Tourmaline Achieves Record Production, Adds 829 Million Boe Of 2p Reserves And Reduces 2026 Ep Capex

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Tourmaline Oil Corp. (TSX: TOU) ("Tourmaline" or the "Company") is pleased to release financial and operating results
and fourth quarter of 2025.

HIGHLIGHTS

- Record Q4 2025 average production of 659,204 boepd and January 2026 average production of over 685,000 bo
- 829 million boe proved plus probable ("2P") reserve addition in 2025, including a corporate record single year org addition of 457 million boe, both after accounting for 2025 production.
- Continued corporate operating costs reduction in Q4 2025, down over 9% from the first half of 2025 to $4.66/boe.
- Peace River High ("PRH") asset sale completed in February 2026 for proceeds of $765 million, prior to customary adjustments.
- 2026 forecasted EP capital expenditures reduced by $350 million as the Company remains focused on optimizing [1][2] ("FCF").
- Quarterly base dividend of $0.50/share to be paid on March 31, 2026 to shareholders of record at the close of bu 16, 2026.
- Net debt[3] at year-end 2025 of $1.5 billion, inclusive of the impact of the PRH asset sale, or 0.45x forecasted 202 ("CF"), down from Q3 2025 net debt of $2.3 billion.

PRODUCTION UPDATE

- Record Q4 2025 average production of 659,204 boepd, within the previous Q4 guidance range of 655,000 - 665,(
- Q4 2025 average liquids production (oil, condensate, NGLs) was also a record at 152,673 bbls/d.
- January 2026 production averaged over 685,000 boepd prior to the impact of the PRH asset sale, a new record a expectations.
- First quarter 2026 average production of 660,000 - 670,000 boepd is anticipated, after taking into account the sal assets which closed on February 2, 2026.
- In order to improve operating netbacks[5], Tourmaline has elected to terminate its discretionary deep cut gas plan the Alberta Deep Basin in 2026 as contracts expire. This will reduce corporate average ethane production volume approximately 20,000 bpd on a full year basis but is expected to increase forecasted 2026 operating netback by a $65 million and forecasted 2027 operating netback by approximately $110 million through the elimination of deep fees as well as C2+ transportation and fractionation fees.

FINANCIAL RESULTS

- Q4 2025 CF was $890 million ($2.29 per fully diluted share[6]). Full year 2025 CF was $3.4 billion ($8.84 per fully
- Tourmaline sold its PRH complex to a Canadian senior producer for cash proceeds of $765 million, prior to custo adjustments. Through this transaction, Tourmaline has sold its most mature, highest-cost production and will repl low-cost production streams flowing through newly constructed Tourmaline facilities. Although Tourmaline pionee Lake horizontal play in 2009-2010, this disposition will allow the Company to enhance its focus on the Company's gas complexes. Tourmaline intends to utilize approximately $500 million of the proceeds of this disposition for pe long-term debt reduction and approximately $265 million for the NEBC infrastructure buildout over the next two ye
- Net debt at year end 2025 was $1.5 billion, inclusive of the impact of the PRH asset sale, and down from Q3 202 $2.3 billion. The Company is setting a long-term net debt target of $1.75 billion (approximately 0.5x net debt to ca

CAPITAL BUDGET/EP PLAN

- The multi-year EP Plan has been updated for full year 2025 results, asset sales, strong well performance, new co hedges, and cost reduction initiatives realized to date.
- The Company believes that during these unusually volatile times, the optimal business approach is to steadily re continuously improve the overall cost structure. The Company is already executing on this plan.
- Q4 2025 EP capital spending was $812.7 million, within the original quarterly guidance range. Full year 2025 EP was $2.93 billion.
- The PRH asset sale and the redirection of discretionary Deep Basin deep cut volumes will reduce total corporate total of approximately 50,000 boepd on a full year basis. Q1 2026 average production of 660,000 - 670,000 boep expected (which includes Deep Basin deep cut production volumes for the entire quarter and PRH production vol February 2, 2026). The full year 2026 anticipated average production range is now 620,000 - 640,000 boepd.
- The 2026 full year EP capital program will be reduced by $350 million to $2.55 billion along with a $50 million cut capital for a total capital expenditure reduction of $400 million. This reduction includes $175 million of the original EP capex in the PRH complex and $175 million of expenditures in the gas complexes. The Company believes it i defer certain gas-focused expenditures until a sustained, stronger local price environment materializes. The gas c expenditure reduction will have a negligible impact on production guidance (~1.0%) given stronger than anticipate performance to date. The Company has identified an additional $200 million of drilling and completion capital tha deferred from the 2026 EP capital program if commodity prices deteriorate further.

- At strip pricing[7], Tourmaline's revised EP Plan anticipates 2026 CF of $3.4 billion and FCF of $0.7 billion. All els US $0.10/mcf that AECO pricing improves, Tourmaline's 2026 CF and FCF increase by approximately $45 millio every US $1.00/mcf that both JKM and TTF pricing improve, Tourmaline's 2026 CF and FCF increase by approxi million and Tourmaline's 2027 CF and FCF increase by approximately $70 million.

2025 RESERVES

- Year-end 2025 proved developed producing ("PDP") reserves[8] of 1.47 billion boe were up 27% after accounting production of 233 million boe. Total proved ("TP") reserves of 3.26 billion boe were up 20% after accounting for 2 2P reserves of 6.09 billion boe were up 15% after accounting for 2025 production.
- The 2025 2P organic reserve addition of 457 million boe was the largest single year organic 2P addition in corpo
- After 17 years of operations, Tourmaline now has 27.7 TCF of economic 2P natural gas reserves and 1.48 billion condensate and NGL reserves, all of which are pipeline-connected to markets across North America. At year-en the current internally estimated drilling inventory of 26,512 gross locations was booked in the 2025 year-end rese
- Year-end 2025 oil, condensate and NGL 2P reserves of 1.48 billion barrels represent the second largest convent reserve base in Canada, based on public disclosure.
- Tourmaline has only booked 4,073 gross locations of a total drilling inventory of 26,512 gross locations (15.4% of inventory) to achieve year-end 2025 2P reserves of 6.1 billion boe.
- Tourmaline replaced 356% of its 2025 annual production of 233 million boe with 2P additions of 829 million boe, i production.
- Tourmaline's 2025 PDP finding and development ("F&D") costs were $9.81 per boe including changes in future d capital ("FDC"), yielding a PDP reserve recycle ratio of 1.5 times. TP finding, development and acquisition ("FD& were $10.95 per boe, including changes in FDC. 2P FD&A costs in 2025 were $9.09 per boe, including changes i
- The Company elected to increase drill and complete costs across the entire booked inventory (4,073 gross locati the steady migration to longer horizontals and an increasing percentage of plug and perf style completions. Futur was also increased to reflect the Company's planned NEBC infrastructure buildout. These 2025 additions to the C FDC amount incorporated in the year-end 2025 reserve report resulted in a $3.21/boe increase to the Company's including FDC and an increase of $4.61/boe to the Company's 2P F&D costs including FDC. These additions to t total FDC amounts are not expected to reoccur in future reserve reports. 2025 2P FD&A costs including the incre $9.09/boe, compared to 5-year 2P FD&A costs of $7.74/boe, including changes in FDC.
- Tourmaline's 2P reserve value (before taxes) equates to $98.86 per diluted share (after tax reserve value of $75. share) using the January 1, 2026 engineering price deck and a 10% discount rate. TP reserve value (before tax) diluted share and $50.43 per diluted share (after tax). PDP reserve value is $38.94 per diluted share (before tax) diluted share (after tax). The decrease in the 2P reserve value in the current reserve report (compared to the De reserve report) is a result of a significant increase in reserve volumes being more than offset by significant backw JKM gas price as well as weaker AECO prices in the engineering price deck after 2027.

MARKETING UPDATE

- Tourmaline's average realized natural gas price in Q4 2025 was CAD $3.77/mcf, significantly (CAD $1.51/mcf) a 5A benchmark price of CAD $2.26/mcf over the same period, as the Company continues to benefit from its divers portfolio and strategic hedging program.
- Tourmaline has an average of 879 mmcfpd of natural gas hedged for 2026 at a weighted average fixed price of C This includes 55 mmcfpd hedged at a weighted average price of CAD $14.69/mcf in international markets and 13 weighted average price of CAD $6.70/mcf in Western U.S. markets.
- In Q1 2026, Tourmaline has over 370 mmcfpd of physical gas exposed to the premium price Eastern markets (D Chicago, Iroquois, Emerson and ANR SE), providing a strong uplift to Q1 cash flow. These markets traded at an $24.00/mcf for the last ten days of January.
- The Company entered into a long-term natural gas storage agreement with AltaGas at its Dimsdale Storage Faci 2025, and AltaGas has announced a positive final investment decision ("FID") for the Phase 2 expansion of the f Tourmaline will have access to 6 bcf of storage capacity starting April 2026, increasing to 10 bcf in mid-2027 for The Company views the acquisition of an additional large storage position as a strategic opportunity to improve f performance and enhance operational flexibility in periods of natural gas volatility. This is another aspect of the C ongoing efforts to fully vertically integrate the overall gas business.
- Tourmaline will have an average of 213,000 mmbtu/d exposed to international pricing (TTF/JKM) in 2026. This w 253,000 mmbtu/d by exit 2027 and 333,000 mmbtu/d by exit 2028. Both JKM and TTF prices have improved sinc 2025.

COST REDUCTION/MARGIN IMPROVEMENT UPDATE

- Tourmaline embarked upon a comprehensive cost reduction initiative in mid-2025 with the focus on reducing all a cost equation. These realized cost reductions are expected to be sustainable on a long-term basis.
- Q4 2025 operating costs were $4.66/boe, down 3% from third quarter 2025 operating costs of $4.80/boe and dow half of 2025 operating costs of $5.14/boe.
- The sale of the PRH complex will reduce go-forward corporate operating costs by a further 7%, resulting in a 202 guidance of $4.50/boe, a 9% year-over-year reduction.

- With the success of cost reduction initiatives to date, Tourmaline is revising its aggregate operating and transport target by 2031 from $1.00/boe to $1.50/boe, with approximately $0.70/boe already achieved since the first half of target was initiated.
- Lower aggregate debt levels combined with the Company's recently initiated commercial paper program are expe approximately $20-25 million in interest cost reductions in 2026 based on prevailing interest rates.
- Tourmaline has entered into agreements to control frac sand capacity in a transload facility in the NEBC Montney facility is expected to commence operations in Q2 2026. This vertical integration of the Company's sand business save over $40M per year in capital costs.
- The NEBC infrastructure buildout will systematically reduce costs as various components of the buildout are comp major component to be completed is the liquids hub and associated pipelines located in proximity to the Aitken ga complex. The project was commissioned in February 2026 with an initial capacity of 20,000 bbl/d and will handle from North Montney Phase 1 and future North Montney development phases with resulting expected overall corp $0.05/boe over the EP Plan period.
- By 2031, through expected total cost reductions of $1.50/boe, and sand-related capital savings of over $40 millio Tourmaline anticipates up to $500 million per year of aggregate structural cost reductions, compared to the Comp of 2025 total cost structure, which will flow through to lower corporate break evens and FCF margin improvement

EP UPDATE

- Tourmaline drilled 331 gross wells in 2025 and led the Canadian industry[9] with a total of 1.7 million metres drille year.
- In 2025, Tourmaline delivered its best overall well performance in the past five years in the NEBC Montney gas c complex (21% higher than the previous 5-year average based on the IP90 of 102 wells). This outperformance has the full suite of the BC Montney assets, from Aitken-Birch-Gundy in the north to Groundbirch-Doe-Monias in the s
- The Company is currently planning to drill and complete a total of approximately 280 net wells in 2026 including a 140 net wells in both the Alberta Deep Basin and the NEBC gas condensate complexes. Tourmaline continues to lateral length with the 2025 Deep Basin and NEBC program averaging 8,400 completed lateral feet, up over 1,10 2024. Drilling and completion costs per foot in the Deep Basin and NEBC are now in decline, dropping from $805 in 2024 to $780 per lateral foot in 2025 despite steadily higher tonnage in NEBC completions.
- The 2026 EP capital budget reduction will not impact the original start-up timing of the Aitken and Groundbirch/M projects in NEBC. Aitken is on schedule for a Q4 2026 completion, with Groundbirch/Monias completion expecte
- The Company's ongoing new zone/new pool exploration program has resulted in 2.55 TCFe of 2P reserves (as a 2025) and 1,356 Tier1/Tier 2 drilling locations, with the vast majority of these additions occurring in the last five ye several potential high impact exploration and delineation wells planned in the 2026 program.

ENVIRONMENTAL PERFORMANCE IMPROVEMENT

- Tourmaline has achieved Grade 'A' certification for methane performance across its NEBC assets under MiQ's gl certification standard. Tourmaline is the first Canadian company to be certified under MiQ and the first company i to have certified integrated gas production and processing facilities.
- Tourmaline's cleantech engineering team continues to develop and implement new proprietary emission reductio execute expanded water management initiatives, explore industry leading methane mitigation technologies, and r third-party environmental research.
- Since embarking on the diesel displacement initiative for drilling rigs and frac spreads in June 2017, the Company 240 million litres of diesel, providing an emissions reduction of 160,000 tonnes of carbon dioxide and saving appr million (including the cost of the replacement natural gas). Drilling and completions operations powered by natura lower emissions of carbon dioxide, nitrogen oxides, sulphur dioxide and particulate matter compared to traditiona drilling and completions operations.
- The compressed natural gas in long-haul trucking joint development with Clean Energy Fuels Corp., announced i continues to progress with 5 stations operational across Alberta and British Columbia. An additional four new stat in 2026. This initiative is expected to reduce costs and emissions in the long-haul trucking industry and build Can gas demand.
- Tourmaline completed construction of a new water recycling facility in 2025 and is planning to build three additio recycling facilities in 2026. These facilities reduce freshwater usage and reduce well stimulation costs.
- The Company is a leader in methane emission mitigation and operates the West Wolf Emissions Testing Centre, the world, where new technologies to accurately measure and ultimately reduce methane emissions are develop

DIVIDEND

- Tourmaline's Board of Directors has declared a quarterly base dividend of $0.50 per share, payable on March 31, shareholders of record at the close of business on March 16, 2026. The quarterly base dividend is designated as dividend for Canadian income tax purposes.
- Weak WCSB local gas pricing and unusually low pricing at the PG&E and Malin sales hubs this winter will limit F the Company's ability to fund a special dividend in Q1. Sustained stronger pricing and the Company's ongoing m improvement activities are expected to lead to further base dividend increases in the future. Special dividends are be used in those periods of particularly strong pricing to return the majority of the incremental FCF to shareholde

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(1) This news release contains certain specified financial measures consisting of non-GAAP financial measures, non-GAAP financial ratios, capital management measures and supplementary financial measures. See "Non-GAAP and Other Financial Measures" in this news release for information regarding the following specified financial measures: "cash flow", "capital expenditures", "EP expenditures", "free cash flow", "operating netback", "operating netback per boe", "cash flow per diluted share", "free cash flow per diluted share", "adjusted working capital", "net debt", "reserve value per diluted share", "operating expenses per boe", "cash general and administrative expenses per boe" and "transportation costs per boe". Since these specified financial measures do not have standardized meanings under International Financial Reporting Standards ("GAAP"), securities regulations require that, among other things, they be identified, defined, qualified and, where required, reconciled with their nearest GAAP measure and compared to the prior period. See "Non-GAAP and Other Financial Measures" in this news release and in the Company's Management's Discussion and Analysis as at and for the year ended December 31, 2025 (the "Annual MD&A"), which information is incorporated by reference into this news release, for further information on the composition of and, where required, reconciliation of these measures.

(2) "Free cash flow" is a non-GAAP financial measure defined as cash flow less capital expenditures, excluding acquisitions and dispositions. Free cash flow is prior to dividend payments. See "Non-GAAP and Other Financial Measures" in this news release.

(3) "Net debt" is a capital management measure. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(4) "Cash flow" is a non-GAAP financial measure defined as cash flow from operating activities adjusted for the change in non-cash working capital (deficit) and current taxes. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(5) "Operating netback" is a non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(6) "Cash flow per diluted share" is a non-GAAP financial ratio. Cash flow, a non-GAAP financial measure, is used as a component of the non-GAAP financial ratio. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(7) Strip Pricing as of March 2, 2026.

(8) 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.

(9) As reported by Daily Oil Bulletin Energy on February 25, 2026.

CORPORATE SUMMARY - DECEMBER 31, 2025

	Three Months Ended			Twelve Months Ended		
	December 31,			December 31,		
	2025	2024	Change	2025	2024	Change
OPERATIONS						
Production						
Natural gas (mcf/d)	3,039,185	2,779,365	9 %	2,946,447	2,643,532	11 %
Crude oil, condensate and NGL (bbl/d)	152,673	138,852	10 %	147,121	138,584	6 %
Oil equivalent (boe/d)	659,204	605,413	9 %	638,196	579,173	10 %
Product prices(1)						
Natural gas ($/mcf)	$ 3.77	$ 3.48	8 %	$ 3.62	$ 3.38	7 %
Crude oil, condensate and NGL ($/bbl)	$ 47.08	$ 56.99	(17) %	$ 50.27	$ 54.78	(8) %
Operating expenses ($/boe)	$ 4.66	$ 4.52	3 %	$ 4.93	$ 4.75	4 %

Transportation costs ($/boe)	$ 5.06	$ 4.97	2 %	$ 5.14	$ 5.11	1 %
Operating netback ($/boe)(2)	$ 16.32	$ 17.40	(6) %	$ 16.02	$ 16.26	(1) %
Cash general and administrative expenses ($/boe)(3)	$ 0.69	$ 0.82	(16) %	$ 0.78	$ 0.77	1 %
FINANCIAL ($000, except share and per share)						
Commodity sales from production						
Total revenue from commodity sales and realized gains	1,714,660	1,623,819	6 %	6,591,299	6,044,773	9 %
Royalties	135,121	125,699	7 %	513,879	509,252	1 %
Cash flow	890,117	850,330	5 %	3,395,570	3,218,491	6 %
Cash flow per share (diluted)	$ 2.29	$ 2.27	1 %	$ 8.84	$ 8.93	(1) %
Net earnings	(655,002)	407,445	(261) %	262,672	1,264,109	(79) %
Net earnings per share (diluted)	$ (1.69)	$ 1.09	(255) %	$ 0.68	$ 3.51	(81) %
Capital expenditures (net of dispositions)(2)	827,986	460,193	80 %	2,932,280	1,901,461	54 %
Weighted average shares outstanding (diluted)				383,938,857	360,249,193	7 %
Net debt				(1,523,871)	(1,702,732)	(11) %
PROVED + PROBABLE RESERVES(4)						
Natural gas (bcf)				27,671.4	24,837.0	11 %
Crude oil (mbbls)				124,518	119,331	4 %
Natural gas liquids (mbbls)				1,355,332	1,236,385	10 %
Mboe				6,091,751	5,495,212	11 %

Notes:

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

(2) See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(3) Excluding interest and financing charges.

(4) 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.

2025 RESERVE SUMMARY

The following tables summarize the Company's gross reserves 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. Company net reserves are defined as the working net carried and royalty interest reserves after deduction of all applicable burdens.

Reserves and Future Net Revenue Data (Forecast Prices and Costs)

Summary of Crude Oil, Natural Gas and Natural Gas Liquids Reserves and
Net Present Values of Future Net Revenue
as of December 31, 2025
Forecast Prices and Costs[1]

	Light & Medium Crude Oil		Conventional Natural Gas		Shale Natural Gas[2]	
Reserves Category	Company Gross (Mbbls)	Company Net (Mbbls)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (MMcf)	Comp (MMc
Proved Developed Producing	21,160	17,174	3,055,049	2,735,539	3,718,591	3,177
Proved Developed Non-Producing	913	719	77,273	69,212	235,875	207,9
Proved Undeveloped	46,004	35,868	2,707,566	2,420,305	5,028,848	4,397
Total Proved	68,077	53,760	5,839,887	5,225,056	8,983,313	7,783
Total Probable	56,441	44,105	3,887,703	3,405,262	8,960,502	7,602
Total Proved Plus Probable	124,518	97,865	9,727,590	8,630,317	17,943,815	15,38

Reserves Category	Net Present Values of Future Net Revenue ($000s)							
	Before Income Taxes Discounted at (%/year)						After Income T (%/year)	
	0	5	8	10	15	20	0	5
Proved Developed Producing	22,301,966	17,992,059	16,036,155	14,951,707	12,814,736	11,253,708	18,441,419	15
Proved Developed Non-Producing	1,676,830	1,274,026	1,096,787	998,260	803,042	660,138	1,243,603	94
Proved Undeveloped	22,289,928	13,562,876	10,305,918	8,646,213	5,674,702	3,770,473	16,576,660	9,8
Total Proved	46,268,724	32,828,961	27,438,860	24,596,180	19,292,480	15,684,319	36,261,681	25
Total Probable	47,073,880	23,307,656	16,451,121	13,361,389	8,489,541	5,799,002	34,976,107	17
Total Proved Plus Probable	93,342,604	56,136,618	43,889,981	37,957,569	27,782,020	21,483,321	71,237,789	43

Notes:

(1) Numbers may not add due to rounding.

(2) Shale Natural Gas is required to be presented separately from Conventional Natural Gas as its own product type pursuant to National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). While the Tourmaline Montney reserves do not strictly fit the definition of "shale gas" as defined in NI 51-101 because the natural gas is not "primarily adsorbed" as stated within the definition, the Montney reserves have been included as shale gas for purposes of this disclosure.

(3) The after-tax net present value of the Company's oil and gas reserves reflects Company-level tax pools. The Company's financial statements and management's discussion and analysis should be consulted for information at the Company level.

Total Future Net Revenue ($000s)
(Undiscounted)
as of December 31, 2025
Forecast Prices and Costs(1)

Reserves Category	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment and Reclamation Costs(2)	Future Net Revenue Before Income Tax	Income Tax
Proved Developed Producing	44,048,706	6,307,932	12,849,844	81,045	2,507,918	22,301,966	3,860,5
Proved Developed Non-Producing	2,767,252	371,004	548,968	113,251	57,200	1,676,830	433,228
Proved Undeveloped	55,161,594	8,535,555	11,285,023	12,392,477	658,610	22,289,928	5,713,2
Total Proved	101,977,552	15,214,491	24,683,836	12,586,772	3,223,728	46,268,724	10,007,
Total Probable	98,478,991	18,257,702	22,549,878	9,655,820	941,711	47,073,880	12,097,
Total Proved Plus Probable	200,456,543	33,472,193	47,233,714	22,242,592	4,165,439	93,342,604	22,104,

Notes:

(1) Numbers may not add due to rounding.

(2) Abandonment and Reclamation Costs includes all active and inactive assets, with or without associated reserves, inclusive of all wells (existing and undrilled), facilities and pipelines.

(3) The after-tax net present value of the Company's oil and gas reserves reflects Company-level tax pools. The Company's financial statements and management's discussion and analysis should be consulted for information at the Company level.

Summary of Pricing and Inflation Rate Assumptions
Forecast Prices and Costs (1)

Year	Inflation	Crude Oil and Natural Gas Liquids Pricing							
	%	CAD/USD Exchange Rate $US/$Cdn	NYMEXWTI Near Month Futures Contract Crude Oil atCushing, Oklahoma		MSW, Light Crude Oil (40 API, 0.3%S) at Edmonton	Alberta Natural Gas Liquids (Then Current Dollars)			
			Constant 2026 $US/Bbl	Then Current $US/ Bbl	Then Current $Cdn/Bbl	Spec Ethane $Cdn/Bbl	Edmonton Propane $Cdn/Bbl	Edmonton Butane $Cdn/Bbl	Edmonton C5+ Stream Quality $Cdn/Bbl
2026	0.0	0.728	59.92	59.92	77.54	9.59	25.10	36.95	80.01
2027	2.0	0.737	63.82	65.10	83.60	10.64	27.28	39.79	86.19
2028	2.0	0.740	67.55	70.28	90.18	11.34	29.67	42.87	92.83
2029	2.0	0.740	67.78	71.93	92.32	11.66	30.37	43.89	95.05
2030	2.0	0.740	67.79	73.37	94.17	11.89	30.98	44.77	96.94
2031	2.0	0.740	67.79	74.84	96.06	12.14	31.60	45.67	98.89
2032	2.0	0.740	67.79	76.34	97.98	12.39	32.23	46.58	100.87
2033	2.0	0.740	67.79	77.87	99.93	12.64	32.87	47.51	102.88
2034	2.0	0.740	67.79	79.42	101.93	12.90	33.53	48.46	104.94
2035	2.0	0.740	67.79	81.01	103.97	13.17	34.20	49.43	107.04
2036	2.0	0.740	67.79	82.63	106.05	13.43	34.89	50.42	109.18
2037	2.0	0.740	67.79	84.29	108.17	13.70	35.58	51.43	111.36
2038	2.0	0.740	67.79	85.97	110.34	13.97	36.30	52.46	113.59
2039	2.0	0.740	67.79	87.69	112.54	14.25	37.02	53.51	115.86
2040	2.0	0.740	67.79	89.45	114.79	14.54	37.76	54.58	118.18
2041+	2.0	0.740	67.79	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Year	Natural Gas and Sulphur Pricing										
	NYMEX Henry Hub Near Month Contract		Midwest Price @ Chicago	AECO/NIT Spot		Alberta Plant Gate			Huntingdon/ Sumas	British Colum	
						Spot		ARP $Cdn/ MMbtu	Spot $US/ MMbtu	Westcoast Station 2 $Cdn/ MMbtu	Sp $C Ml
	Constant 2026 $US/ MMbtu	Then Current $US/MMbtu	Then Current $US/ MMbtu	Then Current $Cdn/ MMbtu	Dawn Price @ Ontario Then Current $US/MMbtu	Constant 2026 $Cdn/ MMbtu	Then Current $Cdn/ MMbtu				
2026	3.74	3.74	3.47	3.00	3.51	2.78	2.78	2.78	2.41	2.66	2.2
2027	3.70	3.78	3.55	3.30	3.54	3.02	3.08	3.08	3.56	3.07	2.6
2028	3.70	3.85	3.63	3.49	3.61	3.13	3.26	3.26	3.64	3.25	2.8
2029	3.71	3.93	3.70	3.58	3.69	3.16	3.35	3.35	3.72	3.34	2.9
2030	3.70	4.01	3.78	3.65	3.77	3.16	3.42	3.42	3.80	3.41	2.9
2031	3.70	4.09	3.85	3.72	3.85	3.16	3.49	3.49	3.89	3.47	3.0
2032	3.70	4.17	3.94	3.80	3.93	3.17	3.57	3.57	3.97	3.54	3.1
2033	3.70	4.26	4.01	3.88	4.02	3.17	3.64	3.64	4.06	3.62	3.1
2034	3.70	4.34	4.10	3.95	4.10	3.17	3.72	3.72	4.14	3.69	3.2
2035	3.70	4.43	4.17	4.03	4.18	3.17	3.79	3.79	4.23	3.77	3.3
2036	3.70	4.52	4.26	4.11	4.27	3.17	3.87	3.87	4.32	3.84	3.3
2037	3.70	4.61	4.34	4.20	4.35	3.17	3.95	3.95	4.40	3.92	3.4
2038	3.70	4.70	4.43	4.28	4.44	3.17	4.02	4.02	4.49	4.00	3.5
2039	3.70	4.79	4.52	4.36	4.53	3.17	4.11	4.11	4.58	4.08	3.6
2040	3.70	4.89	4.61	4.45	4.62	3.17	4.19	4.19	4.67	4.16	3.6
2041+	3.70	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	3.17	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2

Notes:

(1) Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Reserve Report and Deloitte LLP in the Deloitte Reserve Report, were an equal weighted average of the December 31, 2025 price forecasts published by GLJ and McDaniel & Associates Consultants Ltd. as at January 1, 2026 and Sproule Associates Ltd. as at December 31, 2025 (each of which is available on their respective websites at www.gljpc.com, www.mcdan.com and www.sproule.com). GLJ assigns a value to the Company's existing physical diversification contracts for natural gas at consuming market regions including U.S. Gulf Coast, U.S. Midwest, U.S. West and Canadian East, and international markets based on forecasted differentials to NYMEX Henry Hub as per the aforementioned consultant average price forecast, contracted volumes and transportation costs. No incremental value is assigned to potential future contracts which were not in place as of December 31, 2025.

RESERVES PERFORMANCE RATIOS

The following tables highlight Tourmaline's reserves, F&D and FD&A costs as well as the associated recycle ratios.

Reserves, Capital Expenditures and Cash Flow(1)

As at, and for the Year ended December 31,	2025	2024	2023
Reserves (Mboe)			
Proved Producing	1,470,580	1,345,354	1,204,499
Total Proved	3,255,943	2,912,173	2,614,619
Proved Plus Probable	6,091,751	5,495,212	5,008,374
Capital Expenditures ($ millions)			
Exploration and Development(2)	2,989	2,226	2,023
Net Property Acquisitions (Dispositions)(3)	229	(325)	51
Corporate Acquisitions(3)	502	1,709	1,442
Total(4)	3,720	3,610	3,516
Cash Flow ($/boe)			
Cash Flow	14.58	15.18	19.52
Cash Flow - Three Year Average	16.26	20.20	21.58

Notes:

(1) Cash flow is defined as cash provided by operations adjusted for the change in non-cash operating working capital (deficit) and current income taxes. See "Non-GAAP and Other Financial Measures" below and in the Annual MD&A for further discussion.

(2) Includes capitalized G&A of $51 million, $45 million and $43 million for 2025, 2024 and 2023, respectively.

(3) Includes purchase price (cash and/or common shares) plus net debt, if applicable.

(4) Represents the capital expenditures used for purposes of F&D and FD&A calculations.

Finding and Development Costs

Finding and Development Costs, Excluding FDC	2025	2024	2023	3-Year Avg.
Total Proved				
Reserve Additions (MMboe)	387.8	232.8	209.3	
F&D Costs ($/boe)	7.71	9.56	9.66	8.72
F&D Recycle Ratio(1)	1.9	1.6	2.0	1.9
Total Proved Plus Probable				
Reserve Additions (MMboe)	457.5	167.1	230.7	
F&D Costs ($/boe)	6.53	13.32	8.77	8.46
F&D Recycle Ratio(1)	2.2	1.1	2.2	1.9

Finding and Development Costs, Including FDC	2025	2024	2023	3-Year Avg.
Total Proved				
Change in FDC ($ millions)	1,669.4	(161.5)	231.8	
Reserve Additions (MMboe)	387.8	232.8	209.3	
F&D Costs ($/boe)	12.01	8.87	10.77	10.82
F&D Recycle Ratio(1)	1.2	1.7	1.8	1.5
Total Proved Plus Probable				
Change in FDC ($ millions)	2,316.9	(422.0)	912.9	
Reserve Additions (MMboe)	457.5	167.1	230.7	
F&D Costs ($/boe)	11.60	10.79	12.72	11.74
F&D Recycle Ratio(1)	1.3	1.4	1.5	1.4

Finding, Development and Acquisition Costs

Finding, Development and Acquisition Costs, Excluding FDC	2025	2024	2023	3-Year Avg.
Total Proved				
Reserve Additions (MMboe)	576.7	509.5	482.6	
FD&A Costs ($/boe)	6.45	7.09	7.28	6.91
FD&A Recycle Ratio(1)	2.3	2.1	2.7	2.4
Total Proved Plus Probable				
Reserve Additions (MMboe)	829.5	698.8	698.0	
FD&A Costs ($/boe)	4.48	5.17	5.04	4.87
FD&A Recycle Ratio(1)	3.3	2.9	3.9	3.3

Finding, Development and Acquisition Costs, Including FDC	2025	2024	2023	3-Year Avg.
Total Proved				
Change in FDC ($ millions)	2,597.7	1,201.6	1,654.1	
Reserve Additions (MMboe)	576.7	509.5	482.6	
FD&A Costs ($/boe)	10.95	9.44	10.71	10.39
FD&A Recycle Ratio(1)	1.3	1.6	1.8	1.6
Total Proved Plus Probable				
Change in FDC ($ millions)	3,820.9	1,473.8	3,326.1	
Reserve Additions (MMboe)	829.5	698.8	698.0	
FD&A Costs ($/boe)	9.09	7.28	9.80	8.74
FD&A Recycle Ratio(1)	1.6	2.1	2.0	1.9

Note:

(1) The recycle ratio is calculated by dividing the cash flow per boe by the appropriate F&D or FD&A costs related to the reserve additions for that year.

Conference Call Tomorrow at 9:00 a.m. MT (11:00 a.m. ET)

Tourmaline will host a conference call tomorrow, March 5, 2026 starting at 9:00 a.m. MT (11:00 a.m. ET).

To participate without operator assistance, you may register and enter your phone number at https://emportal.ink/4c60ro6 to receive an instant automated call back.

To participate using an operator, please dial 1-888-510-2154 (toll-free in North America), or 1-437-900-0527 (international dial-in), a few minutes prior to the conference call.

REPLAY DETAILS

If you are unable to dial into the live conference call on March 5, 2026, a replay will be available by dialing

1-888-660-6345 (international 1-289-819-1450), referencing Replay Code 13689. The recording will expire on March 19, 2026.

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 including estimated average production levels for Q1 2026 and full-year 2026; the reduction in estimated average ethane production levels and estimated increased 2026 and 2027 operating netbacks following the termination of the Company's use of discretionary deep cut gas processing; the use of proceeds from the sale of the Company's PRH Complex and the reduction in operating costs resulting from such sale; the Company's long-term net debt target; the anticipated 2026 full year EP capital program and the reduction thereto, including the impact on production guidance resulting from such reduction; anticipated commodity price improvement; the 2026 EP capital program; 2026 CF and FCF; the expected CF and FCF increases resulting from a U.S. $0.10/mcf tightening of the AECO basis; the expected CF and FCF increases resulting from a U.S. $1.00/mcf increase in both TTF and JKM pricing; production levels, CF, FCF and other information included in the Company's EP Plan; average production volumes exposed to international pricing in 2026 (JKM/TTF); expected interest cost reductions resulting from lower debt levels and the Company's commercial paper program; anticipated capital cost reductions resulting from the vertical integration of the Company's sand business; the anticipated growth, margin expansion and improvement in all operating metrics associated with the NEBC Montney infrastructure and development project; expected total cost reductions that the Company expects to realize by 2031 as a result of operating cost reductions and sand-related capital savings, and the flow through to lower corporate break evens and FCF margin improvement; the number of wells that the Company plans to drill and complete in 2026; the expectation that the EP capital budget reduction will not impact the original start up timing of the Aitken and Groundbirch/Monias gas plant projects in NEBC; the future declaration and payment of base and special dividends and the timing, cadence and amount thereof; the expansion of Tourmaline's market diversification portfolio; the timing and scale of future growth and developments projects, including the NEBC infrastructure build out; projected operating and drilling costs and drilling times; anticipated future commodity prices; the number of new compressed natural gas fueling stations that are planned for 2026; the expectation that sustained stronger pricing and the Company's ongoing margin improvement activities will lead to further base dividend increases in the future and that special dividends will be used in those periods of extremely strong pricing to return the majority of the incremental FCF to shareholders; as well as Tourmaline's future drilling locations, 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 and interest rates; applicable royalty rates and tax laws; future well production rates and reserve volumes; operating costs, the timing of receipt of regulatory approvals; the performance of existing and future 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 and the benefits to be derived therefrom; the state of the economy and the exploration and production business; the availability and cost of financing, labour and services; ability to maintain its investment grade credit rating; 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 is dependent upon, among other things, FCF, 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 is 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 information, 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; supply chain disruptions; 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; changes in rates of inflation; 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; 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; uncertainties associated with counterparty credit risk; failure to obtain required regulatory and other approvals including drilling permits and the impact of not receiving such approvals on the Company's long-term planning; climate change risks; severe weather (including wildfires, floods and drought); risks of wars or other hostilities or geopolitical events, civil insurrection and pandemics; risks relating to Indigenous land claims and duty to consult; data breaches and cyber attacks; risks relating to the use of artificial intelligence; changes in legislation, including but not limited to tax laws, royalties and environmental regulations (including greenhouse gas emission reduction requirements and other decarbonization or social policies and including uncertainty with respect to the interpretation and impact of omnibus Bill C-59 and the related amendments to the Competition Act (Canada)); trade policy, barriers, disputes or wars (including new tariffs or changes to existing international trade arrangements); and general economic and business conditions and markets. 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.sedarplus.ca) 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 Ltd. ("GLJ") and Deloitte LLP, each dated effective December 31, 2025, 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 price forecast used in the reserve evaluations is an average of forecast prices published by Sproule Associates Ltd. as at December 31, 2025 and GLJ and McDaniel & Associates Consultants Ltd. as at January 1, 2026 (each of which is available on their respective websites at www.sproule.com, www.gljpc.com, and www.mcdan.com), and will be contained in the Company's Annual Information Form for the year ended December 31, 2025, which will be filed on SEDAR+ (accessible at www.sedarplus.ca) on or before March 31, 2026.

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.

The reserve data provided in this news release presents only a portion of the disclosure required under National Instrument 51-101. All of the required information will be contained in the Company's Annual Information Form for the year ended December 31, 2025, which will be filed on (SEDAR+ accessible at www.sedarplus.ca) on or before March 31, 2026.

BOE Equivalency

In this news release, production and reserves information may be presented on a "barrel of oil equivalent" or "BOE" basis. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, as the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

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. These metrics are "F&D" costs, "FD&A" costs, "recycle ratio", "F&D recycle ratio", and "FD&A recycle ratio". These metrics are considered "non-GAAP ratios" and 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. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A. The non-GAAP financial measures used as a component of these non-GAAP ratios are capital expenditures and cash flow.

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.

"F&D" costs are calculated by dividing the sum of the total capital expenditures for the year (in dollars) by the change in reserves within the applicable reserves category (in boe). F&D costs, including FDC, includes all capital expenditures in the year as well as the change in FDC required to bring the reserves within the specified reserves category on production.

"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 "recycle ratio" is calculated by dividing the cash flow per boe by the appropriate F&D or FD&A costs related to the reserve additions for that year.

The Company uses F&D and 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.

FINANCIAL OUTLOOKS

Also included in this news release are estimates of Tourmaline's 2026 CF and FCF and long-term net debt, which are based on, among other things, the various assumptions as to production levels, receipt of drilling permits, capital expenditures and other assumptions disclosed in this news release and, with respect to 2026 CF and FCF and long-term net debt, Tourmaline's estimated average production of 620,000 - 640,000 boepd, commodity price assumptions for natural gas ($3.85/mmbtu US, $1.88/mcf AECO, $2.49/mmbtu PG&E Citygate U.S., $13.00/mcf JKM U.S.), crude oil ($66.77/bbl WTI U.S.) and an exchange rate assumption (USD/CAD) of $0.74. In addition, such estimates are provided for illustration only and are based on budgets and forecasts as of the date hereof that are subject to change and a variety of contingencies including prior years' results. To the extent such estimates constitute a financial outlook, they are included to provide readers with an understanding of Tourmaline's anticipated CF and FCF and long-term net levels based on the capital expenditure, production, pricing, exchange rate and other assumptions described herein and readers are cautioned that the information may not be appropriate for other purposes.

NON-GAAP AND OTHER FINANCIAL MEASURES

This news release contains the terms "cash flow", "capital expenditures", "EP expenditures", "free cash flow", and "operating netback", which are considered "non-GAAP financial measures" and the terms "cash flow per diluted share", "free cash flow per diluted share", "operating netback per boe", and "cash flow per-boe", which are considered "non-GAAP financial ratios". These terms do not have a standardized meaning prescribed by GAAP. In addition, this news release contains the terms "adjusted working capital" and "net debt", which are considered "capital management measures" and do not have standardized meanings prescribed by GAAP. Accordingly, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. Investors are cautioned that these measures should not be construed as an alternative to or more meaningful than the most directly comparable GAAP measures in evaluating the Company's performance. See "Non-GAAP and Other Financial Measures" in the most recent Management's Discussion and Analysis for more information on the definition and description of these terms.

Non-GAAP Financial Measures
Cash Flow

Management uses the term "cash flow" for its own performance measure and to provide shareholders and potential investors with a measurement of the Company's efficiency and its ability to generate the cash (net of current income taxes) necessary to fund its future growth expenditures, to repay debt or to pay dividends. The most directly comparable GAAP measure for cash flow is cash flow from operating activities. A summary of the reconciliation of cash flow from operating activities to cash flow is set forth below:

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	2025	2024	2025	2024
Cash flow from operating activities (per GAAP)	$700,112	$666,110	$3,387,019	$2,729,780
Current income taxes[1]	(11,039)	(36,665)	(33,228)	(65,173)
Current income taxes paid (recovered)	3,246	(34)	31,382	526,768
Change in non-cash working capital (deficit)	197,798	220,919	10,397	27,116
Cash flow	$ 890,117	$850,330	$ 3,395,570	$ 3,218,491

(1) For the purposes of this reconciliation, current income taxes exclude $11.3 million of income taxes related to the capital gain on the sale of Topaz shares during the three and twelve months ended December 31, 2025 (three and twelve months ended December 31, 2024 - $19.0M). Refer to Notes 11 and 14 of the Company's consolidated financial statements as at and for the year ended December 31, 2025 for further details.

Capital Expenditures

Management uses the term "capital expenditures" as a measure of capital investment in exploration and production activity, as well as property acquisitions and divestitures. The most directly comparable GAAP measure for capital expenditures is cash flow used in investing activities. A summary of the reconciliation of cash flow used in investing activities to capital expenditures is set forth below:

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	2025	2024	2025	2024
Cash flow used in investing activities (per GAAP)	$ 523,856	$ 123,552	$2,733,529	$ 1,638,627
Corporate acquisitions	-	(169,040)	-	(169,040)
Change in non-cash working capital	82,904	174,216	(10,675)	100,409
Investment in long-term asset	-	-	(11,800)	-
Proceeds from sale of investments	221,226	331,465	221,226	331,465
Capital expenditures	$ 827,986	$ 460,193	$2,932,280	$ 1,901,461

EP Expenditures

Management uses the term "EP expenditures" or exploration and production expenditures as a measure of capital investment in exploration and production activity, and such spending is compared to the Company's annual budgeted exploration and production expenditures. The most directly comparable GAAP measure for exploration and production spending is cash flow used in investing activities. A summary of the reconciliation of cash flow used in investing activities to exploration and production expenditures is set forth below:

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	2025	2024	2025	2024
Cash flow used in investing activities (per GAAP)	$ 523,856	$123,552	$2,733,529	$ 1,638,627
Change in non-cash working capital	82,904	174,216	(10,675)	100,409
Proceeds from sale of investments	221,226	331,465	221,226	331,465
Corporate acquisitions	-	(169,040)	-	(169,040)
Investment in long-term asset	-	-	(11,800)	-
Property acquisitions	(2,024)	(7,379)	(19,307)	(33,083)
Proceeds from divestitures	801	300,858	75,622	357,692
Other	(14,028)	(10,256)	(62,883)	(52,607)
Exploration and production expenditures	$ 812,735	$ 743,416	$2,925,712	$ 2,173,463

Free Cash Flow

Management uses the term "free cash flow" for its own performance measure 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 its future growth expenditures, to repay debt and provide shareholder returns. Free cash flow is defined as cash flow less capital expenditures, excluding acquisitions and dispositions. Free cash flow is prior to dividend payment. The most directly comparable GAAP measure for cash flow is cash flow from operating activities. See "Non-GAAP Financial Measures - Cash Flow" and " Non-GAAP Financial Measures - Capital Expenditures" above.

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	2025	2024	2025	2024
Cash flow	$ 890,117	$850,330	$3,395,570	$ 3,218,491
Capital expenditures	(827,986)	(460,193)	(2,932,280)	(1,901,461)
Property acquisitions	2,024	7,379	19,307	33,083
Proceeds from divestitures	(801)	(300,858)	(75,622)	(357,692)
Free Cash Flow	$63,354	$ 96,658	$ 406,975	$992,421

Operating Netback

Management uses the term "operating netback" as a key performance indicator and one that is commonly presented by other oil and natural gas producers. Operating netback is defined as the sum of commodity sales from production, premium on risk management activities and realized gain on financial instruments less the sum of royalties, transportation costs and operating expenses. A summary of the reconciliation of operating netback from commodity sales from production, which is a GAAP measure, is set forth below:

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	2025	2024	2025	2024
Commodity sales from production	$ 1,423,017	$1,215,050	$4,940,024	$4,729,771
Premium on risk management activities	202,830	280,791	1,230,294	828,468
Realized gain on financial instruments	88,813	127,978	420,981	486,534
Royalties	(135,121)	(125,699)	(513,879)	(509,252)
Transportation costs	(306,801)	(276,602)	(1,198,061)	(1,082,592)
Operating expenses	(282,530)	(251,594)	(1,148,182)	(1,006,541)
Operating netback	$ 990,208	$969,924	$3,731,177	$3,446,388

Non-GAAP Financial Ratios

Operating Netback per-boe

Management calculates "operating netback per-boe" as operating netback divided by total production for the period. Operating netback per-boe is a key performance indicator and measure of operational efficiency and one that is commonly presented by other oil and natural gas producers. A summary of the calculation of operating netback per boe is set forth below:

	Three Months Ended December 31,		Years Ended December 31,	
($/boe)	2025	2024	2025	2024
Revenue, excluding processing income	$ 28.27	$ 29.15	$ 28.30	$ 28.52
Royalties	(2.23)	(2.26)	(2.21)	(2.40)
Transportation costs	(5.06)	(4.97)	(5.14)	(5.11)
Operating expenses	(4.66)	(4.52)	(4.93)	(4.75)
Operating netback	$ 16.32	$ 17.40	$ 16.02	$ 16.26

Cash Flow per-boe

Management uses cash flow per boe to highlight how much cash flow is generated by each boe produced. The ratio is calculated by dividing cash flow by total production for the period. See "Non-GAAP Financial Measures - Cash Flow". See "Reserves Performance Ratios" section for information on annual cash flow per boe and comparative period data used.

Finding and Development Costs, Finding, Development and Acquisition Costs and Recycle Ratio

See "Reserves Performance Ratios" and "Industry Metrics" for information on the composition of the non-GAAP financial measures used as a component of and comparative period data for finding and development costs, finding, development and acquisition costs and recycle ratio.

Capital Management Measures

Adjusted Working Capital

Management uses the term "adjusted working capital" for its own performance measures and to provide shareholders and potential investors with a measurement of the Company's liquidity. A summary of the reconciliation of working capital (deficit) to adjusted working capital (deficit), is set forth below:

	As at December 31,	
(000s)	2025	2024
Working capital (deficit)	$ (419,306)	$ (167,623)
Fair value of financial instruments - short-term (asset)	(135,676)	(315,365)
Lease liabilities - short-term	8,034	8,385
Decommissioning obligations - short-term	75,000	60,000
Unrealized foreign exchange in working capital - (asset) liability	991	(15,354)
Adjusted working capital (deficit)	$ (470,957)	$(429,957)

Net Debt

Management uses the term "net debt", as a key measure for evaluating its capital structure and to provide shareholders and potential investors with a measurement of the Company's total indebtedness. A summary of the composition of net debt, is set forth below:

	As at December 31,	
(000s)	2025	2024
Long-term debt	$ (1,052,914)	$ (1,272,775)
Adjusted working capital (deficit)	(470,957)	(429,957)
Net debt	$ (1,523,871)	$ (1,702,732)

Supplementary Financial Measures

The following measures are supplementary financial measures: cash flow per diluted share, reserve value per diluted share, operating expenses ($/boe), cash general and administrative expenses ($/boe) and transportation costs ($/boe). These measures are calculated by dividing the numerator by a diluted share count or by total production for the period, depending on the financial measure discussed.

ESTIMATED DRILLING INVENTORY

This news release discloses drilling locations. Drilling locations are categorized as follows: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii). Of the 26,512 (gross) locations disclosed in this news release, 2,316 are proved undeveloped locations (including drilled-uncompleted locations ("DUCs")), 1,757 are probable undeveloped locations, and 22,439 are unbooked. Proved producing wells, proved undeveloped locations, including DUCs, and probable undeveloped 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, 2025, 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.

SUPPLEMENTAL INFORMATION REGARDING PRODUCT TYPES

This news release includes references to full-year 2025 average daily production, Q4 2025 average daily production, January 2026 average daily production, Q1 2026 expected average daily production and full-year 2026 expected average daily production. The following table is intended to provide supplemental information about the product type composition for each of the production figures that are provided in this news release:

	Light and Medium Crude Oil[1]	Conventional Natural Gas	Shale Natural Gas	Natural Gas Liquids[1]	Oil E Total
	Company Gross (Bbls)	Company Gross (Mcf)	Company Gross (Mcf)	Company Gross (Bbls)	Com (Boe
2025 Average Daily Production	53,122	1,562,414	1,384,033	93,999	638,
Q4 2025 Average Daily Production	56,295	1,591,495	1,447,690	96,378	659,
January 2026 Average Daily Production	55,500	1,660,000	1,520,000	99,500	685,
Q1 2026 Expected Average Daily Production	51,465	1,563,795	1,551,165	94,375	665,
2026 Expected Average Daily Production	48,450	1,515,125	1,500,385	78,965	630,

(1) For the purposes of this disclosure, condensate has been combined with Light and Medium Crude Oil as the associated revenues and certain costs of condensate are similar to Light and Medium Crude Oil. Accordingly, NGLs in this disclosure exclude condensate.

GENERAL

See also "Forward-Looking Statements" and "Non-GAAP and Other Financial Measures" in the most recently filed Management's Discussion and Analysis.

Certain Definitions:

1H	first half
2H	second half
AECO	Alberta Energy Company and is the Canadian benchmark price for natural gas
AECO basis	the price differential between AECO and NYMEX Henry Hub
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
C2+	a hydrocarbon mixture consisting of ethane and heavier hydrocarbons.
CNG	compressed natural gas
DUC	drilled but uncompleted wells
Dutch TTF or TTF	a natural gas pricing location within the Netherlands
EP	

exploration and production

FERC	Federal Energy Regulatory Commission
gj	gigajoule
gjs/d	gigajoules per day
JKM	Japan Korea Marker
LPG	Liquefied Petroleum Gas
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrels of oil equivalent
mboepd	thousand barrels of oil equivalent per day
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
mstb	thousand stock tank barrels
natural gas	conventional natural gas and shale gas
NEBC	Northeast British Columbia
NGL or NGLs	natural gas liquids
NYMEX Henry Hub	the benchmark pricing point for U.S. natural gas futures contracts traded on the New York Mercant Exchange
PGE	Pacific Gas & Electric
PRH	Peace River High
Tcf	trillion cubic feet

MANAGEMENT'S DISCUSSION AND ANALYSIS AND CONSOLIDATED FINANCIAL STATEMENTS

To view Tourmaline's Management's Discussion and Analysis and Consolidated Financial Statements for the periods ended December 31, 2025 and 2024, please refer to SEDAR+ (www.sedarplus.ca) or Tourmaline's website at www.tourmalineoil.com.

ABOUT TOURMALINE OIL CORP.

Tourmaline is Canada's largest and most active natural gas producer dedicated to producing the lowest-development-cost natural gas in North America. We are an investment grade exploration and production company providing strong and predictable operating and financial performance through the development of our two core areas in the Western Canadian Sedimentary Basin. With our existing large reserve base, decades-long drilling inventory, relentless focus on execution, cost management, safety and environmental performance improvement, we are excited to provide shareholders an excellent return on capital and an attractive source of income through our base dividend and surplus free cash flow distribution strategies.

SOURCE Tourmaline Oil Corp.

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