NEWS RELEASE **MARCH 6, 2018**

TOURMALINE GROWS 2017 CASH FLOW BY 65%, DELIVERS EARNINGS OF $346.8 MILLION, AND ANNOUNCES INAUGURAL DIVIDEND IN Q1 2018

Calgary, Alberta - Tourmaline Oil Corp. (TSX:TOU) ("Tourmaline" or the "Company") is pleased to announce very strong 2017 financial and operating results as well as payment of the Company's first dividend.

HIGHLIGHTS

- Tourmaline grew 2017 cash flow[(1)] by 65% to $1.2 billion ($4.47/diluted share).
- Tourmaline delivered full-year 2017 earnings of $346.8 million ($1.29/diluted share) underscoring the inherent profitability of the core EP business.
- Record low full-year 2017 operating costs of $3.19/boe.
- Tourmaline realized 31% production growth in 2017 over 2016, with 2017 average production of 242,325 boepd - within original full year guidance.
- Liquids production growth of 64% in 2017 over 2016 (oil, condensate, NGLs).
- Record low EP capital efficiency of $9,500/boepd in 2017.
- Tourmaline added 558 mmboe of 2P reserves and grew liquid reserves 73% after taking into account 2017 annual production.
- 2P reserve value increased by $2.4 billion in 2017 up to $15.1 billion. Approximately 96% of the 2017 2P reserve additions were delivered organically by the internal EP program.
- Record low finding, development and acquisition costs ("FD&A") in 2017 of $3.76/boe for 2P reserves (including changes in future development capital ("FDC")), $6.79/boe for total proved reserves (including FDC) and $8.23/boe for PDP reserves (including FDC) - all down significantly from 2016.
- 2017 2P recycle ratio of 3.6 based on cash flow of $13.63/boe and 2P FD&A costs of $3.76/boe (including FDC), total proved recycle ratio of 2.0 and PDP recycle ratio of 1.7.

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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 Management's Discussion and Analysis for the year ended December 31, 2017.

- After nine years of operation, Tourmaline has total 2P reserves of 2.22 billion boe including 2P natural gas reserves of 10.7 tcf and 2P liquid reserves of 431.6 mmboe of oil, condensate and liquids (December 31, 2017), with only 14% of the current overall drilling inventory booked.
- Tourmaline's owned-and-operated infrastructure represents the fourth largest gas processing capability in the Basin.

2017 FINANCIAL RESULTS

Tourmaline grew 2017 cash flow by 65% in 2017 to $1.2 billion ($4.47/diluted share) from $731.8 million ($3.12/diluted share) in 2016, a 43% per diluted share increase. Q4 2017 cash flow of $348.2 million ($1.29/diluted share) was up 38% over Q4 2016 cash flow of $252.5 million ($1.02/diluted share) and up 39% over the third quarter of 2017. These record cash flows for the Company were realized during a year of generally weak natural gas prices. Tourmaline's gas diversification and hedging strategies provided a realized natural gas price of $2.89/mcf, a 42% premium over the full-year AECO 5A index price of $2.04/mcf. As previously disclosed, the EP program delivered free cash flow[(2)] in Q4 2017. Free cash flow is expected to increase during the first quarter of 2018 compared to the fourth quarter of 2017.

The Company delivered very strong full-year 2017 earnings of $346.8 million ($1.29/diluted share) underscoring the Company's ability to generate profitable, full-cycle growth, even in weak commodity price environments.

INTRODUCTION OF DIVIDEND

Tourmaline will proceed with the implementation of its previously-announced dividend program. The first quarterly dividend of $0.08/common share will be paid on March 29, 2018 to shareholders of record at the close of business on March 14, 2018. This quarterly cash dividend is designated as an "eligible dividend" for Canadian income tax purposes.

GAS MARKETING AND TRANSPORTATION UPDATE

The TCPL Sundre Crossover project is expected to be complete in April of 2018, allowing approximately 380 mmcfpd of gas currently flowing to AECO through the NGTL system to instead flow southwards through the GTN system to Malin, Oregon. Tourmaline has approximately 100 mmcfpd of firm transportation of this redirected gas flow.

A second expansion of this system is planned for 2019, redirecting an additional 280 mmcfpd of natural gas from AECO into the GTN system. Tourmaline has secured approximately 100 mmcfpd of firm transportation of that additional redirected gas flow as well. In aggregate, these two projects significantly reduce gas volumes at the AECO complex. Subsequent to the completion of the second expansion, Tourmaline will have in aggregate approximately 300 mmcfpd of firm transportation on the GTN system.

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(2) *"Free cash flow" is defined as cash flow less total capital expenditures, including EP capital and other corporate expenditures and excludes acquisition and disposition activities, and is prior to dividend payments. See "Non-GAAP Financial Measures" herein.*

These two projects are a subset of Tourmaline's ongoing multiple initiatives to ensure diversification of natural gas transportation and market options, a strategy that was embarked upon over five years ago. The Company will have approximately 550 mmcfpd of gas flowing to hubs with NYMEX-based pricing in 2019.

PRODUCTION UPDATE

Tourmaline grew 2017 average production to 242,325 boepd, a 31% increase over 2016 average production of 185,672 boepd (13% annual production per diluted share growth). Fourth quarter 2017 average production of 263,309 boepd was up 37% over fourth quarter 2016 average production of 191,814 boepd and up 11% over the previous quarter (Q3 2017). 2017 average liquid production of 38,737 bpd (oil, condensate, NGLs) was up 64% over 2016 average liquid production of 23,586 bpd. Current production is 270,000-275,000 boepd and full-year 2018 average production guidance remains unchanged at 270,000-280,000 boepd. The Company has approximately 37 wells to tie-in and bring on-production during March and early April 2018.

COST MANAGEMENT

Full-year 2017 operating costs of $3.19/boe established a new corporate record as the Company continues to pursue multiple cost reduction opportunities in all aspects of the business. The Company is very pleased with reducing overall 2017 corporate average operating costs as they also included a growing light oil complex and increased liquids production throughout the EP portfolio.

The Company has the lowest per-stage horizontal drill-and-complete capital costs across all three core-operated EP areas. 2017 drill-and-complete capital costs were generally held flat with 2016. Tourmaline is targeting a further 5-10% per well capital cost reduction in the 2018/2019 time frame.

CAPITAL BUDGET OUTLOOK

The current full-year 2018 capital budget remains at $1.1 billion and the Company expects to spend less than $300.0 million during the first quarter of 2018. The Company will review the overall 2H 2018 capital program allocation between liquids and gas projects in the second quarter of 2018 during spring break-up.

Exit 2017 net debt(3) of $1.74 billion was down by $34.9 million from Q3 of 2017. As previously announced, the Company has already reduced Q1 2018 debt by a further $72 million. Tourmaline expects a 2018 exit net debt-to-cash flow ratio of approximately 1.1 times.

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(3) "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 Management's Discussion and Analysis for the year ended December 31, 2017.

EP UPDATE

Liquids Business Growth

Over the past two years, Tourmaline has increased its focus on the liquids opportunities throughout the EP portfolio, growing overall liquids production by over 100% in the past 18 months to 50,000 bpd currently (oil, condensate, NGLs). The Company has embarked upon a series of drilling and related facility projects that are anticipated to profitably grow overall corporate liquids production a further 50% to 75,000 bpd by Q4 2019.

Tourmaline is forecasting full-year average liquids production of 50,000 bpd in 2018 and expects to eclipse the current forecast average of 60,000 boepd for 2019 as ongoing liquids project timing is finalized during the second quarter.

Sunrise Dawson Montney Turbidite

Tourmaline has now drilled 44 wells into the liquid-rich Montney turbidite horizons at Sunrise-Dawson and has evolved a well-defined performance and cost curve for these development wells. Average EUR per well is 3.11 bcf of sales gas, 275 mstb of condensate and 90 mstb of NGL. Average well cost for these 1,500m laterals is $2.86 million Cdn (drill, complete and equip) yielding average IRRs of 197% and a 10-month payout utilizing January 1, 2018 engineering pricing. These wells are amongst the most profitable subsurface targets in the Western Canadian Sedimentary Basin with a net present value of $11.9 million (NPV 10 – before tax) yielding capital efficiencies of approximately $7,500/boepd. Currently, Tourmaline has 18 Montney turbidite wells shut-in awaiting facility capacity. The ongoing Doe 2-11 sweetening and debottlenecking facility project will add 3,500 bpd of condensate production during the fourth quarter of 2018.

Alberta Deep Basin Cardium Gas Condensate Play

Tourmaline is currently drilling the next Cardium gas condensate delineation pad at Anderson 6-1; these horizontal wells will be drilled in March 2018 and completed in May 2018. The initial 16-25-50-23W5M discovery well has an IP 365 of 10.4 mmcfpd and 306 bpd of total liquids (293 bbls/day of condensate), one of the highest deliverability gas wells in Western Canada in 2017 with one of the top liquids production rates drilled during the past year (cumulative 3.97 bcf gas, 119 mstb to date, EUR 15.0 bcf (raw), 315 mstb condensate/NGLs in the Company's year-end independent reserve report). The step-out well at 7-30-50-22W5 has an IP 60 of 17.5 mmcfpd and 750 bbls/day of total liquids (680 bpd condensate). This well is assigned recoverable reserves of 8.0 bcf and 289 mstb condensate and NGLs in the Company's year-end independent reserve report. Tourmaline is currently averaging $3.5-4.0 million drill-and complete-costs for these Cardium horizontal targets. The Company has an expansive future drilling inventory defined along the 225 km long play trend, most of which is covered by 3D seismic, one of the key success drivers for this play.

Peace River High Triassic Lower Montney Oil Play

Tourmaline continues to delineate and expand the Lower Montney oil play on the Peace River High, in conjunction with the ongoing Upper and Lower Charlie Lake oil development activities. As previously disclosed, the Company acquired 35 sections of primarily undeveloped land for the Lower Montney oil play in Q4 2017 as well as initiating a facility debottlenecking project with associated accelerated development drilling. This project will add an additional 3,000 bbls/day of oil (net) with approximately 5 mmcfpd (net) of associated gas during the fourth quarter of 2018. The 1-4-78-8W6M Lower Montney oil well has an IP 90 of 668 bpd oil and 5.2 mmcfpd of natural gas (cumulative recovery of 66 mstb oil and 0.55 bcf of gas to date). The 15-16-78-8W6M Lower Montney oil well has an IP 90 of 345 bpd and 5.0 mmcfpd of natural gas (cumulative recovery of 29 mstb oil and 0.41 bcf of gas to date). The 2-4-78-8W6M well has an IP 60 of 935 bpd oil and 5.2 mmcfpd of natural gas (cumulative recovery of 61 mstb oil and 0.36 bcf of gas to date). The Company estimates a current Lower Montney oil inventory of approximately 93 drilling locations that is expected to increase as the 2018 delineation drilling program proceeds. In aggregate in 2018, Tourmaline plans to drill, complete and tie-in 75 oil wells in the Peace River Triassic oil complex (Upper and Lower Charlie Lake and Lower Montney).

CORPORATE SUMMARY – DECEMBER 31, 2017

	Three Months Ended December 31,			Twelve Months Ended December 31,		
	2017	**2016**	**Change**	**2017**	**2016**	**Change**
OPERATIONS						
Production						
Natural gas *(mcf/d)*	**1,306,935**	982,713	33%	**1,221,529**	972,513	26%
Crude oil and NGL *(bbl/d)*	**45,486**	28,028	62%	**38,737**	23,586	64%
Oil equivalent *(boe/d)*	**263,309**	191,814	37%	**242,325**	185,672	31%
Product prices[1]						
Natural gas *($/mcf)*	**$ 2.70**	$ 3.20	(16)%	**$ 2.89**	$ 2.51	15%
Crude oil and NGL *($/bbl)*	**$ 48.31**	$ 38.42	26%	**$ 42.24**	$ 37.68	12%
Operating expenses *($/boe)*	**$ 3.08**	$ 2.86	8%	**$ 3.19**	$ 3.31	(4)%
Transportation costs *($/boe)*	**$ 3.01**	$ 2.92	3%	**$ 2.93**	$ 2.41	22%
Operating netback[4] *($/boe)*	**$ 14.80**	$ 15.00	(1)%	**$ 14.27**	$ 11.50	24%
Cash general and administrative expenses *($/boe)*[2]	**$ 0.44**	$ 0.39	13%	**$ 0.46**	$ 0.44	5%
FINANCIAL						
($000, except share and per share)						
Revenue	**527,106**	388,449	36%	**1,883,611**	1,219,160	55%
Royalties	**21,113**	21,752	(3)%	**80,638**	48,857	65%
Cash flow[4]	**348,227**	252,542	38%	**1,205,758**	731,801	65%
Cash flow per share *(diluted)*[4]	**$ 1.29**	$ 1.02	26%	**$ 4.47**	$ 3.12	43%
Net earnings (loss)	**88,079**	59,621	48%	**346,773**	(31,971)	1,185%
Net earnings (loss) per share *(diluted)*	**$ 0.33**	$ 0.24	38%	**$ 1.29**	$ (0.14)	1,021%
Capital expenditures *(net of dispositions)*	**352,233**	1,244,974	(72)%	**1,406,616**	1,933,289	(27)%
Weighted average shares outstanding *(diluted)*				**269,595,109**	234,386,245	15%
Net debt[4]				**(1,737,241)**	(1,590,850)	9%
PROVED + PROBABLE RESERVES[3]						
Natural gas *(bcf)*				**10,707.6**	8,930.6	20%
Crude oil *(mbbls)*				**65,288**	54,362	20%
Natural gas liquids *(mbbls)*				**366,321**	204,027	80%
Mboe				**2,216,206**	1,746,822	27%

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

(2) Excluding interest and financing charges.

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

(4) See "Non-GAAP Financial Measures" in the Company's Management's Discussion and Analysis for the year ended December 31, 2017.

Conference Call Tomorrow at 7:00 a.m. MT (9:00 a.m. ET)

Tourmaline will host a conference call tomorrow, March 7, 2018 starting at 7:00 a.m. MT (9:00 a.m. ET). 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 5489594.

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 (collectively, "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 the following: anticipated petroleum and natural gas production and production growth for various periods; the future declaration and payment of dividends and the timing and amount thereof; drilling inventory or locations; cash flow; cash flow per share; free cash flow; net debt-to-cash flow levels; 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 the following: 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. Without limitation of the foregoing, future dividend payments, if any, and the level thereof is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time will be dependent upon, among other things, free cash flow, financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of Tourmaline to pay dividends will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility.

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.

RESERVES DATA

The reserves data set forth above is based upon the reports of GLJ Petroleum Consultants Ltd. ("GLJ") and Deloitte LLP, each dated effective December 31, 2017, which have been consolidated into one report by GLJ and adjusted to apply certain of GLJ's assumptions and methodologies and pricing and cost assumptions. The consolidated report includes 100% of the reserves and future net revenue attributable to the properties of Exshaw Oil Corp., a subsidiary of the Company, without reduction to reflect the 9.4% third-party minority interest in Exshaw. The price forecast used in the reserve evaluations is an average of the January 1, 2018 price forecasts for GLJ, Sproule Associates Ltd. and McDaniel & Associates Consultants Ltd., each of which is available on their respective websites, www.gljpc.com, www.sproule.com and www.mcdan.com, and will be contained in the Company's Annual Information Form for the year ended December 31, 2017, which will be filed on SEDAR (accessible at www.sedar.com) on or before March 31, 2018.

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

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

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to effects of aggregations. The estimated values of future net revenue disclosed in this news release do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

NON-GAAP FINANCIAL MEASURES

This news release includes references to "free cash flow", "cash flow" and “net debt” which are financial measures commonly used in the oil and gas industry and do not have a standardized meaning prescribed by International Financial Reporting Standards ("GAAP"). Accordingly, the Company’s use of these terms may not be comparable to similarly defined measures presented by other companies. Management uses the term "free cash flow", “cash flow" 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, to pay dividends or to repay debt. Investors are cautioned that these non-GAAP measures should not be construed as an alternative to net income or cash from operating activities determined in accordance with GAAP as an indication of the Company’s performance. Free cash flow is calculated as cash flow less total capital expenditures, including EP capital and other corporate expenditures and excludes acquisition and disposition activities, and is prior to dividend payments. See "Non-GAAP Financial Measures" in the Management's Discussion and Analysis for the year ended December 31, 2017 for the definition and description of "cash flow" and "net debt".

FINANCIAL OUTLOOK

Also included in this news release are estimates of Tourmaline's 2018 exit net debt-to-cash flow ratio, which is 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 2018 average production of

270,000-280,000 boepd and commodity price assumptions for natural gas (AECO - $2.50/mcf for 2018), and crude oil (WTI (US) - $52.00/bbl for 2018) and an exchange rate assumption of $0.80 (US/CAD) for 2018. To the extent such estimate constitutes a financial outlook, it was approved by management and the Board of Directors of Tourmaline on March 6, 2018 and is included to provide readers with an understanding of Tourmaline's anticipated net debt-to-cash flow ratio 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.

TYPE CURVE INFORMATION

The performance and cost or "type curve" information included in this news release, including initial production rates, represents estimates of the production decline and ultimate volumes expected to be recovered from wells over the life of the well. This information is based on internally generated type curves based on a combination of historical performance of older wells and management's expectation of what might be achieved from future wells. The information represents what management thinks an average well will achieve. Individual wells may be higher or lower but over a larger number of wells management expects the average to come out to the type curve. Over time type curves can and will change based on achieving more production history on older wells or more recent completion information on newer wells. There is no certainty that future wells will generate results to match historic type curves presented herein.

INDUSTRY METRICS

This news release contains metrics commonly used in the oil and natural gas industry. Each of these metrics is determined by the Company as set out below or elsewhere in this news release. The metrics are "capital efficiency", "recycle ratio", "EUR" and "FD&A costs". These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies. As such, they should not be used to make comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare the Company's performance over time, however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the performance in previous periods and therefore should not be unduly relied upon.

Capital efficiency is calculated by dividing the EP capital spending for the year by the new production added during the year after taking into account production declines.

Recycle ratio is calculated by dividing the cash flow per boe by the appropriate the FD&A costs related to the reserve additions for that year.

EUR is calculated as estimated ultimate recovery of oil from a typical well in the area. EUR was determined internally by the Company by a non-independent qualified reserves evaluator incorporating current well results and historical well performance from the Company's analogous pools in the nearby area.

FD&A costs are calculated by dividing the sum of the total capital expenditures for the year inclusive of the net acquisition costs and disposition proceeds (in dollars) by the change in reserves within the applicable reserves category inclusive of changes due to acquisitions and dispositions (in boe). FD&A costs, including FDC, includes all capital expenditures in the year inclusive of the net acquisition costs and disposition proceeds as well as the change in FDC required to bring the reserves within the specified reserves category on production.

The Company uses FD&A as a measure of the efficiency of its overall capital program including the effect of acquisitions and dispositions. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

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.

ESTIMATED DRILLING INVENTORY

This news release discloses drilling locations in four categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii). Of the 14,471 (gross) locations disclosed in this news release, 1,056 are proved undeveloped locations, 21 are proved non-producing locations, 997 are probable undeveloped locations, nil are probable non-producing and 12,397 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 and Deloitte LLP as of December 31, 2017 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

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 Company's 2017 year-end Management's Discussion and Analysis.

CERTAIN DEFINITIONS:

2P	*proved plus probable*
3D	*three dimensional*
bbl	barrel
bbls/day	barrels per day
bbl/mmcf	barrels per million cubic feet
bcf	billion cubic feet
bcfe	billion cubic feet equivalent
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
EP	exploration and production
EUR	estimated ultimate recovery
FCP	final circulating pressure
gj	gigajoule
gjs/d	gigajoules per day
mbbls	thousand barrels
mmbbls	million 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 or NGLs	natural gas liquids
NPV 10 – before tax	net present value at December 31, 2017 discounted at 10% – before tax
PDP	proved developed producing
tcf	trillion cubic feet
TCPL	TransCanada Pipelines

MANAGEMENT'S DISCUSSION AND ANALYSIS AND CONSOLIDATED FINANCIAL STATEMENTS

To view Tourmaline's Management's Discussion and Analysis and Consolidated Financial Statements for the years ended December 31, 2017 and 2016, please refer to the SEDAR (www.sedar.com) as well as Tourmaline's website at www.tourmalineoil.com.

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.

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