Gran Tierra Energy Inc. Reports Second Quarter 2026 Results

- ***Achieved Total Company Average Second Quarter Production of 41,501 BOEPD[1]***
- ***Net Income of $25 Million, Adjusted EBITDA[2] of $85 Million and Positive Free Cash Flow***
- ***Announcement of Prospective and Contingent Resource Report on Dawson Clearwater and Mount Head Areas in Canada***
- ***Completed Suroriente Capital Carry Improving Profitability of the Block***
- ***Announcement of the Disposition of Lodgepole Assets for C$12.8 Million***
- ***Satisfied the Conditions Precedent for Tisquirama Contract Providing Further Growth Potential in Colombia***

CALGARY, ALBERTA, August 4, 2026, Gran Tierra Energy Inc. ("Gran Tierra" or the "Company") (NYSE American:GTE) (TSX:GTE) (LSE:GTE) announced the Company's financial and operating results for the quarter ended June 30, 2026 (the **"Quarter"**). All dollar amounts are in United States (**"U.S."**) dollars and all reserves and production volumes are on an average working interest (**"WI"**) before royalties basis unless otherwise indicated. Production is expressed in barrels (**"bbl"**) of oil equivalent (**"boe"**) per day (**"boepd"** or **"boe/d"**) and are based on WI sales before royalties. For per boe amounts based on net after royalty (**"NAR"**) production, see Gran Tierra's Quarterly Report on Form 10-Q filed August 4, 2026.

Message to Shareholders

Gary Guidry, President and Chief Executive Officer of Gran Tierra, commented: "Our second quarter results benefited from a stronger commodity price environment, reduced total operating costs and the continued strength of our portfolio, with production within our guidance range and improved margins and cash generation across the business. During the Quarter, we advanced several priorities that make our portfolio more durable. We completed our capital carry at Suroriente, improving the profitability on the block and satisfied the conditions precedent for the Tisquirama contract, adding another growth opportunity in Colombia. In Ecuador, we received additional field development plan approvals and are transitioning from exploration into development. In Canada, we continued to optimize the portfolio with the sale of our Lodgepole assets and sharpened our focus on the resource potential in the Dawson Clearwater and Mount Head areas. The resource report disclosed in this release speaks to the scale of that opportunity, and Dawson Clearwater and Mount Head will be a focus of our drilling activity in 2027. Looking ahead, our priorities remain unchanged. We will allocate capital with discipline, operate our fields safely and reliably, and continue to strengthen our balance sheet, generate free cash flow and build long-term value for our shareholders."

Dawson Clearwater and Mount Head Resource Report:

- McDaniel, effective June 30, 2026, assigned Gran Tierra unrisked best estimate contingent resources (2C) of approximately 6.5 MMbbl at Dawson Clearwater, and unrisked best-estimate prospective resources (P50) of approximately 55 MMbbl at Dawson Clearwater and 12 MMbbl at Mount Head. Combined, this represents approximately 67 MMbbl of unrisked best-estimate prospective resources. On a mean basis, unrisked prospective resources are approximately 72 MMbbl and risked mean prospective resources are approximately 33 MMbbl.
- Gran Tierra operates both plays and holds a 100% working interest at Dawson Clearwater and Mount Head.

- The Company holds approximately 139 net sections in the Clearwater area and 30 net sections at Mount Head, roughly 108,000 net acres in total. McDaniel's Clearwater estimates cover only the 41 net sections at Dawson and Seal. The remaining Clearwater acreage carries no assigned resources at this time.
- Shallow depths and horizontal multilateral drilling give the Clearwater low drilling and completion costs relative to other Western Canadian oil plays.
- Mount Head targets 37 to 41 degree API light oil, diversifying Gran Tierra's production mix and realized pricing beyond its South American crude.
- Both plays are suited to waterflood, allowing Gran Tierra to apply the secondary recovery expertise developed across its Colombian fields.

Key Highlights of the Quarter:

- **Production:** Gran Tierra's total average WI production was 41,501 boepd, which was 9% lower than first quarter of 2026 (the **"Prior Quarter"**) and 12% lower than the second quarter of 2025. The decrease in production when compared to the second quarter of 2025 is attributable to lower production in Colombia and the sale of Simonette and Lodgepole assets in Canada, partially offset by higher than anticipated production results from Conejo-1 well and additional production from the Perico Block in Ecuador acquired in December 2025. The decrease in production when compared to the Prior Quarter is primarily attributable to the sale of Simonette and Lodgepole assets and lower production levels in the Acordionero and Cohembi fields resulting from the temporary unplanned failure of artificial lift systems which have been rectified.
- **Net Income:** Gran Tierra generated net income of $25 million or $0.70 per share[3], basic and diluted, compared to a net loss of $119 million in the Prior Quarter and a net loss of $13 million or $0.36 per share[3] basic and diluted in the second quarter of 2025.
- **Gross Profit[4]**: The Company's gross profit[4] was approximately $75 million for the Quarter, which was up from approximately $37 million for the Prior Quarter and up from $23 million in the second quarter of 2025. On a per boe basis, our gross profit[4] for the Quarter was $19.90, up from $8.49 in the Prior Quarter and up from $5.60 in the second quarter of 2025.
- **Operating Netback[2]:** The Company's operating netback[2] was $34.73 per boe, up 49% from the Prior Quarter and up 62% from the second quarter of 2025, primarily as a result of higher oil prices recognized during the Quarter.
- **Adjusted EBITDA[2]:** Adjusted EBITDA[2] was $85 million compared to $74 million in the Prior Quarter and $77 million in the second quarter of 2025. Twelve-month trailing net debt(2)(5) to Adjusted EBITDA[2] was 1.7 times and the Company continues to have a long-term target ratio of 1.0 times.
- **Net Cash Provided by Operating Activities:** Net Cash Provided by Operating Activities was $57 million ($1.62 per share[3]), down 67% from the Prior Quarter and up 66% from the second quarter of 2025.
- **Funds Flow from Operations[2]:** Funds flow from operations[2] was $60 million ($1.70 per share[3]), up 41% from the Prior Quarter and up 12% from the second quarter of 2025.
- **Cash and Debt:** As of June 30, 2026, the Company had a cash balance of $127 million, total gross debt of $606 million and net debt(2)(5) of $479 million. During the six months ended June 30, 2026, Gran Tierra repurchased $9.2 million in face value of the Company's 9.75% Senior Notes due April 15, 2031 at a discount of 12% to the face value of the repurchased

bonds. Subsequent to the Quarter, the Company repurchased an additional $15.0 million of 9.75% Senior Notes due April 15, 2031 at a discount of 10% to the face value of the repurchased bonds.

- **Liquidity:** In addition to the $127 million cash on hand as of June 30, 2026, the Company currently has approximately $53 million in undrawn availability from its credit and lending facilities.
- **Hedging**: The Company hedges a portion of production to protect a base level of cash flow while keeping upside to higher prices. For the second half of 2026, oil hedged is roughly 16,000 barrels per day (**"bbl/d"**), about 52% of oil production, with floors near US$60 per bbl. During the Quarter, the Company bought back the ceilings on 5,000 bbl/d of its three-way collars, and more than 66% of total oil production remains uncapped and fully exposed to stronger prices. On gas, approximately 20,000 gigajoules (**"GJ"**) per day are fixed at C$2.71 per GJ through September 2026, and approximately 6,700 GJ per day are fixed at the same price for the fourth quarter of 2026. Both are above the Q2 2026 AECO average of C$1.55 per GJ.

Operational Update:

- **Colombia**
  - **Completion of Suroriente Carry:** During the Quarter, Gran Tierra completed its $123.0 million capital carry commitment under the Suroriente joint venture with Ecopetrol S.A. (the **"Suroriente Carry"**). The post-Suroriente Carry period commenced on July 18, 2026, improving the economics and the overall profitability of the block.
  - **Cohembi Drilling Program Completed:** Gran Tierra completed the six-well development drilling program at the Cohembi field in the Putumayo Basin, with the final two wells drilled and brought on production during the Quarter. The program fulfilled the Company's drilling commitment under the Suroriente Carry and was delivered under budget.
- **Ecuador**
  - **Field Development Plan ("FDP") Approvals:** Gran Tierra received government approval of three additional field development plans in June 2026 for Charapa, Conejo and Perico fields, bringing total approvals to five of the Company's six fields. With these approvals, Ecuador operations are transitioning from exploration to development. The Company was able to retain all acreage on the approved blocks and currently has ~156,000 acres of land for 20 years with an additional ~16,000 acres from Espejo currently pending FDP approval. Ecuador production averaged 7,993 bopd in the Quarter, supported by strong performance from Conejo discoveries and an earlier than expected response to water injection at Chanangue.

Sale of Lodgepole Assets

- On June 23, 2026, the Company completed a disposition of 54% WI and associated title rights in the Lodgepole area effective January 1, 2026, for a total cash consideration of C$12.8 million (US$9.3 million). In addition to the cash, the Company derecognized asset retirement obligations attributed to the Lodgepole area totaling C$17.5 million (US$12.8 million) on an undiscounted basis and C$9.0 million (US$6.6 million) on a discounted basis. No gain or loss was recognized in the statement of operations as the disposal did not materially change the relationship between capital costs and the proved reserves of oil and natural gas assets.

Clearwater Asset Exchange

- During the Quarter, we completed an asset exchange transaction in which we transferred a 30% working interest ("WI") in certain oil and natural gas rights, wells, and tangible assets located in the Marten Hills area, in exchange for oil and natural gas rights, wells, and tangible assets in the Seal/Dawson area, WI ranging from 35% to 100%. In connection with this transaction, we received cash consideration of C$0.8 million (US$0.6 million).

Completion of Conditions Precedent for Tisquirama Contract

- During the Quarter, Gran Tierra satisfied all outstanding conditions precedent to the effectiveness of the contract previously announced on March 17, 2026, with Ecopetrol S.A., by which Gran Tierra will earn a 49% WI in the Tisquirama block in the Middle Magdalena Valley Basin of Colombia, which contains the Tisquirama and San Roque fields.

Additional Key Financial Metrics:

- **Capital Expenditures:** Capital expenditures of $54 million were higher than the $45 million in the Prior Quarter and higher than the $51 million in the second quarter of 2025. During the Quarter, the Company completed the Suroriente Carry and the six-well development drilling program at the Cohembi field in the Putumayo Basin, with the final two wells drilled and brought on production during the Quarter. The Company's 2026 capital program was planned to be weighted to the first half of the year and we expect capital expenditures to be within the previously stated guidance.
- **Oil, Natural Gas, and Natural Gas Liquids ("NGL") Sales:** Gran Tierra generated sales of $187 million, up 25% from the second quarter of 2025 due to a 45% increase in Brent price, partially offset by a 16% decrease in sales volumes and higher quality and transportation discounts in Colombia associated with the use of alternative transportation routes for Putumayo production, as the Colombia and Ecuador border remained closed. These discounts had an impact of approximately $5.9 million for the Quarter and $10 million year to date in 2026. Sales increased 9% from the Prior Quarter primarily due to a 23% increase in Brent price and lower quality and transportation discounts in Colombia, and higher premiums in Ecuador, partially offset by a 20% decrease in sales volumes, primarily attributable to only one lifting in Ecuador compared to two in the Prior Quarter, and a 90% increase in royalties per boe as a result of higher benchmark oil prices and the sliding scale royalty regime in Colombia, Ecuador, and Canada.
- **Free Cash Flow[2]:** During the Quarter, the Company generated free cash flow[2] of approximately $6.0 million, an increase when compared to free cash flow[2] of $2.7 million generated in the second quarter of 2025, primarily due to a higher realized price during the Quarter.
- **South American Quality and Transportation Discounts:** The Company's average quality and transportation discounts per bbl in South America during the Quarter increased to $10.31, comparable to $10.30 in the second quarter of 2025 and decreased compared to $14.85 in the Prior Quarter. The decrease from the Prior Quarter was primarily due to a decrease in Vasconia and Oriente differentials and lower transportation discounts.
    - The Castilla oil differential per bbl was $9.71, up from $9.67 in the Prior Quarter and up from $4.73 in the second quarter of 2025 (Castilla is the benchmark for the Company's Middle Magdalena Valley Basin oil production). The Vasconia differential per bbl was $1.42, down from $5.91 in the Prior Quarter and down from $1.71 in the second quarter of 2025. The Ecuadorian benchmark, Oriente, per bbl was $2.01, down from $8.17 in the Prior Quarter and down from $7.26 in the second quarter of 2025.
    - During the Quarter, the Company had one lifting in Ecuador compared to two in the Prior Quarter. The Company sales price is the average Brent price less discounts for the month prior to lifting (M-1). The impact of the M-1

pricing of $101.89 per bbl increased revenue by approximately $4 million when compared to the average Brent price for the Quarter of $96.68 per bbl.

- **Operating Expenses:** On a per boe basis, operating expenses increased by 2% when compared to the second quarter of 2025 primarily due to lower sales volume, partially offset by a decrease in total operating expenses. Total operating expenses decreased by 22% to $52 million compared to the Prior Quarter and decreased by 7% compared to the second quarter of 2025 primarily due to lower workover activities, reduced field personnel costs, lower oil treatment and testing service costs, and inventory fluctuations resulting from inventory accumulation at the end of the Quarter.
- **Transportation Expenses:** The Company's transportation expenses decreased by 26% to $3.9 million, compared to transportation expenses of $5.3 million in the Prior Quarter, and decreased by 13% compared to transportation expenses of $4.5 million in the second quarter of 2025. Transportation expenses decreased when compared to the Prior Quarter and the second quarter of 2025 primarily due to lower sales volumes transported in Colombia and Canada and having one lifting completed in Ecuador compared to two in the Prior Quarter.
- **General and Administrative ("G&A") Expenses:** G&A expenses before stock-based compensation were $3.49 per boe, a slight decrease from $3.51 per boe in the Prior Quarter primarily due to lower consulting costs, lower information technology costs, and lower salaries associated with headcount optimization. G&A expenses before stock-based compensation during the Quarter increased from $3.40 per boe in the second quarter of 2025 primarily due to lower sales volumes.
- **Cash Netback[2]**: Cash netback[2] per boe increased to $15.90 during the Quarter, a 60% increase from the Prior Quarter and a 23% increase from the second quarter of 2025, primarily due to a higher operating netback[2] as a result of a higher realized price during the Quarter.

Financial and Operational Highlights (all amounts in $000s, except per share and boe amounts)

Consolidated Information	Three Months Ended June 30,		Three Months Ended March 31,	Six Months Ended June 30,	
	2026	2025	2026	2026	2025
Net Income (Loss)	**$24,861**	$(12,741)	$(119,172)	**$(94,311)**	$(32,021)
Per Share - Basic[3]	**$0.70**	$(0.36)	$(3.38)	**$(2.67)**	$(0.90)
Per Share - Diluted[3]	**$0.70**	$(0.36)	$(3.38)	**$(2.67)**	$(0.90)
Gross Profit[4]	**$75,460**	$23,313	$36,697	**$112,157**	$51,414
Depletion and Accretion[6]	**$56,253**	$65,948	$63,908	**$120,161**	$134,379
Operating Netback[2]	**$131,713**	$89,261	$100,605	**$232,318**	$185,793
Oil, Natural Gas and NGL Sales	**$187,181**	$149,357	$172,057	**$359,238**	$317,530
Operating Expenses	**(51,561)**	(55,602)	(66,149)	**(117,710)**	(122,692)
Transportation Expenses	**(3,907)**	(4,494)	(5,303)	**(9,210)**	(9,045)
Operating Netback[2]	**$131,713**	$89,261	$100,605	**$232,318**	$185,793

G&A Expenses Before Stock-Based Compensation	**$13,219**	$14,136	$15,149	**$28,368**	$26,062
G&A Stock-Based Compensation (Recovery) Expense	**(3,757)**	546	19,676	**15,919**	29
G&A Expenses, Including Stock Based Compensation	**$9,462**	$14,682	$34,825	**$44,287**	$26,091
EBITDA[2]	**$132,156**	$84,908	$(26,015)	**$106,141**	$164,618
Adjusted EBITDA[2]	**$85,071**	$76,987	$73,935	**$159,006**	$162,149
Net Cash Provided by Operating Activities	**$57,414**	$34,677	$172,734	**$230,148**	$107,907
Funds Flow from Operations[2]	**$60,289**	$53,906	$42,823	**$103,112**	$109,250
Capital Expenditures (Before Changes in Working Capital)	**$54,309**	$51,170	$45,359	**$99,668**	$145,897
Free Cash Flow[2]	**$5,980**	$2,736	$(2,536)	**$3,444**	$(36,647)
Average Daily Production (boe/d)					
WI Production Before Royalties	**41,501**	47,196	45,497	**43,488**	46,923
Royalties	**(9,511)**	(7,396)	(7,756)	**(8,638)**	(7,738)
Production NAR	**31,990**	39,800	37,741	**34,850**	39,185
Decrease (Increase) in Inventory	**176**	(1,469)	2,526	**1,345**	(509)
Sales	**32,166**	38,331	40,267	**36,195**	38,676
Royalties, % of WI Production Before Royalties	**23%**	16%	17%	**20%**	16%
Cash Netback ($/boe)(2)(7)					
Gross Profit(4)(7)	**$19.90**	$5.60	$8.49	**$13.82**	$6.12
Depletion and Accretion(6)(7)	**$14.83**	$15.85	$14.79	**$14.81**	$16.00
Operating Netback(2)(7)	**$34.73**	$21.45	$23.28	**$28.63**	$22.12
Average Realized Price before Royalties	**63.94**	42.82	47.48	**54.84**	45.36
Royalties	**(14.59)**	(6.93)	(7.67)	**(10.57)**	(7.56)
Average Realized Price	**49.35**	35.89	39.81	**44.27**	37.80
Transportation Expenses	**(1.03)**	(1.08)	(1.23)	**(1.13)**	(1.08)
Average Realized Price Net of Transportation Expenses	**48.32**	34.81	38.58	**43.14**	36.72
Operating Expenses	**(13.59)**	(13.36)	(15.31)	**(14.51)**	(14.60)
Operating Netback(2)(7)	**34.73**	21.45	23.28	**28.63**	22.12
Cash G&A Expenses	**(3.49)**	(3.40)	(3.51)	**(3.50)**	(3.10)
Other Taxes	**(0.37)**	(0.14)	(0.24)	**(0.30)**	(0.13)
Severance Expenses	**(0.03)**	—	(0.57)	**(0.32)**	—
Realized Foreign Exchange Gain (Loss)	**0.07**	(0.14)	(0.38)	**(0.17)**	(0.33)

Cash Settlement on Derivative Instruments	**(8.97)**	0.39	(2.56)	**(5.56)**	0.25
Interest Expense, Excluding Amortization of Debt Issuance Costs, Non-Cash Interest, and Senior Notes Exchange Fees	**(4.17)**	(4.87)	(4.90)	**(4.56)**	(4.72)
Interest Income	**0.13**	0.06	0.09	**0.11**	0.08
Other Cash Gain	**0.43**	0.09	0.10	**0.25**	0.04
Net Lease Payments	**(0.03)**	0.04	(0.05)	**(0.04)**	0.04
Current Income Tax Expense	**(2.40)**	(0.53)	(1.35)	**(1.84)**	(1.25)
Cash Netback[(2)(7)]	**$15.90**	$12.95	$9.91	**$12.70**	$12.99
Share Information (000s)					
Common Stock Outstanding, End of Period	**35,380**	35,289	35,346	**35,380**	35,289
Weighted Average Number of Shares of Common Stock Outstanding - Basic	**35,369**	35,335	35,300	**35,334**	35,555
Weighted Average Number of Shares of Common Stock Outstanding - Diluted	**35,369**	35,335	35,300	**35,334**	35,555

Colombia Information	**Three Months Ended June 30,**		**Three Months Ended March 31,**	**Six Months Ended June 30,**	
	2026	**2025**	**2026**	**2026**	**2025**
Operating Netback[2]					
Gross Profit[4]	**$44,585**	$19,880	$24,377	**$68,962**	$46,828
Depletion and Accretion[6]	**$38,072**	$47,897	$40,633	**$78,705**	$92,896
Operating Netback[2]	**$82,657**	$67,777	$65,010	**$147,667**	$139,724
Oil Sales	$118,136	$109,692	$102,324	**$220,460**	$227,340
Operating Expenses	**(33,152)**	(38,180)	(35,042)	**(68,194)**	(80,670)
Transportation Expenses	**(2,327)**	(3,735)	(2,272)	**(4,599)**	(6,946)
Operating Netback[2]	**$82,657**	$67,777	$65,010	**$147,667**	$139,724
Average Daily Production (boe/d)					
WI Production Before Royalties	**19,994**	25,108	21,319	**20,653**	25,378
Royalties	**(3,968)**	(3,845)	(3,230)	**(3,601)**	(4,131)
Production NAR	**16,026**	21,263	18,089	**17,052**	21,247
(Increase) Decrease in Inventory	**(57)**	110	799	**369**	(133)
Sales	**15,969**	21,373	18,888	**17,421**	21,114
Royalties, % of WI Production Before Royalties	**20%**	15%	15%	**17%**	16%
Operating Netback ($/boe)[(2)(7)]					
Gross Profit[(4)(7)]	**$24.57**	$8.66	$12.25	**$18.12**	$10.25
Depletion and Accretion[(6)(7)]	**$20.98**	$20.87	$20.41	**$20.69**	$20.33
Operating Netback[(2)(7)]	**$45.56**	$29.53	$32.66	**$38.81**	$30.58

Brent	$96.68	$66.71	$78.38	$87.60	$70.81
Quality and Transportation Discount	(15.39)	(10.31)	(18.19)	(17.68)	$(11.32)
Royalties	(16.18)	(8.60)	(8.79)	(11.98)	(9.73)
Average Realized Price	65.11	47.80	51.40	57.94	49.75
Transportation Expenses	(1.28)	(1.63)	(1.14)	(1.21)	(1.52)
Average Realized Price Net of Transportation Expenses	63.83	46.17	50.26	56.73	48.23
Operating Expenses	(18.27)	(16.64)	(17.60)	(17.92)	(17.65)
Operating Netback[(2)(7)]	$45.56	$29.53	$32.66	$38.81	$30.58

Ecuador Information	Three Months Ended June 30,		Three Months Ended March 31	Six Months Ended June 30,	
	2026	2025	2026	2026	2025
Operating Netback[2]					
Gross Profit[4]	$24,811	$(419)	$6,378	$31,189	$942
Depletion and Accretion[6]	$9,775	$4,351	$15,861	$25,636	$14,847
Operating Netback[2]	$34,586	$3,932	$22,239	$56,825	$15,789
Oil Sales	$41,964	$8,495	$40,745	$82,709	$29,518
Operating Expenses	(6,196)	(4,122)	(15,952)	(22,148)	(12,195)
Transportation Expenses	(1,182)	(441)	(2,554)	(3,736)	(1,534)
Operating Netback[2]	$34,586	$3,932	$22,239	$56,825	$15,789
Average Daily Production (boe/d)					
WI Production Before Royalties	7,993	4,592	8,759	8,373	4,315
Royalties	(3,788)	(1,364)	(2,584)	(3,189)	(1,394)
Production NAR	4,205	3,228	6,175	5,184	2,921
Decrease (Increase) in Inventory	233	(1,579)	1,727	976	(376)
Sales	4,438	1,649	7,902	6,160	2,545
Royalties, % of WI Production Before Royalties	47%	30%	30%	38%	32%
Operating Netback ($/boe)[(2)(7)]					
Gross Profit[(4)(7)]	$33.15	$(1.53)	$6.76	$18.43	$1.32
Depletion and Accretion[(6)(7)]	$13.06	$15.87	$16.81	$15.15	$20.83
Operating Netback[(2)(7)]	$46.20	$14.34	$23.57	$33.58	$22.15
Brent (M-1 Pricing)[8]	$101.89	$66.91	$65.12	$83.65	$71.36
Quality and Transportation Premium (Discount)	2.01	(10.27)	(7.82)	(9.47)	(7.26)
Royalties	(47.84)	(25.65)	(14.12)	(25.30)	(22.69)
Average Realized Price	56.06	30.99	43.18	48.88	41.41
Transportation Expenses	(1.58)	(1.61)	(2.71)	(2.21)	(2.15)

Average Realized Price Net of Transportation Expenses	**54.48**	29.38	40.47	**46.67**	39.26
Operating Expenses	**(8.28)**	(15.04)	(16.90)	**(13.09)**	(17.11)
Operating Netback[2][7]	**$46.20**	$14.34	$23.57	**$33.58**	$22.15

Canadian Information	**Three Months Ended June 30,**		**Three Months Ended March 31**	**Six Months Ended June 30,**	
	2026	**2025**	**2026**	**2026**	**2025**
Operating Netback[2]					
Gross Profit[4]	**$6,064**	$3,852	$5,942	**$12,006**	$3,644
Depletion and Accretion[6]	**$8,406**	$13,700	$7,414	**$15,820**	$26,636
Operating Netback[2]	**$14,470**	$17,552	$13,356	**$27,826**	$30,280
Oil Sales	**$24,196**	$22,275	$20,987	**$45,182**	$43,100
Natural Gas Sales	**3,673**	6,048	6,074	**9,747**	12,761
NGL Sales	**5,079**	5,005	5,040	**10,119**	11,935
Royalties	**(5,866)**	(2,158)	(3,113)	**(8,979)**	(7,124)
Oil, Natural Gas and NGL Sales After Royalties	**$27,081**	$31,170	$28,988	**$56,069**	$60,672
Operating Expenses	**(12,213)**	(13,300)	(15,155)	**(27,368)**	(29,827)
Transportation Expenses	**(398)**	(318)	(477)	**(875)**	(565)
Operating Netback[2]	**$14,470**	$17,552	$13,356	**$27,826**	$30,280
Average Daily Production					
Crude Oil (bbl/d)	**2,928**	4,335	3,674	**3,299**	3,981
Natural Gas (mcf/d)	**39,366**	50,124	43,398	**41,370**	49,992
NGLs (bbl/d)	**4,026**	4,807	4,512	**4,268**	4,917
WI Production Before Royalties (boe/d)	**13,514**	17,496	15,419	**14,462**	17,230
Royalties (boe/d)	**(1,755)**	(2,187)	(1,942)	**(1,848)**	(2,213)
Production NAR (boe/d)	**11,759**	15,309	13,477	**12,614**	15,017
Sales (boe/d)	**11,759**	15,309	13,477	**12,614**	15,017
Royalties, % of WI Production Before Royalties	**13%**	13%	13%	**13%**	13%
Benchmark Prices					
West Texas Intermediate ($/bbl)	**92.70**	63.81	72.73	**82.77**	67.60
AECO Natural Gas Price (C$/GJ)	**1.55**	1.60	1.91	**1.73**	1.82
Average Realized Price					
Crude Oil ($/bbl)	**90.81**	56.46	63.47	**75.67**	59.82
Natural Gas ($/mcf)	**1.03**	1.33	1.56	**1.30**	1.41
NGLs ($/bbl)	**13.86**	11.44	12.41	**13.10**	13.41

Operating Netback ($/boe)[2][7]					
Gross Profit[4][7]	**$4.93**	$2.42	$4.28	**$4.59**	$1.17
Depletion and Accretion[6][7]	**$6.84**	$8.61	$5.34	**$6.04**	$8.55
Operating Netback[2][7]	**$11.77**	$11.03	$9.62	**$10.63**	$9.72
Average Realized Price	**$26.79**	$20.93	$23.12	**$24.85**	$21.74
Royalties	**(4.77)**	(1.36)	(2.24)	**(3.43)**	(2.28)
Transportation Expenses	**(0.32)**	(0.20)	(0.34)	**(0.33)**	(0.18)
Operating Expenses	**(9.93)**	(8.35)	(10.92)	**(10.46)**	(9.56)
Operating Netback[2][7]	**$11.77**	$11.03	$9.62	**$10.63**	$9.72

[1] Gran Tierra's second quarter total company average quarterly production reflects the Lodgepole disposition as of June 23, 2026.

[2] Operating netback, earnings before interest, taxes and depletion, depreciation and accretion ("**DD&A**") ("**EBITDA**"), Adjusted EBITDA, funds flow from operations, net debt, free cash flow, and cash netback, are non-GAAP measures and do not have a standardized meaning under GAAP. Cash flow refers to the GAAP line item "net cash provided by operating activities". Refer to "Non-GAAP Measures" in this press release for descriptions of these non-GAAP measures and reconciliations to the most directly comparable measures calculated and presented in accordance with GAAP.

[3] Weighted average shares outstanding based on June 30, 2026 balance of 35,368,716 shares (basic and diluted) and June 30, 2025 balance of 35,334,692 shares (basic and diluted).

[4] Gross profit is calculated as oil, gas and NGL sales, less operating and transportation expenses, and depletion and accretion related to producing assets.

[5] Net Debt is based on $606 million outstanding of Senior Notes less $127 million of cash and cash equivalents as at June 30, 2026.

[6] Depletion and Accretion is calculated as DD&A expenses less depreciation of administrative assets.

[7] Per boe amounts are based on WI sales before royalties. For per boe amounts based on NAR production, see Gran Tierra's Quarterly Report on Form 10-Q filed on August 4, 2026.

[8] Ecuador oil sales are priced on an "M-1" basis, a pricing convention whereby the realized price for volumes lifted in a given month is determined by reference to the average Brent crude oil price of the immediately preceding calendar month, rather than the month in which lifting occurs.

Disclosure of Contingent Resources and Prospective Resources Data

Contingent Resources: Canada

Gran Tierra's Canadian operations hold contingent resources in the Hoadley Glauconitic and Dawson Clearwater projects. The Hoadley Glauconitic contingent resources were previously disclosed in the Company's January 28, 2026 press release and are restated here because they form part of the updated evaluation described below. They do not represent an addition to the Company's resource base. The Dawson Clearwater contingent resources are being disclosed for the first time. These resources were evaluated by McDaniel & Associates Consultants Ltd. ("**McDaniel**"), the Company's independent qualified reserves evaluator, in a report with an effective date of June 30, 2026 (the "**GTE McDaniel Resources Report**"), prepared in compliance with National Instrument 51-101 ("**NI 51-101**") and the Canadian Oil and Gas Evaluation Handbook ("**COGEH**"), and are classified as development on hold. See "**Contingent Resources**" and "**Disclosures of Resources Information and Cautionary Note to U.S. Investors**" below.

- **Hoadley Glauconitic:** unrisked best-estimate (2C) contingent resources of approximately 74 MMBOE (44% WI), unchanged from the volumes disclosed in the January 28, 2026 press release, approximately 50% of which is natural gas, with a chance of development of 80%.
- **Clearwater:** unrisked best-estimate (2C) contingent resources of approximately 6.5 MMBOE (100% WI), approximately 100% oil, with a chance of development of 64**%**.

Summary of Unrisked and Risked Contingent Resources

The following table sets forth Gran Tierra's unrisked and risked gross contingent resources for its Canadian operations, expressed in thousands of barrels of oil equivalent (**"Mboe"**), prepared by McDaniel with an effective date of June 30, 2026 and derived from the GTE McDaniel Resources Report. The contingent resources would be considered for classification as reserves if commodity prices support development and the Company commits capital to a development plan, subject to confirmation by its independent evaluator.

Gross[5] Contingent Resources[1,2,4]
By Product Type

Hoadley Glauconitic Play[7]	**Unrisked**			**Risked**	**Chance of Development[3]**	**Working Interest**
Product	**1C**	**2C**	**3C**	**2C**	**%**	**%**
Light and Medium Crude Oil (Mbbls)	825	1,237	1,650	990	80%	44%
Heavy Crude Oil (Mbbls)	—	—	—	—	80%	44%
Conventional Natural Gas (MMcf)	148,483	222,724	296,965	178,179	80%	44%
Natural Gas Liquids (Mbbls)	23,609	35,413	47,217	28,330	80%	44%
TOTALS (Mboe)[6]	**49,181**	**73,771**	**98,362**	**59,017**	**80%**	**44%**

Gross[5] Contingent Resources[1,2,4]
By Product Type

Clearwater E1	**Unrisked**			**Risked**	**Chance of Development[3]**	**Working Interest**
Product	**1C**	**2C**	**3C**	**2C**	**%**	**%**
Light and Medium Crude Oil (Mbbls)	—	—	—	—	70%	100%
Heavy Crude Oil (Mbbls)	1,900	2,850	3,800	1,995	70%	100%
Conventional Natural Gas (MMcf)	—	—	—	—	70%	100%
Natural Gas Liquids (Mbbls)	—	—	—	—	70%	100%
TOTALS (Mboe)[6]	**1,900**	**2,850**	**3,800**	**1,995**	**70%**	**100%**

Gross[5] Contingent Resources[1,2,4]
By Product Type

Clearwater G1	**Unrisked**			**Risked**	**Chance of Development[3]**	**Working Interest**
Product	**1C**	**2C**	**3C**	**2C**	**%**	**%**
Light and Medium Crude Oil (Mbbls)	—	—	—	—	60%	100%
Heavy Crude Oil (Mbbls)	2,400	3,600	4,800	2,160	60%	100%
Conventional Natural Gas (MMcf)	—	—	—	—	60%	100%
Natural Gas Liquids (Mbbls)	—	—	—	—	60%	100%
TOTALS (Mboe)[6]	**2,400**	**3,600**	**4,800**	**2,160**	**60%**	**100%**

[1] Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

[2] Under the COGEH, a range of contingent resources estimates (low, best and high) are recommended. The following classification of contingent resources is used as presented by McDaniel: (a) Low estimate (1C) means there is at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate; (b) Best estimate (2C) means there is at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the median best estimate; (c) High estimate (3C) means there is at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

[3] The chance of development is defined as the estimated probability that, once discovered, a known accumulation will be commercially developed. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution.

[4] There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

[5] Company gross contingent resources are based on the working interest share of the property gross resources.

[6] Based on Mcf to boe conversion of 6 to 1. A boe conversion of 6 to 1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

[7] The Hoadley Glauconitic contingent resources included in this table were previously disclosed in the Company's January 28, 2026 press release. They are presented here as part of the total Canadian contingent resource base and are not incremental resources.

See "Contingent Resources" and "Disclosures of Resources Information and Cautionary Note to U.S. Investors" below.

Hoadley Glauconitic Contingent Resources (Previously Disclosed)

As previously disclosed in the January 28, 2026 press release, the Hoadley trend is a Lower Cretaceous transgressive barrier-island sandstone complex, over 120km long and up to 25km wide, characterized by laterally extensive, onlapping glauconitic shoreface reservoirs and strong reservoir continuity along depositional strike. The sands are typically well sorted and laterally continuous, providing good reservoir connectivity along strike. Trapping is primarily stratigraphic, with up-dip pinch-out of barrier sands into regional marine shale.

The contingent resources for the Hoadley Glauconitic sands are based on reservoir characterization and performance analysis. Significant offsetting development activity by the Company and other operators provides a high probability of commercial development, supported by extensive existing infrastructure and a long history of conventional oil and gas development in the area. In the current commodity price environment, development activity within the Hoadley Glauconitic has moderated in recent years, however, the play remains economic under the lower price environment. Development has been deferred as the Company has prioritized higher-return internal opportunities. Glauconitic development is sensitive to local gas pricing, and future development is expected to proceed as economic conditions improve.

Positive factors for the Hoadley Glauconitic Resource include:

- Excellent well control, with over 2,500 well penetrations leading to high confidence
- Proven gas field with over 1,100 wells producing from the Glauconitic

Negative factors for the Hoadley Glauconitic Resource include:

- Sensitivities to fluctuating commodity pricing
- Depletion risk in proximity to high permeability trends

Dawson Clearwater Contingent Resources

The Dawson Clearwater reservoir comprises Lower Cretaceous Clearwater Formation sandstones deposited within areally extensive marine offshore wave-dominated deltaic/shoreface environments. Characterized by a series of cleaning-upward sand lobes. High quality reservoir sandstones are identified from core calibrated petrophysical logs that show average porosities of 25-30% and permeability range of 50 to 300 mD. This reservoir has high quality oil at 12° to 15° API.

The contingent resources for the Dawson Clearwater sands are based on reservoir characterization and performance analysis. Offsetting development activity provides a high probability of commercial development and activity within the play remains economic. In Dawson specifically, three wells currently exist in the Clearwater. Clearwater development is sensitive to heavy oil pricing and future development expected to proceed contingent on favourable commodity pricing and corporate approval.

Positive factors for the Dawson Clearwater Resource include:

- Shallow depth and advances in horizontal multilateral drilling have led to low drilling and completion costs and attractive economics
- Multi-zone potential
- Waterflood projects are showing early promise across the play
- Virgin reservoir pressure

Negative factors for the Dawson Clearwater Resource include:

- High rock quality heterogeneity and potential for variable oil viscosity
- Sensitivity to fluctuating commodity pricing and heavy oil differential
- Remote location with limited infrastructure
- Limited well control and 3D seismic in area
- Waterflood projects are still in early stages, especially outside of Marten Hills and Nipisi

Prospective Resources: Canada

Gran Tierra's Canadian operations hold prospective resources, principally in the Clearwater project, together with the Mount Head project. The prospective resources were evaluated by McDaniel, the Company's independent qualified reserves evaluator, in a report with an effective date of June 30, 2026 (the "GTE McDaniel Prospective Resources Report"), prepared in compliance with NI 51-101 and the COGEH. See "Prospective Resources" and "Disclosures of Resources Information and Cautionary Note to U.S. Investors" below.

- **Canada:** Certain of Gran Tierra's Canadian assets are estimated to contain unrisked mean prospective resources of approximately 72 MMBOE (all oil) across its Mount Head and Clearwater plays, with risked mean prospective resources of approximately 33 MMBOE.

Summary of Unrisked and Risked Prospective Resources

The following table presents Gran Tierra's unrisked and risked gross prospective resources for its Canadian operations, expressed in thousands of barrels of oil equivalent (Mboe), prepared by McDaniel with an effective date of June 30, 2026 and derived from the GTE McDaniel Prospective Resources Report. The prospective resources are associated with undiscovered accumulations and would first need to be confirmed by drilling.

Gross[7] Prospective Resources[(1)(2)(5)(8)]
By Product Type

	Unrisked[6]				**Risked[4]**	**Working Interest**
Canada - Clearwater[3]	**Low Mbbl**	**Best Mbbl**	**Mean Mbbl**	**High Mbbl**	**Mean Mbbl**	**%**
Light and Medium Crude Oil (Mbbls)	—	—	—	—	—	100%
Heavy Crude Oil (Mbbls)	17,019	54,822	59,269	107,448	28,084	100%
Conventional Natural Gas (MMcf)	—	—	—	—	—	100%
Natural Gas Liquids (Mbbls)	—	—	—	—	—	100%
TOTALS (Mboe)	**17,019**	**54,822**	**59,269**	**107,448**	**28,084**	**100%**

Canada - Mount Head[3]	Gross[7] Prospective Resources(1)(2)(5)(8) By Product Type					Working Interest
	Unrisked[6]				Risked[4]	
	Low Mbbl	Best Mbbl	Mean Mbbl	High Mbbl	Mean Mbbl	%
Light and Medium Crude Oil (Mbbls)	3,938	11,695	12,361	21,674	4,907	100%
Heavy Crude Oil (Mbbls)	—	—	—	—	—	100%
Conventional Natural Gas (MMcf)	—	—	—	—	—	100%
Natural Gas Liquids (Mbbls)	—	—	—	—	—	100%
TOTALS (Mboe)	**3,938**	**11,695**	**12,361**	**21,674**	**4,907**	**100%**

[1] Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

[2] Under the COGEH, a range of prospective resources estimates (low, best and high) are recommended. The following classification of prospective resources is used as presented by McDaniel: (a) Low estimate means there is at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate; (b) Best estimate means there is at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the median best estimate; (c) High estimate means there is at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate; and (d) Mean estimate represents the arithmetic average of the expected recoverable volume. It is the most accurate single point representation of the volume distribution.

[3] McDaniel has sub-classified the prospective resources by maturity status, consistent with the requirements of the COGEH. The COGEH defines "prospect" as a potential accumulation within a play that is sufficiently well defined to represent a viable drilling target. The COGEH defines a "play" as a family of geologically similar fields, discoveries, prospects and leads.

[4] The risked mean prospective resource volumes have been determined by multiplying the unrisked mean volumes by the associated chance of commerciality. The arithmetic sum of the individual risked mean values can be considered the best estimate risked prospective resources for the portfolio as per COGEH Volume 2 Section 2.8.2.

[5] There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

[6] The unrisked total is not representative of the portfolio unrisked total and is provided to give an indication of the resources range, assuming all prospects are successful.

[7] Company gross prospective resources are based on the working interest share of the property gross resources. The net present value of future net revenue of the prospective resource estimates has not been prepared and therefore, the net prospective resources volumes are not reported.

[8] Given the uncertainty of discovery associated with the prospective resources, costs and timelines to production, as well as recovery technologies, cannot be determined at this time.

See "Prospective Resources" and "Disclosures of Resources Information and Cautionary Note to U.S. Investors" below.

Note: Company gross resources reflect Gran Tierra's working interest share of property gross resources. Gran Tierra holds a 100% working interest in the Canadian Dawson Clearwater and Mount Head plays.

The net present value of future net revenue of the prospective resource estimates has not been prepared and, accordingly, net prospective resources volumes are not reported. There is no certainty that any portion of the prospective resources will be discovered or, if discovered, that it will be commercially viable to produce any portion of the prospective resources.

Dawson Clearwater Prospective Resources

The Dawson Clearwater reservoir comprises Lower Cretaceous Clearwater Formation sandstones deposited within a really extensive marine offshore wave-dominated deltaic/shoreface environments. The succession is characterized by a series of cleaning-upward sand lobes. High quality reservoir sandstones are identified from core calibrated petrophysical logs that show average porosities of 25-30% and permeability range of 50 to 300 mD. This reservoir has high quality oil at 12° to 15° API.

In the Dawson area, three wells have produced commercially from the Clearwater Formation. There are numerous commercial developments across northern Alberta with analogous geology to the Clearwater at Dawson.

Significant positive factors for Clearwater Prospective Resources include:

- Shallow, high quality heavy-oil reservoirs in sandstone bodies
- Production established from two pads and two zones within Dawson
- Development technologies and strategies from similar analog fields can be applied to this play

- Virgin reservoir pressure

Negative factors for Clearwater Prospective Resources include:

- High rock quality heterogeneity and potential for variable oil viscosity
- Remote location with limited infrastructure
- Limited well control and 3D seismic in area
- The play is in the early part of the exploration cycle

Chance of Discovery / Development

Through an evaluation of the risks that are relevant to the Clearwater prospective resources, which are described herein, McDaniel has determined that the chance of discovery in both Clearwater G1 and E1 is 90%, with the chance of development at 50% for the Clearwater G1 and 60% for the Clearwater E1.

Mount Head Prospective Resources

The Mississippian has been a target for oil exploration in South-West Alberta since the 1940s, with significant discoveries such as the Shell Waterton and Turner Valley fields. The Mount Head formation, within the Mississippian Visean stage, was deposited in a broad, shallow-water shelf environment, characterized by thin bedded dolo-wackestones and packstones to dolo-mudstones in event bed flooding zones.

Core calibrated petrophysical analysis shows average porosities of 6% to 8% with permeabilities from 4mD to 10mD in stacked flow units associated with depositional cycles. Historical production tests from the Mount Head formation produce light, sweet crude over 40° API.

The primary trapping mechanism of the Mount Head play in this area of South-West Alberta is an erosional subcrop unconformity, creating a stratigraphic-structural trap at the Foothills-Plains transition. The Jurassic Rierdon and Sawtooth shales provide a robust top seal, while NE-SW oriented erosional features provide lateral truncations for the subcrop trap.

Significant positive factors for Mount Head Prospective Resources include:

- Proven productive dolostone facies within the play fairway
- All-weather access locations
- 3D seismic covering a majority of the trap
- Development technologies and strategies from similar analog fields can be applied to this play
- Virgin reservoir pressure

Negative factors for Mount Head Prospective Resources include:

- High reservoir heterogeneity and lateral extent of productive facies
- Limited well control in area
- The play is in the early stages of the exploration cycle

Chance of Discovery / Development

Through an evaluation of the risks that are relevant to the Mount Head prospective resources, which are described herein, McDaniel has determined that the chance of discovery in both Mount Head C and B is 70%, with the chance of development at 60% for the Mount Head C and 50% for the Mount Head B.

Conference Call Information:

Gran Tierra will host its second quarter 2026 results conference call on Wednesday, August 5, 2026, at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time. Interested parties may access the conference call by registering at the following link: https://register-conf.media-server.com/register/BI848611503f0e48dbb81d7e757fc89270. Please note that there is no longer a general dial-in number to participate and each individual party must register through the provided link. Once parties have registered, they will be provided a unique PIN and call-in details. There is also a feature that allows parties to elect to be called back through the "Call Me" function on the platform. Interested parties can also continue to access the live webcast from their mobile or desktop devices at the following link: https://edge.media-server.com/mmc/p/okmrqhav, which is also available on Gran Tierra's website at https://www.grantierra.com/investor-relations/presentations-events/.

2025 Sustainability Report:

Gran Tierra has published its 2025 Sustainability Report and is available on the Company website at www.grantierra.com/esg.

Corporate Presentation:

Gran Tierra's Corporate Presentation has been updated and is available on the Company website at www.grantierra.com.

About Gran Tierra Energy Inc.

Gran Tierra Energy Inc., together with its subsidiaries, is an independent international energy company currently focused on oil and natural gas exploration and production in Canada, Colombia and Ecuador. The Company is currently developing its existing portfolio of assets in Canada, Colombia and Ecuador; however, Gran Tierra recently entered into an exploration, development and production sharing agreement with the State Oil Company of the Republic of Azerbaijan ("**SOCAR**") and may eventually expand our operations into Azerbaijan and will continue to pursue additional new growth opportunities that would further strengthen the Company's portfolio. The Company's common stock trades on the NYSE American, the Toronto Stock Exchange and the London Stock Exchange under the ticker symbol GTE. Additional information concerning Gran Tierra is available at www.grantierra.com. Except to the extent expressly stated otherwise, information on the Company's website or accessible from our website or any other website is not incorporated by reference into and should not be considered part of this press release. Investor inquiries may be directed to info@grantierra.com or (403) 265-3221.

Gran Tierra's Securities and Exchange Commission (the **"SEC"**) filings are available on the SEC website at http://www.sec.gov. The Company's Canadian securities regulatory filings are available on SEDAR+ at http://www.sedarplus.ca and UK regulatory filings are available on the National Storage Mechanism website at https://data.fca.org.uk/#/nsm/nationalstoragemechanism.

Contact Information

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For more information on Gran Tierra please go to: www.grantierra.com.

Forward Looking Statements and Advisories:

This press release contains opinions, forecasts, projections, and other statements about future events or results that constitute forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, and financial outlook and forward looking information within the meaning of applicable Canadian securities laws (collectively, "forward-looking statements"), which can be identified by such terms as "expect", "plan", "anticipate", "target", "outlook", "can," "will," "should," "guidance," "forecast," "signal," "measures taken to" and "believes", derivations thereof and similar terms identify forward-looking statements. Such forward-looking statements include, but are not limited to, the Company's capital budget amount and uses; the Company's strategies related to exploration, drilling and operation activities; expectations regarding reservoir prospects and production amounts; future well results (including initial oil and natural gas production rates and productive capacity based on past performance); expected future net cash provided by operating activities (described in this press release as "cash flow"), free cash flow, operating netback, EBITDA and certain associated metrics; anticipated capital expenditures, including the location and impact of capital expenditures; operating and general and administrative costs; production guidance for 2026; and the Company's expectations as to debt repayment, hedging and its positioning for 2026 and beyond. The forward-looking statements contained in this press release reflect several material factors and expectations and assumptions of Gran Tierra including, without limitation, that Gran Tierra will continue to conduct its operations in a manner consistent with its current expectations, the accuracy of testing and production results and seismic data, pricing and cost estimates (including with respect to commodity pricing and exchange rates), and the general continuance of current or, where applicable, assumed operational, regulatory and industry conditions in Canada, Colombia and Ecuador and areas of potential expansion, and the ability of Gran Tierra to execute its business and operational plans (including any debt repayment plan) in the manner currently planned. Gran Tierra believes the material factors, expectations and assumptions reflected in the forward-looking statements are reasonable at this time, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

Among the important factors that could cause actual results to differ materially from those indicated by the forward-looking statements in this press release are: certain of Gran Tierra's operations are located in South America and unexpected problems can arise due to guerilla activity, strikes, local blockades or protests; technical difficulties and operational difficulties may arise which impact the production, transport or sale of Gran Tierra's products; other disruptions to local operations; global and regional changes in the demand, supply, prices, differentials or other market conditions affecting oil and gas, including inflation and changes resulting from a global health crisis, geopolitical events, including the ongoing conflicts in Ukraine, the Middle East and Venezuela, or from the imposition or lifting of crude oil production quotas or other actions that might be imposed by OPEC and other producing countries and resulting company or third-party actions in response to such changes; changes in commodity prices, including volatility or a prolonged decline in these prices relative to historical or future expected levels; the risk that current global economic and credit conditions may impact oil and natural gas prices and oil and natural gas consumption more than Gran Tierra currently predicts, which could cause Gran Tierra to further modify its strategy and capital spending program; prices and markets for oil and natural gas are unpredictable and volatile; the effect of hedges; the accuracy of productive capacity of any particular field; geographic, political and weather conditions can impact the production, transport or sale of Gran Tierra's products; the ability of Gran Tierra to execute its business plan, which may include acquisitions, and realize expected benefits from current or future initiatives; the risk that unexpected delays and difficulties in developing currently owned properties may occur; the ability to replace reserves and production and develop and manage reserves on an economically viable basis; the accuracy of testing and production results and seismic data, pricing and cost estimates (including with respect to commodity pricing and exchange rates); the risk profile of planned exploration activities; the effects of drilling down-dip; the effects of waterflood and multi-stage fracture stimulation operations; the extent and effect of delivery disruptions, equipment performance and costs; actions by third parties; the timely receipt of regulatory or other required approvals for Gran Tierra's operating activities; the failure of exploratory drilling to result in commercial wells; unexpected delays due to the limited availability of drilling equipment and personnel; volatility or declines in the trading price of Gran Tierra's common stock or bonds; the risk that Gran Tierra does not receive the anticipated benefits of government programs, including government tax refunds; Gran Tierra's ability to comply with financial covenants in its credit agreement and indentures and make borrowings under its credit agreement; and the risk factors detailed from time to time in Gran Tierra's periodic reports filed with the SEC, including, without limitation, under the caption "Risk Factors" in Gran Tierra's Annual Report on Form 10-K for the year ended December 31, 2025 filed on March 4, 2026 and its other filings with the SEC.

These filings are available on the SEC's website at http://www.sec.gov and on SEDAR+ at www.sedarplus.ca and UK regulatory filings are available on the National Storage Mechanism website at https://data.fca.org.uk/#/nsm/nationalstoragemechanism.

The forward-looking statements contained in this press release are based on certain assumptions made by Gran Tierra based on management's experience and other factors believed to be appropriate. Gran Tierra believes these assumptions to be reasonable at this time, but the forward-looking statements are subject to risk and uncertainties, many of which are beyond Gran Tierra's control, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. The risk that the assumptions on which the 2026 outlook is based prove incorrect may increase the later the period to which the outlook relates. All forward-looking statements are made as of the date of this press release and the fact that this press release remains available does not constitute a representation by Gran Tierra that Gran Tierra believes these forward-looking statements continue to be true as of any subsequent date. Actual results may vary materially from the expected results expressed in forward-looking statements. Gran Tierra disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as expressly required by applicable law. In addition, historical, current and forward-looking sustainability-related statements may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve, and assumptions that are subject to change in the future. Gran Tierra's forward-looking statements are expressly qualified in their entirety by this cautionary statement.

Non-GAAP Measures

This press release includes non-GAAP financial measures as further described herein. These non-GAAP measures do not have a standardized meaning under GAAP. Investors are cautioned that these measures should not be construed as alternatives to net income or loss, cash flow from operating activities or other measures of financial performance as determined in accordance with GAAP. Gran Tierra's method of calculating these measures may differ from other companies and, accordingly, they may not be comparable to similar measures used by other companies. Each non-GAAP financial measure is presented along with the corresponding GAAP measure so as to not imply that more emphasis should be placed on the non-GAAP measure.

Net Debt, as presented as at June 30, 2026 is comprised of $560 million (gross) of long-term senior notes outstanding and $46 million (gross) of current senior notes outstanding less cash and cash equivalents of $127 million. These components are drawn from amounts presented in accordance with GAAP in the Company's condensed consolidated balance sheet. Management believes that net debt is a useful supplemental measure for management and investors in order to evaluate the financial sustainability of the Company's business and leverage. The most directly comparable GAAP measure is total debt.

Operating netback, as presented, is defined as gross profit adjusting for depletion and accretion related to producing assets. Operating netback per boe, as presented, is defined as operating netback over WI sales volume. See the table entitled Financial and Operational Highlights above for the components of consolidated operating netback and corresponding reconciliation.

Cash netback, as presented, is most directly comparable to gross profit and is calculated as gross profit adjusted for depletion and accretion related to producing assets, cash G&A expenses, other taxes, severance expenses, realized foreign exchange gains or losses, cash settlement on derivative instruments, interest expense (excluding amortization of debt issuance costs, non-cash interest, and senior notes exchange fees), interest income, other cash gains or losses, net lease payments, and current income tax expense or recovery. Cash netback per boe, as presented, is defined as cash netback over WI sales volumes. Management believes that operating netback and cash netback are useful supplemental measures for investors to analyze financial performance and provide an indication of the results generated by Gran Tierra's principal business activities prior to the consideration of other income and expenses. See the table entitled Financial and Operational Highlights above for the components of operating netback and operating netback per boe. A reconciliation from gross profit to cash netback is as follows:

Operating and Cash Netback - Non-GAAP Measure ($000s)	Three Months Ended June 30,		Three Months Ended March 31	Six Months Ended June 30,	
	2026	**2025**	**2026**	**2026**	**2025**
Gross Profit	**$ 75,460**	$ 23,313	$ 36,697	**$ 112,157**	$ 51,414
Adjustments to reconcile gross profit to operating netback					
Depletion and accretion	**56,253**	65,948	63,908	**120,161**	134,379
Operating Netback (non-GAAP)	**131,713**	**89,261**	100,605	**232,318**	**185,793**
Cash G&A expenses	**(13,219)**	(14,136)	(15,149)	**(28,368)**	(26,062)
Other taxes	**(1,389)**	(577)	(1,041)	**(2,430)**	(1,058)
Severance expenses	**(95)**	—	(2,468)	**(2,563)**	—
Realized foreign exchange gain (loss)	**260**	(602)	(1,625)	**(1,365)**	(2,753)
Cash settlement on derivative instruments	**(34,032)**	1,631	(11,082)	**(45,114)**	2,074
Interest expense, excluding amortization of debt issuance costs, non-cash interest, and senior notes exchange fees	**(15,832)**	(20,284)	(21,169)	**(37,001)**	(39,686)
Interest income	**503**	251	401	**904**	676
Other cash gain	**1,625**	377	420	**2,045**	377
Net lease payments	**(130)**	180	(219)	**(349)**	349
Current income tax expense	**(9,115)**	(2,195)	(5,850)	**(14,965)**	(10,460)
Cash Netback (non-GAAP)	**$ 60,289**	**$ 53,906**	$ 42,823	**$ 103,112**	$ 109,250

EBITDA, as presented, is defined as net income or loss adjusted for DD&A expenses, interest expense, and income tax expense or recovery. Adjusted EBITDA, as presented, is defined as EBITDA adjusted for asset impairment, severance expenses, non-cash lease expense, lease payments, foreign exchange gains or losses, stock-based compensation expense or recovery, unrealized derivative instruments gains or losses, and other non-cash gains or losses. Management uses this supplemental measure to analyze performance and income generated by our principal business activities prior to the consideration of how non-cash items affect that income, and believes that this financial measure is a useful supplemental information for investors to analyze our performance and our financial results. A reconciliation from net income or loss to EBITDA and adjusted EBITDA is as follows:

EBITDA - Non-GAAP Measure ($000s)	Three Months Ended June 30,		Three Months Ended March 31	Six Months Ended June 30,		Twelve Month Trailing June 30
	2026	**2025**	**2026**	**2026**	**2025**	**2026**
Net Income (Loss)	**$ 24,861**	$ (12,741)	$ (119,172)	**$ (94,311)**	$ (32,021)	$ (255,409)
Adjustments to reconcile net income (loss) to EBITDA and Adjusted EBITDA						
DD&A expenses	**62,334**	68,635	69,874	**132,208**	140,837	269,724
Interest expense	**24,473**	24,366	49,878	**74,351**	47,601	128,059
Income tax expense	**20,488**	4,648	(26,595)	**(6,107)**	8,201	(54,061)
EBITDA (non-GAAP)	**$ 132,156**	$ 84,908	$ (26,015)	**$ 106,141**	$ 164,618	$ 88,313
Asset Impairment	**—**	—	—	**—**	—	136,261
Severance expenses	**95**	—	2,468	**2,563**	—	2,563
Non-cash lease expense	**1,503**	1,725	1,468	**2,971**	3,461	5,331
Lease payments	**(1,633)**	(1,545)	(1,687)	**(3,320)**	(3,112)	(6,181)
Foreign exchange loss	**2,603**	3,716	1,425	**4,028**	7,554	5,208

Stock-based compensation (recovery) expense	**(3,757)**	546	19,676	**15,919**	29	19,104
Unrealized derivative instruments (gain) loss	**(45,896)**	(12,401)	77,328	**31,432**	(10,491)	33,290
Other non-cash loss (gain)	**—**	38	(728)	**(728)**	90	(3,376)
Adjusted EBITDA (non-GAAP)	**$ 85,071**	$ 76,987	$ 73,935	**$ 159,006**	$ 162,149	$ 280,513

Funds flow from operations, as presented, is defined as net income or loss adjusted for DD&A expenses, deferred tax expense or recovery, stock-based compensation expense or recovery, amortization of debt issuance costs, Senior Notes exchange fees, non-cash interest, non-cash lease expense, lease payments, unrealized foreign exchange gains or losses, unrealized derivative instruments gains or losses, and other non-cash gains or losses. Management uses this financial measure to analyze performance and income or loss generated by our principal business activities prior to the consideration of how non-cash items affect that income or loss, and believes that this financial measure is also useful supplemental information for investors to analyze performance and our financial results. Free cash flow, as presented, is defined as funds flow from operations adjusted for capital expenditures. Management uses this financial measure to analyze cash flow generated by our principal business activities after capital requirements and believes that this financial measure is also useful supplemental information for investors to analyze performance and our financial results. A reconciliation from net income or loss to funds flow from operations and free cash flow is as follows:

Funds Flow From Operations - Non-GAAP Measure ($000s)	**Three Months Ended June 30,**		**Three Months Ended March 31,**	**Six Months Ended June 30,**	
	2026	**2025**	**2026**	**2026**	**2025**
Net Income (Loss)	**$ 24,861**	$ (12,741)	$ (119,172)	**$ (94,311)**	$ (32,021)
Adjustments to reconcile net income (loss) to funds flow from operations					
DD&A expenses	**62,334**	68,635	69,874	**132,208**	140,837
Deferred tax expense (recovery)	**11,373**	2,453	(32,445)	**(21,072)**	(2,259)
Stock-based compensation (recovery) expense	**(3,757)**	546	19,676	**15,919**	29
Amortization of debt issuance costs	**1,722**	4,082	11,293	**13,015**	7,915
Senior Notes exchange fees	**785**	—	12,903	**13,688**	—
Non-cash interest	**6,134**	—	4,513	**10,647**	—
Non-cash lease expense	**1,503**	1,725	1,468	**2,971**	3,461
Lease payments	**(1,633)**	(1,545)	(1,687)	**(3,320)**	(3,112)
Unrealized foreign exchange loss (gain)	**2,863**	3,114	(200)	**2,663**	4,801
Other non-cash loss (gain)	**—**	38	(728)	**(728)**	90
Unrealized derivative instrument (gain) loss	**(45,896)**	(12,401)	77,328	**31,432**	(10,491)
Funds Flow From Operations (non-GAAP)	**$ 60,289**	$ 53,906	$ 42,823	**$ 103,112**	$ 109,250
Capital expenditures	**$ 54,309**	$ 51,170	$ 45,359	**$ 99,668**	$ 145,897
Free Cash Flow (non-GAAP)	**$ 5,980**	$ 2,736	$ (2,536)	**$ 3,444**	$ (36,647)

Presentation of Oil and Gas Information

Boes have been converted on the basis of six thousand cubic feet ("Mcf") natural gas to 1 boe of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 boe 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, given that the value ratio based on the current price of oil as compared with natural gas is significantly different from the energy equivalent of six to one, utilizing a boe conversion ratio of 6 Mcf: 1 boe would be misleading as an indication of value.

The estimates of the Company's contingent and prospective resources provided herein are estimates only and there is no guarantee that the estimated contingent and prospective resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and variances could be material. Estimates of contingent and prospective resources are by their nature more speculative than estimates of proved reserves and would require substantial capital spending over a significant number of years to implement recovery. Actual locations drilled and quantities that may be ultimately recovered from the properties will differ substantially. In addition, the Company has made no commitment to drill, and likely will not drill, all of the drilling locations that have been attributable to these quantities.

References to a formation where evidence of hydrocarbons has been encountered is not necessarily an indicator that hydrocarbons will be recoverable in commercial quantities or in any estimated volume. Gran Tierra's reported production is a mix of crude oil, conventional natural gas, shale gas and natural gas liquids for which there is no precise breakdown since the Company's sales volumes typically represent blends of more than one product type. Well test results should be considered as preliminary and not necessarily indicative of long-term performance or of ultimate recovery. Well log interpretations indicating oil and gas accumulations are not necessarily indicative of future production or ultimate recovery. If it is indicated that a pressure transient analysis or well-test interpretation has not been carried out, any data disclosed in that respect should be considered preliminary until such analysis has been completed.

This press release contains certain oil and gas metrics, including operating netback, cash netback and gross profit per boe, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. These metrics are calculated as described in this press release and management believes that they are useful supplemental measures for the reasons described in this press release.

Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods.

Contingent Resources

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent resources should not be construed as reserves. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

Under the COGEH, a range of contingent resources estimates (low, best and high) are recommended. The following classification of contingent resources is used as presented by McDaniel: (a) Low estimate (1C) means there is at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate; (b) Best estimate (2C) means there is at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate; and (c) High estimate (3C) means there is at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

The chance of development is defined as the estimated probability that, once discovered, a known accumulation will be commercially developed. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution. The contingent resources disclosed herein have an economic status that is undetermined and are sub-classified in terms of maturity as development on hold, meaning there is a reasonable chance of development but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

Company gross contingent resources are based on the working interest share of the property gross resources. There is no certainty that it will be commercially viable to produce any portion of the contingent resources. For additional information regarding the Company's contingent resources, including the significant positive and negative factors relevant to the estimate and a description of the applicable projects, see Disclosure of Contingent Resources and Prospective Resources Data - Contingent Resources: Canada.

Prospective Resources

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources should not be construed as reserves or contingent resources. Prospective resources have both an associated chance of discovery and a chance of development.

Under the COGEH, a range of prospective resources estimates (low, best and high) are recommended. The following classification of prospective resources is used as presented by McDaniel: (a) Low estimate means there is at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate; (b) Best estimate means there is at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the median best estimate; (c) High estimate means there is at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate; and (d) Mean estimate represents the arithmetic average of the expected recoverable volume and is the most accurate single point representation of the volume distribution.

Chance of discovery, as defined in the COGEH, is the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. Chance of development is defined as the estimated probability that, once discovered, a known accumulation will be commercially developed. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution. The chance of commerciality is defined as the product of the chance of discovery and the chance of development. The risked mean prospective resource volumes have been determined by multiplying the unrisked mean volumes by the associated chance of commerciality. The arithmetic sum of the individual risked mean values can be considered the best estimate risked prospective resources for the portfolio as per COGEH Volume 2 Section 2.8.2.

There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. The unrisked total is not representative of the portfolio unrisked total and is provided to give an indication of the resources range, assuming all prospects are successful. Company gross prospective resources are based on the working interest share of the property gross resources. The net present value of future net revenue of the prospective resource estimates has not been prepared and, therefore, the net prospective resources volumes are not reported.

Given the uncertainty of discovery associated with the prospective resources, costs and timelines to production, as well as recovery technologies, cannot be determined at this time. For additional information regarding the Company's prospective resources, including the significant positive and negative factors relevant to the estimate, chance of discovery and chance of development, and a description of the applicable projects and related information, see Disclosure of Contingent Resources and Prospective Resources Data - Prospective Resources: Canada.

Risk Factors and Uncertainties in Estimating Quantities of Resources

There are numerous uncertainties inherent in estimating quantities of resources. The resources information for the contingent and prospective resources set forth herein are estimates only.

In general, estimates of resources are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate resource recovery, the timing and amount of capital expenditures, marketability of oil, NGLs and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For these reasons, estimates of the resources attributable to any particular group of properties, the classification of such resources based on risk of recovery and estimates of future net revenue associated with resources prepared by different engineers, or by the same engineer at different times, may vary. Gran Tierra's actual production, revenue, taxes and development and operating expenditures with respect to its resources will vary from estimates thereof and such variations could be material.

The estimates of Gran Tierra's resources provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and variances could be material. With respect to the discovered resources (including contingent resources), there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to the undiscovered resources (including prospective resources), there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

There are numerous factors and uncertainties that affect the anticipated development of the Company's resources.

The chances of development for the estimated resources are subject to a number of factors, including overall project economics, the employed recovery technology or technology under development, regulatory and environmental approval, the availability of markets and production facilities and political risk to the development. The Company will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil, natural gas and NGLs from its resource properties in the future. If the Company's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, that the terms will be acceptable to the Company. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain opportunities, reduce its pace of development or terminate its operations on such properties. An inability of the Company to access sufficient capital for its exploration and development purposes could have a material adverse effect on the Company's ability to execute its business strategy to develop its prospects.

The significant economic factors that affect the Company's future development of its resources are:

- future commodity prices for oil and natural gas (and the Company's outlook relating to such prices);
- the future capital costs of drilling, completing, tying in and equipping the wells necessary to develop such lands at the relevant times;
- the future costs of operating wells at the relevant times; and
- the levels of royalties applicable to productions from such lands.

The significant uncertainties that affect the Company's development of its resources are:

- the ability of the Company to obtain the capital necessary to fund the development of such lands at the relevant times;
- the future drilling and completion results the Company achieves in its development activities (e.g. with respect to the development of particular intervals or geographic areas, the uncertainty would be whether the initial drilling and completion results are sufficient to justify the development of such interval or geographic area);
- drilling and completion results achieved by others on lands in proximity to the Company's lands;

- transportation and processing infrastructure becoming available in a timeline consistent with proposed development plans;
- the availability of regulatory approvals for development of the lands and the necessary infrastructure; and
- governmental actions and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities.

Disclosures of Resources Information and Cautionary Note to U.S. Investors

All estimates of contingent resources disclosed in this press release have been prepared by McDaniel in accordance with NI 51-101 and the COGEH and are derived from the GTE McDaniel Resources Report. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of the contingent resources. Investors should not view the disclosure of contingent resources in this press release as an estimate of reserves prepared in accordance with SEC requirements.

All estimates of prospective resources disclosed in this press release have been prepared by McDaniel in accordance with NI 51-101 and the COGEH and are derived from the GTE McDaniel Prospective Resources Report. Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects and are subject to both a chance of discovery and a chance of development. There is no certainty that any portion of the prospective resources disclosed herein will be discovered or, if discovered, will be commercially viable or developed. The U.S. Securities and Exchange Commission (the “SEC”) permits oil and gas companies that are subject to domestic issuer reporting requirements under U.S. federal securities law, in their filings with the SEC, to disclose only estimated proved, probable and possible reserves that meet the SEC’s definitions of such terms. Investors should not view the disclosure of prospective resources in this press release as an estimate of reserves prepared in accordance with SEC requirements.