



MANAGEMENT'S DISCUSSION AND ANALYSIS AND CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2016 AND DECEMBER 31, 2015

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MANAGEMENT'S DISCUSSION AND ANALYSIS

For the years ended December 31, 2016 and December 31, 2015

This management's discussion and analysis ("MD&A") should be read in conjunction with Tourmaline Oil Corp.'s consolidated financial statements and related notes for the years ended December 31, 2016 and 2015. Both the consolidated financial statements and the MD&A can be found at www.sedar.com. This MD&A is dated March 7, 2017.

Additional information relating to Tourmaline can be found at www.sedar.com.

The financial information contained herein has been prepared in accordance with International Financial Reporting Standards ("IFRS") and sometimes referred to in this MD&A as Generally Accepted Accounting Principles ("GAAP") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are expressed in Canadian currency, unless otherwise noted.

Certain financial measures referred to in this MD&A are not prescribed by IFRS. See "Non-GAAP Financial Measures" for information regarding the following non-GAAP financial measures used in this MD&A: "cash flow", "operating netback", "working capital (adjusted for the fair value of financial instruments)", "net debt", "adjusted EBITDA", "senior debt", "total debt", and "total capitalization".

Forward-Looking Statements - Certain information regarding Tourmaline set forth in this document, including management's assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. Such statements represent Tourmaline's internal projections, forecasts, estimates or beliefs concerning, among other things, an outlook on the estimated amounts and timing of capital investment or expenditures, anticipated future debt, expenses, production, cash flow and revenues or other expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. These statements are only predictions and actual events or results may differ materially. Although Tourmaline believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies. Many factors could cause Tourmaline's actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Tourmaline.

In particular, forward-looking statements included in this MD&A include, but are not limited to, statements with respect to: the size of, and future net revenues and cash flow from, crude oil, NGL (natural gas liquids) and natural gas reserves; future prospects; the focus of and timing of capital expenditures; expectations regarding the ability to raise capital and to continually add reserves through acquisitions and development; access to debt and equity markets; projections of market prices and costs; the performance characteristics of the Company's crude oil, NGL and natural gas properties; crude oil, NGL and natural gas production levels and product mix; Tourmaline's future operating and financial results; capital investment programs; supply and demand for crude

oil, NGL and natural gas; future royalty rates; future decommissioning obligations; drilling, development and completion plans and the results therefrom; future land expiries; dispositions and joint venture arrangements; amount of operating, transportation and general and administrative expenses; treatment under governmental regulatory regimes and tax laws; and estimated tax pool balances. In addition, statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

These forward-looking statements are subject to numerous risks and uncertainties, most of which are beyond the Company's control, including the impact of general economic conditions; volatility and uncertainty in market prices for crude oil, NGL and natural gas; industry conditions; currency fluctuation; imprecision of reserve estimates; liabilities inherent in crude oil and natural gas operations; environmental risks; incorrect assessments of the value of acquisitions and exploration and development programs; competition; the lack of availability of qualified personnel or management; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; hazards such as fire, explosion, blowouts, cratering, and spills, any of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; stock market volatility; ability to access sufficient capital from internal and external sources; the receipt of applicable regulatory or third-party approvals; and the other risks considered under "Risk Factors" in Tourmaline's most recent annual information form available at www.sedar.com.

With respect to forward-looking statements contained in this MD&A, Tourmaline has made assumptions regarding: future commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment and services; effects of regulation by governmental agencies; future operating costs; and decommissioning obligations.

Management has included the above summary of assumptions and risks related to forward-looking information provided in this MD&A in order to provide shareholders with an understanding of Tourmaline's future operations and such information may not be appropriate for other purposes. Tourmaline's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that the Company will derive therefrom. Readers are cautioned that the foregoing lists of factors are not exhaustive.

These forward-looking statements are made as of the date of this MD&A and the Company disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

Boe Conversions - Per barrel of oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6:1). Barrel of oil equivalents (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, as the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

PRODUCTION

	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
Natural gas (mcf/d)	982,713	927,480	6%	972,513	807,888	20%
Crude oil (bbl/d)	13,880	14,321	(3)%	12,953	11,560	12%
NGL (bbl/d)	14,148	10,709	32%	10,633	8,195	30%
Oil equivalent (boe/d)	191,814	179,610	7%	185,672	154,403	20%
Natural gas %	85%	86%		87%	87%	

Production for the three months ended December 31, 2016 averaged 191,814 boe/d compared to 179,610 boe/d for the same quarter of 2015. The 7% increase in production can primarily be attributed to the Q4 2016 exploration and production (“E&P”) program, which included 70.4 wells drilled (net). The 32% increase in NGL volumes reflects an increase in liquids recovered via deep-cut processing and additional NGL production acquired from Shell Canada in November 2016. The 2016 fourth quarter production was negatively impacted by firm service interruptions on all three major pipeline systems, as well as weather related delays which caused multiple tie-ins to be postponed until the first quarter of 2017. The full-year average production of 185,672 boe/d was approximately 2.3% below the low end of the 2016 published guidance of 190,000-195,000 boe/d.

For the year ended December 31, 2016, average production increased 31,269 boe/d or 20% from 154,403 boe/d in 2015 to 185,672 boe/d in 2016. The increase in natural gas production is related to the Company’s successful E&P program, as well as corporate and property acquisitions over the past year. The growth in oil and NGL production is primarily the result of increased drilling in the Spirit River/Peace River High Charlie Lake oil plays, incremental liquids recovered in the Wild River area via deep-cut processing, and strong condensate recoveries from new wells commencing production as the liquids-rich Montney Turbidite is developed in northeast British Columbia. Approximately 85% of the growth in production volumes since the fourth quarter of 2015 can be attributed to wells brought on-stream from the Company’s E&P program, with the remainder of the change being from corporate and property acquisitions (net of dispositions).

Full-year average production guidance for 2017 is between 240,000-260,000 boe/d as disclosed in the Company’s February 22, 2017 press release.

REVENUE

(000s)	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
Revenue from:						
Natural gas	\$ 302,372	\$ 213,461	42%	\$ 819,978	\$ 807,466	2%
Oil and NGL	99,481	78,501	27%	304,537	266,486	14%
Realized gain (loss) from:						
Natural gas	\$ (12,984)	\$ 41,639	(131)%	\$ 73,891	\$ 148,685	(50)%
Oil and NGL	(420)	31,217	(101)%	20,754	74,824	(72)%
Total revenue from natural gas, oil and NGL sales	\$ 388,449	\$ 364,818	6%	\$1,219,160	\$ 1,297,461	(6)%

Revenue for the three months ended December 31, 2016 increased 6% to \$388.4 million from \$364.8 million for the same quarter of 2015. The increase in fourth quarter 2016 revenue is consistent with the increase in production. Revenue for the year ended December 31, 2016 decreased 6% to \$1,219.2 million from \$1,297.5 million in 2015. Revenue for the year ended December 31, 2016 was impacted by the significant decrease in both natural gas and oil prices, even after taking into account production volumes which were 20% higher than the prior year. Revenue includes all natural gas, oil and NGL sales and realized gains and losses on financial instruments.

TOURMALINE REALIZED PRICES:

	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
Natural gas (\$/mcf)	\$ 3.20	\$ 2.99	7%	\$ 2.51	\$ 3.24	(23)%
Oil (\$/bbl)	\$ 58.82	\$ 72.94	(19)%	\$ 55.73	\$ 70.62	(21)%
NGL (\$/bbl)	\$ 18.40	\$ 13.82	33%	\$ 15.69	\$ 14.48	8%
Oil equivalent (\$/boe)	\$ 22.01	\$ 22.08	–%	\$ 17.94	\$ 23.02	(22)%

BENCHMARK OIL AND GAS PRICES:

	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
Natural gas						
NYMEX Henry Hub (USD\$/mcf)	\$ 3.18	\$ 2.24	42%	\$ 2.55	\$ 2.63	(3)%
AECO (CAD\$/mcf)	\$ 3.11	\$ 2.48	25%	\$ 2.18	\$ 2.71	(20)%
West Coast Station 2 (CAD\$/mcf)	\$ 2.27	\$ 1.04	118%	\$ 1.64	\$ 1.70	(4)%
ATP 5A Day Ahead (CAD\$/GJ) ⁽¹⁾	\$ 2.92	\$ –	–%	\$ 2.22	\$ –	–%
PG&E Malin (USD\$/mmbtu)	\$ 2.83	\$ 2.22	27%	\$ 2.34	\$ 2.52	(7)%
PG&E City Gate (USD\$/mmbtu)	\$ 3.27	\$ 2.71	21%	\$ 2.71	\$ 2.99	(9)%
Oil						
NYMEX (USD\$/bbl)	\$ 49.29	\$ 42.16	17%	\$ 43.47	\$ 48.76	(11)%
Edmonton Par (CAD\$/bbl)	\$ 60.76	\$ 52.88	15%	\$ 52.95	\$ 57.62	(8)%

(1) ATP 5A Day Ahead Index prices commenced December 1, 2015.

RECONCILIATION OF AECO INDEX TO TOURMALINE'S REALIZED GAS PRICES:

(\$/mcf)	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
Weighted Average index natural gas prices	\$ 3.12	\$ 2.31	35%	\$ 2.14	\$ 2.52	(15)%
Heat/quality differential	0.22	0.19	16%	0.16	0.22	(27)%
Realized gain (loss)	(0.14)	0.49	(129)%	0.21	0.50	(58)%
Tourmaline realized natural gas price	\$ 3.20	\$ 2.99	7%	\$ 2.51	\$ 3.24	(23)%
Premium to index pricing due to higher heat content	7%	8%		7%	9%	

CURRENCY – EXCHANGE RATES:

	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
CAD/USD\$ ⁽¹⁾	\$ 0.7491	\$ 0.7485	–%	\$ 0.7555	\$ 0.7819	(3)%

(1) Average rates for the period.

The realized average natural gas price for the three months ended December 31, 2016 was \$3.20/mcf, which is 7% higher than the same period of the prior year. The increase reflects higher natural gas benchmark prices in the quarter which were partially offset by realized losses on commodity contracts.

For the twelve months ended December 31, 2016, the realized natural gas price was \$2.51/mcf, or 23% lower than the same period of the prior year. The lower natural gas price reflects lower index prices experienced during the year and lower realized gains on commodity contracts.

In the third quarter of 2016, the Company began transporting natural gas on the TCPL GTN pipeline system and selling at Malin, Oregon and in the fourth quarter of 2016, the Company transported gas on the PG&E California Pipeline and sold gas at City Gate, near San Francisco. As a result, the Company's realized price on natural gas has increased due to the premium received at Malin and City Gate compared to selling at AECO.

The realized natural gas price for the fourth quarter of 2016, included a loss on commodity contracts of \$13.0 million compared to a gain of \$41.6 million for the same period of the prior year. For the year ended December 31, 2016, the realized price included a gain of \$73.9 million compared to \$148.7 million in the prior year. Realized gains on commodity contracts for the three and twelve months ended December 31, 2016 have decreased compared to the same period of the prior year primarily due to a lower premium received on commodity contracts in 2016 as well as increasing benchmark commodity prices in the fourth quarter of 2016. The gains on commodity contracts include realized gains on natural gas sold at Malin and City Gate, which received a significant premium over AECO index prices. Realized prices exclude the effect of unrealized gains or losses on commodity contracts. Once these gains and losses are realized they are included in the per-unit amounts.

Realized oil prices decreased by 19% and 21% for the three and twelve months ended December 31, 2016, respectively. The realized price for the fourth quarter of 2016 included a loss on commodity contracts of \$0.4 million (year ended December 31, 2016 gain - \$20.8 million) compared to a gain of \$31.2 million on commodity contracts in the fourth quarter of 2015 (year ended December 31, 2015 - \$74.8 million). The fourth quarter 2015 gains reflect in-the-money oil commodity contracts which were unwound in Q4 2015 resulting in realized gains for that quarter.

NGL prices for the fourth quarter of 2016 increased 33% from \$13.82/bbl to \$18.40/bbl, when compared to the same quarter of 2015. The increase in NGL prices is consistent with the increase in benchmark commodity prices over the same periods. Additionally, in 2016, there has been a recovery in the price of propane which was significantly discounted in 2015 due to oversupply in the market.

ROYALTIES

(000s)	Three Months Ended December 31,		Years Ended December 31,	
	2016	2015	2016	2015
Natural gas	\$ 11,162	\$ 3,754	\$ 17,660	\$ 20,007
Oil and NGL	10,590	7,586	31,197	26,619
Total royalties	\$ 21,752	\$ 11,340	\$ 48,857	\$ 46,626
Royalties as a percentage of revenue	5.4%	3.9%	4.3%	4.3%

For the quarter ended December 31, 2016, the average effective royalty rate was 5.4% compared to 3.9% for the same quarter of 2015. For the year ended December 31, 2016, the average effective royalty rate of 4.3% was consistent with the rate in 2015. The increased royalty rate for the fourth quarter of 2016 reflects a higher natural gas price received when compared to the same quarter 2015. Royalty rates are impacted by changes in commodity prices whereby the actual royalty rate increases when prices increase.

In 2016, the Company continued to benefit from the New Well Royalty Reduction Program and the Natural Gas Deep Drilling Program in Alberta, as well as the Deep Royalty Credit Program in British Columbia. The Company also receives gas cost allowance from the Crown, which reduces royalties, to account for expenses incurred to process and transport the Crown's portion of natural gas production.

On January 29, 2016, the Alberta Government (the "Government") released a new Royalty Regime effective January 1, 2017. The new regime will apply to wells drilled after the effective date, whereby all other wells will follow the old framework for a further 10 years. On April 21, 2016, the Government provided further details and calibration on the Modernized Royalty Framework ("MRF"). On July 11, 2016, the Government further announced two new royalty programs: the Enhanced Hydrocarbon Recovery Program ("EHRP") and the Emerging Resources Program ("ERP").

The EHRP began January 1, 2017 and replaced the existing Enhanced Oil Recovery Program. It will help to promote incremental production through enhanced recovery methods. The ERP is also effective January 1, 2017, and will encourage industry to access new oil and gas resources in higher-risk and higher-cost areas that have large resource potential.

On July 12, 2016, the Government announced that new wells spud before January 1, 2017 may elect to opt-in early to the MRF, if they meet certain criteria. Accordingly, wells spud before July 13, 2016 will continue to operate under the previous royalty framework until December 31, 2026. Wells spud during the early election period (July 13, 2016 to December 31, 2016) that did not elect to opt-in early to the MRF or did not meet the criteria will continue to operate under the previous royalty framework until December 31, 2026.

On September 29, 2016, the Government announced that wells re-entered on or after January 1, 2017 will be subject to the MRF. A drilling and completion cost allowance will be calculated on the incremental activity and the royalty will be calculated based on production from all legs according to the MRF rules.

The Company did not opt-in early to the MRF. Based on the details provided to date, the Company believes that the MRF is generally consistent with the initial goal of incentivizing the use of technology to improve productivity and rewards producers deploying the most competitive operating practices. With the new framework coming into

effect January 1, 2017, the Company does anticipate an increase in the corporate royalty rate but based on the Company's current development plans and operational practices, the increase is not expected to be significant.

The Company expects its royalty rate for 2017 to be approximately 8%. The royalty rate is sensitive to commodity prices, and as such, an increase in commodity prices will increase the actual rate.

OTHER INCOME

(000s)	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
Other income	\$ 6,159	\$ 6,854	(10)%	\$ 25,933	\$ 29,176	(11)%

Other income decreased from \$6.9 million in the fourth quarter of 2015 to \$6.2 million for the same quarter of 2016. For the year ended December 31, 2016, other income decreased from \$29.2 million in 2015 to \$25.9 million in 2016. The decrease in other income is due to lower processing fees received in 2016 as the Company is now processing less third-party volumes at its owned-and-operated gas processing facilities. As the Company's production increases, third-party volumes processed at those facilities is reduced. Conversely, if the Company's production is temporarily reduced in a certain area, processing income from third parties could increase for a short period of time.

OPERATING EXPENSES

(000s) except per-unit amounts	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
Operating expenses	\$ 50,526	\$ 69,830	(28)%	\$ 224,800	\$ 246,467	(9)%
Per boe	\$ 2.86	\$ 4.23	(32)%	\$ 3.31	\$ 4.37	(24)%

Operating expenses include all periodic lease and field-level expenses and excludes income recoveries from processing third-party volumes. For the fourth quarter of 2016, total operating expenses were \$50.5 million compared to \$69.8 million in 2015, a decrease of 28% over a production base increase of 7% for the same period. Operating costs for the year ended December 31, 2016 were \$224.8 million, compared to \$246.5 million for the same period of 2015, reflecting a 9% decrease in total costs over a 20% increase in production.

On a per-boe basis, the costs decreased from \$4.23/boe for the fourth quarter of 2015 to \$2.86/boe in the fourth quarter of 2016. The fourth quarter 2016 operating costs were reduced by third-party equalization payments received. For the year ended December 31, 2016, operating costs were \$3.31/boe, down from \$4.37/boe in the prior year. Operating expenses in 2016 have decreased significantly due to lower power costs, lower water trucking costs as a result of capital investments in water management infrastructure, as well as lower contractor costs. Furthermore, the Company's investments in processing facilities in 2014 and 2015 have reduced the volume of gas flowing to third-party facilities, also contributing to the reduction in operating expenses on a per-boe basis. Additionally, during 2016, the Company incurred lower workover and turnaround costs. Along with a commitment to continue to drive down the overall cost structure, the Company is also realizing increased

operational efficiencies in all three core areas along with fixed costs being distributed over a significantly higher production base.

The Company's operating costs for 2017 are forecast to average approximately \$3.60/boe. The slight increase over 2016 per-boe costs takes into consideration higher anticipated property taxes, higher operating costs relating to newly acquired Shell Canada assets as well as increased volumes through deep cut facilities, which carries higher operating costs. Actual cash costs can change, however, depending on a number of factors, including the Company's actual production levels.

TRANSPORTATION

<i>(000s) except per unit amounts</i>	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
Natural gas transportation	\$ 40,627	\$ 23,023	76%	\$ 126,379	\$ 82,254	54%
Oil and NGL transportation	10,984	9,101	21%	37,641	32,380	16%
Total transportation	\$ 51,611	\$ 32,124	61%	\$ 164,020	\$ 114,634	43%
Per boe	\$ 2.92	\$ 1.94	51%	\$ 2.41	\$ 2.03	19%

Transportation costs for the three months ended December 31, 2016 were \$51.6 million, compared to \$32.1 million for the same period of 2015. Transportation costs for the year ended December 31, 2016 were \$164.0 million, compared to \$114.6 million for the same period of 2015, reflecting increased costs related to higher production volumes and higher costs per boe.

On a per-boe basis, the costs increased to \$2.92/boe for the fourth quarter of 2016 (year ended December 31, 2016 - \$2.41/boe) from \$1.94/boe in the fourth quarter of 2015 (year ended December 31, 2015 - \$2.03/boe). The per-unit increase in costs in 2016 is primarily due to the Company beginning to transport natural gas to Malin in the third quarter and City Gate in the fourth quarter of 2016 where it received a higher price for its natural gas. The increased distance also resulted in higher per-boe fuel and transportation costs. Additionally, during the quarter, the Company incurred higher unutilized transportation fees on new firm transportation agreements for natural gas. As production increases, these unutilized charges will be reduced.

GENERAL & ADMINISTRATIVE EXPENSES ("G&A")

<i>(000s) except per-unit amounts</i>	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
G&A expenses	\$ 14,203	\$ 13,608	4%	\$ 58,415	\$ 57,869	1%
Administrative and capital recovery	(1,464)	(2,376)	(38)%	(4,519)	(9,662)	(53)%
Capitalized G&A	(5,774)	(5,839)	(1)%	(23,692)	(22,901)	3%
Total G&A expenses	\$ 6,965	\$ 5,393	29%	\$ 30,204	\$ 25,306	19%
Per boe	\$ 0.39	\$ 0.33	18%	\$ 0.44	\$ 0.45	(2)%

Total G&A expenses for the fourth quarter of 2016 were \$7.0 million compared to \$5.4 million for the same quarter of the prior year. G&A expenses in the fourth quarter of 2015 were lower due to an office rent incentive

received as well as a reduction in compensation expense related to annual bonuses. G&A expenses per boe for the fourth quarter of 2016 were \$0.39/boe, compared to \$0.33/boe for the same quarter of 2015.

For the year ended December 31, 2016, total G&A expenses were \$30.2 million or \$0.44/boe compared to \$25.3 million or \$0.45/boe for the same period of 2015. Although G&A expenses were relatively consistent with the prior year, there was a decrease in administrative and capital recoveries in 2016 as a result of the reduced capital expenditures program in 2016 compared to 2015.

G&A expenses for 2017 are expected to average approximately \$0.45/boe. Actual costs per boe can change, however, depending on a number of factors including the Company's actual production levels.

SHARE-BASED PAYMENTS

(000s)	Three Months Ended December 31,		Years Ended December 31,	
	2016	2015	2016	2015
Share-based payments	\$ 10,482	\$ 13,666	\$ 45,642	\$ 61,684
Capitalized share-based payments	(5,241)	(6,833)	(22,821)	(30,842)
Total share-based payments	\$ 5,241	\$ 6,833	\$ 22,821	\$ 30,842

The Company uses the fair-value method for the determination of non-cash related share-based payments expense. During the fourth quarter of 2016, 2,792,700 stock options were granted to employees, officers, directors and key consultants at a weighted-average exercise price of \$34.47, and 962,769 options were exercised, bringing \$27.0 million of cash into treasury.

The Company recognized \$5.2 million of share-based payment expense in the fourth quarter of 2016 compared to \$6.8 million in the fourth quarter of 2015. Capitalized share-based payments for the fourth quarter of 2016 were \$5.2 million compared to \$6.8 million for the same quarter of the prior year.

For the year ended December 31, 2016, share-based payment expense totalled \$22.8 million and a further \$22.8 million in share-based payments were capitalized (2015 - \$30.8 million and \$30.8 million, respectively).

Share-based payments are lower in 2016 compared to the same period of 2015 which reflects options with a higher fair value being expensed in 2015 compared to 2016.

DEPLETION, DEPRECIATION AND AMORTIZATION ("DD&A")

(000s) except per unit amounts	Three Months Ended December 31,		Years Ended December 31,	
	2016	2015	2016	2015
Total depletion, depreciation and amortization	\$ 156,996	\$ 170,755	\$ 666,182	\$ 690,860
Less mineral lease expiries	(2,092)	(4,667)	(16,703)	(54,061)
Depletion, depreciation and amortization	\$ 154,904	\$ 166,088	\$ 649,479	\$ 636,799
Per boe	\$ 8.78	\$ 10.05	\$ 9.56	\$ 11.30

DD&A expense was \$154.9 million for the fourth quarter of 2016 compared to \$166.1 million for the same period of 2015. The per-unit DD&A rate for the fourth quarter of 2016 was \$8.78/boe compared to \$10.05/boe for the same quarter of 2015.

For the year ended December 31, 2016, DD&A expense was \$649.5 million (year ended December 31, 2015 - \$636.8 million) with a DD&A rate of \$9.56/boe (year ended December 31, 2015 - \$11.30/boe). The decrease in per-boe depletion in 2016 over the same periods of 2015 can be attributed to lower future development costs per well as drilling and completion costs have decreased over the past year thereby adding a higher proportion of reserves with lower associated future development costs, resulting in a lower depletion rate.

Mineral lease expiries for the three months and year ended December 31, 2016 were \$2.1 million and \$16.7 million, respectively (December 31, 2015 – \$4.7 million and \$54.1 million, respectively). The Company prioritizes drilling on what it believes to be the most cost-efficient and productive acreage, and with such a large land base, the Company has chosen to not continue some of the expiring sections of land. Tourmaline expects to continue to see mineral lease expiries of a similar magnitude on a go-forward basis but attempts to mitigate all expiries through land swaps, asset dispositions or drilling to maintain the lease.

FINANCE EXPENSES

(000s)	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
Interest expense	\$ 9,816	\$ 9,201	7%	\$ 40,550	\$ 36,683	11%
Accretion expense	1,329	816	63%	3,607	2,854	26%
Foreign exchange (gain) loss on U.S. denominated debt	16,970	34,592	(51)%	(47,778)	34,592	(238)%
Realized (gain) loss on cross-currency swaps	(16,970)	(34,592)	(51)%	47,778	(34,592)	(238)%
Realized loss on interest rate swaps	294	1,088	(73)%	2,708	3,140	(14)%
Transaction costs on corporate and property acquisitions	1,579	–	100%	1,793	1,948	(8)%
Total finance expenses	\$ 13,018	\$ 11,105	17%	\$ 48,658	\$ 44,625	9%

Finance expenses for the three and twelve months ended December 31, 2016 totalled \$13.0 million and \$48.7 million compared to \$11.1 million and \$44.6 million, respectively, for the same periods of 2015. The finance expenses for 2016 compared 2015 include increased interest expense attributed to a higher average bank debt outstanding, partially offset by a lower average effective interest rate. The average bank debt outstanding and the average effective interest rate on the debt for the year ended December 31, 2016 was \$1,428.7 million and 2.50%, respectively (year ended December 31, 2015 – \$1,225.4 million and 2.63%, respectively).

For the year ended December 31, 2016, the Company drew from the credit facility and term loan in U.S. dollars, as permitted under the credit facility and term loan, which when repaid created a foreign exchange (gain) or loss. Concurrent with the draw of U.S. dollar denominated borrowings, the Company entered into cross-currency swaps to manage the foreign currency risk resulting from holding U.S. dollar denominated borrowings. The Company fixed the Canadian dollar amount for purposes of principal and interest repayment resulting in a (gain) or loss on cross-currency swaps equivalent to the realized foreign exchange (gains) and losses. These

transactions allow the Company to take advantage of the interest rate spread between CDOR and LIBOR (for U.S. borrowings) without taking on foreign exchange risk.

DEFERRED INCOME TAXES (RECOVERY)

For the three months ended December 31, 2016, the provision for deferred income tax expense was \$21.8 million compared to \$18.2 million for the same period in 2015. The increase is primarily due to higher pre-tax earnings recorded in the fourth quarter of 2016 compared to the respective period in 2015.

For the year ended December 31, 2016, the provision for deferred income tax recovery was \$3.2 million compared to a deferred income tax expense of \$83.4 million for the same period in 2015. The decrease is due to the loss before taxes of \$36.0 million for the year ended December 31, 2016 compared to income before taxes of \$162.0 million for the year ended December 31, 2015. Additionally, 2015 was impacted by the increase in Alberta's corporate tax rate from 10% to 12%.

CASH FLOW FROM OPERATING ACTIVITIES, CASH FLOW AND NET EARNINGS (LOSS)

(000s) except per unit amounts	Three Months Ended December 31,			Years Ended December 31,		
	2016	2015	Change	2016	2015	Change
Cash flow from operating activities	\$ 192,134	\$ 228,959	(16)%	\$ 696,901	\$ 835,755	(17)%
Per share ⁽¹⁾	\$ 0.77	\$ 1.04	(26)%	\$ 2.97	\$ 3.89	(24)%
Cash flow ⁽²⁾	\$ 252,542	\$ 242,351	4%	\$ 731,801	\$ 850,220	(14)%
Per share ⁽¹⁾⁽²⁾	\$ 1.02	\$ 1.10	(7)%	\$ 3.12	\$ 3.96	(21)%
Net earnings (loss)	\$ 59,621	\$ 34,636	72%	\$ (31,971)	\$ 80,087	(140)%
Per share ⁽¹⁾	\$ 0.24	\$ 0.16	50%	\$ (0.14)	\$ 0.37	(138)%
Operating netback per boe ⁽²⁾	\$ 15.00	\$ 15.22	(1)%	\$ 11.50	\$ 15.79	(27)%

(1) Per share amounts have been calculated using the weighted average number of diluted common shares except the net earnings (loss) per share amounts in periods which Tourmaline has reported a net loss. In these periods, the weighted average number of basic common shares has been used as there is an anti-dilutive impact on per-share calculations. For the year ended December 31, 2016, the weighted average number of common shares – diluted would be 234,386,245 excluding the anti-dilutive impact.

(2) See "Non-GAAP Financial Measures".

Cash flow for the three months ended December 31, 2016 was \$252.5 million or \$1.02 per diluted share compared to \$242.4 million or \$1.10 per diluted share for the same period of 2015. For the year ended December 31, 2016, cash flow was \$731.8 million or \$3.12 per diluted share, compared to \$850.2 million or \$3.96 per diluted share in the prior year.

The Company had after-tax net earnings for the three months ended December 31, 2016 of \$59.6 million or \$0.24 per diluted share compared to after-tax net earnings of \$34.6 million or \$0.16 per diluted share for the same period of 2015. For the year ended December 31, 2016, the after-tax net (loss) was \$32.0 million or \$0.14 per share compared to after-tax net earnings of \$80.1 million or \$0.37 per diluted share for the year ended December 31, 2015.

The decrease in both cash flow and after-tax net earnings (loss) in 2016 reflects significantly lower realized oil and natural gas prices, partially offset by an increase in production over 2015. Net (loss) for the year ended December 31, 2016 has also been significantly impacted by unrealized losses on financial instruments of \$103.5 million, compared to an unrealized loss of \$0.6 million from the same period of the prior year. These unrealized losses are primarily related to future calls, written by the Company, on oil and natural gas, most of which are currently above strip pricing. By entering into these future calls, the Company has been able to realize a higher premium on physical commodity contracts in the current year.

CAPITAL EXPENDITURES

(000s)	Three Months Ended December 31,		Years Ended December 31,	
	2016	2015	2016	2015
Land and seismic	\$ 6,114	\$ 1,629	\$ 19,907	\$ 39,005
Drilling and completions	206,708	218,957	496,861	895,377
Facilities	55,740	98,491	213,909	491,019
Property acquisitions	1,000,096	662	1,225,545	92,003
Property dispositions	(30,000)	(335)	(48,000)	(6,998)
Other	6,316	6,095	25,067	25,733
Total cash capital expenditures	\$ 1,244,974	\$ 325,499	\$ 1,933,289	\$ 1,536,139

The 2016 fourth quarter E&P expenditures were \$268.6 million compared to \$319.1 million for the same quarter of 2015. Total capital invested for the fourth quarter of 2016 was \$1,245.0 million (net of \$30.0 million in dispositions) compared to \$325.5 million for the same period of 2015 (net of \$0.3 million for property dispositions). Of the \$1,245.0 million in expenditures, \$970.1 million related to acquisitions (net of dispositions) during the quarter.

During 2016, the Company invested \$1,933.3 million of cash consideration (net of dispositions), compared to \$1,536.1 million (net of dispositions) in 2015. Expenditures on E&P were \$730.7 million in 2016 compared to \$1,425.4 million for 2015, a decrease of \$694.7 million primarily related to lower facility expenditures and significantly lower per-well drilling and completion costs in 2016.

Facilities expenditures in 2016 include work on the new Brazeau Gas Plant commissioned in the first quarter of 2016, and progress payments on the new Doe Gas Plant, the Mulligan marketing terminal, and the Sundown Gas Plant expansion, all of which are expected to be commissioned in the first half of 2017.

The following table summarizes the drill, complete and tie-in activities for the period:

	Year Ended December 31, 2016		Year Ended December 31, 2015	
	Gross	Net	Gross	Net
Drilled	175	154.61	200	171.25
Completed ⁽¹⁾	135	112.94	182	155.11
Tied-in	155	139.71	216	187.03

(1) A multi-well pad is included as a single completion.

Acquisitions and Dispositions

2016

On January 29, 2016, the Company acquired assets in the Minehead-Edson-Ansell area of the Alberta Deep Basin for cash consideration of \$183.0 million, before customary adjustments. The acquisition resulted in an increase in Property, Plant and Equipment (“PP&E”) of approximately \$179.2 million, an increase in Exploration and Evaluation (“E&E”) assets of \$4.8 million, and the assumption of \$1.0 million in decommissioning liabilities. The assets acquired included land interests, production, reserves and facilities in the area.

On March 1, 2016, the Company sold non-core assets for cash consideration of \$18.0 million, before customary adjustments.

On November 30, 2016, the Company acquired assets from Shell Canada located in the Alberta Deep Basin and the North East B.C. Gundy area for total consideration of \$1,367.8 million, including cash consideration of \$1,000.1 million and 10,017,938 Tourmaline common shares at a deemed price of \$36.70, before customary adjustments. The acquisition resulted in an increase in PP&E of approximately \$1,333.4 million, an increase in E&E assets of \$38.5 million, and the assumption of \$4.1 million in decommissioning liabilities. Total transaction costs incurred by the Company of \$1.6 million were associated with this acquisition and expensed in the consolidated statement of income (loss) and comprehensive income (loss). The assets acquired include land interests, production, reserves and facilities.

On December 23, 2016, the Company sold 50% of its interest in the planned Mulligan marketing terminal in the Gordondale area of Alberta for \$30.0 million, before customary adjustments.

2015

On April 1, 2015, the Company acquired Perpetual Energy Inc.’s (“Perpetual”) interests in the West Edson area of the Alberta Deep Basin with the issuance of 6,750,000 Tourmaline shares at a price of \$38.32 per share for total consideration of \$258.7 million. The acquisition resulted in an increase in PP&E of approximately \$226.9 million and an increase in E&E assets of \$34.2 million. The interests included Perpetual’s land interests, production, reserves and facilities that were jointly-owned with Tourmaline.

On July 20, 2015, the Company acquired all of the issued and outstanding shares of Bergen Resources Inc. (“Bergen”). As consideration, the Company issued 725,000 common shares at a deemed price of \$33.90 per share for total consideration of \$24.6 million. Total transaction costs incurred by the Company of \$0.2 million associated with this acquisition were expensed in the consolidated statement of income (loss) and comprehensive income (loss). The acquisition resulted in an increase in PP&E of approximately \$26.8 million and E&E assets of \$2.1 million. The acquisition of Bergen consolidated the Company’s working interest in a core area of the Peace River High.

On August 14, 2015, the Company acquired all of the issued and outstanding shares of Mapan Energy Ltd. (“Mapan”). As consideration, the Company issued 2,718,026 common shares at a deemed price of \$32.98 per share for total consideration of \$89.6 million. The acquisition resulted in an increase in PP&E of approximately \$58.5 million. Total transaction costs incurred by the Company of \$1.1 million associated with this acquisition

were expensed in the consolidated statement of income (loss) and comprehensive income (loss). The acquisition of Mapan provided for an increase in lands and production in the Alberta Deep Basin, one of the Company's core areas.

E&P capital expenditures in 2017 are forecast to be \$1.3 billion. The Company expects drilling and completions costs of approximately \$850.0 million, facilities expenditures (including equipment, pipelines and tie-ins) of \$455.0 million, as well as, land and seismic expenditures of \$26.0 million. The capital budget is closely monitored and will continue to be adjusted as required depending on cash flow available.

LIQUIDITY AND CAPITAL RESOURCES

On April 5, 2016, the Company issued 10,387,500 common shares at a price of \$27.11 per share for total gross proceeds of \$281.6 million (net proceeds - \$269.9 million). The proceeds were used to temporarily reduce bank debt, which were subsequently redrawn, to fund the Company's 2016 exploration and development program.

On May 17, 2016, the Company issued 1,320,000 flow-through common shares at a price of \$35.50 per share, for total consideration of \$46.9 million. The proceeds were used to temporarily reduce bank debt and then to fund the Company's 2016 exploration and development program.

On October 20, 2016, the Company issued 890,500 flow-through common shares at a price of \$44.50 per share, for total consideration of \$39.6 million. The proceeds were used to temporarily reduce bank debt and then to fund the Company's 2016 exploration and development program.

On November 10, 2016, the Company issued 21,758,700 subscription receipts at a price of \$34.75 per subscription receipt for total gross proceeds of \$756.1 million (net proceeds - \$725.1 million). Upon closing of the Shell Canada acquisition each subscription receipt was exchanged for one common share and the proceeds were used to partially fund the acquisition.

On November 30, 2016, the Company closed the acquisition of assets from Shell Canada with the issuance of 10,017,938 common shares at a price of \$36.70 per share for consideration of \$367.7 million. Concurrently, the 21,758,700 subscription receipts were exchanged into common shares.

The Company has a covenant-based, unsecured, bank credit facility in place with a syndicate of banks. This is a four-year extendible revolving facility in the amount of \$1,800.0 million with a maturity date of June 2020. The maturity date may, at the request of the Company and with consent of the lenders, be extended on an annual basis. The credit facility includes an expansion feature ("accordion") which allows the Company, upon approval from the lenders, to increase the facility amount by up to \$500.0 million by adding a new financial institution or by increasing the commitment of its existing lenders. The Company also has a \$50.0 million operating revolver, resulting in total bank credit facility capacity of \$1,850.0 million. The facility can be drawn in either Canadian or U.S. funds and bears interest at the bank's prime lending rate, banker's acceptance rates or LIBOR (for U.S. borrowings), plus applicable margins, which range from 0.50% to 3.90% depending on the type of borrowing and the Company's senior debt to adjusted EBITDA ratio.

The Company also has a \$250.0 million term loan with a Canadian Chartered Bank. The term loan can be drawn in either Canadian or U.S. funds and bears interest at the bank's prime lending rate, banker's acceptance rates or

LIBOR (for U.S. borrowings), plus 220 basis points with a maturity of November 2020. The maturity date may, at the request of the Company and with consent of the lender, be extended on an annual basis. The covenants for the term loan are the same as those under the Company's current credit facility and the term loan will rank equally with the obligation under the Company's credit facility.

On February 3, 2017, the Company increased its term loan to \$650.0 million with a syndicate of banks and extended its maturity date to February 2022. The term loan can be drawn in either Canadian or U.S. funds and bears interest at the bank's prime lending rate, banker's acceptance rates or LIBOR (for U.S. borrowings), plus 200 basis points with a maturity date of February, 2022. The maturity date may, at the request of the Company and with consent of the lender, be extended on an annual basis. The covenants for the term loan are the same as those under the Company's current credit facility and the term loan will rank equally with the obligation under the Company's credit facility.

As a result, the Company's aggregate borrowing capacity has been increased to \$2,500.0 million.

Under the terms of the revolving credit facility, Tourmaline has provided its covenant that, on a rolling four-quarter basis: (i) the ratio of senior debt (which generally means, the indebtedness, liabilities and obligations of the Company to the lenders under the facility) to adjusted EBITDA shall not exceed 3.75:1, (ii) the ratio of total debt to adjusted EBITDA shall not exceed 4:1, and (iii) the ratio of senior debt to total capitalization shall not exceed 0.55:1. At December 31, 2016, adjusted EBITDA for the purposes of the above noted covenant calculations was \$822.4 million (December 31, 2015 - \$886.4 million), on a rolling four-quarter basis. As at December 31, 2016, the Company is in compliance with all debt covenant calculations.

As at December 31, 2016, the Company had negative working capital of \$184.3 million, after adjusting for the fair value of financial instruments (the unadjusted working capital deficiency was \$223.8 million) (December 31, 2015 - \$283.8 million and \$247.4 million, respectively). As at December 31, 2016, the Company had \$248.8 million in long-term debt outstanding and \$1,157.8 million drawn against the revolving credit facility for total bank debt of \$1,406.6 million (net of prepaid interest and debt issue costs) (December 31, 2015 - \$1,266.6 million). Net debt at December 31, 2016 was \$1,590.9 million (December 31, 2015 - \$1,550.4 million).

For 2017, management intends to continue matching the capital budget to the expected cash flow and as such management believes the Company has sufficient resources to fund its 2017 exploration and development program. For 2016, E&P spending, excluding acquisitions and divestitures, was \$730.7 million consistent with the cash flow for the same period of \$731.8 million. As at December 31, 2016, the Company also has \$674.8 million in unutilized borrowing capacity. The 2017 exploration and development program will continue to be diligently monitored and adjusted as necessary depending on commodity prices in order to remain consistent with cash flow. Management is dedicated to keeping a strong balance sheet, which has proven to be very important, especially in times of depressed commodity prices.

SHARES AND STOCK OPTIONS OUTSTANDING

As at March 7, 2017, the Company has 269,115,312 common shares outstanding and 20,249,497 stock options granted and outstanding.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

In the normal course of business, Tourmaline is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

PAYMENTS DUE BY YEAR

(000s)	1 Year	2-3 Years	4-5 Years	>5 Years	Total
Operating leases	\$ 5,638	\$ 10,867	\$ 1,361	\$ –	\$ 17,866
Firm transportation and processing agreements	236,597	526,670	497,017	1,386,009	2,646,293
Capital commitments ⁽¹⁾	306,378	603,909	215,909	33,788	1,159,984
Flow-through share commitments	83,592	–	–	–	83,592
Revolving credit facility ⁽²⁾	–	–	1,231,745	–	1,231,745
Term debt ⁽³⁾	5,496	10,993	254,870	–	271,359
	\$ 637,701	\$ 1,152,439	\$ 2,200,902	\$ 1,419,797	\$ 5,410,839

(1) Includes drilling commitments, and capital spending commitments under the joint arrangement in the Spirit River complex of \$300.0 million per year from 2015 until 2019. The capital spending commitment can be deferred to future periods in the event of an economic downturn, and as agreed upon by both parties. In 2016, an economic downturn event resulted in \$216.0 million of capital spending being deferred into future periods.

(2) Includes interest expense at an annual rate of 1.70% being the rate applicable to outstanding debt on the credit facility at December 31, 2016.

(3) Includes interest expense at an annual rate of 2.20% being the applicable rate on the term debt net of the interest rate swap at December 31, 2016.

OFF BALANCE SHEET ARRANGEMENTS

The Company has certain lease arrangements, all of which are reflected in the commitments and contractual obligations table, which were entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease.

FINANCIAL RISK MANAGEMENT

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has implemented and monitors compliance with risk management policies.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities. The Company's financial risks are discussed in note 5 of the Company's consolidated financial statements for the year ended December 31, 2016.

As at December 31, 2016, the Company has entered into certain financial derivative contracts in order to manage commodity risk. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, even though the Company considers all commodity contracts to be effective economic hedges. Such financial derivative commodity contracts are recorded on the consolidated statement of financial position at fair value, with changes in the fair value being recognized as an unrealized gain or loss on the consolidated statement of income and comprehensive income. The contracts that the Company entered into in 2016 are summarized in note 5 of the Company's consolidated financial statements for the year ended December 31, 2016.

The following table provides a summary of the unrealized gains and losses on financial instruments for the year ended December 31, 2016:

(000s)	Three Months Ended December 31,		Years Ended December 31,	
	2016	2015	2016	2015
Unrealized (loss) on financial instruments	\$ (27,499)	\$ (11,755)	\$ (103,484)	\$ (559)

The Company has entered into physical contracts to manage commodity risk. These contracts are considered normal sales contracts and are not recorded at fair value in the consolidated financial statements. Physical contracts in place at December 31, 2016 have been summarized in note 5 of the Company's consolidated financial statements for the year ended December 31, 2016.

Financial derivative and physical delivery contracts entered into subsequent to December 31, 2016 are detailed in note 5 of the Company's consolidated financial statements for the year ended December 31, 2016.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimates that differ materially from current estimates. The Company's use of estimates and judgments in preparing the consolidated financial statements is discussed in note 1 of the consolidated financial statements for the year ended December 31, 2016.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P"), as defined by National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings* ("NI 52-109"), to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the periods in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR"), as defined by NI 52-109, to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

The Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the Company's DC&P and ICFR. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as at December 31, 2016, the Company's DC&P and ICFR are effective.

There were no changes in the Company's DC&P or ICFR during the period beginning on October 1, 2016 and ending December 31, 2016 that have materially affected, or are reasonably likely to materially affect, the Company's DC&P or ICFR. It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

The Company uses the guidelines as set forth in the Committee of Sponsoring Organizations of the Treadway Commission 2013 Internal Control-Integrated Framework.

BUSINESS RISKS AND UNCERTAINTIES

Tourmaline monitors and complies with current government regulations that affect its activities, although operations may be adversely affected by changes in government policy, regulations or taxation. In addition, Tourmaline maintains a level of liability, property and business interruption insurance which is believed to be adequate for Tourmaline's size and activities, but is unable to obtain insurance to cover all risks within the business or in amounts to cover all possible claims.

See "Forward-Looking Statements" in this MD&A and "Risk Factors" in Tourmaline's most recent annual information form for additional information regarding the risks to which Tourmaline and its business and operations are subject.

IMPACT OF NEW ENVIRONMENTAL REGULATIONS

The oil and gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

The use of fracture stimulations has been ongoing safely in an environmentally responsible manner in western Canada for decades. With the increase in the use of fracture stimulations in horizontal wells, there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology. This increased attention to fracture stimulations may result in increased regulation or changes of law which may make the conduct of the Company's business more expensive or prevent the Company from conducting its business as currently conducted. Tourmaline focuses on conducting transparent, safe and responsible operations in the communities in which its people live and work.

CHANGES IN ACCOUNTING POLICIES

The following amendment to an existing standard, as issued by the International Accounting Standards Board (“IASB”), has been adopted by the Company effective January 1, 2016:

IFRS 11 – Joint Arrangements which provides new guidance on the accounting for the acquisition of an interest in a joint operation that constitutes a business. There were no changes to consolidated financial statements as a result of adopting this amendment.

STANDARDS ISSUED BUT NOT YET ADOPTED

The following pronouncements from the IASB will become effective for financial reporting periods beginning on or after January 1, 2017 and have not yet been adopted by the Company. These new or revised standards permit early adoption with transitional arrangements depending upon the date of initial application.

IFRS 9 – Financial Instruments replaces the existing guidance in IAS 39 *Financial Instruments: Recognition and Measurement*. The new standard includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for calculating impairment on financial assets, and the new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. IFRS 9 is effective for annual reporting periods beginning on or after January 1, 2018 with early adoption permitted.

IFRS 15 – Revenue from Contracts with Customers establishes a comprehensive framework for determining whether, how much and when revenue is recognized. It replaces existing revenue recognition guidance, including IAS 18 *Revenue*, IAS 11 *Construction Contracts* and IFRIC 13 *Customer Loyalty Programmes*. IFRS 15 is effective for annual reporting periods beginning on or after January 1, 2018 with early adoption permitted.

IFRS 16 – Leases sets out the principles for the recognition, measurement, presentation and disclosure of leases for both parties to a contract, i.e. the customer (‘lessee’) and the supplier (‘lessor’) and replaces the previous leases standard, IAS 17. IFRS 16 is effective for annual reporting periods beginning on or after January 1, 2019.

IAS 7 – Statement of Cash Flows amendments will require disclosures that enable users of the financial statements to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flow and non-cash changes. The amendments to IAS 7 are effective for annual reporting periods beginning on or after January 1, 2017.

The Company is in the early stages of evaluating the impact of the above noted standards on its consolidated financial statements.

NON-GAAP FINANCIAL MEASURES

This MD&A or documents referred to in this MD&A make reference to the terms “cash flow”, “operating netback”, “working capital (adjusted for the fair value of financial instruments)”, “net debt”, “adjusted EBITDA”, “senior debt”,

“total debt”, and “total capitalization” which are not recognized measures under GAAP, and do not have a standardized meaning prescribed by GAAP. Accordingly, the Company’s use of these terms may not be comparable to similarly defined measures presented by other companies. Management uses the terms “cash flow”, “operating netback”, “working capital (adjusted for the fair value of financial instruments)” and “net debt”, for its own performance measures and to provide shareholders and potential investors with a measurement of the Company’s efficiency and its ability to generate the cash necessary to fund a portion of its future growth expenditures or to repay debt. Investors are cautioned that the non-GAAP measures should not be construed as an alternative to net income determined in accordance with GAAP as an indication of the Company’s performance. The terms “adjusted EBITDA”, “senior debt”, “total debt”, and “total capitalization” are not used by management in measuring performance but are used in the financial covenants under the Company’s credit facility. Under the Company’s credit facility “adjusted EBITDA” means generally net income or loss, excluding extraordinary items, plus interest expense and income taxes and adjusted for non-cash items and gains or losses on dispositions, “senior debt” means the sum of drawn amounts on the credit facility, the term loan and outstanding letters of credit less cash and cash equivalents and excluding debt issue costs (“bank debt”), “total debt” means generally the sum of “senior debt” plus subordinated debt, Tourmaline currently does not have any subordinated debt, and “total capitalization” means generally the sum of the Company’s shareholders’ equity and all other indebtedness of the Company including bank debt, all determined on a consolidated basis in accordance with GAAP.

Cash Flow

A summary of the reconciliation of cash flow from operating activities (per the statement of cash flow), to cash flow, is set forth below:

(000s)	Three Months Ended December 31,		Years Ended December 31,	
	2016	2015	2016	2015
Cash flow from operating activities (per GAAP)	\$ 192,134	\$ 228,959	\$ 696,901	\$ 835,755
Change in non-cash working capital	60,408	13,392	34,900	14,465
Cash flow	\$ 252,542	\$ 242,351	\$ 731,801	\$ 850,220

Operating Netback

Operating netback is calculated on a per-boe basis and is defined as revenue (excluding processing income) less royalties, transportation costs and operating expenses, as shown below:

(\$/boe)	Three Months Ended December 31,		Years Ended December 31,	
	2016	2015	2016	2015
Revenue, excluding processing income	\$ 22.01	\$ 22.08	\$ 17.94	\$ 23.02
Royalties	(1.23)	(0.69)	(0.72)	(0.83)
Transportation costs	(2.92)	(1.94)	(2.41)	(2.03)
Operating expenses	(2.86)	(4.23)	(3.31)	(4.37)
Operating netback	\$ 15.00	\$ 15.22	\$ 11.50	\$ 15.79

Working Capital (Adjusted for the Fair Value of Financial Instruments)

A summary of the reconciliation of working capital to working capital (adjusted for the fair value of financial instruments) is set forth below:

(000s)	As at December 31,	
	2016	2015
Working capital (deficit)	\$ (223,781)	\$ (247,391)
Fair value of financial instruments – short-term (asset) liability	39,517	(36,392)
Working capital (deficit) (adjusted for the fair value of financial instruments)	\$ (184,264)	\$ (283,783)

Net Debt

A summary of the reconciliation of net debt is set forth below:

(000s)	As at December 31,	
	2016	2015
Bank debt	\$ (1,406,586)	\$ (1,266,604)
Working capital (deficit)	(223,781)	(247,391)
Fair value of financial instruments – short-term (asset) liability	39,517	(36,392)
Net debt	\$ (1,590,850)	\$ (1,550,387)

SELECTED QUARTERLY INFORMATION

(\$000s, unless otherwise noted)	2016				2015			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
PRODUCTION								
Natural gas (mcf)	90,409,566	82,363,542	89,091,644	94,075,078	85,328,135	72,395,759	69,606,629	67,548,751
Oil and NGL(bbls)	2,578,571	1,852,618	2,060,260	2,141,099	2,302,708	1,761,403	1,469,591	1,677,123
Oil equivalent (boe)	17,646,832	15,579,875	16,908,867	17,820,279	16,524,064	13,827,363	13,070,696	12,935,248
Natural gas (mcf/d)	982,713	895,256	979,029	1,033,792	927,480	786,910	764,908	750,542
Oil and NGL (bbls/d)	28,028	20,138	22,640	23,529	25,030	19,146	16,149	18,635
Oil equivalent (boe/d)	191,814	169,347	185,812	195,828	179,610	150,297	143,634	143,725
FINANCIAL								
Total revenue from natural gas, oil and NGL sales, net of royalties	366,697	292,495	238,572	272,539	353,478	297,889	293,752	305,716
Cash flow from operating activities	192,134	185,067	143,392	176,308	228,959	261,398	151,028	194,370
Cash flow ⁽¹⁾	252,542	185,531	134,298	159,430	242,351	197,100	203,029	207,740
Per diluted share	1.02	0.79	0.58	0.72	1.10	0.90	0.95	1.01
Net earnings (loss)	59,621	24,738	(77,940)	(38,390)	34,636	28,489	(5,197)	22,159
Per basic share	0.24	0.11	(0.34)	(0.17)	0.16	0.13	(0.02)	0.11
Per diluted share	0.24	0.10	(0.34)	(0.17)	0.16	0.13	(0.02)	0.11
Total assets	9,357,523	7,790,816	7,694,141	7,844,728	7,640,671	7,471,042	7,071,801	6,801,583
Working capital (deficit)	(223,781)	(162,280)	(60,567)	(201,588)	(247,391)	(297,698)	(70,156)	(195,907)
Working capital (deficit)(adjusted for the fair value of financial instruments) ⁽¹⁾	(184,264)	(148,431)	(43,755)	(227,133)	(283,783)	(339,177)	(86,090)	(232,572)
Cash capital expenditures	1,244,974	224,448	49,010	414,857	325,499	422,629	290,629	497,382
Total outstanding shares (000s)	268,596	234,966	234,161	221,484	221,336	220,813	216,378	204,284
PER UNIT								
Natural gas (\$/mcf)	3.20	2.80	1.87	2.20	2.99	3.20	3.17	3.69
Oil and NGL (\$/bbl)	38.42	39.98	38.94	33.60	47.65	45.91	53.34	43.13
Revenue (\$/boe)	22.01	19.54	14.61	15.66	22.08	22.61	22.85	24.84
Operating netback (\$/boe) ⁽¹⁾	15.00	12.69	8.63	9.71	15.22	15.06	16.37	16.70

(1) See Non-GAAP Financial Measures.

The oil and gas exploration and production industry is cyclical in nature. The Company's financial position, results of operations and cash flows are principally impacted by production levels and commodity prices, particularly natural gas prices.

On an annual basis, the Company has had continued production growth over the last two years. The Company's average annual production has increased from 112,929 boe per day in 2014 to 154,403 boe per day in 2015 and

185,672 boe per day in 2016. The production growth can be attributed primarily to the Company's exploration and development activities, and from acquisitions of producing properties.

The Company's cash flow was \$929.0 million in 2014, \$850.2 million in 2015, and \$731.8 million in 2016. The decrease in cash flow year-over-year continues to reflect the significant declines in commodity prices over the same periods. Commodity price fluctuations can indirectly impact expected production by changing the amount of funds available to reinvest in exploration, development and acquisition activities in the future. Changes in commodity prices impact revenue and cash flow available for exploration, and also the economics of potential capital projects as low commodity prices can potentially reduce the quantities of reserves that are commercially recoverable. The Company's capital program is dependent on cash flow generated from operations and access to capital markets.

SELECTED ANNUAL INFORMATION

<i>(\$000s unless otherwise noted)</i>	2016	2015	2014
PRODUCTION			
Natural gas (<i>mcf</i>)	355,939,830	294,879,274	214,056,451
Oil and NGL (<i>bbls</i>)	8,632,548	7,210,731	5,542,937
Oil equivalent (<i>boe</i>)	67,955,853	56,357,277	41,219,012
Natural gas (<i>mcf/d</i>)	972,513	807,888	586,456
Oil and NGL (<i>bbls/d</i>)	23,586	19,755	15,186
Oil equivalent (<i>boe/d</i>)	185,672	154,403	112,929
FINANCIAL			
Total revenue from natural gas, oil and NGL sales, net of royalties	1,170,303	1,250,835	1,241,925
Cash flow from operating activities	696,901	835,755	915,381
Cash flow ⁽¹⁾	731,801	850,220	929,002
Per diluted share	3.12	3.96	4.58
Net earnings (loss)	(31,971)	80,087	488,872
Per basic share	(0.14)	0.37	2.46
Per diluted share	(0.14)	0.37	2.41
Total assets	9,357,523	7,640,671	6,622,303
Working capital (deficit)	(223,781)	(247,391)	(189,928)
Working capital (deficit) (adjusted for the fair value of financial instruments) ⁽¹⁾	(184,264)	(283,783)	(223,655)
Cash capital expenditures (net)	1,933,289	1,536,139	1,563,566
Basic outstanding shares (<i>000s</i>)	268,596	221,336	203,162
PER UNIT			
Natural gas (<i>\$/mcf</i>)	2.51	3.24	4.58
Oil and NGL (<i>\$/bbl</i>)	37.68	47.33	68.78
Revenue (<i>\$/boe</i>)	17.94	23.02	33.05
Operating netback (<i>\$/boe</i>)	11.50	15.79	23.35

⁽¹⁾ See Non-GAAP Financial Measures.