NEWS RELEASE **MARCH 7, 2017**

TOURMALINE OIL CORP. EARNS $59.6 MILLION IN Q4 2016

Calgary, Alberta - Tourmaline Oil Corp. (TSX:TOU) ("Tourmaline" or the "Company") achieved exceptional growth in reserves (64%) and top-tier production growth (20%) in 2016 while continuously improving its industry-leading cost structure.

HIGHLIGHTS

- Q4 after-tax earnings of $59.6 million ($0.24/diluted share), re-emphasizing the underlying profitability of Tourmaline's E&P business, even in a low commodity price environment.
- Q4 2016 cash flow(1) of $252.5 million ($1.02/diluted share), a 36.0% increase over Q3 2016 cash flow.
- 2016 annual cash flow of $731.8 million consistent with E&P capital spending of $730.7 million.
- Fourth quarter 2016 production averaged 191,814 boepd, a 13% increase over Q3 production and a 7% increase over the fourth quarter of 2015. Full-year 2016 average production of 185,672 boepd represented a 20% increase (10% per diluted share) over 2015 average production of 154,403 boepd.
- Current daily Company production is approximately 235,000 boepd. The Company expects average Q1 2017 production of between 230,000 and 235,000 boepd. Tourmaline has an additional 40 wells to bring on-stream during March.
- Continued industry-leading all-in cash costs of $6.80/boe in 2016 (operating, transportation, general and administrative and financing), a 10% reduction from 2015 cash costs of $7.56/boe.
- Full-year 2016 operating costs decreased 24% to $3.31/boe compared to $4.37/boe in 2015. 2016 cash G&A costs were $0.44/boe, amongst the lowest in the industry. The Company continues to pursue cost reductions in all aspects of its E&P business.
- Top decile 2016 effective interest rate on the Company's debt of 2.5% (2015 - 2.68%).
- Exit net debt of $1.59 billion resulting in a net debt to annualized cash flow ratio of 1.57.(2)
- Proved plus probable reserves ("2P") increased to 1,746.8 mmboe during 2016, a 58% increase over 2015 reserves of 1,108.3 mmboe and a 64% increase (34% per diluted share) before taking into account annual production of 68.0 mmboe. Total proved ("TP") reserves increased 44% and proved developed producing ("PDP") reserves increased 60% over 2015 before taking into account annual production of 68.0 mmboe.

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(1) "Cash flow" is defined as cash provided by operations before changes in non-cash operating working capital. See "Non-GAAP Financial Measures" in the attached Management's Discussion and Analysis.

(2) See note 5 of the attached Consolidated Financial Statements for the year ended December 31, 2016 for further disclosure on how this ratio is calculated.

- After eight years, Tourmaline now has 1.75 billion boe of independently-recognized 2P reserves at year-end 2016, essentially all of which will be serviced by Company-owned infrastructure.
- The estimated 2P reserve NAV[(3)] (NPV discounted at 10 percent before tax) at year end 2016 was $47.11/per diluted share. The Company has only booked 1,595 net locations (1,819 gross) in the 2016 reserve report of a well-defined future development drilling inventory of 14,713 gross locations. The infrastructure skeleton, which is now complete in all three core areas, essentially reaches all of the future locations.
- The 2017 E&P capital program is forecast to be $1.3 billion, which includes a 17-rig drilling program that will deliver 30% annual production growth for less than anticipated 2017 cash flow of $1.4 billion. Net debt at the end of 2017 is expected to be $1.5 billion or 1.1x 2017 forecast cash flow.
- In 2016, Tourmaline's E&P capital program of approximately $730.7 million generated over 75,000 boe/d of new production resulting in capital efficiencies of approximately $9,500 boe/d, an improvement of 39% over 2015 E&P capital efficiency of approximately $15,500 boe/d.

[(3)] *2P Reserve NAV per share is calculated as 2P NPV discounted at 10 percent reserve value divided by total diluted shares outstanding at December 31, 2016. It should not be assumed that the NAV per share represents the fair market value of Tourmaline's shares.*

CORPORATE SUMMARY – DECEMBER 31, 2016

	Three Months Ended December 31,			Twelve Months Ended December 31,		
	2016	**2015**	**Change**	**2016**	**2015**	**Change**
OPERATIONS						
Production						
Natural gas *(mcf/d)*	**982,713**	927,480	6%	**972,513**	807,888	20%
Crude oil and NGL *(bbl/d)*	**28,028**	25,030	12%	**23,586**	19,755	19%
Oil equivalent *(boe/d)*	**191,814**	179,610	7%	**185,672**	154,403	20%
Product prices[1]						
Natural gas *($/mcf)*	**$ 3.20**	$ 2.99	7%	**$ 2.51**	$ 3.24	(23)%
Crude oil and NGL *($/bbl)*	**$ 38.42**	$ 47.65	(19)%	**$ 37.68**	$ 47.33	(20)%
Operating expenses *($/boe)*	**$ 2.86**	$ 4.23	(32)%	**$ 3.31**	$ 4.37	(24)%
Transportation costs *($/boe)*	**$ 2.92**	$ 1.94	51%	**$ 2.41**	$ 2.03	19%
Operating netback[4] *($/boe)*	**$ 15.00**	$ 15.22	(1)%	**$ 11.50**	$ 15.79	(27)%
Cash general and administrative expenses *($/boe)*[2]	**$ 0.39**	$ 0.33	18%	**$ 0.44**	$ 0.45	(2)%
FINANCIAL *($000, except share and per share)*						
Revenue	**388,449**	364,818	6%	**1,219,160**	1,297,461	(6)%
Royalties	**21,752**	11,340	92%	**48,857**	46,626	5%
Cash flow[4]	**252,542**	242,351	4%	**731,801**	850,220	(14)%
Cash flow per share *(diluted)*[4]	**$ 1.02**	$ 1.10	(7)%	**$ 3.12**	$ 3.96	(21)%
Net earnings	**59,621**	34,636	72%	**(31,971)**	80,087	(140)%
Net earnings per share *(diluted)*	**$ 0.24**	$ 0.16	50%	**$ (0.14)**	$ 0.37	(138)%
Capital expenditures *(net of dispositions)*	**1,244,974**	325,499	282%	**1,933,289**	1,536,139	26%
Weighted average shares outstanding *(diluted)*				**234,386,245**	214,772,602	9%
Net debt[4]				**(1,590,850)**	(1,550,387)	3%
PROVED + PROBABLE RESERVES[3]						
Natural gas *(bcf)*				**8,930.6**	5,694.1	57%
Crude oil *(mbbls)*				**54,362**	42,306	28%
Natural gas liquids *(mbbls)*				**204,027**	116,962	74%
Mboe				**1,746,822**	1,108,279	58%

(1) Product prices include realized gains and losses on financial instrument contracts.

(2) Excluding interest and financing charges.

(3) Reserves are "Company gross reserves", which are defined as the working interest share of reserves prior to the deduction of interest owned by others (burdens). Royalty interest reserves are not included in Company gross reserves.

(4) See "Non-GAAP Financial Measures" in the attached Management's Discussion and Analysis.

Conference Call Tomorrow at 6:15 a.m. MT (8:15 a.m. ET)

Tourmaline will host a conference call tomorrow, March 8, 2017 starting at 6:15 a.m. MT (8:15 a.m. ET). To participate, please dial 1-888-231-8191 (toll-free in North America), or local dial-in 647-427-7450, a few minutes prior to the conference call.

Conference ID number is 51459352.

Reader Advisories

CURRENCY

All amounts in this news release are stated in Canadian dollars unless otherwise specified.

FORWARD-LOOKING INFORMATION

This news release contains forward-looking information within the meaning of applicable securities laws. The use of any of the words "forecast", "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information. More particularly and without limitation, this news release contains forward-looking information concerning Tourmaline's plans and other aspects of its anticipated future operations, management focus, objectives, strategies, financial, operating and production results and business opportunities, including anticipated petroleum and natural gas production for various periods, drilling inventory or locations, cash flow, net debt and debt to cash flow levels, capital spending, cost reduction initiatives, projected operating and drilling costs, as well as Tourmaline's future drilling prospects and plans, business strategy, future development and growth opportunities, prospects and asset base. The forward-looking information is based on certain key expectations and assumptions made by Tourmaline, including expectations and assumptions concerning: prevailing commodity prices and currency exchange rates; applicable royalty rates and tax laws; interest rates; future well production rates and reserve volumes; operating costs the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions; the state of the economy and the exploration and production business; the availability and cost of financing, labour and services; and ability to market crude oil, natural gas and NGL successfully.

Statements relating to "reserves" are also deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

Although Tourmaline believes that the expectations and assumptions on which such forward-looking information is based are reasonable, undue reliance should not be placed on the forward-looking information because Tourmaline can give no assurances that they will prove to be correct. Since forward-looking information addresses future events and conditions, by its very nature it involves inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to: the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to reserves, production, revenues, costs and expenses; health, safety and environmental risks; commodity price and exchange rate fluctuations; interest rate fluctuations; marketing and transportation; loss of markets; environmental risks; competition; incorrect assessment of the value of acquisitions; failure to complete or realize the anticipated benefits of acquisitions or dispositions; ability to access sufficient capital from internal and external sources; failure to obtain required regulatory and other approvals; and changes in legislation, including but not limited to tax laws, royalties and environmental regulations. Readers are cautioned that the foregoing list of factors is not exhaustive.

Additional information on these and other factors that could affect Tourmaline, or its operations or financial results, are included in the Company's most recently filed Management's Discussion and Analysis (See "Forward-Looking Statements" therein) , Annual Information Form (See "Risk Factors" and "Forward-Looking Statements" therein) and other reports on file with applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or Tourmaline's website (www.tourmalineoil.com).

The forward-looking information contained in this news release is made as of the date hereof and Tourmaline undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless expressly required by applicable securities laws.

RESERVES DATA

The reserves data set forth above is based upon the reports of GLJ Petroleum Consultants Ltd. ("GLJ") and Deloitte LLP, each dated effective December 31, 2016, which have been consolidated into one report by GLJ and adjusted to apply certain of GLJ's assumptions and methodologies and pricing and cost assumptions. The consolidated report includes 100% of the reserves and future net revenue attributable to the properties of Exshaw Oil Corp. ("Exshaw"), a subsidiary of the Company, without reduction to reflect the 9.4% third-party minority interest in Exshaw. The price forecast used in the reserve evaluations is an average of the January 1, 2017 price forecasts for GLJ, Sproule Associates Ltd. and McDaniel & Associates Consultants Ltd., each of which is available on their respective websites, www.gljpc.com, www.sproule.com and www.mcdan.com, and will be contained in the Company's Annual Information Form for the year ended December 31, 2016, which will be filed on SEDAR (accessible at www.sedar.com) on or before March 31, 2017.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable crude oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

All evaluations and reviews of future net revenue are stated prior to any provisions for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis and utilizes the Company's tax pools. It does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the after-tax value of the Company, which may be significantly different. The Company's financial statements and the management's discussion and analysis should be consulted for information at the level of the Company.

The estimated values of future net revenue disclosed in this news release do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

The reserve data provided in this news release presents only a portion of the disclosure required under National Instrument 51-101. All of the required information will be contained in the Company's Annual Information Form for the year ended December 31, 2016, which will be filed on SEDAR (accessible at www.sedar.com) on or before March 31, 2017.

See also the Company's news release dated February 22, 2017 for more information with respect to the Company's reserves data.

FINANCIAL OUTLOOK

Also included in this news release are estimates of Tourmaline's 2017 cash flow and net debt, which are based on, among other things, the various assumptions as to production levels, capital expenditures, and other assumptions disclosed in this news release and including Tourmaline's estimated 2017 average production of 240,000-260,000 boepd and commodity price assumptions for natural gas (AECO - $3.15/mcf for 2017), and crude oil (WTI (US) - $60/bbl for 2017) and an exchange rate assumption of $0.77 (US/CAD) for 2017. To the extent such estimates constitute a financial outlook, they were approved by management and the Board of Directors of Tourmaline on March 7, 2017 and are included to provide readers with an understanding of Tourmaline's anticipated cash flow and net debt based on the capital expenditure, production and other assumptions described herein and readers are cautioned that the information may not be appropriate for other purposes.

INDUSTRY METRICS

The terms cash costs, operating netbacks and capital efficiency, while commonly used in the oil and gas industry, do not have standardized meanings and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons.

ESTIMATED DRILLING INVENTORY

This news release discloses drilling locations in four categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii). Of the 14,713 undrilled locations disclosed in this news release, 906 are proved undeveloped locations, 20 are proved non-producing locations, 893 are probable undeveloped locations, and 12,894 are unbooked. Proved undeveloped locations, proved non-producing locations, probable undeveloped locations and probable non-producing locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by GLJ

Petroleum Consultants Ltd. and Deloitte LLP as of December 31, 2016 and account for drilling locations that have associated proved and/or probable reserves, as applicable.

Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

GENERAL

See also "Forward-Looking Statements", "Boe Conversions" and "Non-GAAP Financial Measures" in the attached Management's Discussion and Analysis.

CERTAIN DEFINITIONS:

bbl	barrel
bbls/day	barrels per day
bbl/mmcf	barrels per million cubic feet
bcf	billion cubic feet
bpd or bbl/d	barrels per day
boe	barrel of oil equivalent
boepd or boe/d	barrel of oil equivalent per day
bopd or bbl/d	barrel of oil, condensate or liquids per day
FCP	final circulating pressure
gj	gigajoule
gjs/d	gigajoules per day
mbbls	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcfpd or mcf/d	thousand cubic feet per day
mcfe	thousand cubic feet equivalent
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmbtu/d	million British thermal units per day
mmcf	million cubic feet
mmcfpd or mmcf/d	million cubic feet per day
MPa	megapascal
mstboe	thousand stock tank barrels of oil equivalent
NGL	natural gas liquids

MANAGEMENT’S DISCUSSION AND ANALYSIS

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

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

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

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

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

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

In particular, forward-looking statements included in this MD&A include, but are not limited to, statements with respect to: the size of, and future net revenues and cash flow from, crude oil, NGL (natural gas liquids) and natural gas reserves; future prospects; the focus of and timing of capital expenditures; expectations regarding the ability to raise capital and to continually add reserves through acquisitions and development; access to debt and equity markets; projections of market prices and costs; the performance characteristics of the Company's crude oil, NGL and natural gas properties; crude oil, NGL and natural gas production levels and product mix; Tourmaline’s future operating and financial results; capital investment programs; supply and demand for crude oil, NGL and natural gas; future royalty rates; future decommissioning obligations; drilling, development and completion plans and the results therefrom; future land expiries; dispositions and joint venture arrangements; amount of operating, transportation and general and administrative expenses; treatment under governmental regulatory regimes and tax laws; and estimated tax pool balances. In addition, statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

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

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

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

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

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

PRODUCTION

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

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

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

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

REVENUE

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

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

TOURMALINE REALIZED PRICES:

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

BENCHMARK OIL AND GAS PRICES:

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

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

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

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

CURRENCY – EXCHANGE RATES:

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

(1) Average rates for the period.

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

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

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

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

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

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

ROYALTIES

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

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

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

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

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

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

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

The Company did not opt-in early to the MRF. Based on the details provided to date, the Company believes that the MRF is generally consistent with the initial goal of incentivizing the use of technology to improve productivity and rewards producers deploying the most competitive operating practices. With the new framework coming into effect January 1, 2017, the Company does anticipate an increase in the corporate royalty rate but based on the Company's current development plans and operational practices, the increase is not expected to be significant.

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

OTHER INCOME

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

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

OPERATING EXPENSES

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

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

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

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

TRANSPORTATION

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

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

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

GENERAL & ADMINISTRATIVE EXPENSES ("G&A")

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

Total G&A expenses for the fourth quarter of 2016 were $7.0 million compared to $5.4 million for the same quarter of the prior year. G&A expenses in the fourth quarter of 2015 were lower due to an office rent incentive received as well as a reduction in compensation expense related to annual bonuses. G&A expenses per boe for the fourth quarter of 2016 were $0.39/boe, compared to $0.33/boe for the same quarter of 2015.

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

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

SHARE-BASED PAYMENTS

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

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

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

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

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

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

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

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

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

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

FINANCE EXPENSES

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

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

For the year ended December 31, 2016, the Company drew from the credit facility and term loan in U.S. dollars, as permitted under the credit facility and term loan, which when repaid created a foreign exchange (gain) or loss. Concurrent with the draw of U.S. dollar denominated borrowings, the Company entered into cross-currency swaps to manage the foreign currency risk resulting from holding U.S. dollar denominated borrowings. The Company fixed the Canadian dollar amount for purposes of principal and interest repayment resulting in a (gain) or loss on cross-currency swaps equivalent to the realized foreign exchange (gains) and losses. These transactions allow the Company to take advantage of the interest rate spread between CDOR and LIBOR (for U.S. borrowings) without taking on foreign exchange risk.

DEFERRED INCOME TAXES (RECOVERY)

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

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

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

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

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

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

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

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

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

CAPITAL EXPENDITURES

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

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

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

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

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

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

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

Acquisitions and Dispositions

2016

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

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

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

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

2015

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

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

On August 14, 2015, the Company acquired all of the issued and outstanding shares of Mapan Energy Ltd. ("Mapan"). As consideration, the Company issued 2,718,026 common shares at a deemed price of $32.98 per share for total consideration of $89.6 million. The acquisition resulted in an increase in PP&E of approximately $58.5 million. Total transaction costs incurred by the Company of $1.1 million associated with this acquisition were expensed in the consolidated statement of income (loss) and comprehensive income (loss). The acquisition of Mapan provided for an increase in lands and production in the Alberta Deep Basin, one of the Company's core areas.

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

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

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

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

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

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

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

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

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

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

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

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

SHARES AND STOCK OPTIONS OUTSTANDING

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

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

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

PAYMENTS DUE BY YEAR

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

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

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

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

OFF BALANCE SHEET ARRANGEMENTS

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

FINANCIAL RISK MANAGEMENT

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

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

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

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

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

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

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

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

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

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

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

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

BUSINESS RISKS AND UNCERTAINTIES

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

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

IMPACT OF NEW ENVIRONMENTAL REGULATIONS

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

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

CHANGES IN ACCOUNTING POLICIES

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

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

STANDARDS ISSUED BUT NOT YET ADOPTED

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

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

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

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

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

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

NON-GAAP FINANCIAL MEASURES

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

Cash Flow

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

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

Operating Netback

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

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

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

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

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

Net Debt

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

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

SELECTED QUARTERLY INFORMATION

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

(1) See Non-GAAP Financial Measures.

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

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

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

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

SELECTED ANNUAL INFORMATION

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

(1) See Non-GAAP Financial Measures.

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	As at December 31,	
(000s)	**2016**	**2015**
Assets		
Current assets:		
Accounts receivable	**$ 201,288**	$ 175,624
Prepaid expenses and deposits	**10,575**	14,769
Fair value of financial instruments *(notes 4 and 5)*	**895**	39,677
Total current assets	**212,758**	230,070
Long-term asset	**6,034**	6,688
Fair value of financial instruments (*notes 4 and 5*)	**2,990**	–
Exploration and evaluation assets *(note 6)*	**678,531**	620,142
Property, plant and equipment *(note 7)*	**8,457,210**	6,783,771
Total Assets	**$ 9,357,523**	$ 7,640,671
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 396,127**	$ 474,176
Fair value of financial instruments *(notes 4 and 5)*	**40,412**	3,285
Total current liabilities	**436,539**	477,461
Bank debt *(note 9)*	**1,406,586**	1,266,604
Fair value of financial instruments *(notes 4 and 5)*	**40,266**	9,701
Deferred premium on flow-through shares	**16,167**	5,982
Decommissioning obligations *(note 8)*	**212,669**	163,459
Deferred taxes *(note 12)*	**477,015**	485,888
Shareholders' equity:		
Share capital *(note 11)*	**5,818,867**	4,266,234
Non-controlling interest *(note 10)*	**27,549**	28,431
Contributed surplus	**188,883**	171,958
Retained earnings	**732,982**	764,953
Total shareholders' equity	**6,768,281**	5,231,576
Total Liabilities and Shareholders' Equity	**$ 9,357,523**	$ 7,640,671

Commitments (note 19).

Subsequent events (notes 5 and 21).

See accompanying notes to the consolidated financial statements.

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

(000s) except per-share amounts	Years Ended December 31, 2016	2015
Revenue:		
Oil and natural gas sales	**$ 1,124,515**	$ 1,073,952
Royalties	**(48,857)**	(46,626)
Net revenue from oil and natural gas sales	**1,075,658**	1,027,326
Realized gain on financial instruments	**94,645**	223,509
Unrealized (loss) on financial instruments *(note 5)*	**(103,484)**	(559)
Other income *(note 15)*	**25,933**	29,176
Total net revenue	**1,092,752**	1,279,452
Expenses:		
Operating	**224,800**	246,467
Transportation	**164,020**	114,634
General and administration	**30,204**	25,306
Share-based payments	**22,821**	30,842
Depletion, depreciation and amortization	**666,182**	690,860
Realized foreign exchange (gain)	**(353)**	–
Unrealized foreign exchange (gain)	**(287)**	–
(Gain) on divestitures	**(27,272)**	(35,232)
Total expenses	**1,080,115**	1,072,877
Income from operations	**12,637**	206,575
Finance expenses *(note 16)*	**48,658**	44,625
Income (loss) before taxes	**(36,021)**	161,950
Deferred taxes (recovery) *(note 12)*	**(3,168)**	83,438
Net income (loss) and comprehensive income (loss) before non-controlling interest	**(32,853)**	78,512
Net income (loss) and comprehensive income (loss) attributable to:		
Shareholders of the Company	**(31,971)**	80,087
Non-controlling interest *(note 10)*	**(882)**	(1,575)
	$ (32,853)	$ 78,512
Net income (loss) per share attributable to common shareholders *(note 13)*		
Basic	**$ (0.14)**	$ 0.37
Diluted	**$ (0.14)**	$ 0.37

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, 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 property 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**

(000s)	**Share Capital**	**Contributed Surplus**	**Retained Earnings**	**Non-Controlling Interest**	**Total Equity**
Balance at December 31, 2014	$ 3,615,378	$ 124,325	$ 684,866	$ 30,006	$ 4,454,575
Issue of common shares *(note 11)*	233,828	–	–	–	233,828
Issue of common shares on corporate acquisition (*notes 7 and 11*)	372,878	–	–	–	372,878
Share issue costs, net of tax (*note 11*)	(7,060)	–	–	–	(7,060)
Share-based payments	–	30,842	–	–	30,842
Capitalized share-based payments	–	30,842	–	–	30,842
Options exercised *(note 11)*	51,210	(14,051)	–	–	37,159
Income attributable to common shareholders	–	–	80,087	–	80,087
(Loss) attributable to non-controlling interest	–	–	–	(1,575)	(1,575)
Balance at December 31, 2015	$ 4,266,234	$ 171,958	$ 764,953	$ 28,431	$ 5,231,576

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(000s)	Years Ended December 31, 2016	2015
Cash provided by (used in):		
Operations:		
Net income (loss)	**$ (31,971)**	$ 80,087
Items not involving cash:		
Depletion, depreciation and amortization	**666,182**	690,860
Accretion on decommissioning obligations	**3,607**	2,854
Share-based payments	**22,821**	30,842
Deferred taxes (recovery)	**(3,168)**	83,438
Unrealized loss on financial instruments	**103,484**	559
Unrealized foreign exchange (gain)	**(287)**	–
Other non-cash items	**654**	–
(Gain) on divestitures	**(27,272)**	(35,232)
Non-controlling interest	**(882)**	(1,575)
Decommissioning expenditures	**(1,367)**	(1,613)
Changes in non-cash operating working capital *(note 18)*	**(34,900)**	(14,465)
Total cash flow from operating activities	**696,901**	835,755
Financing:		
Issue of common shares	**1,206,422**	281,047
Share issue costs	**(45,684)**	(10,066)
Increase in bank debt	**139,982**	361,494
Total cash flow from financing activities	**1,300,720**	632,475
Investing:		
Exploration and evaluation	**(56,592)**	(115,331)
Property, plant and equipment	**(699,152)**	(1,335,803)
Property acquisitions	**(1,225,545)**	(92,003)
Proceeds from divestitures	**48,000**	6,998
Net repayment of long-term obligation	**–**	(2,957)
Changes in non-cash investing working capital *(note 18)*	**(64,332)**	(192,186)
Total cash flow used in investing activities	**(1,997,621)**	(1,731,282)
Changes in cash	**–**	(263,052)
Cash, beginning of year	**–**	263,052
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, 2016 AND 2015

(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 7, 2017.

(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 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, and 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.

Certain comparative amounts have been reclassified to conform with the current year's presentation.

(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, investments, 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.

Investments:

An instrument is classified at fair value through profit or loss if it is held for trading or is designated as such upon initial recognition. Financial instruments are designated at fair value through profit or loss if the Company manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Company's risk management or investment strategy. Upon initial recognition, attributable transaction costs are recognized in profit or loss when incurred. Financial instruments at fair value through profit or loss are measured at fair value, and changes therein are recognized in profit or loss.

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 and interest 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 loss on U.S. denominated debt, realized gain on cross-currency swaps, realized loss on interest rate swaps 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, 2016:

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

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, 2017 and have not yet been adopted by the Company. These new or revised standards permit early adoption with transitional arrangements depending upon the date of initial application.

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

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

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

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

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

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, 2016 and December 31, 2015, 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, 2016 and December 31, 2015. 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, 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.

(000s)	As at December 31, 2015 Carrying Amount	 Fair Value
Financial assets:		
Commodity price risk contracts (1)	$ 39,677	$ 39,677
Financial liabilities:		
Bank debt	1,266,604	1,266,604
Commodity price risk contracts (1)	12,986	12,986

(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, 2016, Tourmaline's receivables consisted of $179.2 million (December 31, 2015 - $120.1 million) from petroleum and natural gas marketers, $15.4 million (December 31, 2015 - $35.3 million) from partners in jointly-owned assets, and $6.7 million (December 31, 2015 - $20.2 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 2016, Tourmaline had three 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, 2016, the Company has $3.0 million (December 31, 2015 - $4.8 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, 2016 (December 31, 2015 - nil) and did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended December 31, 2016 (December 31, 2015 – 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, 2016 is $396.1 million (December 31, 2015 - $474.2 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, 2016, 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, 2016:

(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	$ 396,127	$ 396,127	$ 396,127	$ –	$ –	$ –
Revolving credit facility (1)	1,157,788	1,231,745	–	–	1,231,745	–
Term debt (2)	248,798	271,359	5,496	5,496	260,367	–
Derivative financial liabilities:						
Financial commodity contracts	74,463	74,463	38,272	29,368	6,823	–
Financial interest rate swaps	6,215	6,215	2,140	2,140	1,935	–
	$ 1,883,391	**$ 1,979,909**	**$ 442,035**	**$ 37,004**	**$ 1,500,870**	**$ –**

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

(2) Includes interest expense at 2.20% being the rate applicable to outstanding debt on the term loan at December 31, 2016.

(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 has minimal impact on the value of the financial assets and liabilities on the consolidated statement of financial position at December 31, 2016. Changes in the US to Canadian exchange rate, however, could 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, 2016 would have decreased or increased shareholders' equity and net income (loss) by $10.7 million (December 31, 2015 - $9.1 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, 2016, 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 derivative contracts in place as at December 31, 2016[1]:

(000s)		2017	2018	2019	2020	Fair Value
Gas						
AECO swaps	*mmbtu/d*	14,282	–	–	–	$ (1,290)
	CAD$/mmbtu	$ 3.15				
NYMEX swaps	*mmbtu/d*	36,795	4,932	–	–	$ (10,737)
	USD$/mmbtu	$ 3.07	$ 3.11			
NYMEX call options (writer) [2]	*mmbtu/d*	110,000	110,000	90,000	20,000	$ (39,327)
	USD$/mmbtu	$ 3.59	$ 3.68	$ 3.94	$ 3.75	
Oil						
Financial swaps	*bbls/d*	4,500	1,000	–	–	$ (11,087)
	USD$/bbl	$ 51.56	$ 55.65			
Financial call swaptions [3]	*bbls/d*	3,000	3,125	–	–	$ (12,022)
	USD$/bbl	$ 67.03	$ 54.29			
Total Fair Value						$ (74,463)

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

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

(3) 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.

No financial contracts were entered into subsequent to December 31, 2016.

The Company has entered into the following interest rate swap arrangements[1]:

(000s)

Term	Type (Floating to Fixed)	Amount	Company Fixed Interest Rate	Counter Party Floating Rate Index	Fair Value
Apr 5, 2016 – Apr 5, 2019	Swap	$ 50,000	0.867%	Floating Rate	$ 274
Nov 28, 2014 – Nov 28, 2019	Swap	$ 250,000	2.065%	Floating Rate	$ (6,215)
Jun 6, 2016 – Jun 6, 2020	Swap	$ 50,000	1.025%	Floating Rate	$ 388
Apr 5, 2016 – Apr 5, 2021	Swap	$ 50,000	0.988%	Floating Rate	$ 722
Jun 13, 2016 – Jun 13, 2021	Swap	$ 25,000	0.973%	Floating Rate	$ 412
Aug 31, 2016 – Aug 31, 2021	Swap	$ 25,000	0.958%	Floating Rate	$ 476
Sep 30, 2016 – Sep 28, 2021	Swap	$ 25,000	0.900%	Floating Rate	$ 552
Nov 28, 2019 – Nov 28, 2022	Swap	$ 50,000	1.025%	Floating Rate	$ 1,061
Total Fair Value					$ (2,330)

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

The Company has entered into the following financial derivative contracts subsequent to December 31, 2016:

(000s)

Type of Contract	Amount	Time Period	Contract Price
Interest Rate Swap	$ 75,000	February 3, 2017 to February 3, 2022	1.43%
Interest Rate Swap	$ 25,000	February 24, 2017 to February 24, 2022	1.45%
Interest Rate Swap	$ 25,000	February 14, 2020 to February 14, 2023	1.80%

The following table provides a summary of the unrealized gains and losses on financial instruments for the years ended December 31, 2016 and 2015:

	Years Ended December 31,	
(000s)	**2016**	**2015**
Unrealized gain (loss) on financial instruments – commodity contracts	**$ (111,532)**	$ 5,656
Unrealized gain (loss) on financial instruments – interest rate swaps	**8,048**	(6,215)
Total unrealized gain (loss) on financial instruments	**$ (103,484)**	$ (559)

For the financial instruments in place at December 31, 2016, 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 after-tax loss would have been $10.3 million lower (December 31, 2015 - $5.5 million lower after-tax earnings). An equal and opposite impact would have occurred to the after-tax loss 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 contracts in place at December 31, 2016[1][5]:

		2017	2018	2019	2020	2021
Gas						
Fixed price – AECO	*mcf/d*	186,167	–	–	–	–
	CAD$/mcf	$ 2.93				
Basis differentials - AECO [2][3]	*mmbtu/d*	88,404	97,500	97,500	97,500	76,664
	USD$/mmbtu	$ (0.64)	$ (0.68)	$ (0.68)	$ (0.68)	$ (0.64)
Basis differentials – Stn 2	*mcf/d*	45,443	47,908	19,474	17,856	9,478
	CAD$/mcf	$ (0.22)	$ (0.20)	$ (0.05)	$ (0.07)	$ (0.26)
AECO Monthly Calls / Call	*mcf/d*	5,557	71,086	–	–	–
Swaptions [3]	*CAD$/mcf*	$ 2.85	$ 4.26			
Oil						
Fixed differential [4]	*bbls/d*	962	–	–	–	–
	USD$/bbl	$ (6.84)				

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

(2) Tourmaline also has 53.5 mmcf/d of NYMEX-AECO basis differentials at $(0.68) from 2022-2024. A portion of these basis deals have a cap on NYMEX, 5.8 mmcf/d at USD$4.71/mcf, 42.5 mmcf/d at USD$4.58/mcf from 2018-2022 and 37.5 mmcf/d at USD$4.55/mcf from 2023-2024.

(3) These are monthly calls for 2017 that are European Swaptions, whereby the Company provides the option to extend a gas swap into the period subsequent to the call date or increase the volumes under contract. In 2018, there is a combination of monthly calls and European Swaptions.

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

(5) Tourmaline also has entered into deals to sell 30,000 mmbtu/d at Chicago GDD pricing less transportation costs from April 2015 to October 2020; 20,000 mmbtu/d at Chicago GDD pricing less transportation costs from April 2015 to March 2020; 25,000 mmbtu/d at Emerson GDD pricing less transportation costs from November 2016 to October 2017; and 20,000 mmbtu/d at Ventura GDD pricing less transportation costs from April 2015 to October 2020.

The Company has entered into the following physical contracts subsequent to December 31, 2016:

Type of Contract	Quantity	Time Period	Contract Price
Fixed Price - AECO	40,000 GJs/d	November 2017 – March 2018	CAD $3.20/GJ average
Fixed Price – AECO	15,000 GJs/d	February 2017 – December 2017	CAD $2.88/GJ average
Fixed Price – AECO	10,000 GJs/d	March 2017 – December 2017	CAD $2.88/GJ
NYMEX – AECO Basis Differentials (1)	20,000 mmbtu/d	January 2018 – December 2020	USD $(0.80)/mmbtu average
NYMEX – AECO Basis Differentials (1)	20,000 mmbtu/d	November 2017 – December 2020	USD $(0.77)/mmbtu average

(1) Basis deals have a cap on NYMEX at USD$3.80

(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 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 long-term 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, 2016, the Company's ratio of net debt to annualized cash flow was 1.57 to 1.0 (December 31, 2015 - 1.60 to 1.0).

	As at December 31,	
(000s)	**2016**	**2015**
Net debt:		
Bank debt	**$(1,406,586)**	$(1,266,604)
Working capital (deficit)	**(223,781)**	(247,391)
Fair value of financial instruments – short-term (asset) liability	**39,517**	(36,392)
Net debt	**$(1,590,850)**	$(1,550,387)
Annualized cash flow:		
Cash flow from operating activities for Q4	**$ 192,134**	$ 228,959
Change in non-cash working capital	**60,408**	13,392
Cash flow for Q4	**$ 252,542**	$ 242,351
Annualized cash flow (based on most recent quarter annualized)	**$ 1,010,168**	$ 969,404
Net debt to annualized cash flow	**1.57**	1.60

The Company has not paid or declared any dividends since the date of incorporation, nor are any contemplated in the foreseeable future. There have been no changes in the Company's approach to capital management since December 31, 2015.

6. EXPLORATION AND EVALUATION ASSETS

(000s)	
As at January 1, 2015	$ 635,633
Capital expenditures	115,331
Transfers to property, plant and equipment *(note 7)*	(119,503)
Acquisitions	71,557
Divestitures	(28,815)
Expired mineral leases	(54,061)
As at December 31, 2015	$ 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**

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, 2016 and 2015, 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, 2015	$ 6,733,617
Capital expenditures	1,366,645
Transfers from exploration and evaluation *(note 6)*	119,503
Change in decommissioning liabilities *(note 8)*	39,450
Acquisitions	445,295
Divestitures	(18,525)
As at December 31, 2015	$ 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**

Accumulated Depletion, Depreciation and Amortization

(000s)	
As at January 1, 2015	$ 1,267,344
Depletion, depreciation and amortization	636,799
Divestitures	(1,929)
As at December 31, 2015	$ 1,902,214
Depletion, depreciation and amortization	649,479
Divestitures	(286)
As at December 31, 2016	**$ 2,551,407**

Net Book Value

(000s)	
As at December 31, 2015	$ 6,783,771
As at December 31, 2016	**$ 8,457,210**

Future development costs for the year ended December 31, 2016 of $6,417.4 million (December 31, 2015 - $4,523.1 million) were included in the depletion calculation.

Capitalization of G&A and Share-Based Payments

A total of $23.7 million in G&A expenditures have been capitalized and included in PP&E assets at December 31, 2016 (December 31, 2015 - $22.9 million). Also included in PP&E are non-cash share-based payments of $22.8 million at December 31, 2016 (December 31, 2015 - $30.8 million).

Impairment Assessment

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. At December 31, 2016, the Company determined that no indicators of impairment existed on any of its CGUs; therefore, impairment tests were not performed.

For the year ended December 31, 2015, the Company identified indicators of impairment on all of its CGUs due to the decline in the current and forward commodity prices for oil and natural gas since December 31, 2014. Impairment tests were performed accordingly and the Company determined that there was no impairment to PP&E at December 31, 2015.

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 unaudited interim condensed 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)

Perpetual Energy Inc.

On April 1, 2015, the Company acquired Perpetual Energy Inc.'s ("Perpetual") interests in the West Edson area of the Alberta Deep Basin with the issuance of 6,750,000 Tourmaline shares at a deemed price of $38.32 per share for total consideration of $258.7 million. The interests included Perpetual's land interests, production, reserves and facilities that were jointly-owned with Tourmaline. The value attributed to the property, plant and equipment acquired was supported by an engineering report prepared at December 31, 2014 by independent reserve engineers and internally rolled-forward to the acquisitions date using proved plus probable reserves discounted at a rate based on what a market participant would have paid as well as market metrics in the prevailing area at that time.

The acquisition resulted in an increase in production and processing capacity along with allowing the Company to leverage operational synergies created from having full ownership of the assets.

Results from operations are included in the Company's 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)	**Perpetual Energy Inc.**
Fair value of net assets acquired:	
Property, plant and equipment	$ 226,943
Exploration and evaluation	34,160
Decommissioning obligations	(2,443)
Total	$ 258,660
Consideration:	
Common shares issued	$ 258,660

Included in the consolidated statements of income (loss) and comprehensive income (loss) for the year ended December 31, 2015 are the following amounts relating to Perpetual since April 1, 2015:

(000s)	
Oil and natural gas sales	$ 23,399
Net income (loss) and comprehensive income (loss)	$ 4,882

If the Company had completed the business combination on January 1, 2015, the pro-forma results of the oil and gas sales and net income (loss) and comprehensive income (loss) for the year ended December 31, 2015 would have been as follows:

(000s)	As Stated	Perpetual	Pro Forma Year Ended December 31, 2015
Oil and natural gas sales	$ 1,073,952	$ 9,881	$ 1,083,833
Net income (loss) and comprehensive income (loss)	$ 80,087	$ 2,058	$ 82,145

Corporate Acquisitions

Bergen Resources Inc.

On July 20, 2015, the Company acquired all of the issued and outstanding shares of Bergen Resources Inc. ("Bergen"). As consideration, the Company issued of 725,000 Tourmaline shares at a deemed price of $33.90 per share for total consideration of $24.6 million. Total transaction costs incurred by the Company of $0.2 million associated with this acquisition were expensed in the consolidated statement of income (loss) and comprehensive income (loss). The acquisition resulted in an increase in PP&E of approximately $26.8 million and E&E assets of $2.1 million along with net debt of $8.4 million.

Results from operations for Bergen are included in the Company's consolidated financial statements from the closing date of the transaction. The value attributed to the property, plant and equipment acquired was supported by an engineering report prepared at December 31, 2014 by independent reserve engineers using proved plus probable reserves discounted at a rate based on what a market participant would have paid as well as market metrics in the prevailing area at that time. The acquisition of Bergen consolidated the Company's working interest in a core area of the Peace River High.

Included in the consolidated statements of income (loss) and comprehensive income (loss) for the year ended December 31, 2015 are the following amounts relating to Bergen since July 20, 2015:

(000s)	
Oil and natural gas sales	$ 2,481
Net income (loss) and comprehensive income (loss)	$ (721)

If the Company had acquired Bergen on January 1, 2015, the pro-forma results of the oil and gas sales and net income (loss) and comprehensive income (loss) for the year ended December 31, 2015 would have been as follows:

(000s)	As Stated	Bergen	Pro Forma Year Ended December 31, 2015
Oil and natural gas sales	$ 1,073,952	$ 1,921	$ 1,075,873
Net income (loss) and comprehensive income (loss)	$ 80,087	$ (1,705)	$ 78,382

Mapan Energy Ltd.

On August 14, 2015, the Company acquired all of the issued and outstanding shares of Mapan Energy Ltd. ("Mapan"). As consideration, the Company issued of 2,718,026 Tourmaline shares at a deemed price of $32.98 per share for total consideration of $89.6 million. Total transaction costs incurred by the Company of $1.1 million associated with this acquisition were expensed in the consolidated statement of income (loss) and comprehensive income (loss). The acquisition of Mapan resulted in an increase in lands and production in a core area of the Alberta Deep Basin.

Results from operations for Mapan are included in the Company's consolidated financial statements from the closing date of the transaction. The value attributed to the property, plant and equipment acquired was supported by an engineering report prepared at December 31, 2014 by independent reserve engineers using proved plus probable reserves discounted at a rate based on what a market participant would have paid as well as market metrics in the prevailing area at that time. The acquisition has been accounted for using the purchase method based on fair values as follows:

(000s)	**Mapan Energy Ltd.**
Fair value of net assets acquired:	
Cash	$ 11,011
Working capital	4,000
Property, plant and equipment	58,471
Fair value of financial instruments	(122)
Decommissioning obligations	(3,157)
Deferred income tax asset	19,437
Total	$ 89,640
Consideration:	
Common shares issued	$ 89,640

Included in the consolidated statements of income (loss) and comprehensive income (loss) for the year ended December 31, 2015 are the following amounts relating to Mapan since August 14, 2015:

(000s)	
Oil and natural gas sales	$ 12,936
Net income (loss) and comprehensive income (loss)	$ (414)

If the Company had acquired Mapan on January 1, 2015, the pro-forma results of the oil and gas sales and net income (loss) and comprehensive income (loss) for the year ended December 31, 2015 would have been as follows:

(000s)	**As Stated**	**Mapan**	**Pro Forma Year Ended December 31, 2015**
Oil and natural gas sales	$ 1,073,952	$ 21,697	$ 1,095,649
Net income (loss) and comprehensive income (loss)	$ 80,087	$ (1,252)	$ 78,835

Acquisition and Disposition of Oil and Natural Gas Properties

In addition to the above noted acquisitions, for the year ended December 31, 2016, the Company completed property acquisitions for total cash consideration of $42.5 million (December 31, 2015 - $92.0 million) and, a further $8.0 million in non-cash consideration (December 31, 2015 - $73.4 million). The Company also assumed $1.4 million in decommissioning liabilities (December 31, 2015 - $3.0 million). The Company also completed property dispositions for the year ended December 31, 2016 for total cash consideration of $48.0 million (December 31, 2015 - $7.0 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 $392.0 million (December 31, 2015 – $224.5 million), with some abandonments expected to commence in 2034. A risk-free rate of 2.31% (December 31, 2015 – 2.15%) and an inflation rate of 2.0% (December 31, 2015 – 1.8%) were used to calculate the fair value of the decommissioning obligations. The decommissioning obligations at December 31, 2016 have been adjusted by approximately $27.1 million (December 31, 2015 – $22.7 million) which includes $32.9 million relating to the revaluation of acquired decommissioning liabilities partially offset by $5.8 million due an increase in the risk-free rate as well as extending the expected abandonment date.

(000s)	**Years Ended December 31,**	
	2016	**2015**
Balance, beginning of year	**$ 163,459**	$ 114,038
Obligation incurred	**14,798**	16,780
Obligation incurred on corporate acquisitions	**–**	3,516
Obligation incurred on property acquisitions	**6,520**	5,484
Obligation divested	**(1,406)**	(270)
Obligation settled	**(1,367)**	(1,613)
Accretion expense	**3,607**	2,854
Change in future estimated cash outlays	**27,058**	22,670
Balance, end of year	**$ 212,669**	$ 163,459

9. BANK DEBT

(000s)	**Years Ended December 31,**	
	2016	**2015**
Revolving credit facility(1)	**$ 1,161,439**	$ 1,021,585
Term debt(1)	**249,302**	249,302
Debt issue costs	**(4,155)**	(4,283)
Bank debt	**$ 1,406,586**	$ 1,266,604

(1) Amounts shown net of prepaid interest.

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

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, (ii) the ratio of total debt to adjusted EBITDA shall not exceed 4:1, and (iii) the ratio of senior debt to total capitalization shall not exceed 0.55:1. At December 31, 2016, adjusted EBITDA for the purposes of the above noted covenant calculations was $822.4 million (December 31, 2015 - $886.4 million), on a rolling four-quarter basis. As at, and for the years ending December 31, 2016 and December 31, 2015, the Company is in compliance with all debt covenants.

The Company also has a $250.0 million five-year term loan with a Canadian Chartered Bank. The term loan can be drawn in either Canadian or U.S. funds and bears interest at the bank's prime lending rate, banker's acceptance rates or LIBOR (for U.S. borrowings), plus 220 basis points with a maturity date of November, 2020. The maturity date may, at the request of the Company and with consent of the lender, be extended on an annual basis. The covenants for the term loan are the same as those under the Company's current credit facility and the term loan will rank equally with the obligation under the Company's credit facility.

The Company's aggregate borrowing capacity is $2,100.0 million at December 31, 2016.

As at December 31, 2016, the Company had $248.8 million in long-term debt outstanding and $1,157.8 million drawn against the revolving credit facility for total bank debt of $1,406.6 million (net of prepaid interest and debt issue costs) (December 31, 2015 - $1,266.6 million). In addition, Tourmaline has outstanding letters of credit of $18.6 million (December 31, 2015 - $13.4 million), which reduce the credit available on the facility. The effective interest rate on the Company's bank debt for the year ended December 31, 2016 was 2.50% (December 31, 2015 – 2.68%).

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,**	
	2016	**2015**
Balance, beginning of year	**$ 28,431**	$ 30,006
Share of subsidiary's net (loss) for the year	**(882)**	(1,575)
Balance, end of year	**$ 27,549**	$ 28,431

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

(000s) except share amounts	Year Ended December 31, 2016 Number of Shares	Amount	Year Ended December 31, 2015 Number of Shares	Amount
Balance, beginning of year	**221,335,925**	**$ 4,266,234**	203,162,112	$ 3,615,378
For cash on public offering of common shares (1)(4)(6)	**32,146,200**	**1,037,722**	4,947,500	195,425
For cash on public offering of flow-through common shares (2)(3)(5)(7)	**2,210,500**	**69,760**	1,122,700	38,403
Issued on corporate and property acquisitions (*note 7*)	**10,017,938**	**367,658**	10,193,026	372,878
For cash on exercise of stock options (*note 14*)	**2,885,249**	**82,217**	1,910,587	37,159
Contributed surplus on exercise of stock options	**–**	**28,717**	–	14,051
Share issue costs	**–**	**(45,684)**	–	(10,066)
Tax effect of share issue costs	**–**	**12,243**	–	3,006
Balance, end of year	**268,595,812**	**$ 5,818,867**	221,335,925	$ 4,266,234

(1) 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.

(2) 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, 2016, the Company is committed to spend $44.0 million on qualified exploration expenditures by December 31, 2017. The expenditures were renounced to investors in January 2017 with an effective renunciation date of December 31, 2016.

(3) 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, 2016, the Company is committed to spend the full amount on qualified exploration expenditures by December 31, 2017. The expenditures were renounced to investors in January 2017 with an effective renunciation date of December 31, 2016.

(4) 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.

(5) On March 12, 2015, the Company issued 0.64 million flow-through shares at a price of $50.00 per share for total gross proceeds of $32.0 million. The implied premium on flow-through common shares was determined to be $6.3 million or $9.87 per share. As at December 31, 2016, the Company had spent the full committed amount. The expenditures were renounced to investors with an effective renunciation date of December 31, 2015.

(6) On June 23, 2015, the Company issued 4.948 million common shares at a price of $39.50 for total gross proceeds of $195.4 million. A total of 60,000 common shares were purchased by insiders.

(7) On November 25, 2015, the Company issued 0.48 million flow-through shares at a price of $34.10 per share for total gross proceeds of $16.5 million. The implied premium on flow-through common shares was determined to be $3.7 million or $7.75 per share. As at December 31, 2016, the Company had spent the full committed amount. The expenditures were renounced to investors with an effective renunciation date of December 31, 2015.

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, 2016	2015
Income (loss) before taxes	**$ (36,021)**	$ 161,950
Canadian statutory rate [1][2]	**26.60%**	26.00%
Expected income taxes (recovery) at statutory rates [3]	**(9,582)**	42,107
Effect on income tax of:		
Share-based payments	**6,116**	8,019
Flow-through shares	**1,689**	1,634
Effect of change in corporate tax rate and other	**1,316**	31,678
Non-taxable portion of gain on disposition	**(2,707)**	–
Deferred income tax (recovery)	**$ (3,168)**	$ 83,438

(1) The statutory rate consists of the combined statutory tax rate for the Company and its subsidiary for the year ended December 31, 2016.

(2) Effective July 1, 2015, the Alberta provincial corporate tax rate increased from 10% to 12%.

(3) May not calculate due to rounding.

The movement in deferred tax balances during the years ended December 31, 2016 and 2015 are as follows:

(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

(000s)	Balance January 1, 2015	Recognized in Net Earnings	Recognized in Liabilities	Recognized in Equity	Acquired in Business Combination	Balance December 31, 2015
Deferred tax liabilities:						
Exploration and evaluation and property, plant and equipment	$ 599,238	$ 102,626	$ 7,288	$ –	$ (14,656)	$ 694,496
Risk management contracts	6,898	288	–	–	(33)	7,153
Long-term asset	1,800	(8)	–	–	–	1,792
Deferred tax assets:						
Decommissioning obligations	(28,713)	(14,156)	–	–	(949)	(43,818)
Long-term obligations	(860)	860	–	–	–	–
Non-capital losses	(148,987)	(10,409)	–	–	(6,822)	(166,218)
Share issue costs	(7,286)	4,236	–	(3,006)	(1,461)	(7,517)
Deferred tax liability (asset)	$ 422,090	$ 83,437	$ 7,288	$ (3,006)	$ (23,921)	$ 485,888

As at December 31, 2016, the Company has estimated federal tax pools of $6.3 billion (December 31, 2015 - $5.4 billion) available for deduction against future taxable income. The Company has $684.2 million (December 31, 2015 - $619.6 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,	
	2016	2015
Net earnings (loss) for the year *(000s)*	**$ (31,971)**	$ 80,087
Weighted average number of common shares – basic	**233,934,112**	213,819,920
Earnings (loss) per share – basic	**$ (0.14)**	$ 0.37

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

	Years Ended December 31,	
	2016	**2015**
Net earnings (loss) for the year *(000s)*	**$ (31,971)**	$ 80,087
Weighted average number of common shares – diluted	**233,934,112**	214,772,602
Earnings (loss) per share – fully diluted	**$ (0.14)**	$ 0.37

There were 20,037,497 options excluded from the weighted-average share calculation for the year ended December 31, 2016 because they were anti-dilutive (December 31, 2015 – 11,176,000). At December 31, 2016, there were 268,595,812 basic common shares outstanding (December 31, 2015 – 221,335,925).

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 26,859,581 shares of common stock. 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, 2016			2015		
	Number of Options		Weighted Average Exercise Price	Number of Options		Weighted Average Exercise Price
Stock options outstanding, beginning of year	**19,746,414**	**$**	**36.50**	17,046,500	$	36.44
Granted	**3,413,000**		**34.34**	4,685,500		29.83
Exercised	**(2,885,249)**		**28.50**	(1,910,587)		19.45
Forfeited	**(236,668)**		**38.92**	(74,999)		42.05
Stock options outstanding, end of year	**20,037,497**	**$**	**37.26**	19,746,414	$	36.50

The weighted average trading price of the Company's common shares was $31.71 during the year ended December 31, 2016 (December 31, 2015 – $34.38).

The following table summarizes stock options outstanding and exercisable at December 31, 2016:

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
$20.79 – $29.26	3,998,632	3.22	25.93	1,740,332	25.20
$30.24 – $39.57	7,014,865	4.06	34.71	2,761,498	34.01
$40.18 – $48.99	7,379,000	2.20	42.11	6,221,333	41.85
$51.47 – $56.76	1,645,000	2.52	53.85	1,096,667	53.85
	20,037,497	3.08	37.26	11,819,830	38.68

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, 2016		2015	
Fair value of options granted (weighted average)	**$**	**10.47**	$	8.65
Risk-free interest rate		**1.15%**		2.32%
Estimated hold period prior to exercise		**4.8 years**		4 years
Expected volatility		**34%**		32%
Forfeiture rate		**2%**		2%
Dividend per share	**$**	**0.00**	$	0.00

15. OTHER INCOME

(000s)	Years Ended December 31, 2016		2015	
Processing income	**$**	**24,792**	$	27,979
Interest income		**140**		235
Other		**1,001**		962
Total other income	**$**	**25,933**	$	29,176

16. FINANCE EXPENSES

	Years Ended December 31,	
(000s)	**2016**	**2015**
Finance expenses:		
Interest on loans and borrowings	**$ 40,550**	$ 36,683
Accretion of decommissioning obligations	**3,607**	2,854
Foreign exchange (gain) loss on U.S. denominated debt	**(47,778)**	34,592
Realized (gain) loss on cross-currency swaps	**47,778**	(34,592)
Realized loss on interest rate swaps	**2,708**	3,140
Transaction costs on corporate and property acquisitions	**1,793**	1,948
Total finance expenses	**$ 48,658**	$ 44,625

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)	**2016**	**2015**
Operating	**$ 29,570**	$ 33,368
General and administration	**17,836**	16,425
Total employee compensation costs	**$ 47,406**	$ 49,793

18. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of:

	Years Ended December 31,	
(000s)	**2016**	**2015**
Source/(use) of cash:		
Trade and other receivables	**$ (25,664)**	$ 27,588
Deposit and prepaid expenses	**4,194**	(3,352)
Trade and other payables	**(77,762)**	(223,746)
	(99,232)	(199,510)
Working capital (deficiency)/surplus acquired	**–**	(7,141)
	$ (99,232)	$ (206,651)
Related to operating activities	**$ (34,900)**	$ (14,465)
Related to investing activities	**$ (64,332)**	$ (192,186)

Cash interest paid was $35.3 million for the year ended December 31, 2016 (December 31, 2015 - $30.2 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	$ 5,638	$ 10,867	$ 1,361	$ –	$ 17,866
Firm transportation and processing agreements	236,597	526,670	497,017	1,386,009	2,646,293
Capital commitments (1)	306,378	603,909	215,909	33,788	1,159,984
Flow through share commitments	83,592	–	–	–	83,592
Revolving credit facility (2)	–	–	1,231,745	–	1,231,745
Term debt (3)	5,496	10,993	254,870	–	271,359
	$ 637,701	$ 1,152,439	$ 2,200,902	$1,419,797	$ 5,410,839

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

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

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

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, 2016 and 2015.

Compensation of Key Management

	Years Ended December 31,	
(000s)	**2016**	**2015**
Short-term compensation (1)(2)	**$ 6,833**	$ 9,085
Share-based payments (3)	**4,705**	6,276
Total compensation paid to key management	**$ 11,538**	$ 15,361

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

(2) 2015 short-term compensation includes management bonuses for both the 2014 and 2015 compensation years.

(3) 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 2016 is based on a weighted-average fair value ranging between $9.49 and $10.67 per option (2015 - $9.81 per option).

21. SUBSEQUENT EVENTS

On February 3, 2017, the Company, increased its term loan to $650.0 million with a syndicate of banks and extended its maturity date to February 2022. The term loan can be drawn in either Canadian or U.S. funds and bears interest at the bank's prime lending rate, banker's acceptance rates or LIBOR (for U.S. borrowings), plus 200 basis points with a maturity date of February, 2022. The maturity date may, at the request of the Company and with consent of the lender, be extended on an annual basis. The covenants for the term loan are the same as those under the Company's current credit facility and the term loan will rank equally with the obligation under the Company's credit facility. As a result, the Company now has a borrowing capacity of $2,500.0 million.

ABOUT TOURMALINE OIL CORP.

Tourmaline is a Canadian senior crude oil and natural gas exploration and production company focused on long-term growth through an aggressive exploration, development, production and acquisition program in the Western Canadian Sedimentary Basin.

FOR FURTHER INFORMATION, PLEASE CONTACT:

Tourmaline Oil Corp.
Michael Rose
Chairman, President and Chief Executive Officer
(403) 266-5992

OR

Tourmaline Oil Corp.
Brian Robinson
Vice President, Finance and Chief Financial Officer
(403) 767-3587; robinson@tourmalineoil.com

OR

Tourmaline Oil Corp.
Scott Kirker
Secretary and General Counsel
(403) 767-3593; kirker@tourmalineoil.com

OR

Tourmaline Oil Corp.
Suite 3700, 250 – 6th Avenue S.W.
Calgary, Alberta   T2P 3H7
Phone: (403) 266-5992
Facsimile: (403) 266-5952
E-mail: info@tourmalineoil.com
Website: www.tourmalineoil.com