CALGARY, Aug. 2, 2017 /CNW/ - Tourmaline Oil Corp. (TSX:TOU) ("Tourmaline" or the "Company") is pleased to release strong financial and operating results for the second quarter of 2017.

HIGHLIGHTS

Financial Results

- Second quarter earnings were $108.6 million ($0.40/share) underscoring the fundamental profitability of Tourmaline's EP business in all three core complexes.
- Second quarter 2017 cash flow(1) was $ 313.3 million ($1.16/share) up 133% (100% per share) from second quarter 2016 cash flow of $134.3 million ($0.58/share).
- Second quarter 2017 operating costs were $3.22/boe, down 6% from second quarter of 2016 and ahead of full-year 2017 guidance of $3.50/boe.
- First half 2017 cash flow was $606.2 million ($2.25/share), more than double first half 2016 cash flow of $293.7 million ($1.29/share) and greater than first half 2017 capital spending of $588.9 million.
- Tourmaline generated $17.3 million of free cash flow(2) during first half 2017.
- Second quarter 2017 operating netback(3) per boe of $15.36 was a 78% improvement over the second quarter of 2016 at $8.63/boe.
- Total cash costs in the quarter of $7.10/boe (operating, transportation, general and administration(4), and financing) remained amongst the best in the sector.

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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) "Free cash flow" is defined as cash flow less capital expenditures.

(3) "Operating netback" is calculated on a per-boe basis and is defined as revenue (excluding processing income) less royalties, transportation costs and operating expenses. See "Non-GAAP Financial Measures" in the attached Management's Discussion and Analysis.

(4) "General and administration cash costs" is defined as general and administrative costs excluding interest and financing charges.

PRODUCTION UPDATE

- Q2 2017 production of 235,540 boepd was up 27% over Q2 2016 production of 185,812 boepd.
- Q2 2017 liquids production of 36,127 bpd was up 60% over Q2 2016 liquids production of 22,640 bpd.
- June 2017 liquids production of 38,932 bpd was very close to the 40,000 bpd milestone, originally expected in Q4 2017.
- Tourmaline continues on track to achieve full-year 2017 average production of 240,000-260,000 boepd, delivering 30% annual growth with a cash flow budget.
- The Company is anticipating reaching the 250,000 boepd milestone in the second half of August.

COST CONTROL

- Second quarter 2017 operating costs were $3.22/boe, down 6% from second quarter of 2016 and ahead of 2017 guidance of $3.50/boe.
- Completion and tie-in of a Company interest power generation system and the doubling of the Spirit River 3-10 sour gas processing capacity during the second quarter will lead to further cost reductions in the Peace River High complex in the second half of 2017. The Peace River High oil complex can already generate a full cycle return at an oil price of $25/bbl US WTI.
- Drilling costs for the first 12 wells at Gundy Creek are averaging between $1.5 and $1.7 million per well, approximately half that of the previous wells drilled on the property in 2014.
- The Company continues to seek all opportunities to reduce capital and cash costs across all three core complexes.

2017 Capital Program

- First half 2017 capital spending was $588.9 million and less than cash flow.
- The Company remains on track to execute a $1.3 billion 2017 EP capital program.
- June 30, 2017 exit net debt(5) was $1.6 billion, down from $1.7 billion at exit Q1 2017 resulting in a net debt-to-forecast annualized cash flow of approximately 1.2 times.
- An exit 2017 net debt-to-cash flow ratio of 1.2 times continues to be anticipated.

(5) "Net debt" is defined as long-term debt plus working capital (adjusted for the fair value of financial instruments). See "Non-GAAP Financial Measures" in the attached Management's Discussion and Analysis.

2018 OUTLOOK AND FIVE-YEAR DEVELOPMENT PLAN

- The Company has elected to moderate capital spending and production growth in 2018 and throughout the current five-year development plan. Annual production growth in 2018 will be modestly reduced from 22% to an estimated 15% with 10% per annum production growth forecast for 2019-2021. The net result of these changes is to accelerate free cash flow forward in the plan and improve overall returns. The Company believes that this is a more appropriate pace of growth in the current commodity price environment.
- The 2018 EP capital program has been reduced from $1.79 billion to $1.52 billion with 2018 average annual production of 280,000-300,000 boepd now anticipated, down from the previous anticipated production range of 290,000-320,000 boepd.
- 2018 forecast free cash flow increases to $208 million from $50 million previously, utilizing the same flat commodity pricing employed in the plan.
- The main revision to the 2018 EP program is a deferral of the start-up of the Gundy Creek facility by nine months, from Q4 2018 to mid-2019. The Gundy Creek facility is currently being designed for 200 mmcfpd capacity. The Montney reserve base and inherent location inventory on the property support a flat 400 mmcfpd production level for over 20 years. The initial plant design and related phase 1 infrastructure will be built to facilitate this potential expansion.
- Tourmaline can rapidly accelerate growth in one or all three core areas should commodity prices exceed current five-year plan guidance.

EP UPDATE

- Tourmaline is currently operating 17 drilling rigs and three frac spreads across all three operated complexes.
- The Company has approximately 175 new wells to tie-in during the second half of 2017 and currently expects to reach the 250,000 boepd production milestone during the second half of August.
- Tourmaline will complete its 1,000th well in early August; the first well was drilled in February 2009. All three core complexes are now completely de-risked in the principal development horizons allowing for continually improving capital efficiencies and full cycle returns.
- Completion of the 50 mmcfpd Wild River 14-20 plant expansion in September 2017 will allow the Company to reach the 1.0 bcf/day production milestone from the Alberta Deep Basin complex.
- The Spirit River 3-10 sour gas injection plant was expanded from 30 to 60 mmcfpd during Q2 2017. The plant expansion is expected to be fully commissioned in mid-August. The increased capacity at 3-10 will allow for processing of additional oil and gas volumes from the expanding Lower Charlie Lake and Montney plays as well as expanding volumes from the Upper Charlie Lake base development.
- Tourmaline has a number of new play discovery and prospect delineation/step-out wells planned in the second half of 2017. These include:
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    - 5-6 horizontal step-out wells to the Lambert 16-25 Cardium gas/condensate discovery, which has now produced 2.3 bcf of gas and 69 mstb of condensate in the first 180 days of production.
    - The first Viking horizontals into the Viking A pool at Brazeau will be drilled during Q3.
    - A four-well Montney horizontal pad following up the high rate Montney oil discovery announced in May will spud this month.
    - Horizontal step-outs to the successful 9-9 Upper Charlie Lake well completed with new confined Cecil frac technology. The well is currently flowing at 320 bopd and 3.5 mmcfpd of gas after two weeks of production.

CORPORATE SUMMARY – SECOND QUARTER 2017

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	Change	2017	2016	Change
OPERATIONS						
Production						
Natural gas (mcf/d)	1,196,477	979,029	22%	1,195,435	1,006,411	19%
Crude oil and NGL (bbl/d)	36,127	22,640	60%	35,176	23,085	52%
Oil equivalent (boe/d)	235,540	185,812	27%	234,415	190,820	23%
Product prices(1)						
Natural gas ($/mcf)	$ 3.19	$ 1.87	71%	$ 3.17	$ 2.04	55%
Crude oil and NGL ($/bbl)	$ 40.01	$ 38.94	3%	$ 40.85	$ 36.22	13%
Operating expenses ($/boe)	$ 3.22	$ 3.41	(6)%	$ 3.36	$ 3.56	(6)%
Transportation costs ($/boe)	$ 2.88	$ 2.06	40%	$ 2.85	$ 1.97	45%
Operating netback(3) ($/boe)	$ 15.36	$ 8.63	78%	$ 14.98	$ 9.18	63%
Cash general and administrative expenses ($/boe)(2)	$ 0.46	$ 0.47	(2)%	$ 0.47	$ 0.45	4%
FINANCIAL ($000, except share and per share)						
Revenue	479,269	247,123	94%	945,914	526,231	80%
Royalties	19,409	8,551	127%	47,260	15,120	213%
Cash flow(3)	313,271	134,298	133%	606,204	293,728	106%
Cash flow per share (diluted)(3)	$ 1.16	$ 0.58	100%	$ 2.25	$ 1.29	74%
Net earnings (loss)	108,580	(77,940)	239%	208,114	(116,330)	279%
Net earnings (loss) per share (diluted)	$ 0.40	$ (0.34)	218%	$ 0.77	$ (0.51)	251%
Capital expenditures (net of dispositions)	189,532	49,010	287%	588,917	463,867	27%
Weighted average shares outstanding (diluted)				269,302,667	227,064,847	19%
Net debt(3)				(1,558,203)	(1,373,849)	13%

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

(2) Excluding interest and financing charges.

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

Conference Call Tomorrow at 9:00 a.m. MDT (11:00 a.m. EDT)

Tourmaline will host a conference call tomorrow, August 3, 2017 starting at 9:00 a.m. MDT (11:00 a.m. EDT). To participate, please dial 1-888-231-8191 (toll-free in North America), or international dial-in 647-427-7450, a few minutes prior to the conference call.

Conference ID is 43383932.

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 and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "forecast", "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "on track", "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 and production growth for various periods, drilling inventory or locations, cash flow, free cash flow and net debt to cash flow levels, the acceleration of free cash flow forward in the Company's five-year development plan and the improvement of overall returns, production levels supported by certain of the Company's reserves and drilling inventory, capital spending, cost reduction initiatives, projected operating and drilling costs, the timing for facility expansions and facility start-up dates, 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 and future 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 it 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.

FINANCIAL OUTLOOK

Also included in this news release are estimates of Tourmaline's 2017 net debt to cash flow level at year-end, 2017 and 2018 capital spending and 2018 free cash flow, 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, 2018 annual production growth of 15% and commodity price assumptions for natural gas (AECO - $2.90/mcf for 2017 and AECO - $3.15/mcf for 2018), and crude oil (WTI (US) - $52.75/bbl for 2017 and WTI (US) - $60.00/bbl for 2018) and an exchange rate assumption of $0.77 (US/CAD) for 2017and 2018. To the extent such estimates constitute a financial outlook, they were approved by management and the Board of Directors of Tourmaline on August 2, 2017 and are included to provide readers with an understanding of Tourmaline's anticipated net debt to cash flow levels, capital spending and free cash flow 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.

INITIAL PRODUCTION (IP) RATES

Any references in this news release to IP rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter and are not necessarily indicative of long-term performance or ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. Such rates are based on field estimates and may be based on limited data available at this time.

INDUSTRY METRICS

The term cash costs, while commonly used in the oil and gas industry, does not have a standardized meaning 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

Certain information in this news release is based on assumptions regarding the Company's drilling locations, which are based on 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 Company's 14,980 undrilled locations, 906 are proved undeveloped locations, 20 are proved non-producing locations, 893 are probable undeveloped locations, nil are probable non-producing and 13,161 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 natural 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 natural 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

This management's discussion and analysis ("MD&A") should be read in conjunction with Tourmaline's unaudited interim condensed consolidated financial statements and related notes as at and for the three and six months ended June 30, 2017 and the consolidated financial statements for the year ended December 31, 2016. The consolidated financial statements and the MD&A can be found at www.sedar.com. This MD&A is dated August 2, 2017.

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. 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".

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

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 risks, uncertainties and contingencies.

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 to 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; 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 and environmental laws and regulations; 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, NGL 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 and skilled labour; changes in income tax and environmental laws and regulations 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; and future operating costs.

Management has included the above summary of assumptions and risks related to forward-looking statements provided in this MD&A in order to provide readers with a more complete perspective on 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 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 June 30,			Six Months Ended June 30,		
	2017	2016	Change	2017	2016	Change
Natural gas (mcf/d)	1,196,477	979,029	22%	1,195,435	1,006,411	19%
Oil (bbl/d)	17,529	12,564	40%	16,704	13,055	28%
NGL (bbl/d)	18,598	10,076	85%	18,472	10,030	84%
Oil equivalent (boe/d)	235,540	185,812	27%	234,415	190,820	23%
Natural gas %	85%	88%		85%	88%	

Production for the three months ended June 30, 2017 averaged 235,540 boe/d, a 27% increase over the average production for the same quarter of 2016 of 185,812 boe/d. For the six months ended June 30, 2017, production increased 23% to 234,415 boe/d from 190,820 boe/d for the same period of 2016.

The increase in production is related to the Company's successful exploration and production program as well as property acquisitions over the past year. Approximately 85% of the growth in production volumes over the past year can be attributed to wells brought on stream from the Company's exploration and production program, after taking decline rates into consideration. The remainder of the change relates to property acquisitions (net of dispositions), primarily the assets acquired from Shell Canada in the fourth quarter of 2016. The growth in oil and NGL production is the result of increased drilling in the Spirit River/Peace River High Charlie Lake oil plays, incremental liquids recovered in the Wild River area via deep-cut processing, and strong condensate recoveries from new wells commencing production as the liquids-rich Montney Turbidite is developed in Northeast British Columbia.

Full-year average production guidance for 2017 is between 240,000-260,000 boe/d which is unchanged from the initial Company guidance released March 7, 2017 in the Company's December 31, 2016 MD&A.

REVENUE

	Three Months Ended June 30,			Six Months Ended June 30,		
(000s)	2017	2016	Change	2017	2016	Change
Revenue from:						
Natural gas	$ 333,486	$ 132,793	151%	$ 654,241	$ 307,043	113%
Oil and NGL	129,866	73,202	77%	258,183	132,495	92%
Realized gain from:						
Natural gas	14,238	34,108	(58)%	31,613	67,028	(53)%
Oil and NGL	1,679	7,020	(76)%	1,877	19,665	(90)%
Total revenue from natural gas, oil and NGL sales	$ 479,269	$ 247,123	94%	$ 945,914	$ 526,231	80%

Revenue for the three months ended June 30, 2017 increased 94% to $479.3 million from $247.1 million for the same quarter of 2016. Revenue for the six-month period ended June 30, 2017 increased 80% from $526.2 million in 2016 to $945.9 million in 2017. Higher revenue for the period is consistent with the significant increase in commodity prices as well as higher production volumes. Revenue includes all petroleum, natural gas and NGL sales and the realized gain on financial instruments.

Revenue for the second quarter of 2017 included a gain on commodity contracts of $15.9 million (for the six months ended June 30, 2017 - $33.5 million) compared to a gain of $41.1 million for the same period of the prior year (for the six months ended June 30, 2016 - $86.7 million). Realized gains on commodity contracts in 2017 have decreased compared to the same periods of the prior year primarily due to a lower premium received on commodity contracts relative to the benchmark commodity prices in 2017. Realized prices exclude the effect of unrealized gains or losses on commodity contracts. Once these gains and losses are realized they are included in the per-unit amounts.

TOURMALINE REALIZED PRICES:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	Change	2017	2016	Change
Natural gas ($/mcf)	$ 3.19	$ 1.87	71%	$ 3.17	$ 2.04	55%
Oil ($/bbl)	$ 60.32	$ 59.51	1%	$ 61.76	$ 54.42	13%
NGL ($/bbl)	$ 20.88	$ 13.29	57%	$ 21.94	$ 12.52	75%
Oil equivalent ($/boe)	$ 22.36	$ 14.61	53%	$ 22.29	$ 15.15	47%

BENCHMARK OIL AND GAS PRICES:

	Three Months Ended June 30,		
	2017	2016	Change
Natural gas			
NYMEX Henry Hub (USD$/mcf)	$ 3.14	$ 2.25	40%
AECO (CAD$/mcf)	$ 2.78	$ 1.40	99%
West Coast Station 2 (CAD$/mcf)	$ 2.21	$ 1.14	94%
ATP 5A Day Ahead (CAD$/GJ)	$ 2.74	$ 1.68	63%
PG&E Malin (USD$/mmbtu)	$ 2.75	$ 1.96	40%
PG&E City Gate (USD$/mmbtu)	$ 3.27	$ 2.17	51%
Oil			
NYMEX (USD$/bbl)	$ 48.15	$ 45.64	5%
Edmonton Par (CAD$/bbl)	$ 61.51	$ 55.10	12%

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

	Three Months Ended June 30,		
($/mcf)	2017	2016	Change
Weighted average index natural gas prices	$ 2.84	$ 1.39	104%
Heat/quality differential	0.22	0.10	120%
Realized gain	0.13	0.38	(66)%
Tourmaline realized natural gas price	$ 3.19	$ 1.87	71%
Premium to benchmark pricing due to higher heat content	8%	7%	

CURRENCY – EXCHANGE RATES:

	Three Months Ended June 30,		
	2017	2016	Change
CAD$/USD$ (1)	$ 0.7439	$ 0.7761	(4)%

(1) Average rates for the period.

The realized average natural gas price for the three and six months ended June 30, 2017 was $3.19/mcf and $3.17/mcf, respectively, which is 71% and 55% higher than the same periods of the prior year. The increase reflects higher natural gas benchmark prices in the quarter which were partially offset by lower realized gains on commodity contracts.

Realized oil prices increased by 1% and 13% for the three and six months ended June 30, 2017 compared to the same periods of the prior year. The increase in price reflects the higher benchmark price for oil, partially offset by the lower gains on commodity contracts.

NGL prices for the second quarter of 2017 increased 57% from $13.29/bbl to $20.88/bbl, when compared to the same quarter of 2016. The increase in NGL prices is consistent with the increase in benchmark commodity prices over the same period. Additionally, in the second quarter of 2016, the price of propane was significantly discounted due to oversupply in the market, which has since recovered.

ROYALTIES

	Three Months Ended June 30		Six Months Ended June 30,	
(000s)	2017	2016	2017	2016
Natural gas	$ 9,550	$ 1,567	$ 22,762	$ 2,980
Oil and NGL	9,859	6,984	24,498	12,140
Total royalties	19,409	$ 8,551	$ 47,260	$ 15,120
Royalties as a percentage of revenue	4.2%	4.2%	5.2%	3.4%

For the quarter ended June 30, 2017, the average effective royalty rate was 4.2%, consistent with the same quarter of 2016. For the six-month period ended June 30, 2017, the average effective royalty rate increased from 3.4% in 2016 to 5.2% in 2017. The increase in the average effective royalty rate for 2017 can primarily be attributed to significantly higher commodity prices received during the period as well as the adoption of the Modernized Royalty Framework ("MRF").

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

On January 1, 2017, the Company adopted the MRF introduced by the Alberta Government in 2016. This new royalty regime is applicable to all new wells drilled beginning January 1, 2017, and all other wells drilled prior to January 1, 2017 will follow the old framework for a further 10 years. The Company believes that the MRF is generally consistent with the initial goal of incentivizing the use of technology to improve productivity and rewards producers deploying the most competitive operating practices. Under the MRF, the Company anticipates an increase in the corporate royalty rate but based on the Company's current development plans and operational practices, the increase is not expected to be significant.

The Company expects its royalty rate for 2017 to be approximately 6.5% which has been revised downward from the previous Company guidance of 8% contained in the Company's December 31, 2016 MD&A. The royalty rate is sensitive to commodity prices, and as such, the lower than forecasted commodity prices are expected to impact the rate for the remainder of 2017.

COMMODITY MARKETING

	Three Months Ended June 30,			Six Months Ended June 30,		
(000s)	2017	2016	Change	2017	2016	Change
Marketing revenue	$ 418	$?	100%	$ 418	$?	100%
Marketing purchases	(458)	?	(100)%	(458)	?	(100)%
Net marketing (loss)	$ (40)	$?	(100)%	$ (40)	$?	(100)%

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

OTHER INCOME

	Three Months Ended June 30,			Six Months Ended June 30,		
(000s)	2017	2016	Change	2017	2016	Change
Other income	$ 6,337	$ 7,169	(12)%	$ 13,516	$ 13,650	(1)%

Other income decreased from $7.2 million in the second quarter of 2016 to $6.3 million for the same quarter of 2017. For the six-month period ended June 30, 2017, other income was $13.5 million consistent with the prior year. The decrease in other income in the second quarter of 2017 is due to the Company 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.

OPERATING EXPENSES

	Three Months Ended June 30,			Six Months Ended June 30,		
(000s) except per unit amounts	2017	2016	Change	2017	2016	Change
Operating expenses	$ 69,005	$ 57,630	20%	$ 142,438	$ 123,520	15%
Per boe	$ 3.22	$ 3.41	(6)%	$ 3.36	$ 3.56	(6)%

Operating expenses include all periodic lease and field-level expenses and exclude income recoveries from processing third-party volumes. For the second quarter of 2017, total operating expenses were $69.0 million compared to $57.6 million in 2016, an increase of 20% over a production base increase of 27% for the same period. Operating costs for the six months ended June 30, 2017 were $142.4 million, compared to $123.5 million for the same period of 2016, reflecting a 15% increase in total costs over a 23% increase in production.

On a per-boe basis, the costs decreased from $3.41/boe for the second quarter of 2016 to $3.22/boe in the second quarter of 2017. For the six months ended June 30, 2017, operating costs were $3.36/boe, down from $3.56/boe in the prior year. Along with a commitment to continue to drive down the overall cost structure, the Company continues to realize increased operational efficiencies in all three core areas along with fixed costs being distributed over a significantly higher production base.

The Company now expects full year 2017 operating expenses per boe to average approximately $3.50/boe in 2017 which has been revised downward from $3.60 originally disclosed March 7, 2017. Actual operating costs per boe can change, however, depending on a number of factors, including the Company's actual production levels.

TRANSPORTATION

	Three Months Ended June 30,			Six Months Ended June 30,		
(000s) except per unit amounts	2017	2016	Change	2017	2016	Change
Natural gas transportation	$ 45,922	$ 25,946	77%	$ 91,900	$ 51,529	78%
Oil and NGL transportation	15,704	8,840	78%	28,825	16,882	71%
Total transportation	$ 61,626	$ 34,786	77%	$ 120,725	$ 68,411	76%
Per boe	$ 2.88	$ 2.06	40%	$ 2.85	$ 1.97	45%

For the second quarter of 2017, total transportation expenses were $61.6 million compared to $34.8 million in 2016. For the six months ended June 30, 2017 transportation expenses were $120.7 million, compared to $68.4 million for the same period of 2016. Both periods reflect increased costs related to higher production volumes.

On a per-boe basis, the transportation increased from $2.06/boe for the second quarter of 2016 to $2.88/boe in the second quarter of 2017. For the six months ended June 30, 2017, transportation costs were $2.85/boe, up from $1.97/boe for the same period of 2016. The increase in per-unit costs in 2017 reflects an increased focus on diversifying markets where Tourmaline sells its natural gas. In the second half of 2016, Tourmaline began selling natural gas at Malin, Oregon and City Gate, California, where the Company received a higher price for its natural gas. The increased distance resulted in higher per-boe fuel and transportation costs. Additionally, pipeline tolls for natural gas transportation have increased in 2017 compared to 2016.

GENERAL & ADMINISTRATIVE EXPENSES ("G&A")

	Three Months Ended June 30,			Six Months Ended June 30,		
(000s) except per unit amounts	2017	2016	Change	2017	2016	Change
G&A expenses	$ 18,305	$ 14,858	23%	$ 35,180	$ 29,663	19%
Administrative and capital recovery	(2,057)	(819)	151%	(3,625)	(1,962)	85%
Capitalized G&A	(6,310)	(6,034)	5%	(11,553)	(12,155)	(5)%
Total G&A expenses	$ 9,938	$ 8,005	24%	$ 20,002	$ 15,546	29%
Per boe	$ 0.46	$ 0.47	(2)%	$ 0.47	$ 0.45	4%

Total G&A expenses in the second quarter of 2017 were $9.9 million compared to $8.0 million for the same quarter of 2016. For the six-month period ended June 30, 2017, G&A expenses were $20.0 million compared to $15.5 million for the same period in 2016. The increase is primarily due to staff and office space additions needed to manage the larger production, reserve and land base.

On a per-boe basis, G&A expenses for the three and six months ended June 30, 2017 have remained consistent throughout the periods.

As production continues to increase in 2017, the G&A costs per boe are expected to decrease and average approximately $0.45/boe which is unchanged from the initial guidance released March 7, 2017. Actual G&A 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 June 30,		Six Months Ended June 30,	
(000s) except per unit amounts	2017	2016	2017	2016
Share-based payments	$ 10,254	$ 12,196	$ 20,528	$ 24,614
Capitalized share-based payments	(5,127)	(6,098)	(10,264)	(12,307)
Total share-based payments	$ 5,127	$ 6,098	$ 10,264	$ 12,307
Per boe	$ 0.24	$ 0.36	$ 0.24	$ 0.35

The Company uses the fair-value method for the determination of non-cash related share-based payments expense. During the second quarter of 2017, 314,500 stock options were granted at a weighted-average exercise price of $28.27 and 615,001 options were exercised, resulting in $14.3 million of cash proceeds.

The Company recognized $5.1 million of share-based payments expense in the second quarter of 2017 compared to $6.1 million in the second quarter of 2016. Capitalized share-based payments for the second quarter of 2017 were $5.1 million compared to $6.1 million for the same period of the prior year.

For the six months ended June 30, 2017, share-based payment expense totalled $10.3 million and a further $10.3 million in share-based payments were capitalized (six months ended June 30, 2016 - $12.3 million and $12.3 million, respectively).

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(000s) except per unit amounts	2017	2016	2017	2016
Total depletion, depreciation and amortization	$ 189,493	$ 168,386	$ 378,167	$ 349,325
Less mineral lease expiries	(5,684)	(959)	(12,185)	(6,880)
Depletion, depreciation and amortization	$ 183,809	$ 167,427	$ 365,982	$ 342,445
Per boe	$ 8.58	$ 9.90	$ 8.63	$ 9.86

DD&A expense, excluding mineral lease expiries, was $183.8 million for the second quarter of 2017 compared to $167.4 million for the same period of 2016. For the six-month period ended June 30, 2017, DD&A expense (excluding mineral lease expiries) was $366.0 million compared to $342.4 million in the same period of 2016. The increase in DD&A expense in 2017 over 2016 is due to higher production volumes.

The per-unit DD&A rate (excluding the impact of mineral lease expiries) was $8.58/boe for the second quarter of 2017 compared to the rate of $9.90/boe for the same quarter of 2016. The per-unit DD&A rate (excluding the impact of mineral lease expiries) was $8.63/boe for the six-month period ended June 30, 2017 compared to the rate of $9.86/boe in the same period of the prior year. The decrease in per-boe depletion in 2017 compared to 2016 can be attributed to lower future development costs 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 ended June 30, 2017 were $5.7 million, compared to expiries in the same quarter of the prior year of $1.0 million. For the six months ended June 30, 2017, expiries were $12.2 million compared to $6.9 million for the same period of 2016. 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 not to continue some of the expiring sections of land. The Company explores all alternatives (including swaps, farm-outs, joint ventures and dispositions) to realize the value from these sections before they expire.

FINANCE EXPENSES

	Three Months Ended June 30,			Six Months Ended June 30,		
(000s)	2017	2016	Change	2017	2016	Change
Interest expense	$ 10,512	$ 9,890	6%	$ 20,587	$ 20,749	(1)%
Accretion expense	1,262	713	77%	2,460	1,503	64%
Foreign exchange (gain) on U.S. denominated debt	(41,641)	(10,483)	297%	(42,147)	(83,242)	(49)%
Realized loss on cross-currency swaps	41,641	10,483	297%	42,147	83,242	(49)%
Realized loss on interest rate swaps	1,042	843	24%	1,792	1,743	3%
Transaction costs on corporate and property acquisitions	49	36	36%	101	214	(53)%
Total finance expenses	$ 12,865	$ 11,482	12%	$ 24,940	$ 24,209	3%

Finance expenses for the three months ended June 30, 2017 totaled $12.9 million compared to $11.5 million for the same period of 2016. The average bank debt outstanding and the average effective interest rate on the debt was $1,520.8 and 2.41% for the three months ended June 30, 2017 compared to $1,428.7 and 2.46% for the same period of 2016. The higher average bank debt outstanding resulted in an increase interest expense in the current period.

For the six months ended June 30, 2017 finance expenses totaled $24.9 million compared to $24.2 million for the same period of 2016. The average bank debt outstanding and the average effective interest rate on the debt for the six months ended June 30, 2017 was $1,478.5 million and 2.45% compared to $1,493.0 million and 2.45% for the same period of 2016, respectively. The increase in finance expenses is mainly due to higher accretion expense during the period resulting from a higher decommissioning liability balance and risk-free rate.

For the three and six month periods ended June 30, 2017, the Company drew from the credit facility in U.S. dollars, as permitted under the credit facility, which when repaid created a foreign exchange gain. Concurrent with the draw of U.S. dollar denominated borrowings, the Company entered into cross-currency swaps to manage the foreign currency risk resulting from holding U.S. dollar denominated borrowings. This transaction allows the Company to take advantage of the interest rate spread between CDOR and LIBOR without taking on foreign exchange risk.

DEFERRED INCOME TAXES (RECOVERY)

For the three and six months ended June 30, 2017, the provision for deferred income tax expense was $45.3 million and $86.7 million compared to deferred income tax recovery of $23.8 million and $36.8 million for the same period in 2016. The deferred income tax expense is primarily due to the pre-tax income of $153.6 million and $294.7 million recorded for the three and six months ended June 30, 2017 compared to a pre-tax loss of $102.1 million and $154.2 million for the same periods of 2016.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
(000s) except per unit amounts	2017	2016	Change	2017	2016	Change
Cash flow from operating activities	$ 278,577	$ 143,392	94%	$ 616,582	$ 319,700	93%
Per share (1)	$ 1.03	$ 0.62	66%	$ 2.29	$ 1.41	62%
Cash flow (2)	$ 313,271	$ 134,298	133%	$ 606,204	$ 293,728	106%
Per share (1)(2)	$ 1.16	$ 0.58	100%	$ 2.25	$ 1.29	74%
Net earnings (loss)	$ 108,580	$ (77,940)	239%	$ 208,114	$ (116,330)	279%
Per share (1)	$ 0.40	$ (0.34)	218%	$ 0.77	$ (0.51)	251%
Operating netback per boe (2)	$ 15.36	$ 8.63	78%	$ 14.98	$ 9.18	63%

(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.

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

Cash flow for the three months ended June 30, 2017 was $313.3 million or $1.16 per diluted share compared to $134.3 million or $0.58 per diluted share for the same period of 2016. Cash flow for the six months ended June 30, 2017 was $606.2 million or $2.25 per diluted share compared to $293.7 million or $1.29 per diluted share for the same period of 2016.

The Company had after-tax net income for the three months ended June 30, 2017 of $108.6 million or $0.40 per diluted share compared to an after-tax net loss of $77.9 million or $0.34 per share for the same period of 2016. For the six-month period ended June 30, 2017, after-tax net income was $208.1 million or $0.77 per share compared to an after-tax net loss of $116.3 million or $0.51 per share for the first half of 2016. The increase in both cash flow and after-tax net earnings in 2017 reflects significantly higher realized oil, natural gas and NGL prices and an increase in production over 2016.

CAPITAL EXPENDITURES

	Three Months Ended June 30,		Six Months Ended June 30,	
(000s)	2017	2016	2017	2016
Land and seismic	$ 8,731	$ 5,904	$ 25,604	$ 8,256
Drilling and completions	121,755	13,802	363,045	164,445
Facilities	56,506	18,017	191,305	108,856
Property acquisitions	30	5,107	825	187,815
Property dispositions	(4,000)	?	(4,000)	(18,000)
Other	6,510	6,180	12,138	12,495
Total cash capital expenditures	$ 189,532	$ 49,010	$ 588,917	$ 463,867

During the second quarter of 2017, the Company invested $189.5 million of cash consideration, net of dispositions, compared to $49.0 million for the same period of 2016. Expenditures on exploration and production were $187.0 million compared to $37.7 million for the same quarter of 2016. During the six-month period ended June 30, 2017, the Company invested $588.9 million of cash consideration, net of dispositions, compared to $463.9 million for the same period of 2016.

The drilling and completion costs of $363.0 million in the first half of 2017 include 211.55 net wells drilled and completed compared to $164.4 million spent on 92.11 net wells drilled and completed for the same period of 2016. The lower costs per well reflect the Company's continuously improving operating practices, combined with reduced drilling and completion service costs.

Facilities expenditures in the quarter include costs associated with the new Doe Gas Plant, which was commissioned in the second quarter of 2017, the Wildhay compressor expansion, which will be commissioned in the second half of 2017, as well as the Edson Gas Plant expansion scheduled to come on-line in 2018 and the preliminary costs for the Gundy Deep Cut Gas Plant, expected to be commissioned in 2019.

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

	Six Months Ended June 30, 2017		Six Months Ended June 30, 2016	
	Gross	Net	Gross	Net
Drilled	125	109.51	34	32.28
Completed	117	102.04	64	59.83
Tied-in	112	99.16	62	56.36

Exploration and production capital expenditures in 2017 are forecast to be $1.3 billion which is unchanged from the initial guidance disclosed in the February 22, 2017 press release. The Company expects drilling and completions costs of approximately $855.0 million, facilities expenditures (including equipment, pipelines and tie-ins) of $425.0 million as well as land and seismic expenditures of $50.0 million. The capital budget is closely monitored and will continue to be adjusted as required depending on cash flow available.

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 northeast 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.

LIQUIDITY AND CAPITAL RESOURCES

The Company has a covenant-based, unsecured, credit facility in place with a syndicate of banks, the details of which are described in note 9 of the Company's consolidated financial statements for the year ended December 31, 2016 and in note 7 of the Company's unaudited interim condensed financial statements for the three and six months ended June 30, 2017. This is an extendible revolving facility in the amount of $1,800.0 million with an initial maturity date of June 2022. The maturity date may, at the request of the Company and with consent of the lenders, be extended on an annual basis. The credit facility includes an expansion feature ("accordion") which allows the Company, upon approval from the lenders, to increase the facility amount by up to $500.0 million by adding a new financial institution or by increasing the commitment of its existing lenders. The 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 term loan with a syndicate of banks. On February 3, 2017, the Company increased the term loan from $250.0 million to $650.0 million 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 the exception of the increase in amount and maturity date extension, the term debt was renewed under the same terms and conditions as those outlined in note 9 of the Company's consolidated financial statements for the year ended December 31, 2016. The maturity date may, at the request of the Company and with consent of the lenders, 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 now $2.5 billion.

As at June 30, 2017, the Company had negative working capital of $134.2 million, after adjusting for the fair value of financial instruments (the unadjusted working capital deficiency was $130.3 million) (December 31, 2016 – $184.3 million and $223.8 million, respectively). As at June 30, 2017, the Company had $648.0 million in long-term debt outstanding and $776.0 million drawn against the revolving credit facility for total bank debt of $1,424.0 million (net of prepaid interest and debt issue costs) (December 31, 2016 - $1,406.6 million). Net debt at June 30, 2017 was $1,558.2 million (December 31, 2016 - $1,590.9 million).

For 2017, management intends to continue matching the capital budget to the expected annual cash flow and as such management believes the Company has sufficient resources to fund its 2017 exploration and development program. As at June 30, 2017, the Company also has $1,061.6 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 the current commodity price environment.

SHARES AND STOCK OPTIONS OUTSTANDING

As at August 2, 2017, the Company has 269,783,946 common shares and 20,040,030 stock options outstanding.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

In the normal course of business, the Company 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	$ 5,692	$ 9,486	$ -	$ -	$ 15,178
Firm transportation and processing agreements	290,479	665,870	619,752	1,738,361	3,314,462
Capital commitments (1)	310,921	607,795	141,174	35,367	1,095,257
Flow-through share commitments	34,436	-	-	-	34,436
Credit facility (2)	-	-	891,705	-	891,705
Term debt (3)	17,481	34,961	677,342	-	729,784
	$ 659,009	$ 1,318,112	$ 2,329,973	$ 1,773,728	$ 6,080,822

(1) Includes drilling commitments, and capital spending commitments under the joint arrangement in the Spirit River complex of $300.0 million per year until 2019. The capital spending commitment can be deferred to future periods in the event of an economic downturn, and as agreed upon by both parties. At June 30, 2017, an economic downturn event, as defined in the joint arrangement in the Spirit River complex had occurred and as a result $75.0 million of the 2017 originally planned capital will be deferred to future periods. To date, the total deferred capital to be spent in future periods is $291.0 million.

(2) Includes interest expense at an annual rate of 2.70% being the rate applicable to outstanding debt on the credit facility at June 30, 2017.

(3)

Includes interest expense at an annual rate of 2.99% being the fixed rate on the term debt at June 30, 2017.

OFF BALANCE SHEET ARRANGEMENTS

The Company has certain lease arrangements, all of which are reflected in the commitments and contractual obligations table above, 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 audited consolidated financial statements for the year ended December 31, 2016.

As at June 30, 2017, the Company has entered into certain financial derivative contracts in order to manage commodity price and interest rate 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 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 (loss) on the consolidated statement of income (loss) and comprehensive income (loss). The contracts that the Company has in place at June 30, 2017 are summarized and disclosed in note 3 of the Company's unaudited interim condensed consolidated financial statements for the three and six months ended June 30, 2017 and 2016.

The Company has entered into physical delivery sales 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 June 30, 2017 have been summarized and disclosed in note 3 of the Company's unaudited interim condensed consolidated financial statements for the three and six months ended June 30, 2017 and 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 interim condensed 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. 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 National Instrument 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 IFRS.

There were no changes in the Company's DC&P or ICFR during the period beginning on April 1, 2017 and ending on June 30, 2017 that have materially affected, or are reasonably likely to materially affect, the Company's 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 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 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.

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 statements of cash flow), to cash flow, is set forth below:

	Three Months Ended, June 30,		Six Months Ended June 30,	
(000s)	2017	2016	2017	2016
Cash flow from operating activities (per GAAP)	$ 278,577	$ 143,392	$ 616,582	$ 319,700
Change in non-cash working capital	34,694	(9,094)	(10,378)	(25,972)
Cash flow	$ 313,271	$ 134,298	$ 606,204	$ 293,728

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, June 30,		Six Months Ended June 30,	
($/boe)	2017	2016	2017	2016
Revenue, excluding processing income	$ 22.36	$ 14.61	$ 22.29	$ 15.15
Royalties	(0.91)	(0.51)	(1.11)	(0.44)
Transportation costs	(2.88)	(2.06)	(2.85)	(1.97)
Operating expenses	(3.22)	(3.41)	(3.36)	(3.56)
Operating netback (1)	$ 15.36	$ 8.63	$ 14.98	$ 9.18

(1) May not add due to rounding.

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

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

(000s)	As at June 30, 2017	As at December 31, 2016
Working capital (deficit)	$ (130,337)	$ (223,781)
Fair value of financial instruments – short-term (net)	(3,875)	39,517
Working capital (deficit) (adjusted for the fair value of financial instruments)	$ (134,212)	$ (184,264)

Net Debt

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

(000s)	As at June 30, 2017	As at December 31, 2016
Bank debt	$ (1,423,991)	$ (1,406,586)
Working capital (deficit)	(130,337)	(223,781)
Fair value of financial instruments – short-term (net)	(3,875)	39,517
Net debt	$ (1,558,203)	$ (1,590,850)

SELECTED QUARTERLY INFORMATION

		2017				201
($000s, unless otherwise noted)	Q2	Q1	Q4	Q3	Q2	Q1
PRODUCTION						
Natural gas (mcf)	108,879,426	107,494,272	90,409,566	82,363,542	89,091,644	94,0
Oil and NGL(bbls)	3,287,567	3,079,321	2,578,571	1,852,618	2,060,260	2,14
Oil equivalent (boe)	21,434,138	20,995,033	17,646,832	15,579,875	16,908,867	17,8
Natural gas (mcf/d)	1,196,477	1,194,380	982,713	895,256	979,029	1,03
Oil and NGL (bbls/d)	36,127	34,215	28,028	20,138	22,640	23,5
Oil equivalent (boe/d)	235,540	233,278	191,814	169,347	185,812	195
FINANCIAL						
Total revenue from natural gas, oil and NGL sales, net of royalties	459,860	438,794	366,697	292,495	238,572	272
Cash flow from operating activities	278,577	338,005	192,134	185,067	143,392	176
Cash flow [(1)]	313,271	292,933	252,542	185,531	134,298	159
Per diluted share	1.16	1.09	1.02	0.79	0.58	0.72
Net earnings (loss)	108,580	99,534	59,621	24,738	(77,940)	(38,
Per basic share	0.40	0.37	0.24	0.11	(0.34)	(0.1
Per diluted share	0.40	0.37	0.24	0.10	(0.34)	(0.1
Total assets	9,630,468	9,612,395	9,357,523	7,790,816	7,694,141	7,84
Working capital (deficit)	(130,337)	(355,097)	(223,781)	(162,280)	(60,567)	(20
Working capital (deficit)(adjusted for the fair value of financial instruments) [(1)]	(134,212)	(337,191)	(184,264)	(148,431)	(43,755)	(22
Cash capital expenditures	189,532	399,385	1,244,974	224,448	49,010	414
Total outstanding shares (000s)	269,784	269,169	268,596	234,966	234,161	221
PER UNIT						
Natural gas ($/mcf)	3.19	3.15	3.20	2.80	1.87	2.20
Oil and NGL ($/bbl)	40.01	41.73	38.42	39.98	38.94	33.6
Revenue ($/boe)	22.36	22.23	22.01	19.54	14.61	15.6
Operating netback ($/boe) [(1)]	15.36	14.59	15.00	12.69	8.63	9.71

(1) See Non-GAAP Financial Measures.

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

On an annual basis, the Company has had continued production growth over the last two years. The Company's average annual production has increased from 154,403 boe per day in 2015 to 185,672 boe per day in 2016 and 234,415 boe per day in the first six months of 2017. The production growth can be attributed primarily to the Company's exploration and development activities, and from acquisitions of producing properties.

The Company's cash flow was $850.2 million in 2015, $731.8 million in 2016 and forecast 2017 forecast cash flow is $1,340.7

million. The increase in forecast cash flow in 2017 reflects the increase in commodity prices for 2017 compared to 2016 as well as the significant increase in production. 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.

INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30,	December 31,
(000s) (unaudited)	2017	2016
Assets		
Current assets:		
Accounts receivable	$ 194,921	$ 201,288
Prepaid expenses and deposits	18,121	10,575
Fair value of financial instruments (note 3)	14,712	895
Total current assets	227,754	212,758
Long-term asset	5,709	6,034
Fair value of financial instruments (note 3)	10,028	2,990
Exploration and evaluation assets (note 4)	690,583	678,531
Property, plant and equipment (note 5)	8,696,394	8,457,210
Total Assets	$ 9,630,468	$ 9,357,523
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 347,254	$ 396,127
Fair value of financial instruments (note 3)	10,837	40,412
Total current liabilities	358,091	436,539
Bank debt (note 7)	1,423,991	1,406,586
Fair value of financial instruments (note 3)	15,184	40,266
Deferred premium on flow-through shares (note 9)	6,676	16,167
Decommissioning obligations (note 6)	225,573	212,669
Deferred taxes	573,096	477,015
Shareholders' equity:		
Share capital (note 9)	5,855,618	5,818,867
Non-controlling interest (note 8)	27,400	27,549
Contributed surplus	203,743	188,883
Retained earnings	941,096	732,982
Total shareholders' equity	7,027,857	6,768,281
Total Liabilities and Shareholders' Equity	$ 9,630,468	$ 9,357,523

Commitments (note 12).

See accompanying notes to the interim condensed consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(000s) except per-share amounts (unaudited)	2017	2016	2017	2016
Revenue:				
Oil and natural gas sales	$ 463,352	$ 205,994	$ 912,424	$ 439,538
Royalties	(19,409)	(8,551)	(47,260)	(15,120)
Net revenue from oil and natural gas sales	443,943	197,443	865,164	424,418
Realized gain on financial instruments	15,917	41,129	33,490	86,693
Unrealized gain (loss) on financial instruments (note 3)	35,669	(64,070)	75,512	(92,713)
Marketing Revenue	418	?	418	?
Other income	6,337	7,169	13,516	13,650
Total net revenue	502,284	181,671	988,100	432,048
Expenses:				
Operating	69,005	57,630	142,438	123,520
Transportation	61,626	34,786	120,725	68,411
Marketing Purchases	458	?	458	?
General and administration	9,938	8,005	20,002	15,546
Share-based payments (note 11)	5,127	6,098	10,264	12,307
Depletion, depreciation and amortization	189,493	168,386	378,167	349,325
Realized foreign exchange (gain) loss	559	?	(118)	?
Unrealized foreign exchange loss	594	?	753	?
(Gain) on divestitures	(968)	(2,621)	(4,201)	(7,074)
Total expenses	335,832	272,284	668,488	562,035
Income (loss) from operations	166,452	(90,613)	319,612	(129,987)
Finance expenses	12,865	11,482	24,940	24,209
Income (loss) before taxes	153,587	(102,095)	294,672	(154,196)
Deferred taxes (recovery)	45,311	(23,841)	86,707	(36,784)
Net income (loss) and comprehensive income (loss) before non-controlling interest	108,276	(78,254)	207,965	(117,412)
Net income (loss) and comprehensive income (loss) attributable to:				
Shareholders of the Company	108,580	(77,940)	208,114	(116,330)
Non-controlling interest (note 8)	(304)	(314)	(149)	(1,082)
	$ 108,276	$ (78,254)	$ 207,965	$ (117,412)
Net income (loss) per share attributable to common shareholders (note 10)				

Basic	$ 0.40	$ (0.34)	$ 0.77	$ (0.51)
Diluted	$ 0.40	$ (0.34)	$ 0.77	$ (0.51)

See accompanying notes to the interim condensed consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(000s) (unaudited)	Share Capital	Contributed Surplus	Retained Earnings	Non-Controlling Interest	Total Equity
Balance at December 31, 2016	$ 5,818,867	$ 188,883	$ 732,982	$ 27,549	$ 6,768,281
Issue of common shares on acquisitions (note 9)	14,854	-	-	-	14,854
Share issue costs, net of tax	(320)	-	-	-	(320)
Share-based payments	-	10,264	-	-	10,264
Capitalized share-based payments	-	10,264	-	-	10,264
Options exercised (notes 9 and 11)	22,217	(5,668)	-	-	16,549
Income attributable to common shareholders	-	-	208,114	-	208,114
Loss attributable to non-controlling interest	-	-	-	(149)	(149)
Balance at June 30, 2017	$ 5,855,618	$ 203,743	$ 941,096	$ 27,400	$ 7,027,857

(000s) (unaudited)	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 9)	319,423	-	-	-	319,423
Share issue costs, net of tax (note 9)	(10,009)	-	-	-	(10,009)
Share-based payments	-	12,307	-	-	12,307
Capitalized share-based payments	-	12,307	-	-	12,307
Options exercised (notes 9 and 11)	43,691	(11,837)	-	-	31,854
Loss attributable to common shareholders	-	-	(116,330)	-	(116,330)
Loss attributable to non-controlling interest	-	-	-	(1,082)	(1,082)
Balance at June 30, 2016	$ 4,619,339	$ 184,735	$ 648,623	$ 27,349	$ 5,480,046

See accompanying notes to the interim condensed consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

	Three Months Ended June 30,		Six Months Ended June 30,	
(000s) (unaudited)	2017	2016	2017	2016
Cash provided by (used in):				
Operations:				
Net income (loss)	$ 108,580	$ (77,940)	$ 208,114	$ (116,330)
Items not involving cash:				
Depletion, depreciation and amortization	189,493	168,386	378,167	349,325
Accretion	1,262	713	2,460	1,503
Share-based payments	5,127	6,098	10,264	12,307
Deferred taxes (recovery)	45,311	(23,841)	86,707	(36,784)
Unrealized (gain) loss on financial instruments	(35,669)	64,070	(75,512)	92,713
(Gain) on divestitures	(968)	(2,621)	(4,201)	(7,074)
Amortization on long-term asset	162	163	325	326
Non-controlling interest	(304)	(314)	(149)	(1,082)
Unrealized foreign exchange loss	594	?	753	?
Decommissioning expenditures	(317)	(416)	(724)	(1,176)
Changes in non-cash operating working capital	(34,694)	9,094	10,378	25,972
Total cash flow from operating activities	278,577	143,392	616,582	319,700
Financing:				
Issue of common shares	14,332	356,626	16,549	360,319
Share issue costs	(400)	(13,533)	(437)	(13,642)
Increase (decrease) in bank debt	65,901	(245,003)	17,405	63,490
Total cash flow from financing activities	79,833	98,090	33,517	410,167
Investing:				
Exploration and evaluation	(22,299)	(9,370)	(54,079)	(14,004)
Property, plant and equipment	(171,203)	(34,533)	(538,013)	(280,048)
Property acquisitions	(30)	(5,107)	(825)	(187,815)
Proceeds from divestitures	4,000	-	4,000	18,000
Changes in non-cash investing working capital	(168,878)	(192,472)	(61,182)	(266,000)
Total cash flow used in investing activities	(358,410)	(241,482)	(650,099)	(729,867)
Changes in cash	-	-	-	-
Cash, beginning of period	-	-	-	-
Cash, end of period	$ -	$ -	$ -	$ -

Cash is defined as cash and cash equivalents.

See accompanying notes to the interim condensed consolidated financial statements.

NOTES TO THE INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

AS AT JUNE 30, 2017 AND FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2017 AND 2016

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

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.

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

1. BASIS OF PREPARATION

These unaudited interim condensed consolidated financial statements have been prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting". These unaudited interim condensed consolidated financial statements do not include all of the information and disclosure required in the annual financial statements and should be read in conjunction with the Company's consolidated financial statements for the year ended December 31, 2016.

These unaudited interim condensed consolidated financial statements are presented in Canadian dollars and include the accounts of Tourmaline Oil Corp., and its 90.6% owned subsidiary Exshaw Oil Corp. (note 8), which both have a functional currency in Canadian dollars. Tourmaline Oil Corp. also includes its 100% owned subsidiary Tourmaline Oil Marketing Corp., which has a functional currency in US dollars.

The accounting policies and significant accounting judgments, estimates, and assumptions used in these unaudited interim condensed consolidated financial statements are consistent with those described in Notes 1 and 2 of the Company's consolidated financial statements for the year ended December 31, 2016, except as noted below.

On January 1, 2017, the Company adopted the amendments made to IAS 7 – Statement of Cash Flows, which 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. There was no impact to the Company as a result of adopting the amended standard.

These unaudited interim condensed consolidated financial statements reflect only the Company's proportionate interest in such activities. The unaudited interim condensed consolidated financial statements were authorized for issue by the Board of Directors on August 2, 2017.

Future accounting changes

The following pronouncements from the IASB will become effective or were amended for financial reporting periods beginning on or after January 1, 2018 and have not yet been adopted by the Company. These new or revised standards permit early adoption with transitional arrangements depending upon the date of initial application.

IFRS 9 – Financial Instruments replaces the existing guidance in IAS 39 Financial Instruments: Recognition and Measurement. The new standard includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for calculating impairment on financial assets, and the new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. IFRS 9 is effective for annual reporting periods beginning on or after January 1, 2018 with early adoption permitted. The Company currently does not apply hedge accounting to its financial instruments and does not currently intend to apply hedge accounting to any of its financial instruments upon adoption of IFRS 9.

IFRS 15 – Revenue from Contracts with Customers establishes a comprehensive framework for determining whether, how much and when revenue is recognized. It replaces existing revenue recognition guidance, including IAS 18 Revenue, IAS 11 Construction Contracts and IFRIC 13 Customer Loyalty Programmes. IFRS 15 is effective for annual reporting periods beginning on or after January 1, 2018 with early adoption permitted. The Company is currently in the process of identifying and reviewing revenue contracts with customers to determine the impact, if any, that the adoption of IFRS 15 will have on its financial statements, including enhanced disclosures of disaggregation of revenue.

IFRS 16 – Leases sets out the principles for the recognition, measurement, presentation and disclosure of leases for both parties to a contract, i.e. the customer ('lessee') and the supplier ('lessor') and replaces the previous leases standard, IAS 17 Leases. IFRS 16 is effective for annual reporting periods beginning on or after January 1, 2019. The Company is in the early stages of evaluating the impact of IFRS 16 on its consolidated financial statements and the extent of the impact has not yet been determined.

2. 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.

Tourmaline classifies the fair value of 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 fair value of accounts receivable, and accounts payable and accrued liabilities approximate their carrying amounts due to their short term nature. Bank debt bears interest at a floating market rate with applicable variable margins, and accordingly the fair market value approximates the carrying amount. The Company's financial instruments have been assessed on the fair value hierarchy described above and classified as Level 2.

3. 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 consistent with those discussed in note 5 of the Company's consolidated financial statements for the year ended December 31, 2016.

As at June 30, 2017, the Company has entered into certain financial derivative contracts in order to manage commodity price, foreign exchange and interest rate 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 and interest rate contracts to be effective economic hedges. As a result, all such contracts are recorded on the interim consolidated statement of financial position at fair value, with changes in the fair value being recognized as an unrealized gain or loss on the interim consolidated statement of income (loss) and comprehensive income (loss).

The Company has the following financial derivative contracts in place as at June 30, 2017 (1):

		2017	2018	2019	2020	Fair Value (000s)
Gas						
AECO swaps	mmbtu/d	18,956	–	–	–	$ 2,127
	CAD$/mmbtu	$ 3.15				
NYMEX swaps	mmbtu/d	90,000	51,164	–	–	$ 3,974
	USD$/mmbtu	$ 3.16	$ 3.15			
Basis differentials – other (2)	mmbtu/d	–	40,932	12,466	2,486	$ (1)
	USD$/mmbtu		$ (0.21)	$ (0.30)	$ (0.30)	
NYMEX call options (writer) (3)	mmbtu/d	110,000	110,000	105,000	20,000	$ (16,231)
	USD$/mmbtu	$ 3.56	$ 3.68	$ 3.83	$ 3.75	
Oil						
Financial swaps	bbls/d	4,500	1,000	–	–	$ 9,092
	USD$/bbl	$ 51.56	$ 55.65			
Financial call swaptions (4)	bbls/d	2,000	3,125	–	–	$ (4,110)
	USD$/bbl	$ 69.45	$ 54.30			
Total fair value						$ (5,149)

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

(2) Includes basis differentials for Malin and PG&E.

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

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

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

	2017	2018	2019	2020	2021	2022	2023	Fair Value
Effective interest rate(1)	1.52%	1.51%	1.54%	1.29%	1.38%	1.45%	1.68%	
Notional amount hedged (000s)	$ 675,000	$ 675,000	$ 639,726	$ 461,027	$ 384,452	$ 157,808	$ 15,890	$ 3,868

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

The following table provides a summary of the unrealized gains (losses) on financial instruments recorded in the consolidated statements of income (loss) and comprehensive income (loss) for the three and six months ended June 30, 2017 and 2016:

(000s)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Unrealized gain (loss) on financial instruments – commodity contracts	$ 28,709	$ (64,346)	$ 69,314	$ (92,109)
Unrealized gain (loss) on financial instruments – interest rate swaps	6,960	276	6,198	(604)
Total unrealized gain (loss) on financial instruments	$ 35,669	$ (64,070)	$ 75,512	$ (92,713)

In addition to the financial commodity contracts discussed above, the Company has entered into physical delivery sales 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 June 30, 2017 (1)(5):

		2017	2018	2019	2020	2021
Gas						
Fixed price – AECO	mcf/d	237,078	131,915	–	–	–
	CAD$/mcf	$ 3.15	$ 2.97			
Basis differentials - AECO (2)(3)	mmbtu/d	104,103	147,500	147,500	147,500	76,664
	USD$/mmbtu	$ (0.66)	$ (0.72)	$ (0.72)	$ (0.72)	$ (0.64)
Basis differentials - Dawn	mmbtu/d	–	18,836	25,000	25,000	6,164
	USD$/mmbtu		$ (0.15)	$ (0.15)	$ (0.15)	$ (0.15)
Basis differentials – Stn 2	mcf/d	57,391	47,913	19,478	17,807	9,478
	CAD$/mcf	$ (0.32)	$ (0.26)	$ (0.21)	$ (0.21)	$ (0.26)
AECO Monthly Calls / Call Swaptions (3)	mcf/d	6,336	71,086	37,913	–	–
	CAD$/mcf	$ 2.85	$ 4.26	$ 2.74		
Oil						
Fixed differential (4)	bbls/d	776	1,552	–	–	–
	USD$/bbl	$ (6.75)	$ (6.95)			

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

(2) Tourmaline also has an average of 54.2 mmcf/d of NYMEX-AECO basis differentials at $(0.68) from 2022-2024. A portion of these basis deals have a cap on NYMEX, 19.1 mmcf/d at USD$4.24/mcf for 2017, 92.5 mmcf/d at USD$4.18/mcf from 2018-2020 and 40.0 mmcf/d at USD$4.57/mcf from 2021-2024.

(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; 5,000 mmbtu/d at Chicago GDD pricing less transportation costs from November 2017 to March 2023; 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.

4. EXPLORATION AND EVALUATION ASSETS

(000s)	
As at December 31, 2016	$ 678,531
Capital expenditures	54,079
Transfers to property, plant and equipment (note 5)	(28,973)
Acquisitions	673
Divestitures	(1,542)
Expired mineral leases	(12,185)
As at June 30, 2017	$ 690,583

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proven and probable reserves, as well as undeveloped land. Additions represent the Company's share of costs on E&E assets during the period.

Impairment Assessment

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. At June 30, 2017 and December 31, 2016, the Company determined that no indicators of impairment existed on its E&E assets; therefore, an impairment test was not performed.

5. PROPERTY, PLANT AND EQUIPMENT

Cost

(000s)	
As at December 31, 2016	$ 11,008,617
Capital expenditures	548,277
Transfers from exploration and evaluation (note 4)	28,973
Change in decommissioning liabilities (note 6)	11,003
Acquisitions	19,945
Divestiture	(3,032)
As at June 30, 2017	11,613,783

Accumulated Depletion, Depreciation and Amortization

(000s)	
As at December 31, 2016	$ 2,551,407
Depletion, depreciation and amortization	365,982
As at June 30, 2017	$ 2,917,389

Net Book Value

(000s)	
As at December 31, 2016	$ 8,457,210
As at June 30, 2017	$ 8,696,394

Future development costs of $6,429.8 million were included in the depletion calculation at June 30, 2017 (December 31, 2016 – $6,417.4 million).

Capitalization of G&A and Share-Based Payments

A total of $11.6 million in G&A expenditures have been capitalized and included in PP&E assets at June 30, 2017 (December 31, 2016 – $23.7 million). Also included in PP&E are non-cash share-based payments of $10.3 million (December 31, 2016 - $22.8 million).

Impairment Assessment

In accordance with IFRS, an impairment test is performed on a CGU if the Company identifies an indicator of impairment. At June 30, 2017 and December 31, 2016, the Company determined that there were no indicators of impairment on any of the Company's CGUs; therefore impairment tests were not performed.

Business Combinations

Minehead-Edson-Ansell

On January 29, 2016, the Company acquired assets in the Minehead-Edson-Ansell area of the Alberta Deep Basin for cash consideration of $183.0 million before customary adjustments. The acquisition resulted in an increase in lands, production, reserves and facilities in a core area of the Alberta Deep Basin.

Results from operations are included in the Company's 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 Gundy assets acquired include land, production and reserves and now provide the Company with sufficient size and scope in the Northeast BC 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

Acquisitions and Dispositions of Oil and Natural Gas Properties

For the six months ended June 30, 2017, the Company completed property acquisitions for cash of $0.8 million (December 31, 2016 - $42.5 million) and, a further $19.8 million in acquisitions involving non-cash consideration (December 31, 2016 - $8.0

million). Of the $19.8 million, $14.9 million relates to assets acquired by issuing 475,000 Tourmaline common shares at a price $31.27 per share. The Company also assumed $0.2 million in decommissioning liabilities as a result of these acquisitions (December 31, 2016 - $1.4 million).

The Company also completed property dispositions for the six months ended June 30, 2017 for total cash consideration of $4.0 million (December 31, 2016 - $48.0 million).

6. 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 $413.0 million (December 31, 2016 – $392.0 million), with some abandonments expected to commence in 2034. A risk-free rate of 2.31% (December 31, 2016 – 2.31%) and an inflation rate of 2.0% (December 31, 2016 – 2.0%) were used to calculate the decommissioning obligations.

(000s)	As at June 30, 2017	As at December 31, 2016
Balance, beginning of period	$ 212,669	$ 163,459
Obligation incurred	9,879	14,798
Obligation incurred on property acquisitions	165	6,520
Obligation divested	?	(1,406)
Obligation settled	(724)	(1,367)
Accretion expense	2,460	3,607
Change in future estimated cash outlays	1,124	27,058
Balance, end of period	$ 225,573	$ 212,669

7. BANK DEBT

The Company has a covenant-based, unsecured, credit facility in place with a syndicate of banks, the details of which are described in note 9 of the Company's consolidated financial statements for the year ended December 31, 2016. This is an extendible revolving facility in the amount of $1,800.0 million with an initial maturity date of June 2022. The maturity date may, at the request of the Company and with consent of the lenders, be extended on an annual basis. The credit facility includes an expansion feature ("accordion") which allows the Company, upon approval from the lenders, to increase the facility amount by up to $500.0 million by adding a new financial institution or by increasing the commitment of its existing lenders. The 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 term loan with a syndicate of banks. On February 3, 2017, the Company increased the term loan from $250.0 million to $650.0 million 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 the exception of the increase in amount and maturity date extension the term debt was renewed under the same terms and conditions as those outlined in note 9 of the Company's consolidated financial statements for the year ended December 31, 2016. The maturity date may, at the request of the Company and with consent of the lenders, 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 now $2.5 billion.

As at June 30, 2017, the Company had $648.0 million in long-term debt outstanding and $776.0 million drawn against the bank credit facility for total bank debt of $1,424.0 million (net of prepaid interest and debt issue costs) (December 31, 2016 - $1,406.6 million). In addition, Tourmaline has outstanding letters of credit of $14.4 million (December 31, 2016 - $18.6 million), which reduce the credit available on the facility. The effective interest rate for the six months ended June 30, 2017 was 2.45% (six months ended June 30, 2016 – 2.45%). As at June 30, 2017, the Company is in compliance with all debt covenants.

8. NON-CONTROLLING INTEREST

The Company 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)	As at June 30, 2017	As at December 31, 2016
Balance, beginning of period	$ 27,549	$ 28,431
Share of subsidiary's net income (loss) for the period	(149)	(882)
Balance, end of period	$ 27,400	$ 27,549

9. 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

	As at June 30,2017		As at December 31,2016	
(000s) except share amounts	Number of Shares	Amount	Number of Shares	Amount
Balance, beginning of period	268,595,812	$ 5,818,867	221,335,925	$ 4,266,234
For cash on public offering of common shares (1)(4)	-	-	32,146,200	1,037,722
For cash on public offering of flow-through common shares (2)(3)	-	-	2,210,500	69,760
Issued on corporate and property acquisitions (note 5)	475,000	14,854	10,017,938	367,658
For cash on exercise of stock options	713,134	16,549	2,885,249	82,217
Contributed surplus on exercise of stock options	-	5,668	-	28,717
Share issue costs	-	(437)	-	(45,684)
Tax effect of share issue costs	-	117	-	12,243
Balance, end of period	269,783,946	$ 5,855,618	268,595,812	$ 5,818,867

(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 June 30, 2017, the Company had spent the full committed amount. The expenditures were renounced to investors in January 2017 with an effective renunciation date of December 31, 2016.

(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 June 30, 2017, the Company is committed to spend $34.4 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.

(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.

10. EARNINGS (LOSS) PER SHARE

Basic earnings-per-share attributed to common shareholders was calculated as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Net earnings (loss) for the period (000s)	$ 108,580	$ (77,940)	$ 208,114	$ (116,330)
Weighted average number of common shares – basic	269,353,945	232,460,854	269,205,374	226,932,309
Earnings (loss) per share – basic	$ 0.40	$ (0.34)	$ 0.77	$ (0.51)

Diluted earnings-per-share attributed to common shareholders was calculated as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Net earnings (loss) for the period (000s)	$ 108,580	$ (77,940)	$ 208,114	$ (116,330)
Weighted average number of common shares – diluted	269,355,639	232,460,854	269,302,667	226,932,309
Earnings (loss) per share – fully diluted	$ 0.40	$ (0.34)	$ 0.77	$ (0.51)

There were 19,944,530 and 16,808,165 options excluded from the weighted-average share calculations for the three and six month periods ended June 30, 2017 because they were anti-dilutive (three and six months ended June 30, 2016 – 18,672,713 options were anti-dilutive).

11. 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 22,931,635 shares of common stock, which represents 8.5% of the current outstanding common shares. The exercise price of each option equals the volume-weighted average market price for the five days preceding the issue date of the Company's stock on the date of grant and the option's maximum term is seven years. Options are granted throughout the year and vest 1/3 on each of the first, second and third anniversaries from the date of grant.

	Six Months Ended June 30,			
	2017		2016	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Stock options outstanding, beginning of period	20,037,497	$ 37.26	19,746,414	$ 36.50
Granted	754,000	29.55	205,300	28.73
Exercised	(713,134)	23.21	(1,117,333)	28.51
Forfeited	(118,333)	42.30	(161,668)	38.94
Stock options outstanding, end of period	19,960,030	$ 37.44	18,672,713	$ 36.87

The average trading price of the Company's common shares was $29.05 during the six months ended June 30, 2017 (six months ended June 30, 2016 – $28.02).

The following table summarizes stock options outstanding and exercisable at June 30, 2017:

Range of Exercise Price	Number Outstanding at Period End	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at Period End	Weighted Average Exercise Price
$22.49 - $29.26	3,779,665	3.78	26.81	1,069,520	26.66
$30.06 - $39.57	7,241,365	3.67	34.61	3,028,498	34.45
$40.18 - $48.99	7,324,000	1.70	42.11	6,319,667	41.95
$51.47 - $56.76	1,615,000	2.02	53.79	1,353,333	54.02
	19,960,030	2.84	37.44	11,771,018	40.02

The fair value of options granted during the six-month period ended June 30, 2017 was estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions and resulting values:

	June 30,	
	2017	2016
Fair value of options granted (weighted average)	$ 9.13	$ 8.43
Risk-free interest rate	1.12%	2.02%
Estimated hold period prior to exercise	5 years	4 years
Expected volatility	33%	34%
Forfeiture rate	2%	2%
Dividend per share	$ 0.00	$ 0.00

12. COMMITMENTS

In the normal course of business, the Company 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	$ 5,692	$ 9,486	$ -	$ -	$ 15,178
Firm transportation and processing agreements	290,479	665,870	619,752	1,738,361	3,314,462
Capital commitments (1)	310,921	607,795	141,174	35,367	1,095,257
Flow-through share commitments	34,436	-	-	-	34,436
Credit facility (2)	-	-	891,705	-	891,705
Term debt (3)	17,481	34,961	677,342	-	729,784
	$ 659,009	$ 1,318,112	$ 2,329,973	$ 1,773,728	$ 6,080,822

(1) Includes drilling commitments, and capital spending commitments under the joint arrangement in the Spirit River complex of $300.0 million per year until 2019. The capital spending commitment can be deferred to future periods in the event of an economic downturn, and as agreed upon by both parties. At June 30, 2017, an economic downturn event, as defined in the joint arrangement in the Spirit River complex had occurred and as a result $75.0 million of the 2017 originally planned capital will be deferred to future periods. To date, the total deferred capital to be spent in future periods is $291.0 million.

(2) Includes interest expense at an annual rate of 2.70% being the rate applicable to outstanding debt on the credit facility at June 30, 2017.

(3) Includes interest expense at an annual rate of 2.99% being the fixed rate on the term debt at June 30, 2017.

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.

SOURCE Tourmaline Oil Corp.

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