compared to the prior year. The decrease in interest charges are attributable to a lower average debt balance, partially offset by higher borrowing rates.

Transaction Costs

	Three months ended June 30,			**Six months ended June 30,**		
(thousands of Canadian dollars)	**2017**	2016	Change	**2017**	2016	Change
Transaction costs	**9**	294	-97%	**147**	294	-50%

Transaction costs are the costs specific to transactions the Company enters into such as acquisitions and dispositions. For the six months ending June 30, 2017, $0.1 million of costs relate to final adjustments on transactions from 2016. $0.3 million during the first six months of 2016 relate to the two property dispositions during the second quarter of 2016.

Depletion and Depreciation

((thousands of Canadian dollars, except per boe amounts)	Three months ended June 30, 2017	2016	Change	Six months ended June 30, 2017	2016	Change
Depletion and depreciation	**4,783**	6,072	-21%	**9,001**	13,825	-35%
$/boe	**17.38**	17.53	-1%	**18.05**	18.45	-2%

The Company's depletion and depreciation expense is computed on a unit-of-production basis using proved plus probable reserves. The unit-of-production rate takes into account capital expenditures incurred to-date, together with future development capital expenditures required to develop those proved plus probable reserves. As a result, the depletion and depreciation provision, on an oil equivalent per-unit basis, may fluctuate period-to-period primarily due to changes in the underlying proved plus probable reserves base and in the amount of costs subject to depletion and depreciation. These costs are segregated and depleted on an area-by-area basis relative to the respective underlying proved plus probable reserves base.

For the three months ended June 30, 2017, the Company recorded depletion expense of $4.8 million or $17.38 per boe compared to $6.1 million or $17.53 per boe in the second quarter of 2016. For the six months ended June 30, 2017 the Company recorded depletion and depreciation expenses of $9.0 million compared to $13.9 million the prior year. The reduction in depletion expense in aggregate and on a per boe basis is due to decreased production, and the reduction to the depletable reserve base due to the Lloydminster and shallow gas asset dispositions.

Gain (loss) on disposition of oil and gas interests

On May 31, 2016, the Company completed a shallow gas disposition for net proceeds of $5.0 million with a net book value of $18.2 million and an associated decommissioning liability of $26.7 million. The asset included approximately 500 gross (396 net) wells and average production of approximately 5,700 mcf/d. The gross proceeds were used to reduce the Company's current debt. The disposition is consistent with Marquee's strategy to divest non-core assets to further focus on development of its core Banff light oil play at Michichi.

On June 6, 2016, the Company disposed of its heavy oil Lloydminster assets for net proceeds of $0.1 million with a net book value of $9.6 million and an associated decommissioning liability of $4.8 million. The property averaged approximately 350 barrels per day of heavy oil production and generated minor cash flow after payment of operating and royalty costs. As previously reported in 2015, Marquee sold a production volume royalty ("PVR") on its Lloydminster property in return for $20 million. A portion of these proceeds were used to fund a strategic acquisition by the Company in its core light oil property at Michichi. Under the PVR agreement, Marquee committed the first 137.5 bbl/d of production from the Lloydminster property to the royalty owner and made a commitment to spend a minimum of $2.75 million per year for 8 years beginning in 2016 on drilling activities related to the PVR lands. Marquee has assigned its interest in the Lloydminster property along with all related PVR obligations and capital commitments to the buyer.

Taxes

Deferred income taxes arise from differences between the accounting and tax basis of assets and liabilities. The estimate of deferred income taxes is based on the current tax status of the Company, enacted legislation and management's best estimates of future events. The effective tax rate differs from the statutory tax rate as it primarily takes into consideration permanent differences, adjustments for changes in tax rates and other tax legislation, and the actual amounts subsequently reported on the Company's corporate tax return.

For the six months ended June 30, 2017, as a result of low oil and natural gas prices and management's judgment related to recognition of deferred tax assets, the Company did not record the benefit of deferred tax.

Funds Flow from Operations and Net Income (Loss)

The MD&A contains the term funds flow from operations which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with IFRS as an indicator of the Company's performance. The Company reconciles funds flow from operations to cash flow from operating activities, which is the most directly comparable measure calculated in accordance with IFRS (see Non-IFRS Measures section for more information).

(thousands of Canadian dollars, except per share and per boe amounts)	**Three months ended June 30,** **2017**	2016	**Six months ended June 30,** **2017**	2016	Change
Funds flow from operations	**2,384**	31	**3,489**	1,353	
Per share, basic and diluted	**0.01**	0.00	**0.01**	0.00	
Net income (loss)	**(1,956)**	1,043	**(5,618)**	(6,875)	
Per share, basic and diluted	**0.00**	0.01	**(0.01)**	(0.02)	

Funds flow from operations for the three months ended June 30, 2017 was $2.4 million or $0.01 per share compared to $0.03 million or $0.00 per share for the second quarter of 2016. For the six months ended June30, 2017 funds flow from operations was $3.5 million compared to $1.4 million for the same period of 2016. The increase compared to the 2016 periods is due to higher prices in 2017.

The net loss for the three months ended June 30, 2017 was $2.0 million ($0.00 per share, basic and diluted) compared to a net income of $1.0 million ($0.00 per share, basic and diluted) for the same period in 2016. For the six months ended June 30, 2017 the net loss was $5.6 million compared to $6.9 million in the prior year.

The following table summarizes the Company's netbacks, funds flow from operations and net income (loss) on a per boe basis for the three and six months ended June 30, 2017, and 2016:

($/boe)	**Three months ended June 30,** **2017**	2016	Change	**Six months ended June 30,** **2017**	2016	Change
Sales	**32.66**	24.09	36%	**32.93**	21.47	53%
Royalties	**(1.90)**	(3.27)	-42%	**(2.24)**	(2.23)	0%
Production costs	**(15.05)**	(12.86)	17%	**(15.65)**	(14.08)	11%
Transportation costs	**(1.13)**	(1.35)	-16%	**(1.14)**	(1.33)	-14%
Operating netback prior to hedging	**14.58**	6.61	121%	**13.90**	3.83	263%
Realized hedging gain (loss)	**1.21**	(0.13)	-1031%	**0.67**	3.11	-78%
Operating netback [1]	**15.79**	6.48	144%	**14.57**	6.94	110%
General and administrative expenses	**(5.41)**	(3.34)	62%	**(5.33)**	(2.96)	80%
Decommissioning expenditures	**(0.02)**	(0.42)	-48%	**(0.19)**	(0.29)	3%
Interest expense	**(1.45)**	(1.78)	-18%	**(1.63)**	(1.49)	10%
Transaction costs	**(0.03)**	(0.85)	-95%	**(0.29)**	(0.39)	-26%
Exploration and evaluation cash	**(0.22)**	-	100%	**(0.13)**	-	100%
Funds flow from operations [1]	**8.66**	0.09	9,555%	**7.00**	1.81	214%
Depletion and depreciation	**(17.38)**	(17.53)	-1%	**(18.06)**	(18.45)	-2%
Decommissioning expenditures	**0.02**	0.42	-48%	**0.19**	0.29	3%
Accretion	**(0.92)**	(0.74)	26%	**(1.03)**	(0.78)	32%
Amortization of debt issue costs	**(0.12)**	-	100	**(0.07)**	-	100%
Share-based compensation	**(0.19)**	(0.31)	-39%	**(0.34)**	(0.39)	-13%
Unrealized gain (loss) on commodity price contracts	**3.18**	(4.29)	-174%	**1.23**	(3.37)	-136%
Exploration and evaluation non-cash	**(0.35)**	-	178%	**(0.19)**	-	-103%
Gain on disposition	-	25.37	-	-	11.72	-
Net income (loss) and comprehensive (loss)	**(7.10)**	3.01	-336%	**(11.27)**	(9.17)	23%

[1] Non-IFRS Measure. See Non-IFRS Measures advisory.

Capital Expenditures

(thousands of Canadian dollars)	**Three months ended June 30, 2017**	2016	**Six months ended June 30, 2017**	2016
Land and lease (1)	**75**	112	**293**	175
Seismic (1)	**18**	16	**166**	62
Drilling and completions (1	**507**	-	**4,975**	-
Equipment and facilities (1	**476**	-	**2,082**	(187)
Dispositions (2)	**-**	(5,127)	**-**	(5,127)
Capitalized general & administrative and other expenses (2)	**170**	249	**330**	427
	1,246	(4,750)	**7,846**	(4,650)

(1) Includes expenditures on exploration and evaluation assets as well as PP&E
(2) Includes non-cash additions

During the second quarter, the Company incurred approximately $1.0 million complete and equip and tie-in costs relating to the three wells drilled in Q1. For the six months ended June 30, 2017, the company drilled three wells for a total drill, complete and equip of $5.4 million. The three wells came on production in early April and are producing at expected levels.

CAPITAL RESOURCES AND LIQUIDITY

Credit Facility

The Company obtained a new senior demand revolving credit facility ("facility") for $12.0 million, with a Canadian Bank on May 30, 2017. The facility can be used for general corporate purposes and capital expenditures, and bear interest at either the Bank's prime rate plus an applicable margin (of 75 bps to 275 bps) or, Bankers' Acceptance ("BA") rates plus an additional margin (of 200 bps to 400 bps) both determined quarterly, in accordance with net debt to trailing EBITDA ratio. Repayments of principal are not required provided the Company is in compliance with all covenants, representations and warranties.

At June 30, 2017, the Company has not drawn on the facility, however, the Company has letters of guarantee outstanding for $0.7 million which reduces the amount available under the revolving loan.

The Company is required to maintain the following covenants at the end of each fiscal quarter:

- Adjusted Working Capital Ratio, of not less than 1:1;
- Net Bank Debt to Trailing EBITDA Ratio not to exceed 3:1; and
- Alberta Energy Regulator Rating Liability Management Rating (LMR) of not less than 1.25:1.

At June 30, 2017, the Company was in compliance with all covenants.

For the purposes of compliance with the Adjusted Working Capital Ratio, the current portion of bank debt and the fair value of any commodity contracts are excluded and the unused portion of the facility is added to working capital.

Net Bank Debt includes drawings on the Facility and the Term loan less cash on hand. EBITDA is defined by the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and extraordinary, unusual or non-recurring items. For quarter ended June 30, 2017 Trailing EBITDA is annualized by multiplying by four; for the fiscal quarter ended September 30, 2017 Trailing EBITDA is annualized by multiplying by 2; for the quarter ended December 31, 2017 Trailing EBITDA is annualized by multiplying by 4/3 and for quarter ended March 31, 2018 and thereafter, the Trailing EBITDA is for the past for twelve months.

The next semi-annual review is scheduled for October 31, 2017. The facility is secured by a general security agreement and first floating charge debenture of $25 million over the Company's assets. The various covenants in the Facility and Term Loan may impact the Company's ability to access the full $12 million on the Facility. Based on the covenant calculations at June 30, 2017, the Company would be able to fully draw on the $12 million and remain in compliance with its covenants.

Term Loan

The Company obtained a Term Loan for $30.0 million, which included the issuance of 37.5 million warrants to purchase common shares on May 30, 2017. The warrants shall be exercisable by the holder, in whole or in part, for four years until May 30, 2021.

The Term Loan matures on May 30, 2022, and bears interest at 10% per annum with interest payments due quarterly beginning June 30, 2017. The effective interest rate is 12.9%. The Term Loan contains certain restrictions that limit the Company's ability to incur additional indebtedness of more than $15 million in a Senior Credit Facility, (including the current facility listed above), and dispose of certain assets.

The principal amount is due upon maturity of the loan. Amounts borrowed under the Term Loan that are repaid are not available for re-borrowing. The Company may not repay the Term Loan prior to the second anniversary thereof. The loan is subject to a prepayment fee of 3%, 2% or 1% if repayments are made during the third, fourth or fifth year. The Term Loan is secured by a general security agreement over all of the present and future property of the Company on a second priority basis, subordinate only to liens securing loans under the Credit Facility.

The Term Loan is subject to financial covenants that require Marquee maintain:

- Adjusted working capital ratio of not less than 1:1
- Net Bank Debt to Trailing Twelve Month EBITDA not to exceed 3:1
- Net Bank Debt to Total Proved Develop Producing Reserves (discounted at 10%) Ratio not to exceed 1:1
- Net Bank Debt to Total Proved Reserves (discounted at 10%) Ratio not to exceed 0.6:1
- Alberta Energy Regulator Rating Liability Management Rating (LMR) of not less than 1.25:1

The Company was in compliance with all financial covenants at June 30, 2017.

Capital Management

The Company carefully monitors capital availability by tracking its current working capital, available credit facility, projected cash flow from operating activities and anticipated capital expenditures. Marquee considers its capital structure to include shareholders' equity and net debt.

In order to maintain or adjust the capital structure, the Company may issue shares, amend, revise or renew terms of the existing credit facility, access alternative forms of debt and equity and adjust its capital spending to manage its current and projected capital structure. The Company's ability to raise additional funds through debt or equity financing may be impacted by external conditions, including future commodity prices and the global economic outlook. The Company continually monitors business conditions including: changes in economic conditions, the risk of its drilling programs, forecasted commodity prices and potential corporate or asset acquisitions.

The Company monitors capital based on three financial ratios: 1) Net Debt to Annualized Funds Flow from Operations, 2) Adjusted Working Capital Ratio and 3) Net Bank Debt to Trailing EBITDA Ratio (See Non-IFRS Measures advisory).

The net debt to annualized funds flow from operations represents the time period it would take to pay off the Company's debt if no further capital expenditures were incurred and if funds flow from operating activities remained constant. This ratio is calculated as net debt divided by annualized cash flows from operating activities before changes in non-cash working capital ("funds flow from operations"). Net debt is defined as outstanding debt plus or minus net working capital (excluding fair value of commodity contracts).

As at June 30, 2017, the Company's ratio of net debt to annualized second quarter funds flow from operations was 2.4 to 1 (June 30, 2016 – 357.0 to 1). The decrease in the ratio at June 30, 2017 was mainly the result increased funds flow for the quarter and reduced debt. The following table summarizes the Company's net debt to funds flow from operations calculation, as at:

(thousands of Canadian dollars, except ratios)	**June 30, 2017**	June 30, 2016
Current assets, excluding commodity contracts	**11,698**	4,945
Bank loan	**-**	(44,737)
Term loan	**(30,000)**	-
Accounts payable and accrued liabilities, excluding commodity contracts	**(4,612)**	(4,483)
Net debt	**(22,914)**	(44,275)
Quarterly funds flow from operations	**2,384**	31
Annualized quarterly funds flow from operations	**9,536**	124
Net debt to funds flow from operations	**2.4 to 1.0**	357.0 to 1.0

The Company is required to maintain, under its Credit Facility and Term Loan, a working capital ratio of greater than 1 to 1, defined as the ratio of current assets (including undrawn available credit on the revolving and operating portion of the credit facility and excluding the fair value of the commodity contracts) divided by current liabilities (less the current portion of bank debt and the fair value of the commodity contracts). At June 30, 2017, the working capital ratio was 5.0 to 1.0 (June 30, 2016 – 2.1 to 1.0) and the Company was in compliance with the covenant. The following table summarizes the Company's working capital calculation as defined by its lending facility covenants, as at:

(thousands of Canadian dollars)	**June 30, 2017**	June 30, 2016
Current assets, excluding commodity price contracts	**11,698**	4,945
Undrawn available credit	**11,343**	4,606
Subtotal	**23,041**	9,551
Current liabilities, excluding bank debt and commodity price contracts	**4,612**	4,483
Working capital ratio	**5.0 to 1.0**	2.1 to 1.0

The Company is required to maintain, under its Credit Facility and Term Loan, a Net Bank Debt to Trailing EBITDA Ratio not to exceed 3:1 (defined above under Credit Facility section). At June 30, 2017, the working capital ratio was 2.0 to 1.0 and the Company was in compliance with the covenant.

The following table summarizes the Company's working capital calculation as defined by its new lending facility covenants, as at:

(thousands of Canadian dollars, except ratios)	**June 30, 2017**
Cash	**5,707**
Bank loan	**-**
Term loan	**(30,000)**
Net Bank Debt	**(24,293)**
Quarterly EBITDA	**3,057**
Annualized EBITDA	**12,228**
Net debt to funds flow from operations	**2.0 to 1.0**

Contractual Obligations

(thousands of Canadian dollars)	2017	2018	2019	2020	2021	Remainder	Total
Office lease	129	361	361	361	-	-	1,212
Processing	1,144	2,300	2,300	2,300	2,300	2,859	13,203
Flow through shares	2,756	-	-	-	-	-	2,756
Term Loan	-	-	-	-	-	30,000	30,000
	4,029	2,661	2,661	2,661	2,300	32,859	47,171

The Company entered into a new office lease effective January 1, 2016 with commitments that expire in 2020.

On August 19, 2015 Marquee completed a facility arrangement with a third party under which the company received $15.0 million in cash, before transaction costs, in exchange for the sale of a gas plant. Under the facility arrangement the Company has been contracted by the purchaser to operate the facility over a 7.5-year term and will continue to process gas from certain producing properties. Marquee will pay the purchaser an annual facility tariff fee of $2.3 million for the life of the agreement, but retain all third-party processing revenues generated.

On December 29, 2016, the Company issued 16,533,500 flow-through shares at $0.17/share for total proceeds of $2.8 million. The Company has committed to spend $2.8 million of qualifying expenditures by December 31, 2017.

The Term Loan matures on May 30, 2022.

Common Share, Stock Options and Warrants Outstanding

The following denotes Marquee common shares outstanding, stock options and warrants:

	August 23, 2017	June 30, 2017	December 31, 2016
Common shares	**435,772,196**	435,772,196	435,772,196
Stock options	**23,440,000**	23,440,000	11,700,000
Warrants	**37,500,000**	37,500,000	-

RISKS AND UNCERTAINTIES

Business Risks

The oil and gas industry is subject to risks in (among others):

- Finding and developing reserves;
- Commodity prices received for such reserves;
- Availability of equipment, manpower and supplies;
- Availability and cost of capital to achieve projected growth;
- Effect of weather on drilling and production; and
- Operating in an environmentally appropriate fashion.

The Company mitigates these business risks by:

- Maintaining cost-effective operations;
- Maintaining a balance between oil and gas properties;
- Operating our own properties to control the amount and timing of capital expenditures;
- Using a commodity hedging strategy to mitigate price risk
- Using new technology to maximize production and recoveries and reduce operating costs;
- Restricting operations to western, central and southern Alberta where locations are accessible, operating and capital costs are reasonable and on-stream times are shorter; and

- Drilling wells in areas with multiple high deliverability zone potential.

Environmental, Health and Safety Risk

Environmental, health and safety risks relate primarily to field operations associated with oil and gas assets. To mitigate this risk, a preventative environmental, health and safety program is in place, as is operational loss insurance coverage. Marquee employees and contractors adhere to the Company's environmental, health and safety program, which is routinely reviewed and updated to ensure that the Company operates in a manner consistent with best practices in the industry. The Board of Directors oversees the risk assessment and risk mitigation process.

Regulation, Tax and Royalty Risk

Regulation, tax and royalty risk relates to changing government royalty regulations, income tax laws and incentive programs impacting the Company's financial and operating results. Management, with the assistance of legal and accounting professionals, stay informed of proposed changes in laws and regulations and proactively responds to and plan for the effects of these changes.

Industry and Economic Factors

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, environmental, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to taxation of oil and natural gas by agreements among the governments of Canada and Alberta, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the Company's operations in a manner materially different than they would affect other oil and gas companies of similar size and with similar assets. All current legislation is a matter of public record and the Company is currently unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry.

The producers of oil are entitled to negotiate sales and purchase agreements directly with oil purchasers. Most domestic Canadian agreements are linked to standard market oil reference prices being Edmonton Mixed Sweet Blend ("MSW") and Western Canadian Select ("WCS"). Oil prices are set by daily, weekly and monthly physical and financial transactions for crude oil. Those prices are primarily based on worldwide and domestic fundamentals of supply and demand. Specific prices depend in part on oil quality, prices of competing fuels, distance to the markets, value of refined products, the supply/demand balance and other contractual terms. The price of natural gas is also determined by negotiation between buyers and sellers.

Domestic prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of other factors beyond the Company's control. These factors include, but are not limited to, the actions of the Organization of the Oil Exporting Countries (OPEC), world economic conditions, government regulation, political developments, the foreign supply of oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions.

In addition to federal regulation, each province has legislation and regulations governing land tenure, royalties, production rates, environmental protection, and other matters.

For a complete discussion of the risks affecting Marquee, refer to the Company's most recently filed Annual Information Form, available on SEDAR at www.sedar.com.

SUMMARY OF QUARTERLY RESULTS

The following table summarizes the Company's key quarterly financial results for the past eight quarters:

(thousands of Canadian dollars except per share amounts)	**June 30 2017**	March 31 2017	Dec. 31 2016	Sept. 30 2016	June 30 2016	March 31 2016	Dec. 31 2015	Sept. 30 2015
Financial								
Oil and natural revenue	**8,989**	7,423	8,013	7,432	8,344	7,749	12,153	12,792
Funds flow from (used in) operations	**2,384**	1,106	(3,886)	(532)	31	1,322	2,304	2,037
Basic & diluted ($/share)(1)	**0.01**	-	-	-	0.01	0.01	0.01	0.01
Net income/(loss)	**(1,956)**	(3,663)	(10,063)	(5,247)	1,043	(7,918)	(26,701)	(17,837)
Basic and diluted ($/share)(1)	**(0.01)**	(0.01)	(0.05)	(0.03)	0.01	(0.04)	(0.13)	(0.09)
Capital expenditures (2)	**-**	6,611	1052	210	377	100	2,386	8,577
Total assets	**175,458**	174,239	169,162	178,553	182,647	217,189	227,941	258,956
Total equity	**86,799**	86,855	90,412	68,134	73,258	72,098	79,821	104,421
Net debt	**22,914**	22,688	17,165	45,019	44,275	49,058	50,279	51,904
Weighted average common shares outstanding	**435,772**	435,772	266,382	205,687	205,687	205,687	201,430	200,969
Operations								
Average daily production								
Crude oil (bbl/d)	**1,174**	1,000	1,047	1,240	1,265	1,457	1,691	1,437
Heavy oil (bbl/d)	**-**	-	-	10	261	407	461	542
NGLs (bbl/d)	**159**	132	172	148	136	157	176	152
Natural gas (mcf/d)	**10,141**	8,082	8,034	8,241	12,864	14,451	15,578	15,430
Total boe/d	**3,024**	2,479	2,558	2,772	3,806	4,430	4,924	4,703

(1) Prior period per share amounts have been recalculated, due to the reverse takeover of AOS by Marquee, to reflect the Marquee number of shares outstanding multiplied by the exchange ratio of 1.67.
(2) Excludes acquisitions and dispositions

Three months ended June 30, 2017 (Q2-2017) compared to March 31, 2017 (Q1-2017)
Volumes increased 22% to 3,024 boe/day compared to 2,479 boe/day in Q1 – due to the three wells drilled in Q1 coming on production in early Q2 at better than expected rates. Revenue increased by 21% to $9.0 million due to increase production and relatively stable prices. Capital expenditures for the period relate to completion, equipping & tie-in costs on the wells drilled in Q1.

Three months ended March 31, 2017 (Q1-2017) compared to December 31, 2016 (Q4-2016)
Volumes decreased by 4% from Q4 and prices on a BOE basis decreased 2% with oil and liquids price up from the prior quarter but gas prices decreased. Total revenue decreased by 7%. Operating costs decreased by $1.8 million to $17.56 per boe. During Q1 the Company, drilled 3 net wells for a drill and equip expenditures of $5.3 million. The wells came on production in early April.

Three months ended December 31, 2016 (Q4-2016) compared to September 30, 2016 (Q3-2016)
Revenue for the fourth quarter was up 8% compared to Q3. Production was down slightly quarter to quarter but prices recovered in the fourth quarter, on a boe basis prices in Q4 were up by 17% compared to Q3. Capital for the quarter represent capitalized G&A and lease rentals on producing properties. The reverse acquisition of AOS was recorded as of the date of

amalgamation – December 6, 2016. The larger loss in Q4 compared to Q3 is partially attributable to the $3.2 million in transaction costs relating to the AOS acquisition.

Three months ended September 30, 2016 (Q3-2016) compared to June 30, 2016 (Q2-2016)
Total revenue was lower in Q3 compared to Q2 as a result of being the first full quarter of decreased volumes as a result of the properties sold. Realized oil prices remained consistent with Q2 but gas prices increased by 82% to $2.58 compared to $1.42 for Q2. The swing from net income of $1,043 in Q2 to a loss of $5,247 in Q3 is mainly due to the gain on sale of property recorded in Q2. Capital expenditures for the quarter represent capitalized G&A and lease rentals on producing and non-producing lands.

Three months ended June 30, 2016 (Q2-2016) compared to March 31, 2016 (Q1-2016)
Total revenue was higher in Q2 2016 compared to Q1 2016 due to increased commodity benchmark and realized prices slightly offset by decreased production. Net income in the Q2 2016 was mainly attributable to the net gain on petroleum and natural gas interests related to the disposition of the Lloydminster and shallow gas assets. Capital expenditures in the period represent capitalized G&A and lease rentals on producing and non-producing lands.

Three months ended March 31, 2016 (Q1-2016) compared to December 31, 2015 (Q4-2015)
Total revenue was lower in Q1 2016 compared to Q4 2015 due to decreased production volumes and decreased commodity benchmark and realized prices. The lower net loss in Q1 2016 compared to Q4 2015 was due to decreased depletion charges, prior quarter impairment charges and exploration and evaluation expenses relating to expired undeveloped land, offset by decreased Q1 2016 operating netbacks. Reduced capital expenditures in the quarter are reflective of zero wells drilled since Q3 2015 and a corporate strategy to defer further optional capital spending until commodity price recovery.

Three months ended December 31, 2015 (Q4-2015) compared to September 30, 2015 (Q3-2015)
Total revenue was lower in Q3 2015 compared to Q2 2015 despite higher production volumes due to decreased commodity benchmark and realized prices. The net loss in Q4 2015 compared to net loss in Q3 2015 was higher due to exploration and evaluation expenditures relating to undeveloped land expiry's, lower operating netbacks, increased depletion and impairment charges. Capital expenditures in the quarter decreased due to Marquee drilling zero wells compared to four horizontal Michichi wells in Q3-2015.

Three months ended September 30, 2015 (Q3-2015) compared to June 30, 2015 (Q2-2015)
Total revenue was lower in Q3 2015 compared to Q2 2015 due to lower production volumes and decreased commodity benchmark and realized prices. The net loss in Q3 2015 compared to net loss in Q2 2015 was higher due to lower operating netbacks, increased depletion, third quarter impairment charge and a deferred tax expense. Capital expenditures in the quarter increased due to Marquee drilling four horizontal Michichi wells compared to zero in Q2-2015.

NON-IFRS MEASURES

Operating Netback
This MD&A contains the term "operating netback" which does not have a standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures by other companies. Marquee uses field operating netbacks to analyze operating performance. Marquee believes this benchmark is a key measure of profitability and overall sustainability for the Company and this term is commonly used in the oil and natural gas industry. Field operating netbacks are not intended to represent operating profits, net earnings or other measures of financial performance calculated in accordance with IFRS.

Operating netbacks are calculated by deducting royalties, production and operating and transportation expenses from revenues before other income (losses), and adding (deducting) commodity contract gains (losses).

Funds Flow From Operations

This MD&A and the financial statements contain the term "funds flow from operations" which should not be considered an alternative to, or more meaningful than "cash flow from operations" as determined in accordance with IFRS as an indicator of the Company's performance. Therefore, reference to funds flow from operations or funds flow from operations per share may not be comparable with the calculation of similar measures for other entities. Management uses funds flow from operations to analyze operating performance and leverage and considers funds flow from operations to be a key measure as it demonstrates the Company's ability to generate cash necessary to fund future capital investments and to repay debt. Funds flow from operations per share is calculated using the weighted average number of shares for the period.

(thousands of Canadian dollars)	Three months ended June 30, **2017**	2016	Change	Six months ended June 30, **2017**	2016	Change
Cash flow from operations	**12**	540	-98%	**259**	2,688	-90%
Changes in non-cash working capital	**2,372**	(509)	-566%	**3,230**	(1,335)	-342%
Funds flow from (used in) operations	**2,384**	31	7,591%	**3,489**	1,353	158%

Net Debt to Annualized Funds Flow

This MD&A and the financial statements also contain the term net debt and net debt to annualized funds flow from operations. Net debt and net debt to annualized funds flow from operations is calculated as net debt, defined as outstanding bank debt plus or minus net working capital (excluding fair value of commodity contracts), divided by annualized quarterly cash flow from operating activities before decommissioning expenditures, transaction costs and changes in non-cash working capital. Management considers net debt and net debt to annualized funds flow as important additional measures of the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds flow from operations remained constant.

Net Bank Debt to EBITDA

The Company uses the terms Net Bank Debt to EBITDA which are used in reference to the financial covenants prescribed by the Company's bank facility and term loan. Under the bank facility and term loan, debt includes drawings on the bank facility and the term loan less cash on hand. EBITDA is defined by the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent quarter. Other non-cash items include impairment, gains or losses on divestitures and the premium on flow-through shares.

For quarter ended June 30, 2017 EBITDA is annualized by multiplying by four; for the fiscal quarter ended September 30, 2017 EBITDA is annualized by multiplying by 2; for the quarter ended December 31, 2017 EBITDA is annualized by multiplying by 4/3 and for quarter ended March 31, 2018, the EBITDA is for the past for twelve months.

BOE Conversions

The term "barrels of oil equivalent" (BOE) may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil (6:1) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared with natural gas is significantly different than the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. (This conversion conforms to National Instrument 51-101). References to natural gas liquids ("NGL") in this MD&A include condensate, propane, butane and ethane. One barrel of NGL is considered to be equivalent to one barrel of crude oil equivalent (BOE).

CRITICAL ACCOUNTING ESTIMATES

The timely preparation of financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets and liabilities, as at the statement of financial position date and the reported amounts of revenues and expenses during the year. Accordingly, actual results may differ from these estimates.

Estimates and judgments are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Accounting estimates will, by definition, seldom equal the actual results. Revisions to accounting estimates are recognized in the period in which estimates are revised and in any future periods affected.

The following discussion sets forth management's significant judgments and estimates made in preparation of these financial statements.

Management Judgment and Estimates

The following are the critical judgments that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these financial statements.

Identification of cash-generating units
Oil and natural gas interests, exploration and evaluation assets and other corporate assets are aggregated into cash-generating-units ("CGUs") based on their ability to generate largely independent cash flows and are used for impairment testing. The classification of assets into CGU's requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures and the way in which management monitors the Company's operations. The Company has identified Michichi as its core CGU.

Impairment of oil and natural gas assets
Judgments are required to assess when impairment indicators, or reversal indicators, exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

Exploration and evaluation assets
The decision to transfer exploration and evaluation assets to property, plant and equipment is based on management's determination of an area's technical feasibility and commercial viability based on proved and probable reserves as well as related future cash flows.

Deferred taxes
Judgments are made by management to determine the likelihood of whether deferred tax assets at the end of the reporting period will be realized from future taxable earnings. To the extent that assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit and loss in the period in which the change occurs.

Key Sources of Estimation Uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

Reserves
The assessment of reported recoverable quantities proved and probable reserves include estimates regarding production volumes, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying value of the Company's oil and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning liabilities, and the recognition of deferred tax assets due to changes in expected future cash flows. The Company's petroleum and natural reserves are independently evaluated by reserve engineers at least annually and are determined pursuant to National Instrument 51-101, Standard of Disclosures for Oil and Gas Activities.

Decommissioning liabilities
The calculation of decommissioning liabilities and related accretion expense includes management's estimates of current risk-free interest rates, future inflation rates, future restoration and reclamation expenditures and the timing of those expenditures. In most instances, removal of assets occurs many years in the future.

Share based payments
The amounts recorded for share-based compensation expense relating to the fair value of stock options and warrants issued are estimated using the Black-Scholes option pricing model including management's estimates of the future volatility of the Company's share value, quoted market value of the Company's shares at grant date, expected forfeiture rates, expected lives of the options and warrants (based on historical experience and general holder behaviours), and the risk-free interest rate (based on government bonds).

Business combinations and asset acquisitions
The values assigned to the common shares issued in the asset acquisitions completed in 2015 and 2014 and the allocation of the purchase price to the net assets in the acquisitions are based on numerous estimates that affect the valuation of certain assets and liabilities acquired including the discount rates, estimates of proved and probable reserves, estimates of fair values of exploration and evaluation assets, future oil and natural gas prices and other factors.

Commodity Price Contracts
The amounts recorded for the fair value of commodity contracts are based on estimates of future commodity prices, foreign exchange rates and the volatility in those prices.

Deferred tax asset
The amounts recorded for deferred tax assets are based on estimates as to the timing of the reversal of temporary differences, substantially enacted tax rates and the likelihood of tax assets being realized. The availability of tax pools and other deductions are subject to audit and interpretation by tax authorities.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Company has reviewed new and revised accounting pronouncements listed below that have been issued, but are not yet effective. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported loss or net assets of the Company.

In July 2014, the IASB completed the final elements of IFRS 9 "Financial Instruments." The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement." IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The mandatory effective date of IFRS 9 is for annual periods on or after January 1, 2018, and must be applied retrospectively with some exceptions. Early adoption is permitted. The Company is evaluating the impact of this standard on the financial statements and does not anticipate a material change to the valuation of its financial assets.

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue", IAS 11 "Construction Contracts" and related interpretations. In July 2015, the IASB issued an amendment to IFRS 15, deferring the effective date by one year. IFRS 15 provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. The Company has commenced the process of identifying and reviewing sales contracts with customers to determine the extent of the impact, if any, that this standard will have on the financial statements.

In January 2016, the IASB issued IFRS 16 "Leases", which replaces IAS 17 "Leases". For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, which required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15, Revenue from Contracts with Customers. The Company is evaluating the impact of the standard on the Company's financial statements.

FORWARD-LOOKING INFORMATION AND STATEMENTS

Certain statements included or incorporated by reference in this Management's Discussion and Analysis may constitute forward looking statements under applicable securities legislation. Such forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this Management's Discussion and Analysis may include, but are not limited to:

- 2017 capital budget and expenditures;
- business strategies, objectives and outlook;
- Oil and natural gas sales;
- future production levels (including the timing thereof) and rates of average annual production growth;
- exploration and development plans;
- acquisition and disposition plans and the timing and the anticipated benefits thereof;
- anticipated cash flows;
- expected cost reductions and production efficiencies derived from recently acquired assets;
- number and quality of future potential drilling locations future drilling plans;
- expected debt levels;
- operating and other expenses;
- royalty and income tax rates; and
- the timing of regulatory proceedings and approvals.

Such forward-looking statements or information are based on a number of assumptions all or any of which may prove to be incorrect. In addition to any other assumptions identified in this document, assumptions have been made regarding, among other things:

- the ability of the Company to obtain equipment, services and supplies in a timely manner to carry out its activities;
- the ability of the Company to market crude oil, natural gas liquids and natural gas successfully to current and new customers;
- the ability to secure adequate product transportation;
- the timely receipt of required regulatory approvals;
- the ability of the Company to obtain financing on acceptable terms;
- interest rates;
- regulatory framework regarding taxes, royalties and environmental matters;
- future crude oil, natural gas liquids and natural gas prices; and
- Management's expectations relating to the timing and results of development activities.

Forward-looking information is based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking information. The material risk factors affecting the Company and its business are contained in Marquee's Annual Information Form.

The forward-looking information contained in this Management's Discussion and Analysis is made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward looking information contained in this Management's Discussion and Analysis is expressly qualified by this cautionary statement.

DIRECTORS

Dr. William Roach
Chairman of the Board

Adrian Goodisman

Stephen J. Griggs

Paul Moase

Leonard Sokolow

Richard Thompson

Robert J. Waters

OFFICERS AND SENIOR EXECUTIVES

Richard Thompson
President and Chief Executive Officer

Howard Bolinger
Chief Financial Officer

Steve Bradford
Vice President, Land and Investor Relations

Rob Lemermeyer
Vice President, Production

Dave Washenfelder
Vice President, Exploration

Sam Yip
Vice President, Engineering

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TRANSFER AGENT AND REGISTRAR

CST Trust Company
Toronto, Ontario

RESERVE EVALUATORS

Sproule Associates Ltd.
Calgary, Alberta

STOCK MARKET INFORMATION

TSX.V: MQX.V (CAD)
OTC: MQXDF (USD)

ABBREVIATIONS

Oil and Natural Gas Liquids
bbl – barrels
mcf –thousand cubic feet
NGL – natural gas liquids
boe – barrels of oil equivalent (6:1)
bbl/d – barrels per day
mcf/d – thousand cubic feet per day
boe/d – barrel of oil equivalent per day

Other
WTI – West Texas Intermediate
MSW – Mixed Sweet