TOURMALINE
OIL CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS AND CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2017 AND DECEMBER 31, 2016

CONTENTS

MANAGEMENT’S DISCUSSION AND ANALYSIS

For the years ended December 31, 2017 and December 31, 2016

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, 2017 and December 31, 2016. Both the consolidated financial statements and the MD&A can be found at www.sedar.com. This MD&A is dated March 6, 2018.

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; the commencement of the payment of dividends and the timing and amount thereof; 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: prevailing and future commodity prices and royalty regimes and tax laws; future well production rates and reserve volumes; 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; decommissioning obligations; and ability to market crude oil, natural gas and NGL successfully. Without limitation of the foregoing, future dividend payments, if any, and the level thereof is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time will be dependent upon, among other things, cash flow, financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of Tourmaline to pay dividends will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility.

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,		
	2017	**2016**	**Change**	**2017**	**2016**	**Change**
Natural gas *(mcf/d)*	**1,306,935**	982,713	33%	**1,221,529**	972,513	26%
Crude oil *(bbl/d)*	**22,264**	13,880	60%	**18,778**	12,953	45%
NGL *(bbl/d)*	**23,222**	14,148	64%	**19,959**	10,633	88%
Oil equivalent *(boe/d)*	**263,309**	191,814	37%	**242,325**	185,672	31%
Natural gas %	**83%**	85%		**84%**	87%	

Production for the three months ended December 31, 2017 increased 37% up to an average of 263,309 boe/d compared to 191,814 boe/d for the same quarter of 2016. For the year ended December 31, 2017, average production increased 56,653 boe/d or 31% from 185,672 boe/d in 2016 to 242,325 boe/d in 2017. The full-year average production was within the 2017 published guidance of 240,000-250,000 boe/d.

The increase in production year over year can primarily be attributed to the Company's successful exploration and production ("E&P") program, which included 253.0 wells drilled (net). Substantially all of the growth in production volumes since the fourth quarter of 2016 can be attributed to wells brought on-stream from the Company's E&P program, after taking declines into consideration. The remainder of the change relates to property acquisitions (net of dispositions), which is primarily the assets acquired from Shell Canada in the fourth quarter of 2016. 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.

Full-year average production guidance for 2018 is unchanged from 270,000-280,000 boe/d as previously disclosed in the Company's November 8, 2017 press release.

REVENUE

	Three Months Ended December 31,			Years Ended December 31,		
(000s)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Revenue from:						
Natural gas	**$ 227,539**	$ 302,372	(25)%	**$ 1,053,409**	$ 819,978	28%
Oil and NGL	**203,735**	99,481	105%	**593,943**	304,537	95%
Realized gain (loss) from:						
Natural gas	**$ 97,394**	$ (12,984)	850%	**$ 232,956**	$ 73,891	215%
Oil and NGL	**(1,562)**	(420)	(272)%	**3,303**	20,754	(84)%
Total revenue from natural gas, oil and NGL sales	**$ 527,106**	$ 388,449	36%	**$ 1,883,611**	$ 1,219,160	55%

Revenue for the three months ended December 31, 2017 increased 36% to $527.1 million from $388.4 million for the same quarter of 2016. The increase in fourth quarter 2017 revenue is consistent with the increase in production volume compared to the prior period. Revenue for the year ended December 31, 2017 increased 55%

to $1,883.6 million from $1,219.2 million in 2016. Higher revenue for the year is consistent with the significant increase in production volumes and higher benchmark commodity prices in 2017. Revenue includes all natural gas, oil and NGL sales and realized gain on risk management activities.

Revenue for the fourth quarter of 2017 included a gain on risk management activities of $95.8 million (for the year ended December 31, 2017 - $236.3 million) compared to a loss of $13.4 million for the same period of the prior year (for the year ended December 31, 2016 – gain of $94.6 million). Realized gains on commodity contracts in 2017 have increased compared to the same periods of the prior year primarily due to an increase in the amount of volume hedged and a higher premium received on the commodity contracts. The premium increased in the second half of 2017 due to the significant decline in the benchmark price of natural gas. 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.

TOURMALINE REALIZED PRICES:

	Three Months Ended December 31,			Years Ended December 31,		
	2017	**2016**	**Change**	**2017**	**2016**	**Change**
Natural gas *($/mcf)*	**$ 2.70**	$ 3.20	(16)%	**$ 2.89**	$ 2.51	15%
Oil *($/bbl)*	**$ 70.16**	$ 58.82	19%	**$ 63.08**	$ 55.73	13%
NGL *($/bbl)*	**$ 27.36**	$ 18.40	49%	**$ 22.64**	$ 15.69	44%
Oil equivalent *($/boe)*	**$ 21.76**	$ 22.01	(1)%	**$ 21.30**	$ 17.94	19%

BENCHMARK OIL AND GAS PRICES:

	Three Months Ended December 31,			Years Ended December 31,		
	2017	**2016**	**Change**	**2017**	**2016**	**Change**
Natural gas						
NYMEX Last Day *(USD$/mcf)*	**$ 2.93**	$ 2.98	(2)%	**$ 3.11**	$ 2.46	26%
AECO 5A *(CAD$/mcf)*	**$ 1.60**	$ 2.93	(45)%	**$ 2.04**	$ 2.05	−%
West Coast Station 2 (*CAD$/mcf*)	**$ 0.54**	$ 2.27	(76)%	**$ 1.48**	$ 1.64	(10)%
Sumas (*USD$/mmbtu*)	**$ 2.67**	$ 2.85	(6)%	**$ 2.62**	$ 2.16	21%
ATP 5A Day Ahead (*CAD$/GJ*)	**$ 1.19**	$ 2.92	(59)%	**$ 2.01**	$ 2.22	(9)%
Chicago City Gate (*USD$/mmbtu*)	**$ 2.86**	$ 2.97	(4)%	**$ 2.90**	$ 2.47	17%
Ventura (*USD$/mmbtu*)	**$ 4.85**	$ 2.93	66%	**$ 3.32**	$ 2.41	38%
PG&E Malin (*USD$/mmbtu*)	**$ 2.67**	$ 2.83	(6)%	**$ 2.73**	$ 2.34	17%
PG&E City Gate (*USD$/mmbtu*)	**$ 3.06**	$ 3.27	(6)%	**$ 3.23**	$ 2.71	19%
Dawn (*USD$/mmbtu*)	**$ 2.93**	$ 3.16	(7)%	**$ 3.04**	$ 2.56	19%
Oil						
NYMEX *(USD$/bbl)*	**$ 55.30**	$ 49.29	12%	**$ 50.85**	$ 43.47	17%
Edmonton Par *(CAD$/bbl)*	**$ 66.68**	$ 60.76	10%	**$ 62.49**	$ 52.95	18%

RECONCILIATION OF WEIGHTED AVERAGE INDEX TO TOURMALINE'S REALIZED GAS PRICES:

	Three Months Ended December 31,			Years Ended December 31,		
($/mcf)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Weighted average index natural gas prices	**$ 1.77**	$ 3.12	(43)%	**$ 2.19**	$ 2.14	2%
Heat/quality differential	**0.12**	0.22	(45)%	**0.17**	0.16	6%
Realized gain (loss) on risk management activities	**0.81**	(0.14)	679%	**0.52**	0.21	148%
Tourmaline realized natural gas price	**$ 2.70**	$ 3.20	(16)%	**$ 2.89**	$ 2.51	15%
Premium to index pricing due to higher heat content	**7%**	7%		**8%**	7%	

CURRENCY – EXCHANGE RATES:

	Three Months Ended December 31,			Years Ended December 31,		
	2017	**2016**	**Change**	**2017**	**2016**	**Change**
CAD/USD$ (1)	**$ 0.7870**	$ 0.7491	5%	**$ 0.7711**	$ 0.7555	2%

(1) Average rates for the period.

The realized average natural gas price for the three months ended December 31, 2017 was $2.70/mcf, which is 16% lower than the same period of the prior year. The decrease reflects lower natural gas benchmark prices in the quarter which were partially offset by realized gains on risk management activities. For the year ended December 31, 2017, the realized natural gas price was $2.89/mcf, or 15% higher than the same period of the prior year. The higher natural gas price reflects higher index prices experienced during the year as well as higher realized gains on risk management activities.

Included in realized gains on risk management activities are the premiums that Tourmaline receives from selling gas to markets outside Alberta. Since the third quarter of 2016, Tourmaline has significantly diversified the markets where its natural gas is sold. These markets include Malin, City Gate, and as of the fourth quarter of 2017 Dawn, all of which during the year had higher natural gas prices compared to AECO. As a result, the Company's realized gains and realized price on natural gas has increased in 2017 due to the Company's diversification strategy.

Realized oil prices increased by 19% and 13% for the three and twelve months ended December 31, 2017, respectively, which is consistent with the increase in the benchmark price for oil in both periods. The realized price for the fourth quarter of 2017 included a loss on commodity contracts of $1.6 million (year ended December 31, 2017 gain - $3.3 million) compared to a loss of $0.4 million on commodity contracts in the fourth quarter of 2016 (year ended December 31, 2016 gain - $20.8 million).

NGL prices for the fourth quarter of 2017 increased 49% from $18.40/bbl to $27.36/bbl, when compared to the same quarter of 2016. For the year ended December 31, 2017, the realized NGL price increased 44% from $15.69/bbl to $22.64/bbl when compared to the prior year. The increase is primarily the result of a recovery in the price of propane which was significantly discounted in 2016 as well as an increase in the other NGL product prices consistent with the higher prices received for oil and natural gas over the year.

ROYALTIES

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	**2017**	**2016**	**2017**	**2016**
Natural gas	**$ 3,020**	$ 11,162	**$ 26,041**	$ 17,660
Oil and NGL	**18,093**	10,590	**54,597**	31,197
Total royalties	**$ 21,113**	$ 21,752	**$ 80,638**	$ 48,857
Royalties as a percentage of revenue	**4.9%**	5.4%	**4.9%**	4.3%

For the fourth quarter of 2017, as well as full year 2017, the average effective royalty rate was 4.9%. This reflects a decrease in the rate when compared to the fourth quarter of 2016 attributable to lower Canadian natural gas benchmark prices. The increase in the average effective royalty rate for full year 2017 can primarily be attributed to higher commodity prices received for the full year as well as the adoption of the Modernized Royalty Framework ("MRF") which increased royalties on new wells drilled after January 1, 2017. Royalty rates are impacted by changes in commodity prices whereby the actual royalty rate increases when prices increase.

The Company continues 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 1, 2017, the Company adopted the MRF introduced by the Alberta Government in 2016. This new royalty regime is applicable to all new wells drilled beginning January 1, 2017, and all other wells drilled prior to January 1, 2017 will follow the old framework for a further 10 years. 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. Under the MRF, the Company anticipates 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 2018 to be approximately 6%. The increase over the 2017 effective royalty rate is expected due to higher forecast commodity prices in 2018. The royalty rate is sensitive to commodity prices, and as such, an increase in commodity prices will increase the actual rate.

COMMODITY MARKETING

	Three Months Ended December 31,			Years Ended December 31,		
(000s)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Marketing revenue	**$ 9,969**	$ –	100%	**$ 14,232**	$ –	100%
Marketing purchases	**(8,661)**	–	(100)%	**(13,348)**	–	(100)%
Net marketing gain	**$ 1,308**	$ –	100%	**$ 884**	$ –	100%

During the second quarter of 2017, the Company commissioned the Mulligan marketing terminal in the Gordondale area of Alberta. The throughput from the marketing terminal is comprised of Tourmaline produced oil and NGL volumes as well as oil and NGL volumes purchased from third parties. The revenue and purchases from third parties are recorded gross for financial statement presentation purposes. Any gains or losses on the sale of third-party product related to the price differential are recorded in marketing revenue.

OTHER INCOME

	Three Months Ended December 31,			Years Ended December 31,		
(000s)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Other income	**$ 13,729**	$ 6,159	123%	**$ 35,342**	$ 25,933	36%

Other income increased from $6.2 million in the fourth quarter of 2016 to $13.7 million for the same quarter of 2017. For the year ended December 31, 2017, other income increased from $25.9 million in 2016 to $35.3 million in 2017. The increase in other income in the fourth quarter of 2017 is due to the Company utilizing existing infrastructure to provide additional services to third parties including gas processing, water disposal, and road access.

OPERATING EXPENSES

	Three Months Ended December 31,			Years Ended December 31,		
(000s) except per-unit amounts	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Operating expenses	**$ 74,644**	$ 50,526	48%	**$ 282,494**	$ 224,800	26%
Per boe	**$ 3.08**	$ 2.86	8%	**$ 3.19**	$ 3.31	(4)%

Operating expenses include all periodic lease and field-level expenses and excludes income recoveries from processing third-party volumes. For the fourth quarter of 2017, total operating expenses were $74.6 million compared to $50.5 million in 2016, an increase of 48% over a production base increase of 37% for the same period. Operating costs for the year ended December 31, 2017 were $282.5 million, compared to $224.8 million for the same period of 2016, reflecting a 26% increase in total costs over a 31% increase in production.

On a per-boe basis, the costs increased from $2.86/boe for the fourth quarter of 2016 to $3.08/boe in the fourth quarter of 2017. The increase per-boe can partially be attributed to higher processing fees related to the increase in NGL production. Additionally, the fourth quarter 2016 operating costs were reduced by third-party equalization payments received. For the year ended December 31, 2017, operating costs were $3.19/boe, down from $3.31/boe in the prior year. Along with a commitment to continue to drive down the overall cost structure, the Company continues to realize 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 2018 are forecast to average approximately $3.30/boe. The slight increase over 2017 per-boe costs takes into consideration higher anticipated property taxes and operating expenses attributable to an increased liquids portfolio, which carry higher operating costs. Actual cash costs can change, however, depending on a number of factors, including the Company's actual production levels.

TRANSPORTATION

(000s) except per unit amounts	Three Months Ended December 31, 2017	2016	Change	Years Ended December 31, 2017	2016	Change
Natural gas transportation	**$ 52,897**	$ 40,627	30%	**$ 191,296**	$ 126,379	51%
Oil and NGL transportation	**20,028**	10,984	82%	**67,877**	37,641	80%
Total transportation	**$ 72,925**	$ 51,611	41%	**$ 259,173**	$ 164,020	58%
Per boe	**$ 3.01**	$ 2.92	3%	**$ 2.93**	$ 2.41	22%

Transportation costs for the three months ended December 31, 2017 were $72.9 million, compared to $51.6 million for the same period of 2016. Transportation costs for the year ended December 31, 2017 were $259.2 million, compared to $164.0 million for the same period of 2016. Both periods reflect increased costs related to higher production volumes.

On a per-boe basis, the costs increased to $3.01/boe for the fourth quarter of 2017 (year ended December 31, 2017 - $2.93/boe) from $2.92/boe in the fourth quarter of 2016 (year ended December 31, 2016 - $2.41/boe). The increase in per-unit costs in 2017 reflects an increased focus on diversifying markets where Tourmaline sells its natural gas. In the third quarter of 2016, Tourmaline began selling natural gas at Malin, Oregon, and in the fourth quarter of 2016 Tourmaline extended its transportation capability and began selling natural gas at City Gate, California. In the fourth quarter of 2017, Tourmaline began selling natural gas at Dawn, Ontario, further diversifying its sales markets. In all of these markets, the Company received a higher price for its natural gas when compared to the AECO benchmark price. The increased distance resulted in higher per-boe fuel and transportation costs. Additionally, pipeline tolls for natural gas transportation have increased in 2017 compared to 2016.

GENERAL & ADMINISTRATIVE EXPENSES ("G&A")

(000s) except per-unit amounts	Three Months Ended December 31, 2017	2016	Change	Years Ended December 31, 2017	2016	Change
G&A expenses	**$ 21,383**	$ 14,203	51%	**$ 74,571**	$ 58,415	28%
Administrative and capital recovery	**(2,886)**	(1,464)	97%	**(8,353)**	(4,519)	85%
Capitalized G&A	**(7,847)**	(5,774)	36%	**(25,608)**	(23,692)	8%
Total G&A expenses	**$ 10,650**	$ 6,965	53%	**$ 40,610**	$ 30,204	34%
Per boe	**$ 0.44**	$ 0.39	13%	**$ 0.46**	$ 0.44	5%

Total G&A expenses for the fourth quarter of 2017 were $10.7 million compared to $7.0 million for the same quarter of the prior year. For the year ended December 31, 2017, G&A expenses were $40.6 million compared to $30.2 million for the same period in 2016. The increase is primarily due to staff and office space additions needed to manage the larger production, reserve and land base.

On a per-boe basis, the increase in G&A expenses for the three months ended December 31, 2017 to $0.44/boe from $0.39/boe in 2016 is primarily due to higher third party service and consulting fees. For the years ended December 31, 2017 and 2016 the G&A expenses per-boe were consistent in both periods.

G&A expenses for 2018 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

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	**2017**	**2016**	**2017**	**2016**
Share-based payments	**$ 8,840**	$ 10,482	**$ 38,262**	$ 45,642
Capitalized share-based payments	**(4,420)**	(5,241)	**(19,131)**	(22,821)
Total share-based payments	**$ 4,420**	$ 5,241	**$ 19,131**	$ 22,821

The Company uses the fair-value method for the determination of non-cash related share-based payments expense. During the fourth quarter of 2017, 2,710,350 stock options were granted to employees, officers, directors and key consultants at a weighted-average exercise price of $26.24.

The Company recognized $4.4 million of share-based payment expense in the fourth quarter of 2017 compared to $5.2 million in the fourth quarter of 2016. Capitalized share-based payments for the fourth quarter of 2017 were $4.4 million compared to $5.2 million for the same quarter of the prior year.

For the year ended December 31, 2017, share-based payment expense totalled $19.1 million and a further $19.1 million in share-based payments were capitalized (for the year ended December 31, 2016 - $22.8 million and $22.8 million, respectively).

Share-based payments are lower in 2017 compared to the same period of 2016 which reflects options with a lower fair value being expensed in 2017 compared to 2016.

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

	Three Months Ended December 31,		Years Ended December 31,	
(000s) except per unit amounts	**2017**	**2016**	**2017**	**2016**
Total depletion, depreciation and amortization	**$ 202,726**	$ 156,996	**$ 774,258**	$ 666,182
Less mineral lease expiries	**(15,467)**	(2,092)	**(36,615)**	(16,703)
Depletion, depreciation and amortization	**$ 187,259**	$ 154,904	**$ 737,643**	$ 649,479
Per boe	**$ 7.73**	$ 8.78	**$ 8.34**	$ 9.56

DD&A expense was $187.3 million for the fourth quarter of 2017 compared to $154.9 million for the same period of 2016. The per-unit DD&A rate for the fourth quarter of 2017 was $7.73/boe compared to $8.78/boe for the same quarter of 2016.

For the year ended December 31, 2017, DD&A expense was $737.6 million (year ended December 31, 2016 - $649.5 million) with a DD&A rate of $8.34/boe (year ended December 31, 2016 - $9.56/boe). The decrease in per-boe depletion in 2017 over the same periods of 2016 can be attributed to lower future development costs per well, 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, 2017 were $15.5 million and $36.6 million, respectively (December 31, 2016 – $2.1 million and $16.7 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

	Three Months Ended December 31,			Years Ended December 31,		
(000s)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Interest expense	**$ 12,550**	$ 9,816	28%	**$ 44,286**	$ 40,550	9%
Accretion expense	**1,505**	1,329	13%	**5,334**	3,607	48%
Foreign exchange (gain) loss on U.S. denominated debt	**2,342**	16,970	(86)%	**(82,746)**	(47,778)	(73)%
Realized (gain) loss on cross-currency swaps	**(2,342)**	(16,970)	86%	**82,746**	47,778	73%
Realized loss on interest rate swaps	**427**	294	45%	**2,975**	2,708	10%
Transaction costs on property acquisitions	**–**	1,579	(100)%	**133**	1,793	(93)%
Total finance expenses	**$ 14,482**	$ 13,018	11%	**$ 52,728**	$ 48,658	8%

Finance expenses for the three months ended December 31, 2017 totaled $14.5 million compared to $13.0 million for the same period of 2016. The average bank debt outstanding and the average effective interest rate on the debt was $1,597.6 million and 2.82% for the three months ended December 31, 2017 compared to $1,393.0 million and 2.46% for the same period of 2016. The increase in both average bank debt outstanding and interest rates resulted in higher interest expense for the current period.

For the year ended December 31, 2017, finance expenses totaled $52.7 million compared to $48.7 million for the same period of 2016. The average bank debt outstanding and the average effective interest rate on the debt for the year ended December 31, 2017 was $1,554.5 million and 2.52% compared to $1,428.7 million and 2.50% for the same period of 2016, respectively. The increase in finance expenses can be attributed to increased interest expense due to a higher average debt outstanding. Accretion expense has also increased during the period resulting from a higher decommissioning liability balance.

For the year ended December 31, 2017, the Company drew from the credit facility in U.S. dollars, as permitted under the credit facility, which when repaid created a foreign exchange gain due to the strengthening of the Canadian dollar over the same period. 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. This transaction allows the Company to take advantage of the interest rate spread between CDOR and LIBOR without taking on foreign exchange risk.

DEFERRED INCOME TAXES (RECOVERY)

For the three months ended December 31, 2017, the provision for deferred income tax expense was $41.9 million compared to $21.8 million for the same period in 2016. The increase is primarily due to higher pre-tax earnings recorded in the fourth quarter of 2017 compared to the respective period in 2016.

For the year ended December 31, 2017, the provision for deferred income tax expense was $151.8 million compared to a deferred income tax recovery of $3.2 million for the same period in 2016. The increase is due to the income before taxes of $498.8 million for the year ended December 31, 2017 compared to a loss before taxes of $36.0 million for the year ended December 31, 2016. Additionally, deferred income taxes increased in 2017 as a result of the October 2017 British Columbia's corporate tax rate increase from 11% to 12%, effective January 1, 2018.

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

	Three Months Ended December 31,			Years Ended December 31,		
(000s) except per unit amounts	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Cash flow from operating activities	**$ 299,793**	$ 192,134	56%	**$ 1,182,900**	$ 696,901	70%
Per share [(1)]	**$ 1.11**	$ 0.77	44%	**$ 4.39**	$ 2.97	48%
Cash flow [(2)]	**$ 348,227**	$ 252,542	38%	**$ 1,205,758**	$ 731,801	65%
Per share [(1)(2)]	**$ 1.29**	$ 1.02	26%	**$ 4.47**	$ 3.12	43%
Net earnings (loss)	**$ 88,079**	$ 59,621	48%	**$ 346,773**	$ (31,971)	1,185%
Per share [(1)]	**$ 0.33**	$ 0.24	38%	**$ 1.29**	$ (0.14)	1,021%
Operating netback per boe [(2)]	**$ 14.80**	$ 15.00	(1)%	**$ 14.27**	$ 11.50	24%

(1) Per share amounts have been calculated using the weighted average number of diluted common shares except the net 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.

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

Cash flow for the three months ended December 31, 2017 was $348.2 million or $1.29 per diluted share compared to $252.5 million or $1.02 per diluted share for the same period of 2016. For the year ended December 31, 2017, cash flow was $1,205.8 million or $4.47 per diluted share, compared to $731.8 million or $3.12 per diluted share in the prior year.

The Company had after-tax net earnings for the three months ended December 31, 2017 of $88.1 million or $0.33 per diluted share compared to after-tax net earnings of $59.6 million or $0.24 per diluted share for the same period of 2016. For the year ended December 31, 2017, the after-tax net earnings were $346.8 million or $1.29 per share compared to an after-tax net loss of $32.0 million or $0.14 per share for the year ended December 31, 2016. The increase in both cash flow and after-tax net earnings for full year 2017 reflects higher realized oil, natural gas and NGL prices and an increase in production over full year 2016.

CAPITAL EXPENDITURES

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	**2017**	**2016**	**2017**	**2016**
Land and seismic	**$ 4,326**	$ 6,114	**$ 34,000**	$ 19,907
Drilling and completions	**234,747**	206,708	**898,579**	496,861
Facilities	**85,311**	55,740	**404,133**	213,909
Property acquisitions	**20,136**	1,000,096	**47,486**	1,225,545
Property dispositions	**(595)**	(30,000)	**(4,595)**	(48,000)
Other	**8,308**	6,316	**27,013**	25,067
Total cash capital expenditures	**$ 352,233**	$ 1,244,974	**$ 1,406,616**	$ 1,933,289

The 2017 fourth quarter E&P expenditures were $324.4 million compared to $268.6 million for the same quarter of 2016. Total capital invested for the fourth quarter of 2017 was $352.2 million (net of $0.6 million in dispositions) compared to $1,245.0 million for the same period of 2016. Of the $1,245.0 million in spending in the fourth quarter of 2016, $970.1 related to acquisitions (net of dispositions) most of which can be attributed to the assets acquired from Shell Canada.

During 2017, the Company invested $1,406.6 million of cash consideration (net of dispositions), compared to $1,933.3 million (net of dispositions) in 2016. Expenditures on E&P were $1,336.7 million in 2017 compared to $730.7 million for 2016. The drilling and completions costs of $898.6 million in 2017 include 98.4 more net wells drilled and 96.2 more net wells completed when compared to 2016.

Facilities expenditures in 2017 include costs associated with the new Doe Gas Plant and the Wildhay compressor expansion which were both commissioned in 2017. Other costs incurred were associated with the Gundy Deep Cut Gas Plant, expected to be commissioned in the second half of 2019 as well as costs related to the Edson Gas Plant expansion, which is to be commissioned in early 2019.

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

	Year Ended December 31, 2017		Year Ended December 31, 2016	
	Gross	**Net**	**Gross**	**Net**
Drilled	**290.00**	**252.97**	175	154.61
Completed	**292.00**	**258.70**	186	162.50
Tied-in	**287.00**	**255.90**	155	139.71

Acquisitions and Dispositions

2017

On July 20, 2017, the Company completed an asset swap in NEBC allowing for the consolidation in the Sundown complex. The Company exchanged predominantly Exploration and Evaluation ("E&E") assets and cash consideration of $19.0 million for producing properties, land and reserves.

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 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.

E&P capital expenditures in 2018 are forecast to be $1.1 billion. The Company expects drilling and completions costs of approximately $780.0 million, facilities expenditures (including equipment, pipelines, tie-ins and major facilities) of $280.0 million, as well as, land and seismic expenditures of $25.0 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 December 5, 2017, the Company issued 1,300,000 flow-through common shares at a price of $31.20 per share, for total consideration of $40.6 million. The proceeds were used to temporarily reduce bank debt and fund the Company's exploration and development program.

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, revolving credit facility in place with a syndicate of banks. This includes a five-year extendible revolving facility in the amount of $1,800.0 million and a $50.0 million operating revolver with a maturity date of June 2022. 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 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.

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 means, generally 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, 2017, adjusted EBITDA for the purposes of the above noted covenant calculations was $1,252.4 million (December 31, 2016 - $822.4 million), on a rolling four-quarter basis.

The Company also has a $950.0 million term loan with a syndicate of banks. 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 157.5 basis points with a maturity date of February 2023. 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.

Additionally, the Company has a letter of credit facility payable on demand in the amount of $50.0 million with a bank. Tourmaline has outstanding letters of credit in the amount of $17.6 million (December 31, 2016 - $18.6 million), which reduce the credit available on the facility.

The Company's aggregate borrowing capacity is $2.85 billion at December 31, 2017. As at, and for the years ending December 31, 2017 and December 31, 2016, the Company is in compliance with all debt covenants.

As at December 31, 2017, the Company had negative working capital of $202.5 million, after adjusting for the fair value of financial instruments (the unadjusted working capital deficiency was $219.2 million) (December 31, 2016 – $184.3 million and $223.8 million, respectively). As at December 31, 2017, the Company had $947.8 million in long-term debt outstanding and $587.0 million drawn against the revolving credit facility for total bank debt of $1,534.8 million (net of prepaid interest and debt issue costs) (December 31, 2016 - $1,406.6 million). Net debt at December 31, 2017 was $1,737.2 million (December 31, 2016 - $1,590.9 million). As at December 31, 2017, the Company also has $1,297.7 million in unutilized borrowing capacity.

For 2018, management intends to continue to diligently monitor and adjust the capital budget based on expected cash flow and as such management believes the Company has sufficient resources to fund its 2018 exploration and development program. 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 6, 2018, the Company has 271,083,946 common shares outstanding and 20,873,417 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	$ 5,529	$ 6,780	$ –	$ –	$ 12,309
Firm transportation and processing agreements	315,028	711,886	640,708	1,708,666	3,376,288
Capital commitments (1)	314,154	603,536	6,534	55,921	980,145
Flow-through share commitments	40,560	–	–	–	40,560
Revolving credit facility (2)	–	–	673,071	–	673,071
Term debt (3)	28,462	56,925	56,925	951,793	1,094,105
	$ 703,733	$ 1,379,127	$ 1,377,238	$ 2,716,380	$ 6,176,478

(1) Includes drilling commitments, and capital spending commitments under the joint arrangement in the Spirit River complex of $300.0 million per year 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 2017, an economic downturn event, as defined in the joint arrangement in the Spirit River complex had occurred resulting in capital spending being deferred to future periods.

(2) Includes interest expense at an annual rate of 2.89% being the rate applicable to outstanding debt on the credit facility at December 31, 2017.

(3) Includes interest expense at an annual rate of 3.00% being the applicable rate on the term debt at December 31, 2017.

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, 2017.

As at December 31, 2017, 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 2017 are summarized in note 5 of the Company's consolidated financial statements for the year ended December 31, 2017.

The following table provides a summary of the unrealized gains and losses on financial instruments for the year ended December 31, 2017:

	Three Months Ended December 31,		**Years Ended December 31,**	
(000s)	**2017**	**2016**	**2017**	**2016**
Unrealized gain (loss) on financial instruments	**$ (11,143)**	$ (27,499)	**$ 67,440**	$ (103,484)

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, 2017 have been summarized in note 5 of the Company's consolidated financial statements for the year ended December 31, 2017.

Financial derivative and physical delivery contracts entered into subsequent to December 31, 2017 are detailed in note 5 of the Company's consolidated financial statements for the year ended December 31, 2017.

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, 2017.

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, 2017, 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, 2017 and ending December 31, 2017 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, 2017:

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. There was no impact to the Company as a result of adopting the amended standard.

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, 2018 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. The Company currently does not apply hedge accounting to its financial instruments and does not currently intend to apply hedge accounting to any of its financial instruments upon adoption of IFRS 9.

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. The Company will adopt IFRS 15 using the modified retrospective approach on January 1, 2018. Based on the Company's review of contracts with customers and its assessment of various revenue streams, at this time, the Company does not anticipate that the adoption of IFRS 15 will have a material impact on Tourmaline's net income (loss) and financial position. However, Tourmaline is still in the process of reviewing all of its contracts and fully assessing the financial statement impact. Tourmaline does anticipate expanding disclosures in the notes to its consolidated financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue streams by product type.

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 Leases. IFRS 16 is effective for annual reporting periods beginning on or after January 1, 2019. The Company is in the early stages of evaluating the impact of IFRS 16 on its consolidated financial statements and the extent of the impact has not yet been determined.

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:

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	**2017**	**2016**	**2017**	**2016**
Cash flow from operating activities (per GAAP)	**$ 299,793**	$ 192,134	**$1,182,900**	$ 696,901
Change in non-cash working capital	**48,434**	60,408	**22,858**	34,900
Cash flow	**$ 348,227**	$ 252,542	**$1,205,758**	$ 731,801

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:

	Three Months Ended December 31,		Years Ended December 31,	
($/boe)	**2017**	**2016**	**2017**	**2016**
Revenue, excluding processing income	**$ 21.76**	$ 22.01	**$ 21.30**	$ 17.94
Royalties	**(0.87)**	(1.23)	**(0.91)**	(0.72)
Transportation costs	**(3.01)**	(2.92)	**(2.93)**	(2.41)
Operating expenses	**(3.08)**	(2.86)	**(3.19)**	(3.31)
Operating netback	**$ 14.80**	$ 15.00	**$ 14.27**	$ 11.50

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:

	As at December 31,	
(000s)	**2017**	**2016**
Working capital (deficit)	**$ (219,168)**	$ (223,781)
Fair value of financial instruments – short-term liability	**16,684**	39,517
Working capital (deficit) (adjusted for the fair value of financial instruments)	**$ (202,484)**	$ (184,264)

Net Debt

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

	As at December 31,	
(000s)	**2017**	**2016**
Bank debt	**$(1,534,757)**	$(1,406,586)
Working capital (deficit)	**(219,168)**	(223,781)
Fair value of financial instruments – short-term liability	**16,684**	39,517
Net debt	**$(1,737,241)**	$(1,590,850)

SELECTED QUARTERLY INFORMATION

	2017				2016			
($000s, unless otherwise noted)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
PRODUCTION								
Natural gas *(mcf)*	**120,238,014**	109,246,506	108,879,426	107,494,272	90,409,566	82,363,542	89,091,644	94,075,078
Oil and NGL*(bbls)*	**4,184,707**	3,587,572	3,287,567	3,079,321	2,578,571	1,852,618	2,060,260	2,141,099
Oil equivalent *(boe)*	**24,224,376**	21,795,323	21,434,138	20,995,033	17,646,832	15,579,875	16,908,867	17,820,279
Natural gas *(mcf/d)*	**1,306,935**	1,187,462	1,196,477	1,194,380	982,713	895,256	979,029	1,033,792
Oil and NGL *(bbls/d)*	**45,486**	38,995	36,127	34,215	28,028	20,138	22,640	23,529
Oil equivalent *(boe/d)*	**263,309**	236,905	235,540	233,278	191,814	169,347	185,812	195,828
FINANCIAL								
Total revenue from natural gas, oil and NGL sales, net of royalties	**505,993**	398,326	459,860	438,794	366,697	292,495	238,572	272,539
Cash flow from operating activities	**299,793**	266,525	278,577	338,005	192,134	185,067	143,392	176,308
Cash flow [(1)]	**348,227**	251,327	313,271	292,933	252,542	185,531	134,298	159,430
Per diluted share	**1.29**	0.93	1.16	1.09	1.02	0.79	0.58	0.72
Net earnings (loss)	**88,079**	50,580	108,580	99,534	59,621	24,738	(77,940)	(38,390)
Per basic share	**0.33**	0.19	0.40	0.37	0.24	0.11	(0.34)	(0.17)
Per diluted share	**0.33**	0.19	0.40	0.37	0.24	0.10	(0.34)	(0.17)
Total assets	**10,181,528**	9,916,804	9,630,468	9,612,395	9,357,523	7,790,816	7,694,141	7,844,728
Working capital (deficit)	**(219,168)**	(352,068)	(130,337)	(355,097)	(223,781)	(162,280)	(60,567)	(201,588)
Working capital (deficit)(adjusted for the fair value of financial instruments) [(1)]	**(202,484)**	(350,112)	(134,212)	(337,191)	(184,264)	(148,431)	(43,755)	(227,133)
Cash capital expenditures	**352,233**	465,466	189,532	399,385	1,244,974	224,448	49,010	414,857
Total outstanding shares *(000s)*	**271,084**	269,784	269,784	269,169	268,596	234,966	234,161	221,484
PER UNIT								
Natural *gas ($/mcf)*	**2.70**	2.52	3.19	3.15	3.20	2.80	1.87	2.20
Oil and NGL *($/bbl)*	**48.31**	37.63	40.01	41.73	38.42	39.98	38.94	33.60
Revenue *($/boe)*	**21.76**	18.84	22.36	22.23	22.01	19.54	14.61	15.66
Operating netback *($/boe)* [(1)]	**14.80**	12.27	15.36	14.59	15.00	12.69	8.63	9.71

(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 154,403 boe per day in 2015 to 185,672 boe per day in 2016 and 242,325 boe per day in 2017. 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 $850.2 million in 2015, $731.8 million in 2016, and $1,205.8 million in 2017. The decrease in cash flow between 2015 and 2016 reflects the significant decline in commodity prices between those two periods. The increase in cash flow in 2017 over 2016 reflects the significant increase in production and also a recovery in commodity prices in 2017. 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

($000s unless otherwise noted)	2017	2016	2015
PRODUCTION			
Natural gas *(mcf)*	**445,858,218**	355,939,830	294,879,274
Oil and NGL *(bbls)*	**14,139,167**	8,632,548	7,210,731
Oil equivalent *(boe)*	**88,448,870**	67,955,853	56,357,277
Natural gas *(mcf/d)*	**1,221,529**	972,513	807,888
Oil and NGL *(bbls/d)*	**38,737**	23,586	19,755
Oil equivalent *(boe/d)*	**242,325**	185,672	154,403
FINANCIAL			
Total revenue from natural gas, oil and NGL sales, net of royalties	**1,802,973**	1,170,303	1,250,835
Cash flow from operating activities	**1,182,900**	696,901	835,755
Cash flow [1]	**1,205,758**	731,801	850,220
Per diluted share	**4.47**	3.12	3.96
Net earnings (loss)	**346,773**	(31,971)	80,087
Per basic share	**1.29**	(0.14)	0.37
Per diluted share	**1.29**	(0.14)	0.37
Total assets	**10,181,528**	9,357,523	7,640,671
Working capital (deficit)	**(219,168)**	(223,781)	(247,391)
Working capital (deficit) (adjusted for the fair value of financial instruments) [1]	**(202,484)**	(184,264)	(283,783)
Cash capital expenditures (net)	**1,406,616**	1,933,289	1,536,139
Basic outstanding shares *(000s)*	**271,084**	268,596	221,336
PER UNIT			
Natural gas *($/mcf)*	**2.89**	2.51	3.24
Oil and NGL *($/bbl)*	**42.24**	37.68	47.33
Revenue *($/boe)*	**21.30**	17.94	23.02
Operating netback *($/boe)*	**14.27**	11.50	15.79

(1) See Non-GAAP Financial Measures.

MANAGEMENT'S REPORT

To the Shareholders of Tourmaline Oil Corp.:

The accompanying consolidated financial statements of Tourmaline Oil Corp. and all the information in the Annual Report are the responsibility of management and have been approved by the Board of Directors. The consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the consolidated financial statements.

Management has established systems of internal controls, which are designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for the preparation of financial information. The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the Audit Committee, with some assistance from the Reserves Committee regarding the annual evaluation of the Company's petroleum and natural gas reserves. The Audit Committee has reviewed the consolidated financial statements with management and the auditors, and has reported to the Board of Directors. The external auditors have access to the Audit Committee without the presence of management.

The consolidated financial statements have been audited on behalf of the shareholders by KPMG LLP, the external auditors. Their examination included such tests and procedures, as they considered necessary, to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with International Financial Reporting Standards. The Board of Directors has approved the financial statements.

(signed)	*(signed)*
Michael L. Rose	Brian G. Robinson
President and	*Vice-President, Finance and*
Chief Executive Officer	*Chief Financial Officer*
Calgary, Alberta	Calgary, Alberta

March 6, 2018

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Tourmaline Oil Corp.:

We have audited the accompanying consolidated financial statements of Tourmaline Oil Corp., which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016 and the consolidated statements of income (loss) and comprehensive income (loss), changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Tourmaline Oil Corp. as at December 31, 2017 and December 31, 2016 and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

(signed) "KPMG LLP"
Chartered Professional Accountants

March 6, 2018
Calgary, Canada

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	As at December 31,	
(000s)	**2017**	**2016**
Assets		
Current assets:		
Accounts receivable	**$ 270,861**	$ 201,288
Prepaid expenses and deposits	**11,268**	10,575
Fair value of financial instruments *(notes 4 and 5)*	**17,338**	895
Total current assets	**299,467**	212,758
Long-term asset	**6,307**	6,034
Fair value of financial instruments (*notes 4 and 5*)	**14,729**	2,990
Exploration and evaluation assets *(note 6)*	**664,552**	678,531
Property, plant and equipment *(note 7)*	**9,196,473**	8,457,210
Total Assets	**$10,181,528**	$ 9,357,523
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 484,613**	$ 396,127
Fair value of financial instruments *(notes 4 and 5)*	**34,022**	40,412
Total current liabilities	**518,635**	436,539
Bank debt *(note 9)*	**1,534,757**	1,406,586
Fair value of financial instruments *(notes 4 and 5)*	**7,398**	40,266
Deferred premium on flow-through shares	**8,396**	16,167
Decommissioning obligations *(note 8)*	**252,222**	212,669
Deferred taxes *(note 12)*	**644,363**	477,015
Shareholders' equity:		
Share capital *(note 11)*	**5,886,709**	5,818,867
Non-controlling interest *(note 10)*	**27,816**	27,549
Contributed surplus	**221,477**	188,883
Retained earnings	**1,079,755**	732,982
Total shareholders' equity	**7,215,757**	6,768,281
Total Liabilities and Shareholders' Equity	**$10,181,528**	$ 9,357,523

Commitments (note 19).

Subsequent events (notes 5 and 21).

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors of Tourmaline Oil Corp.:

(signed)
Andrew B. MacDonald, Director

(signed)
Phillip A. Lamoreaux, Director

CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(000s) except per-share amounts	Years Ended December 31, 2017	2016
Revenue:		
Oil and natural gas sales	**$ 1,647,352**	$ 1,124,515
Royalties	**(80,638)**	(48,857)
Net revenue from oil and natural gas sales	**1,566,714**	1,075,658
Realized gain on risk management activities	**236,259**	94,645
Unrealized gain (loss) on financial instruments *(note 5)*	**67,440**	(103,484)
Marketing revenue	**14,232**	–
Other income *(note 15)*	**35,342**	25,933
Total net revenue	**1,919,987**	1,092,752
Expenses:		
Operating	**282,494**	224,800
Transportation	**259,173**	164,020
Marketing purchases	**13,348**	–
General and administration	**40,610**	30,204
Share-based payments	**19,131**	22,821
Depletion, depreciation and amortization	**774,258**	666,182
Realized foreign exchange (gain) loss	**1,461**	(353)
Unrealized foreign exchange (gain) loss	**637**	(287)
(Gain) on divestitures	**(22,686)**	(27,272)
Total expenses	**1,368,426**	1,080,115
Income from operations	**551,561**	12,637
Finance expenses *(note 16)*	**52,728**	48,658
Income (loss) before taxes	**498,833**	(36,021)
Deferred taxes (recovery) *(note 12)*	**151,793**	(3,168)
Net income (loss) and comprehensive income (loss) before non-controlling interest	**347,040**	(32,853)
Net income (loss) and comprehensive income (loss) attributable to:		
Shareholders of the Company	**346,773**	(31,971)
Non-controlling interest *(note 10)*	**267**	(882)
	$ 347,040	$ (32,853)
Net income (loss) per share attributable to common shareholders *(note 13)*		
Basic	**$ 1.29**	$ (0.14)
Diluted	**$ 1.29**	$ (0.14)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(000s)	Share Capital	Contributed Surplus	Retained Earnings	Non-Controlling Interest	Total Equity
Balance at December 31, 2016	$ 5,818,867	$ 188,883	$ 732,982	$ 27,549	$ 6,768,281
Issue of common shares *(note 11)*	32,162	–	–	–	32,162
Issue of common shares on property acquisition (*notes 7 and 11*)	14,854	–	–	–	14,854
Share issue costs, net of tax (*note 11*)	(1,391)	–	–	–	(1,391)
Share-based payments	–	19,131	–	–	19,131
Capitalized share-based payments	–	19,131	–	–	19,131
Options exercised *(note 11)*	22,217	(5,668)	–	–	16,549
Income attributable to common shareholders	–	–	346,773	–	346,773
Income attributable to non-controlling interest	–	–	–	267	267
Balance at December 31, 2017	**$ 5,886,709**	**$ 221,477**	**$ 1,079,755**	**$ 27,816**	**$ 7,215,757**

(000s)	Share Capital	Contributed Surplus	Retained Earnings	Non-Controlling Interest	Total Equity
Balance at December 31, 2015	$ 4,266,234	$ 171,958	$ 764,953	$ 28,431	$ 5,231,576
Issue of common shares *(note 11)*	1,107,482	–	–	–	1,107,482
Issue of common shares on corporate acquisition (*notes 7 and 11*)	367,658	–	–	–	367,658
Share issue costs, net of tax (*note 11*)	(33,441)	–	–	–	(33,441)
Share-based payments	–	22,821	–	–	22,821
Capitalized share-based payments	–	22,821	–	–	22,821
Options exercised *(note 11)*	110,934	(28,717)	–	–	82,217
(Loss) attributable to common shareholders	–	–	(31,971)	–	(31,971)
(Loss) attributable to non-controlling interest	–	–	–	(882)	(882)
Balance at December 31, 2016	$ 5,818,867	$ 188,883	$ 732,982	$ 27,549	$ 6,768,281

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(000s)	Years Ended December 31, 2017	2016
Cash provided by (used in):		
Operations:		
Net income (loss)	**$ 346,773**	$ (31,971)
Items not involving cash:		
Depletion, depreciation and amortization	**774,258**	666,182
Accretion on decommissioning obligations	**5,334**	3,607
Share-based payments	**19,131**	22,821
Deferred taxes (recovery)	**151,793**	(3,168)
Unrealized (gain) loss on financial instruments	**(67,440)**	103,484
Unrealized foreign exchange (gain) loss	**637**	(287)
Other non-cash items	**656**	654
(Gain) on divestitures	**(22,686)**	(27,272)
Non-controlling interest	**267**	(882)
Decommissioning expenditures	**(2,965)**	(1,367)
Changes in non-cash operating working capital *(note 18)*	**(22,858)**	(34,900)
Total cash flow from operating activities	**1,182,900**	696,901
Financing:		
Issue of common shares	**57,109**	1,206,422
Share issue costs	**(2,005)**	(45,684)
Increase in bank debt	**128,171**	139,982
Total cash flow from financing activities	**183,275**	1,300,720
Investing:		
Exploration and evaluation	**(90,987)**	(56,592)
Property, plant and equipment	**(1,272,738)**	(699,152)
Property acquisitions	**(47,486)**	(1,225,545)
Proceeds from divestitures	**4,595**	48,000
Changes in non-cash investing working capital *(note 18)*	**40,441**	(64,332)
Total cash flow used in investing activities	**(1,366,175)**	(1,997,621)
Changes in cash	**–**	–
Cash, beginning of year	**–**	–
Cash, end of year	**$ –**	$ –

Cash is defined as cash and cash equivalents.

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2017 AND 2016

(tabular amounts in thousands of dollars, unless otherwise noted)

Corporate Information:

Tourmaline Oil Corp. (the "Company") was incorporated under the laws of the Province of Alberta on July 21, 2008. The Company is engaged in the acquisition, exploration, development and production of petroleum and natural gas properties. These consolidated financial statements reflect only the Company's proportionate interest in such activities and are comprised of the Company and its subsidiaries.

The Company's registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, Canada T2P 1G1.

1. BASIS OF PREPARATION

(a) Statement of compliance:

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements were authorized for issue by the Board of Directors on March 6, 2018.

(b) Basis of measurement:

The consolidated financial statements have been prepared on the historical-cost basis except for derivative financial instruments which are measured at fair value. The methods used to measure fair values are discussed in note 4.

Operating expenses in the consolidated statements of income (loss) and comprehensive income (loss) are presented as a combination of function and nature in conformity with industry practice. Depletion, depreciation and amortization are presented in separate lines by their nature, while operating expenses and net administrative expenses are presented on a functional basis. Significant expenses such as salaries and benefits are presented by their nature in the notes to the financial statements.

(c) Functional and presentation currency:

These consolidated financial statements are presented in Canadian dollars. The functional currency of the Company and its subsidiaries is Canadian dollars other than Tourmaline Oil Marketing Corp. which has a functional currency of US dollars.

(d) Use of judgments and estimates:

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below.

Critical judgments in applying accounting policies:

The following are the critical judgments, apart from those involving estimations (see below), 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 consolidated financial statements:

(i) Identification of cash-generating units:

The Company's assets are aggregated into cash-generating units ("CGU") for the purpose of calculating depletion and impairment. A CGU is comprised of assets that are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

(ii) Impairment of petroleum and natural gas assets:

Judgements are required to assess when impairment indicators exist and impairment testing is required. For the purposes of determining whether impairment of petroleum and natural gas assets has occurred, and the extent of any impairment or its reversal, the key assumptions the Company uses in estimating future cash flows are forecasted petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amounts of assets. Impairment charges and reversals are recognized in profit or loss.

(iii) Exploration and evaluation assets:

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgements as to future events and circumstances as to whether economic quantities of reserves have been found in assessing economic and technical feasibility.

(iv) Deferred taxes:

Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent 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 or 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.

(i) Reserves:

Estimation of reported recoverable quantities of proved and probable reserves include judgmental assumptions regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Company's petroleum and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of reserves and estimated cash flows from the Company's petroleum and natural gas interests are independently evaluated by reserve engineers at least annually.

The Company's petroleum and natural gas reserves represent the estimated quantities of petroleum, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all of the expected petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proven and probable if producibility is supported by either production or conclusive formation tests. The Company's petroleum and gas reserves are determined pursuant to National Instrument 51-101 *Standard of Disclosures for Oil and Gas Activities*.

(ii) Share-based payments:

All equity-settled, share-based awards issued by the Company are recorded at fair value using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

(iii) Decommissioning obligations:

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

(iv) Deferred taxes:

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods.

2. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

(a) Consolidation:

The consolidated financial statements include the accounts of Tourmaline Oil Corp., Tourmaline Oil Marketing Corp., and Exshaw Oil Corp., of which the Company owns 90.6% (note 10).

(i) Subsidiaries:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, substantive potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

(ii) Transactions eliminated on consolidation:

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(iii) Jointly-owned assets:

Substantially all of the Company's oil and natural gas activities involve jointly-owned assets. The consolidated financial statements include the Company's share of these jointly-owned assets and a proportionate share of the relevant revenue and related costs.

(b) Foreign Currency:

(i) Foreign currency transactions

Transactions in foreign currencies are translated into the respective entity's functional currency at the exchange rates at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated into the functional currency at the exchange rate at the reporting date. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction. Translation gains and losses are included in earnings in the period in which they arise.

(ii) Foreign Operations

In preparing the Company's consolidated financial statements, the financial statements of each entity are translated into Canadian dollars. The assets and liabilities of foreign operations are translated at the exchange rates at the reporting date. The revenues and expenses of foreign operations are translated at the exchange rates that approximate those dates of the transactions.

Foreign currency differences are recognized in other comprehensive income (loss) ("OCI") and accumulated in the translation reserve, except to the extent that the translation difference is allocated to NCI.

(c) Business Combinations:

The purchase method of accounting is used to account for acquisitions of businesses and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. If the consideration of acquisition given up is less than the fair value of the net assets received, the difference is recognized immediately in the income statement. If the consideration of acquisition is greater than the fair value of the net assets received, the difference is recognized as goodwill on the statement of financial position. Acquisition costs incurred are expensed.

(d) Financial instruments:

(i) Non-derivative financial instruments:

Non-derivative financial instruments comprise cash and cash equivalents, accounts receivable, bank debt, and accounts payable and accrued liabilities. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through profit or loss, any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below:

Cash and cash equivalents:

Cash and cash equivalents comprise cash on hand, term deposits held with banks, other short-term highly-liquid investments with original maturities of three months or less, and are measured similar to other non-derivative financial instruments.

Other:

Other non-derivative financial instruments, such as accounts receivable, bank debt, and accounts payable and accrued liabilities, are measured at amortized cost using the effective interest method, less any impairment losses. The bank debt has a floating rate of interest and therefore the carrying value approximates the fair value.

(ii) Derivative financial instruments:

The Company has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices, interest rates and foreign exchange rates. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus not applied hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the statement of financial position at fair value. Transaction costs are recognized in profit or loss when incurred.

The Company has accounted for its forward physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statement of financial position. Settlements on these physical sales contracts are recognized in oil and natural gas revenue.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through earnings. Changes in the fair value of separable embedded derivatives are recognized immediately in earnings.

(iii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

(e) Property, plant and equipment and intangible exploration assets:

(i) Recognition and measurement:

Exploration and evaluation expenditures:

Pre-license costs are recognized in the statement of operations as incurred.

Exploration and evaluation costs, including the costs of acquiring licenses and directly attributable general and administrative costs, initially are capitalized as either tangible or intangible exploration and evaluation assets according to the nature of the assets acquired. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven and/or probable reserves are determined to exist. A review of each exploration licence or field is carried out, at least annually, to ascertain whether proven or probable reserves have been discovered. Upon determination of proven and/or probable reserves, intangible exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to a separate category within tangible assets referred to as oil and natural gas interests. The cost of undeveloped land that expires or any impairment recognized during a period is charged as additional depletion and depreciation expense.

Development and production costs:

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. The Company allocated its property, plant and equipment to the following CGUs: ‘Deep Basin’, ‘Spirit River’ and ‘BC Montney’. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are measured as the difference between the fair value of the proceeds received or given up and the carrying value of the assets disposed, and are recognized in profit or loss.

(ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

(iii) Depletion and depreciation:

The net carrying value of development or production assets is depleted using the unit-of-production method by reference to the ratio of production in the year to the related proved-plus-probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

Proved-plus-probable reserves are estimated annually by independent qualified reserve evaluators and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. For interim consolidated financial statements, internal estimates of changes in reserves and future development costs are used for determining depletion for the period.

For other assets, depreciation is recognized in profit or loss on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment. Undeveloped land is not depreciated.

The estimated useful lives for depreciable assets are as follows:

Plants and facilities	30 years
Office equipment	25% declining balance
Furniture and fixtures	25% declining balance

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(f) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in profit or loss.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For goodwill and other intangible assets that have indefinite lives, or that are not yet available for use, an impairment test is completed each year. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, as oil and natural gas interests, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped into CGUs. The recoverable amount of an asset or a CGU is the greater of its value in use or its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven-plus-probable reserves. Fair value less costs to sell is determined as the amount that would be obtained from the sale of an asset in an arm's length transaction between knowledgeable and willing parties.

The goodwill acquired in an acquisition, for the purpose of impairment testing, is allocated to the CGUs that are expected to benefit from the synergies of the combination. E&E assets are allocated to the related CGUs when they are assessed for impairment, both at the time of triggering facts and circumstances as well as upon their eventual reclassification to property, plant and equipment.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the assets in the unit (group of units) on a pro-rata basis. Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(g) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax "risk-free" rate that reflects current market assessments of the time value of money. Provisions are not recognized for future operating losses.

(i) Decommissioning obligations:

The Company recognizes the decommissioning obligations for the future costs associated with removal, site restoration and decommissioning costs. The Company's decommissioning obligation is recorded in the period in which it is incurred, discounted to its present value using the risk-free interest rate and the corresponding amount recognized by increasing the carrying amount of petroleum and natural gas assets. The asset recorded is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the decommissioning obligation are charged against the obligation to the extent of the liability recorded.

(ii) Onerous contracts:

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under the contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on associated assets.

(h) Revenue recognition:

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer, which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline. Revenue is measured net of discounts, customs duties and royalties. With respect to the latter, the entity is acting as a collection agent on behalf of others.

Tariffs and tolls charged to other entities for use of pipelines and facilities owned by the Company are recognized as revenue as they accrue in accordance with the terms of the service or tariff and tolling agreements.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(i) Finance income and expenses:

Finance expense comprises interest expense on borrowings, accretion of the discount on provisions, foreign exchange gain (loss) on U.S. denominated debt, realized gain (loss) on cross-currency swaps, realized gain (loss) on interest rate swaps, realized gain (loss) on foreign currency derivatives and transaction costs on business combinations and impairment losses recognized on financial assets.

Interest income is recognized as it accrues in profit or loss, using the effective-interest method.

(j) Deferred taxes:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred-tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred-tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred-tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(k) Flow-through common shares:

Periodically, the Company finances a portion of its exploration and development activities through the issuance of flow-through shares. The resource expenditure deductions for income tax purposes related to exploratory development activities are renounced to investors in accordance with tax legislation. Flow-through shares issued are recorded in share capital at the fair value of common shares on the date of issue. The premium received on issuing flow-through shares is initially recorded as a deferred liability. As qualifying expenditures are incurred, the premium is reversed and a deferred income tax liability is recorded. The net amount is then recognized as deferred income tax expense.

(l) Share-based payments:

The Company applies the fair-value method for valuing share option grants. Under this method, compensation cost attributable to all share options granted are measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options or units that vest. Upon the exercise of the share options, consideration received, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital.

(m) Per-share information:

Basic per-share information is computed by dividing income by the weighted average number of common shares outstanding for the period. The treasury-stock method is used to determine the diluted per share amounts, whereby any proceeds from the share options, warrants or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

(n) Leased assets:

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability.

Other leases are operating leases, which are not recognized on the Company’s statement of financial position.

3. ACCOUNTING CHANGES

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, 2017:

> **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.

Future accounting changes

The following pronouncements from the IASB will become effective or were amended for financial reporting periods beginning on or after January 1, 2018 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. The Company currently does not apply hedge accounting to its financial instruments and does not currently intend to apply hedge accounting to any of its financial instruments upon adoption of IFRS 9.

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. The Company will adopt IFRS 15 using the modified retrospective approach on January 1, 2018. Based on the Company's review of contracts with customers and its assessment of various revenue streams, at this time, the Company does not anticipate that the adoption of IFRS 15 will have a material impact on Tourmaline's net income (loss) and financial position. However, Tourmaline is still in the process of reviewing all of its contracts and fully assessing the financial statement impact. Tourmaline does anticipate expanding disclosures in the notes to its consolidated financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue streams by product type.

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 Leases. IFRS 16 is effective for annual reporting periods beginning on or after January 1, 2019. The Company is in the early stages of evaluating the impact of IFRS 16 on its consolidated financial statements and the extent of the impact has not yet been determined.

4. DETERMINATION OF FAIR VALUE

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) Property, plant and equipment and intangible exploration assets:

The fair value of property, plant and equipment recognized in a business combination, is based on market values. The market value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's-length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in property, plant and equipment) and intangible exploration assets is estimated with reference to the discounted cash flow expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

The market value of other items of property, plant and equipment is based on the quoted market prices for similar items.

(ii) Cash and cash equivalents, accounts receivable, bank debt, accounts payable and accrued liabilities:

The fair value of cash and cash equivalents, accounts receivable, bank debt, accounts payable and accrued liabilities is estimated as the present value of future cash flow, discounted at the market rate of interest at the reporting date. At December 31, 2017 and December 31, 2016, the fair value of these balances approximated their carrying value due to their short term to maturity. The bank debt has a floating rate of interest and therefore the carrying value approximates the fair value.

(iii) Derivatives:

The fair value of commodity price risk management contracts is determined by discounting the difference between the contracted prices and published forward price curves as at the statement of financial position date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates.

(iv) Share options:

The fair value of employee share options is measured using a Black-Scholes option-pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

(v) Measurement:

Tourmaline classifies the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The following tables provide fair value measurement information for financial assets and liabilities as of December 31, 2017 and December 31, 2016. The carrying value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities included in the consolidated statement of financial position approximate fair value due to the short-term nature of those instruments. These assets and liabilities are not included in the following tables.

(000s)	As at December 31, 2017 Carrying Amount	 Fair Value
Financial assets:		
Commodity price, interest rate and foreign exchange rate risk contracts (1)	**$ 32,067**	**$ 32,067**
Financial liabilities:		
Bank debt	**$ 1,534,757**	**$ 1,534,757**
Commodity price and interest rate risk contracts (1)	**41,420**	**41,420**

(1) Commodity price, interest rate and foreign exchange rate risk contracts are fair valued using Level 2 information.

(000s)	As at December 31, 2016 Carrying Amount	 Fair Value
Financial Assets:		
Interest rate risk contracts (1)	$ 3,885	$ 3,885
Financial Liabilities:		
Bank debt	$ 1,406,586	$ 1,406,586
Commodity price and interest rate risk contracts (1)	80,678	80,678

(1) Commodity price and interest rate risk contracts are fair valued using Level 2 information.

5. 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.

(a) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from jointly-owned assets and petroleum and natural gas marketers. As at December 31, 2017, Tourmaline's receivables consisted of $218.0 million (December 31, 2016 - $179.2 million) from petroleum and natural gas marketers, $43.1 million (December 31, 2016 - $15.4 million) from partners in jointly-owned assets, and $9.8 million (December 31, 2016 - $6.7 million) from provincial governments.

Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Company sells a significant portion of its oil and gas to a limited number of counterparties. In 2017, Tourmaline had two counterparties that individually accounted for more than ten percent of annual revenues. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with creditworthy purchasers. Tourmaline historically has not experienced any collection issues with its petroleum and natural gas marketers. Receivables from partners are typically collected within one to three months of the bill being issued to the partner. The Company attempts to mitigate the risk from receivables with partners by obtaining partner approval of significant capital expenditures prior to the expenditure. The receivables, however, are from participants in the petroleum and natural gas sector, and collection of the outstanding balances are dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint asset partners as disagreements occasionally arise that increase the potential for non-collection. To further mitigate collection risk, the Company has the ability to obtain the partners' share of capital expenditures in advance of a project. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint asset partners; however, the Company does have the ability to withhold production from partners in the event of non-payment.

The Company monitors the age of, and investigates issues behind, its receivables that have been past due for over 90 days. At December 31, 2017, the Company has $5.8 million (December 31, 2016 - $3.0 million) over 90 days. The Company is satisfied that these amounts are substantially collectible.

The carrying amount of cash and cash equivalents, accounts receivable and commodity price risk management contracts represents the maximum credit exposure. The Company does not have an allowance for doubtful accounts as at December 31, 2017 (December 31, 2016 - nil) and did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended December 31, 2017 (December 31, 2016 – nil).

(b) Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. The Company's approach to managing liquidity is to ensure that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Company's reputation. Liquidity risk is mitigated by cash on hand, when available, and access to credit facilities.

The Company's accounts payable and accrued liabilities balance at December 31, 2017 is $484.6 million (December 31, 2016 - $396.1 million). It is the Company's policy to pay suppliers within 45-75 days. These terms are consistent with industry practice. As at December 31, 2017, substantially all of the account payable balances were less than 90 days.

The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. The Company also attempts to match its payment cycle with collection of petroleum and natural gas revenues on the 25th of each month.

The following are the contractual maturities of financial liabilities, including estimated interest payments, at December 31, 2017:

(000s)	Carrying Amount	Contractual Cash Flow	Less Than One Year	One – Two Years	Two – Five Years	More Than Five Years
Non-derivative financial liabilities:						
Trade and other payables	$ 484,613	$ 484,613	$ 484,613	$ –	$ –	$ –
Revolving credit facility (1)	587,001	673,071	–	–	673,071	–
Term debt (2)	947,756	1,094,105	28,462	28,462	85,387	951,794
Derivative financial liabilities:						
Financial commodity contracts	41,072	41,072	33,840	7,232	–	–
Financial interest rate swaps	348	348	183	165	–	–
	$ 2,060,790	**$ 2,293,209**	**$ 547,098**	**$ 35,859**	**$ 758,458**	**$ 951,794**

(1) Includes interest expense at 2.89% being the rate applicable to outstanding debt on the credit facility at December 31, 2017.

(2) Includes interest expense at 3.00% being the rate applicable to outstanding debt on the term loan at December 31, 2017.

(c) Market risk:

Market risk is the risk that changes in market conditions, such as commodity prices, interest rates and foreign exchange rates will affect the Company's net income or value of financial instruments. The objective of market risk management is to manage and curtail market risk exposure within acceptable limits, while maximizing the Company's returns.

The Company utilizes both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with the risk management policy that has been approved by the Board of Directors.

Currency risk is the risk that cash flows will fluctuate as a result of changes in the exchange rate between the US and Canadian dollar. The Company mitigates this risk by entering into foreign currency swaps in order to protect itself from large movements in the US to Canadian exchange rate. Changes in the US to Canadian exchange rate could also influence future petroleum and natural gas prices which could impact the value of certain derivative contracts. This influence cannot be accurately quantified.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact the Company's bank debt which is subject to a floating interest rate. Assuming all other variables remain constant, an increase or decrease of 1% in market interest rates for the year ended December 31, 2017 would have decreased or increased shareholders' equity and net income (loss) by $11.7 million (December 31, 2016 - $10.7 million). The unrealized loss on the interest rate swap has been included on the consolidated statement of financial position with changes in the fair value included in the unrealized gain or loss on financial instruments on the consolidated statement of income (loss) and comprehensive income (loss). The realized loss on the interest rate swap has been included in finance expenses on the consolidated statement of income (loss) and comprehensive income (loss).

Commodity price risk is the risk that the fair value or future cash flow will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are based upon the United States dollar and as a result the price received by Canadian producers is affected by the Canadian to United States dollar exchange rate. The commodity prices are also impacted by world economic events that dictate the levels of supply and demand. As at December 31, 2017, the Company has entered into certain financial derivative and physical delivery sales 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. As a result, all such 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 (loss) and comprehensive income (loss). The Company has not offset any financial assets and liabilities, in the consolidated statements of financial position.

The Company has the following financial commodity derivative contracts in place as at December 31, 2017 [(1)]:

		2018	2019	2020	2021	Fair Value *(000s)*
Gas						
NYMEX swaps	*mmbtu/d*	105,493	7,397	–	–	$ 10,542
	USD$/mmbtu	$ 3.06	$ 2.98			
Basis differentials – other [(2)]	*mmbtu/d*	29,644	12,466	2,486	–	$ 1,603
	USD$/mmbtu	$ (0.13)	$ (0.30)	$ (0.30)		
NYMEX call options (writer) [(3)]	*mmbtu/d*	110,000	105,000	20,000	–	$ (5,870)
	USD$/mmbtu	$ 3.68	$ 3.83	$ 3.75		
Oil						
Financial swaps	*bbls/d*	7,748	2,000	–	–	$ (24,811)
	USD$/bbl	$ 52.99	$ 52.96			
Financial call swaptions [(4)]	*bbls/d*	2,125	500	–	–	$ (8,967)
	USD$/bbl	$ 52.18	$ 58.35			
Total fair value						$ (27,503)

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

(2) These are basis differentials for non-AECO markets. A portion of these financial basis deals have a cap on NYMEX, 9.8 mmcf/d at USD $3.78/mcf for 2018-2020.

(3) These are European calls whereby the counterparty can exercise the option monthly on a particular day to purchase NYMEX at a specified price.

(4) These are European and Asian swaptions whereby the Company provides the option to extend an oil swap into the period subsequent to the call date, or retroactively fix the price on the volumes under the contract.

The Company has entered into the following financial commodity derivative contracts subsequent to December 31, 2017:

Type of Contract	Quantity	Time Period	Contract Price
Gas fixed price	30,000 mmbtu/d	February 2018	USD$2.98/mmbtu average
Gas fixed price	10,000 mmbtu/d	March 2018	USD$2.87/mmbtu average
Gas fixed price	10,000 mmbtu/d	May 2018	USD$2.02/mmbtu
Gas fixed price	10,000 mmbtu/d	June 2018	USD$2.09/mmbtu
Gas basis differential[(1)]	40,000 mmbtu/d	May 2018 – October 2018	USD$(0.53)/mmbtu average
Gas financial call writer	20,000 mmbtu/d	January 2020 – December 2020	USD$3.74/mmbtu average
Oil swaps	1,000 boe/d	February 2018 to December 2018	USD$61.41/bbl average
Oil swaps	2,000 boe/d	January 2019 to December 2019	USD$57.26/bbl average

(1) 20,000 mmbtu/d has a cap on NYMEX at USD$3.00.

The Company has entered into multiple interest rate swaps over the next seven years at an annual average interest rate as detailed below:

	2018	2019	2020	2021	2022	2023	2024	Fair Value
Effective interest rate (1)	1.58%	1.61%	1.49%	1.59%	1.76%	2.01%	2.12%	
Notional amount hedged (000s)	$ 775,000	$ 756,781	$ 620,822	$ 559,384	$ 332,055	$ 143,904	$ 25,000	$ 17,089

(1) Canadian dealer offer rate, excluding stamping and stand-by fees.

The Company has the following financial foreign currency derivative contracts in place at December 31, 2017

		2018	2019	2020	2021	Fair Value
Costless collar	*$CAD(000s)*	$ 6,000	–	–	–	$ 1,061
	$CAD/$USD	$1.2500–$1.3175				

The Company has entered into the following financial foreign currency derivative contracts subsequent to December 31, 2017:

Type of Contract	**Notional (000s)**	**Time Period**	**Rate**
Average rate forward	$ 2,000	February 2018 – December 2018	$1.2505 $CAD/$USD
Average rate forward	$ 1,000	March 2018 – December 2018	$1.2600 $CAD/$USD
Costless collar	$ 3,000	March 2018 – December 2018	$1.2500 – $1.2820 $CAD/$USD

The following table provides a summary of the unrealized gains and losses on financial instruments for the years ended December 31, 2017 and 2016:

	Years Ended December 31,	
(000s)	**2017**	**2016**
Unrealized gain (loss) on financial instruments – commodity contracts	**$ 46,960**	$ (111,532)
Unrealized gain on financial instruments – interest rate swaps	**19,419**	8,048
Unrealized gain on financial instruments – foreign currency	**1,061**	–
Total unrealized gain (loss) on financial instruments	**$ 67,440**	$ (103,484)

The Company's financial commodity contracts are sensitive to fluctuations in commodity prices. For the commodity contracts in place at December 31, 2017, if the future strip prices for oil were $1.00 per bbl higher and prices for natural gas were $0.10 per mcf higher, with all other variables held constant, the unrealized gain would decrease by $26.1 million, directly impacting pre-tax earnings (December 31, 2016 - $10.3 million higher pre-tax loss). An equal and opposite impact would have occurred if oil prices were $1.00 per bbl lower and gas prices were $0.10 per mcf lower.

In addition to the financial commodity contracts discussed above, 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.

The Company has the following physical commodity contracts in place at December 31, 2017 (1)(7):

		2018	2019	2020	2021	2022
Gas						
Fixed price (2)	*mcf/d*	151,017	–	–	–	–
	CAD$/mcf	$ 2.91				
Basis differentials - AECO (3)(4)	*mmbtu/d*	204,432	192,432	187,500	94,062	82,500
	USD$/mmbtu	$ (0.79)	$ (0.75)	$ (0.75)	$ (0.68)	$ (0.66)
Basis differentials - Dawn	*mmbtu/d*	34,699	25,000	25,000	6,164	–
	USD$/mmbtu	$ (0.13)	$ (0.15)	$ (0.15)	$ (0.15)	
Basis differentials – Stn 2	*mcf/d*	51,255	39,478	37,812	29,478	20,000
	CAD$/mcf	$ (0.07)	$ 0.25	$ 0.12	$ 0.08	$ 0.25
AECO monthly calls / call swaptions (3)	*mcf/d*	28,435	37,913	–	–	–
	CAD$/mcf	$ 3.43	$ 2.74			
Oil						
Fixed differential - Oil (5)	*bbls/d*	2,328	–	–	–	–
	USD$/bbl	$ (6.68)				
Fixed differential - condensate(6)	*bbls/d*	1,034	–	–	–	–
	USD$/bbl	$ 1.05				

(1) The volumes and prices reported are the weighted-average volumes and prices for the period.

(2) These include AECO and Dawn.

(3) Tourmaline also has an average of 50 mmcf/d of NYMEX-AECO basis differentials at $(0.72) from 2023-2024. A portion of these basis deals have a cap on NYMEX, 135.9 mmcf/d at USD$4.08/mcf from 2018-2020 and 49.8 mmcf/d at USD$4.46/mcf from 2021-2024.

(4) These are monthly calls for 2018 that are European Swaptions, whereby the Company provides the option to extend a gas swap into the period subsequent to the calls date. In 2019, these are one time European Swaptions

(5) Tourmaline sells physical crude at a fixed differential to NYMEX.

(6) Tourmaline sells physical condensate at a fixed differential to NYMEX.

(7) Tourmaline also has entered into deals to sell 50,000 mmbtu/d priced off Chicago GDD less transportation costs and 20,000 mmbtu/d priced off Ventura GDD less transportation costs that extend into 2020; 5,000 mmbtu/d priced off Chicago GDD less transportation costs that extends to 2023; 20,000 mmbtu/d that starts in 2020.

The Company has entered into the following physical commodity contracts subsequent to December 31, 2017:

Type of Contract	Quantity	Time Period	Contract Price
Gas fixed price	70,000 mcf/d	April 2018 – October 2018	CAD$1.24/mcf average
Gas basis differential	10,000 mmbtu/d	February 2018 – December 2018	USD$0.03/mmbtu
Gas basis differential	10,000 mmbtu/d	February 2018 – December 2018	USD$(0.09)/mmbtu

(d) Capital management:

The Company's policy is to maintain a strong capital base to preserve investor, creditor and market confidence and to sustain the future development of the business. The Company considers its capital structure to include shareholders' equity, bank debt and working capital. In order to maintain or adjust the capital structure, the Company may from time to time issue shares, issue debt, adjust its future dividend policy and adjust its capital spending to manage current and projected debt levels. The annual and updated budgets are approved by the Board of Directors.

The key measure that the Company utilizes in evaluating its capital structure is net debt to annualized cash flow, which is defined as bank debt plus working capital (adjusted for the fair value of financial instruments), to annualized cash flow (based on the most recent quarter), defined as cash flow from operating activities before changes in non-cash working capital. Net debt to annualized cash flow represents a measure of the time it is expected to take to pay off the debt if no further capital expenditures were incurred and if cash flow in the next year were equal to the amount in the most recent quarter annualized.

The Company monitors this ratio and endeavours to maintain it at, or below, 2.0 to 1.0 in a normalized commodity price environment. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at December 31, 2017, the Company's ratio of net debt to annualized cash flow was 1.25 to 1.0 (December 31, 2016 - 1.57 to 1.0).

	As at December 31,	
(000s)	**2017**	**2016**
Net debt:		
Bank debt	**$(1,534,757)**	$(1,406,586)
Working capital (deficit)	**(219,168)**	(223,781)
Fair value of financial instruments – short-term (asset) liability	**16,684**	39,517
Net debt	**$(1,737,241)**	$(1,590,850)
Annualized cash flow:		
Cash flow from operating activities for Q4	**$ 299,793**	$ 192,134
Change in non-cash working capital	**48,434**	60,408
Cash flow for Q4	**$ 348,227**	$ 252,542
Annualized cash flow (based on most recent quarter annualized)	**$ 1,392,908**	$ 1,010,168
Net debt to annualized cash flow	**1.25**	1.57

On March 6, 2018, the Board declared its first quarterly dividend of $0.08 per share, payable on March 29, 2018 for shareholders of record on March 14, 2018. There have been no changes other than the introduction of a dividend in the Company's approach to capital management since December 31, 2016.

6. EXPLORATION AND EVALUATION ASSETS

(000s)	
As at January 1, 2016	$ 620,142
Capital expenditures	56,592
Transfers to property, plant and equipment *(note 7)*	(35,470)
Acquisitions	54,713
Divestitures	(743)
Expired mineral leases	(16,703)
As at December 31, 2016	$ 678,531
Capital expenditures	90,987
Transfers to property, plant and equipment *(note 7)*	(81,250)
Acquisitions	24,012
Divestitures	(11,113)
Expired mineral leases	(36,615)
As at December 31, 2017	**$ 664,552**

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proven and/or probable reserves. Additions represent the Company's share of costs on E&E assets during the year. Expired mineral lease expenses have been included in the "Depletion, Depreciation and Amortization" line item on the consolidated statements of income (loss) and comprehensive income (loss).

Impairment Assessment

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. At December 31, 2017 and 2016, the Company determined that no indicators of impairment existed on its E&E assets; therefore, an impairment test was not performed.

7. PROPERTY, PLANT AND EQUIPMENT

Cost

(000s)	
As at January 1, 2016	$ 8,685,985
Capital expenditures	721,973
Transfers from exploration and evaluation *(note 6)*	35,470
Change in decommissioning liabilities *(note 8)*	41,856
Acquisitions	1,553,053
Divestitures	(29,720)
As at December 31, 2016	$11,008,617
Capital expenditures	1,291,869
Transfers from exploration and evaluation *(note 6)*	81,250
Change in decommissioning liabilities *(note 8)*	36,526
Acquisitions	80,368
Divestitures	(13,107)
As at December 31, 2017	**$12,485,523**

Accumulated Depletion, Depreciation and Amortization

(000s)	
As at January 1, 2016	$ 1,902,214
Depletion, depreciation and amortization	649,479
Divestitures	(286)
As at December 31, 2016	$ 2,551,407
Depletion, depreciation and amortization	737,643
As at December 31, 2017	**$ 3,289,050**

Net Book Value

(000s)	
As at December 31, 2016	$ 8,457,210
As at December 31, 2017	**$ 9,196,473**

Future development costs for the year ended December 31, 2017 of $7,095.3 million (December 31, 2016 - $6,417.4 million) were included in the depletion calculation.

Capitalization of G&A and Share-Based Payments

A total of $25.6 million in G&A expenditures have been capitalized and included in PP&E assets at December 31, 2017 (December 31, 2016 - $23.7 million). Also included in PP&E are non-cash share-based payments of $19.1 million at December 31, 2017 (December 31, 2016 - $22.8 million).

Impairment Assessment

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. For the year ended December 31, 2017, the Company identified indicators of impairment on all of its CGUs due to the decline in the current and forward commodity price for natural gas since December 31, 2016.

An impairment is recognized if the carrying value of a CGU exceeds the recoverable amount for that CGU. The Company determines the recoverable amount by using the greater of fair value less cost to sell and the value-in-use. Value in use is generally the future cash flows expected to be derived from production of proven and probable reserves estimated by the Company's third party reserve evaluators and the internally estimated future cash flows of facility infrastructure, when required. At December 31, 2017, the Company used value in use, discounted at pre-tax rates between 8% and 15% dependent on the risk profile of the reserve category.

The following forward commodity price estimates were used in determining whether an impairment to the carrying value of the CGUs existed at December 31, 2017:

Year	WTI Oil (US$/bbl)(1)	Foreign Exchange Rate(1)	Edmonton Light Crude Oil (Cdn$/bbl)(1)	AECO Gas (Cdn$/mmbtu)(1)
2018	57.50	0.7900	68.60	2.43
2019	60.90	0.8000	72.02	2.77
2020	64.13	0.8167	74.48	3.19
2021	68.33	0.8283	78.60	3.48
2022	71.19	0.8400	80.84	3.67
2023	73.15	0.8433	82.83	3.76
2024	75.16	0.8433	85.17	3.85
2025	77.17	0.8433	87.53	3.93
2026	79.01	0.8433	89.66	4.02
2027	80.06	0.8433	91.49	4.10
Thereafter	+2.0%/yr	0.8433	+2.0%/yr	+2.0%/yr

(1) Source: 3 Consultants' average, GLJ Petroleum Consultants, McDaniel & Associates Consultants, and Sproule Associates price forecasts, effective January 1, 2018.

The Company has determined that there was no impairment to PP&E at December 31, 2017.

At December 31, 2016, the Company determined that no indicators of impairment existed on any of its CGUs; therefore, impairment tests were not performed.

Business Combinations

Minehead-Edson-Ansell

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 lands, production, reserves and facilities in a core area of the Alberta Deep Basin.

Results from operations are included in the Company's audited consolidated financial statements from the closing date of the transaction. The acquisition has been accounted for using the purchase method based on fair values as follows:

(000s)	Minehead-Edson-Ansell
Fair value of net assets acquired:	
Property, plant and equipment	$ 179,230
Exploration and evaluation	4,753
Decommissioning obligations	(983)
Total	$ 183,000
Consideration:	
Cash	$ 183,000

Shell Canada

On November 30, 2016, the Company acquired assets in the Alberta Deep Basin and the Northeast B.C. Gundy area ("Gundy assets") for total consideration of $1,367.8 million, including cash consideration of $1,000.1 million before customary adjustments and 10,017,938 Tourmaline common shares at a deemed price of $36.70 per share. Total transaction costs incurred by the Company of $1.6 million associated with this acquisition were expensed in the consolidated statement of income (loss) and comprehensive income (loss). The Deep Basin assets acquired resulted in significant increases in lands, production, reserves and facilities in a core development area of the Company. The Northeast B.C. Gundy assets acquired include land, production and reserves and now provide the Company with sufficient size and scope in the Northeast Montney play to drive strategic Company-operated infrastructure development.

Results from operations are included in the Company's audited consolidated financial statements from the closing date of the transaction. The acquisition has been accounted for using the purchase method based on fair values as follows:

(000s)	Shell Canada
Fair value of net assets acquired:	
Property, plant and equipment	$ 1,333,367
Exploration and evaluation	38,493
Decommissioning obligations	(4,106)
Total	$ 1,367,754
Consideration:	
Cash	$ 1,000,096
Common Shares	367,658
Total	$ 1,367,754

Included in the consolidated statements of income (loss) and comprehensive income (loss) for the year ended December 31, 2016 are the following amounts relating to the Shell Canada assets acquired since November 30, 2016:

(000s)	
Oil and natural gas sales	$ 12,422
Net income (loss) and comprehensive income (loss)	$ 2,569

If the Company had completed the business combination on January 1, 2016, the pro-forma results of the oil and gas sales and net income (loss) and comprehensive income (loss) for the year ended December 31, 2016 would have been as follows:

(000s)	As Stated	Shell	Pro Forma Year Ended December 31, 2016
Oil and natural gas sales	$ 1,124,515	$ 133,254	$ 1,257,769
Net income (loss) and comprehensive income (loss)	$ (31,971)	$ 9,742	$ (22,229)

Acquisition and Disposition of Oil and Natural Gas Properties

For the year ended December 31, 2017, the Company completed property acquisitions for total cash consideration of $47.5 million (December 31, 2016 - $1,410.3 million) and, a further $56.1 million in acquisitions involving non-cash consideration (December 31, 2016 - $8.0 million). Of the $56.1 million, $14.9 million relates to assets acquired by issuing 475,000 Tourmaline common shares at a price of $31.27 per share with the remaining relating to the asset swaps completed in the period. The Company also assumed $0.7 million in decommissioning liabilities as a result of these acquisitions (December 31, 2016 - $48.0 million).

8. DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flow required to settle its decommissioning obligations is approximately $459.8 million (December 31, 2016 – $392.0 million), with some abandonments expected to commence in 2034. A risk-free rate of 2.31% (December 31, 2016 – 2.31%) and an inflation rate of 2.0% (December 31, 2016 – 2.0%) were used to calculate the fair value of the decommissioning obligations. The decommissioning obligations at December 31, 2017 have been adjusted by approximately $14.0 million (December 31, 2016 – $27.1 million) related to an adjustment in the abandonment cost per well.

(000s)	Years Ended December 31, 2017	2016
Balance, beginning of year	**$ 212,669**	$ 163,459
Obligation incurred	**22,508**	14,798
Obligation incurred on property acquisitions	**744**	6,520
Obligation divested	**(86)**	(1,406)
Obligation settled	**(2,965)**	(1,367)
Accretion expense	**5,334**	3,607
Change in future estimated cash outlays	**14,018**	27,058
Balance, end of year	**$ 252,222**	$ 212,669

9. BANK DEBT

(000s)	Years Ended December 31, 2017	2016
Revolving credit facility[1]	**$ 592,185**	$ 1,161,439
Term debt[1]	**949,220**	249,302
Debt issue costs	**(6,648)**	(4,155)
Bank debt	**$ 1,534,757**	$ 1,406,586

(1) Amounts shown net of prepaid interest.

The Company has a covenant-based, unsecured, revolving credit facility in place with a syndicate of banks. This includes a five-year extendible revolving facility in the amount of $1,800.0 million and a $50.0 million operating revolver with a maturity date of June 2022. 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 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.

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 means, generally 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, 2017, adjusted EBITDA for the purposes of the above noted covenant calculations was $1,252.4 million (December 31, 2016 - $822.4 million), on a rolling four-quarter basis.

The Company also has a $950.0 million term loan with a syndicate of banks. 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 157.5 basis points with a maturity date of February 2023. 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 revolving credit facility and the term loan will rank equally with the revolving credit facility.

Additionally, the Company has a letter of credit facility payable on demand in the amount of $50.0 million with a bank. The Company has outstanding letters of credit in the amount of $17.6 million (December 31, 2016 - $18.6 million), which reduces the credit available on this facility.

The Company's aggregate borrowing capacity is $2.85 billion at December 31, 2017. As at, and for the years ending December 31, 2017 and December 31, 2016, the Company is in compliance with all debt covenants.

As at December 31, 2017, the Company had $947.8 million in long-term debt outstanding and $587.0 million drawn against the revolving credit facility for total bank debt of $1,534.8 million (net of prepaid interest and debt issue costs) (December 31, 2016 - $1,406.6 million). The effective interest rate on the Company's bank debt for the year ended December 31, 2017 was 2.52% (December 31, 2016 – 2.50%).

10. NON-CONTROLLING INTEREST

Tourmaline owns 90.6 percent of Exshaw Oil Corp., a private company engaged in oil and gas exploration in Canada.

A reconciliation of the non-controlling interest is provided below:

(000s)	Years Ended December 31, 2017	2016
Balance, beginning of year	**$ 27,549**	$ 28,431
Share of subsidiary's net income (loss) for the year	**267**	(882)
Balance, end of year	**$ 27,816**	$ 27,549

11. SHARE CAPITAL

(a) Authorized

Unlimited number of Common Shares without par value.

Unlimited number of non-voting Preferred Shares, issuable in series.

(b) Common Shares Issued

	Year Ended December 31, 2017		Year Ended December 31, 2016	
(000s) except share amounts	Number of Shares	Amount	Number of Shares	Amount
Balance, beginning of year	**268,595,812**	**$ 5,818,867**	221,335,925	$ 4,266,234
For cash on public offering of common shares (2)(5)	–	–	32,146,200	1,037,722
For cash on public offering of flow-through common shares (1)(3)(4)	**1,300,000**	**32,162**	2,210,500	69,760
Issued on corporate and property acquisitions (*note 7*)	**475,000**	**14,854**	10,017,938	367,658
For cash on exercise of stock options (*note 14*)	**713,134**	**16,549**	2,885,249	82,217
Contributed surplus on exercise of stock options	–	**5,668**	–	28,717
Share issue costs	–	**(2,005)**	–	(45,684)
Tax effect of share issue costs	–	**614**	–	12,243
Balance, end of year	**271,083,946**	**$ 5,886,709**	268,595,812	$ 5,818,867

(1) On December 5, 2017, the Company issued 1.300 million flow-through shares at a price of $31.20 per share for total gross proceeds of $40.6 million. The implied premium on the flow-through common shares was determined to be $8.4 million or $6.46 per share. As at December 31, 2017, the Company is committed to spend the full amount on qualified exploration expenditures by December 31, 2018. The expenditures were renounced to investors in January 2018 with an effective renunciation date of December 31, 2017.

(2) On April 5, 2016, the Company issued 10.388 million common shares at a price of $27.11 per share for total gross proceeds of $281.6 million. A total of 37,500 common shares were purchased by insiders.

(3) On May 17, 2016, the Company issued 1.320 million flow-through shares at a price of $35.50 per share for total gross proceeds of $46.9 million. The implied premium on the flow-through common shares was determined to be $9.0 million or $6.85 per share. As at December 31, 2017, the Company had spent the full committed amount. The expenditures were renounced to investors in January 2017 with an effective renunciation date of December 31, 2016.

(4) On October 20, 2016, the Company issued 0.891 million flow-through shares at a price of $44.50 per share for total gross proceeds of $39.6 million. The implied premium on the flow-through common shares was determined to be $7.7 million or $8.63 per share. As at December 31, 2017, the Company had spent the full committed amount. The expenditures were renounced to investors in January 2017 with an effective renunciation date of December 31, 2016.

(5) On November 30, 2016, the Company issued 21.759 million common shares at a price of $34.75 per share for total gross proceeds of $756.1 million. A total of 175,000 common shares were purchased by insiders.

12. DEFERRED TAXES

The provision for deferred taxes in the consolidated statements of income (loss) and comprehensive income (loss) reflect an effective tax rate which differs from the expected statutory tax rate. Differences were accounted for as follows:

(000s)	Years Ended December 31, 2017	2016
Income (loss) before taxes	**$ 498,833**	$ (36,021)
Canadian statutory rate (1)(2)	**26.82%**	26.60%
Expected income taxes (recovery) at statutory rates (3)	**133,771**	(9,582)
Effect on income tax of:		
Share-based payments	**5,127**	6,116
Flow-through shares	**6,234**	1,689
Effect of change in corporate tax rate (4)	**3,799**	–
Other	**2,862**	1,316
Non-taxable portion of gain on disposition	**–**	(2,707)
Deferred income tax (recovery)	**$ 151,793**	$ (3,168)

(1) The statutory rate consists of the combined statutory tax rate for the Company and its subsidiary for the year ended December 31, 2017.

(2) Effective January 1, 2018, the British Columbia provincial corporate tax rate increased from 11% to 12%.

(3) May not calculate due to rounding.

(4) Reflects the increase in deferred tax expense as a result of the October 2017 British Columbia corporate tax rate increase from 11% to 12% as well as the difference between the current statutory tax rate and the deferred tax rate applied to the current period income.

The movement in deferred tax balances during the years ended December 31, 2017 and 2016 are as follows:

(000s)	Balance January 1, 2017	Recognized in Net Earnings	Recognized in Liabilities	Recognized in Equity	Balance December 31, 2017
Deferred tax liabilities:					
Exploration and evaluation and property, plant and equipment	$ 751,245	$ 267,181	$ 16,169	$ –	$ 1,034,595
Risk management contracts	(20,581)	18,055	–	–	(2,526)
Long-term asset	1,618	85	–	–	1,703
Deferred tax assets:					
Decommissioning obligations	(56,999)	(11,101)	–	–	(68,100)
Non-capital losses	(183,614)	(127,598)	–	–	(311,212)
Share issue costs	(14,654)	5,171	–	(614)	(10,097)
Deferred tax liability (asset)	$ 477,015	$ 151,793	$ 16,169	$ (614)	$ 644,363

(000s)	Balance January 1, 2016	Recognized in Net Earnings	Recognized in Liabilities	Recognized in Equity	Acquired in Business Combination	Balance December 31, 2016
Deferred tax liabilities:						
Exploration and evaluation and property, plant and equipment	$ 694,496	$ 50,211	$ 6,538	$ –	$ –	$ 751,245
Risk management contracts	7,153	(27,734)	–	–	–	(20,581)
Long-term asset	1,792	(174)	–	–	–	1,618
Deferred tax assets:						
Decommissioning obligations	(43,818)	(13,181)	–	–	–	(56,999)
Long-term obligations	–	–	–	–	–	–
Non-capital losses	(166,218)	(17,396)	–	–	–	(183,614)
Share issue costs	(7,517)	5,106	–	(12,243)	–	(14,654)
Deferred tax liability (asset)	$ 485,888	$ (3,168)	$ 6,538	$ (12,243)	$ –	$ 477,015

As at December 31, 2017, the Company has estimated federal tax pools of $7.1 billion (December 31, 2016 - $6.3 billion) available for deduction against future taxable income. The Company has $1.2 billion (December 31, 2016 - $684.2 million) of unused tax losses expiring between 2023 and 2035.

13. EARNINGS (LOSS) PER SHARE

Basic earnings (loss) per share was calculated as follows:

	Years Ended December 31,	
	2017	2016
Net earnings (loss) for the year *(000s)*	**$ 346,773**	$ (31,971)
Weighted average number of common shares – basic	**269,593,202**	233,934,112
Earnings (loss) per share – basic	**$ 1.29**	$ (0.14)

Diluted earnings (loss) per share was calculated as follows:

	Years Ended December 31,	
	2017	**2016**
Net earnings (loss) for the year *(000s)*	**$ 346,773**	$ (31,971)
Weighted average number of common shares – diluted	**269,595,109**	233,934,112
Earnings (loss) per share – fully diluted	**$ 1.29**	$ (0.14)

There were 20,932,882 options excluded from the weighted-average share calculation for the year ended December 31, 2017 because they were anti-dilutive (December 31, 2016 – 20,037,497). At December 31, 2017, there were 271,083,946 basic common shares outstanding (December 31, 2016 – 268,595,812).

14. SHARE-BASED PAYMENTS

The Company has a rolling stock option plan. Under the employee stock option plan, the Company may grant options to its employees up to 23,042,135 shares of common stock, which represents 8.5% of the current outstanding common shares. The exercise price of each option equals the volume-weighted average market price for the five days preceding the issue date of the Company's stock on the date of grant and the option's maximum term is seven years. Options are granted throughout the year and vest 1/3 on each of the first, second and third anniversaries from the date of grant.

	Years Ended December 31, 2017			2016		
	Number of Options		Weighted Average Exercise Price	Number of Options		Weighted Average Exercise Price
Stock options outstanding, beginning of year	**20,037,497**	**$**	**37.26**	19,746,414	$	36.50
Granted	**3,991,850**		**26.72**	3,413,000		34.34
Exercised	**(713,134)**		**23.21**	(2,885,249)		28.50
Expired	**(1,716,832)**		**31.72**	–		–
Forfeited	**(650,999)**		**38.82**	(236,668)		38.92
Stock options outstanding, end of year	**20,948,382**	**$**	**36.13**	20,037,497	$	37.26

The weighted average trading price of the Company's common shares was $26.77 during the year ended December 31, 2017 (December 31, 2016 – $31.71).

The following table summarizes stock options outstanding and exercisable at December 31, 2017:

Range of Exercise Price	Number Outstanding at Period End	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at Year End	Weighted Average Exercise Price
$22.02 – $29.26	6,875,849	4.98	26.44	2,004,632	26.44
$30.06 – $39.57	5,391,033	4.14	35.40	2,608,066	36.17
$40.18 – $48.99	7,104,000	1.20	42.13	7,087,333	42.14
$51.47 – $56.76	1,577,500	1.52	53.85	1,577,500	53.85
	20,948,382	3.22	36.13	13,277,531	39.99

The fair value of options, granted during the year, was estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions and resulting values:

	Years Ended December 31, 2017		2016	
Fair value of options granted (weighted average)	**$**	**7.57**	$	10.47
Risk-free interest rate		**1.53%**		1.15%
Estimated hold period prior to exercise		**5.0 years**		4.8 years
Expected volatility		**32%**		34%
Forfeiture rate		**2%**		2%
Dividend per share	**$**	**0.21**	$	0.00

15. OTHER INCOME

(000s)	Years Ended December 31, 2017		2016	
Processing income	**$**	**29,950**	$	24,792
Disposal income		**3,416**		–
Other		**1,976**		1,141
Total other income	**$**	**35,342**	$	25,933

16. FINANCE EXPENSES

	Years Ended December 31,	
(000s)	**2017**	**2016**
Finance expenses:		
Interest on loans and borrowings	**$ 44,286**	$ 40,550
Accretion of decommissioning obligations	**5,334**	3,607
Foreign exchange (gain) on U.S. denominated debt	**(82,746)**	(47,778)
Realized loss on cross-currency swaps	**82,746**	47,778
Realized loss on interest rate swaps	**2,975**	2,708
Transaction costs on property acquisitions	**133**	1,793
Total finance expenses	**$ 52,728**	$ 48,658

17. SUPPLEMENTAL DISCLOSURES

Tourmaline's consolidated statement of income (loss) and comprehensive income (loss) is prepared primarily by nature of the expenses, with the exception of salaries and wages which are included in both the operating and general and administrative expense line items as follows:

	Years Ended December 31,	
(000s)	**2017**	**2016**
Operating	**$ 35,050**	$ 29,570
General and administration	**26,979**	17,836
Total employee compensation costs	**$ 62,029**	$ 47,406

18. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of:

	Years Ended December 31,	
(000s)	**2017**	**2016**
Source/(use) of cash:		
Trade and other receivables	**$ (69,573)**	$ (25,664)
Deposit and prepaid expenses	**(693)**	4,194
Trade and other payables	**87,849**	(77,762)
	17,583	(99,232)
Related to operating activities	**$ (22,858)**	$ (34,900)
Related to investing activities	**$ 40,441**	$ (64,332)

Cash interest paid was $39.5 million for the year ended December 31, 2017 (December 31, 2016 - $35.3 million).

19. COMMITMENTS

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	$ 5,529	$ 6,780	$ –	$ –	$ 12,309
Firm transportation and processing agreements	315,028	711,886	640,708	1,708,666	3,376,288
Capital commitments [(1)]	314,154	603,536	6,534	55,921	980,145
Flow-through share commitments	40,560	–	–	–	40,560
Revolving credit facility [(2)]	–	–	673,071	–	673,071
Term debt [(3)]	28,462	56,925	56,925	951,793	1,094,105
	$ 703,733	$ 1,379,127	$ 1,377,238	$ 2,716,380	$ 6,176,478

(1) Includes drilling commitments, and capital spending commitments under the joint arrangement in the Spirit River complex of $300.0 million per year 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 2017, an economic downturn event, as defined in the joint arrangement in the Spirit River complex had occurred resulting in capital spending being deferred to future periods.

(2) Includes interest expense at an annual rate of 2.89% being the rate applicable to outstanding debt on the credit facility at December 31, 2017.

(3) Includes interest expense at an annual rate of 3.00% being the applicable rate on the term debt at December 31, 2017.

20. KEY MANAGEMENT PERSONNEL COMPENSATION

Key management personnel are persons who have the authority and responsibility for planning, directing and controlling the activities of the Company, directly or indirectly. Key management includes all directors and executives of the Company. The table below summarizes all key management personnel compensation included in the consolidated financial statements for the years ended December 31, 2017 and 2016.

Compensation of Key Management

	Years Ended December 31,	
(000s)	**2017**	**2016**
Short-term compensation [(1)]	**$ 7,628**	$ 6,833
Share-based payments [(2)]	**3,236**	4,705
Total compensation paid to key management	**$ 10,864**	$ 11,538

(1) Short-term compensation includes annual salaries, management bonuses and employee benefits provided to key management personnel as well as directors' fees.

(2) Based on the grant date fair value of the applicable awards. The fair value of options granted is estimated at the date of grant using a Black-Scholes Option-Pricing Model. The total share-based payment of options issued in 2017 is based on a weighted-average fair value ranging between $6.80 and $7.22 per option (2016 – between $9.49 and $10.67 per option).

21. SUBSEQUENT EVENTS

On February 28, 2018, the Company completed the sale of a series of undeveloped assets across all three CGUs for proceeds of approximately $72.0 million before customary adjustments.