Management's Discussion and Analysis

Q1 2026

ATHABASCA OIL CORPORATION

This Management's Discussion and Analysis of the financial condition and results of operations ("MD&A") of Athabasca Oil Corporation ("Athabasca", the "Company" or the "Parent Company") is dated May 6, 2026 and should be read in conjunction with the unaudited condensed interim consolidated financial statements ("Consolidated Financial Statements") as at and for the three months ended March 31, 2026 and the MD&A and audited consolidated financial statements of the Company for the year ended December 31, 2025. These financial statements, including the comparative figures, were prepared in accordance with International Financial Reporting Standards ("IFRS"). This MD&A contains forward looking information based on the Company's current expectations and projections. For information on the material factors and assumptions underlying such forward-looking information, refer to the "Advisories and Other Guidance" section within this MD&A. Also see the "Advisories and Other Guidance" section within this MD&A for important information regarding the Company's reserves and resource information and abbreviations included in this MD&A. Additional information relating to Athabasca is available on SEDAR at www.sedarplus.ca, including the Company's most recent Annual Information Form dated March 4, 2026 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "ATH".

FOCUSED | EXECUTING | DELIVERING

ATHABASCA'S STRATEGY

Athabasca is a liquids-weighted intermediate producer with exposure to Canada's premier resource plays (Oil Sands, Duvernay). The Company's strategy is guided by:

- Thermal Oil: Predictable, Low Decline Production with Compelling Growth Projects
- Duvernay Energy Corporation ("Duvernay Energy"): Self-funded, Liquids Rich Development
- Financial Sustainability: Low Leverage, Flexible Capital, Prudent Risk Management

Athabasca's strategy is focused on maximizing cash flow per share growth through investing in high margin projects and executing on return of capital initiatives. The Company has long-term growth optionality across a deep inventory of high-quality Thermal Oil projects and flexible Duvernay development opportunities. This balanced portfolio provides shareholders with differentiated exposure to liquids weighted production and significant long reserve life assets.

FIRST QUARTER 2026 HIGHLIGHTS

Corporate Consolidated(1)

- Production of 40,242 boe/d (98% Liquids(2)), representing growth of 7% (14% per basic share).
- Petroleum, natural gas and midstream sales of $396.3 million.
- Operating Income(2) and Operating Netback(2) of $172.2 million ($45.95/boe).
- Adjusted Funds Flow(2) of $128.0 million and $0.27 per share (cash flow from operating activities of $102.0 million).
- Strong Liquidity(2) of $405.6 million, including $290.5 million of cash as at March 31, 2026.
- Returned $199.9 million to shareholders through repurchasing and cancelling 32.7 million common shares on its previous Normal Course Issuer Bid ("NCIB") for the twelve-month period ended March 17, 2026.
- Renewed the Company's fourth annual NCIB with authorization to purchase up to 47.0 million common shares during the twelve-month period commencing March 18, 2026 and ending March 17, 2027.
- Repurchased a total of 2.4 million common shares for $20.8 million in the first quarter of 2026, supported by Free Cash Flow generation in Athabasca (Thermal Oil).

Athabasca (Thermal Oil)

- Production of 35,629 bbl/d including 26,683 bbl/d at Leismer and 8,946 bbl/d at Hangingstone.
- Petroleum, natural gas and midstream sales of $393.9 million.
- Operating Income(2) and Operating Netback(2) of $152.7 million ($45.80/bbl).
- Adjusted Funds Flow(2) of $112.2 million.
- Free Cash Flow(2) of $20.1 million.
- First quarter capital expenditures of $92.1 million. At Leismer, the Company continued to advance its next expansion project, with field activity including completing the winter drilling program and facilities and pipeline construction on Pad 10 and 11. The Company advanced readiness for the facility turnaround which will take place in May with scope including routine maintenance and tie-in points for new expansion equipment. At Corner, work continued on advancing the project which included regulatory, engineering of the central processing facility and road access and lease site construction.

Duvernay Energy(1)

- Production of 4,613 boe/d (81% Liquids(2)).
- Petroleum, natural gas and midstream sales of $28.5 million.
- Operating Income(2) and Operating Netback(2) of $19.6 million ($47.10/boe).
- Adjusted Funds Flow(2) of $15.8 million.
- First quarter capital expenditures of $21.8 million. Activity focused on completion operations on a four well pad (30% working interest) brought on production early in the second quarter of 2026 and the drilling of a land retention well (100% working interest).

(1) Corporate Consolidated and Duvernay Energy reflect gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

FINANCIAL & OPERATIONAL HIGHLIGHTS

The following tables summarize selected financial and operational information of the Company for the periods indicated:

($ Thousands, unless otherwise noted)	Three months ended March 31, 2026	2025
CORPORATE CONSOLIDATED(1)		
Petroleum and natural gas production (boe/d)(2)	40,242	37,714
Petroleum, natural gas and midstream sales	$ 396,277	$ 367,844
Operating Income(2)	$ 172,216	$ 145,590
Operating Income Net of Realized Hedging(2)(3)	$ 173,016	$ 143,947
Operating Netback ($/boe)(2)	$ 45.95	$ 44.07
Operating Netback Net of Realized Hedging ($/boe)(2)(3)	$ 46.16	$ 43.57
Capital expenditures	$ 113,962	$ 63,333
Cash flow from operating activities	$ 102,027	$ 123,353
per share - basic	$ 0.21	$ 0.24
Adjusted Funds Flow(2)	$ 128,025	$ 129,675
per share - basic	$ 0.27	$ 0.25
ATHABASCA (THERMAL OIL)		
Bitumen production (bbl/d)(2)	35,629	34,742
Petroleum, natural gas and midstream sales	$ 393,863	$ 362,375
Operating Income(2)	$ 152,659	$ 135,316
Operating Netback ($/bbl)(2)	$ 45.80	$ 44.56
Capital expenditures	$ 92,125	$ 50,376
Adjusted Funds Flow(2)	$ 112,240	$ 121,353
Free Cash Flow(2)	$ 20,115	$ 70,977
DUVERNAY ENERGY(1)		
Petroleum and natural gas production (boe/d)(2)	4,613	2,972
Percentage Liquids (%)(2)	81%	73%
Petroleum, natural gas and midstream sales	$ 28,535	$ 17,619
Operating Income(2)	$ 19,557	$ 10,274
Operating Netback ($/boe)(2)	$ 47.10	$ 38.42
Capital expenditures	$ 21,837	$ 12,957
Adjusted Funds Flow(2)	$ 15,785	$ 8,322
Free Cash Flow(2)	$ (6,052)	$ (4,635)
NET INCOME AND COMPREHENSIVE INCOME		
Net income and comprehensive income(4)	$ 46,285	$ 72,004
per share - basic(4)	$ 0.10	$ 0.14
per share - diluted(4)	$ 0.10	$ 0.14
COMMON SHARES OUTSTANDING		
Weighted average shares outstanding - basic	481,304,641	514,257,036
Weighted average shares outstanding - diluted	486,004,993	519,227,432

As at ($ Thousands)	March 31, 2026	December 31, 2025
LIQUIDITY AND BALANCE SHEET (CONSOLIDATED)		
Cash and cash equivalents	$ 290,522	$ 316,366
Available credit facilities(5)	$ 115,058	$ 126,595
Face value of long-term debt	$ 212,746	$ 201,209

(1) Corporate Consolidated and Duvernay Energy reflect gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.
(3) Includes realized commodity risk management gain of $0.8 million for the three months ended March 31, 2026 (three months ended March 31, 2025 – loss of $1.6 million).
(4) Net income and comprehensive income per share amounts are based on net income and comprehensive income attributable to shareholders of the Parent Company.
(5) Includes available credit under Athabasca's and Duvernay Energy's Credit Facilities and Athabasca's Unsecured Letter of Credit Facility.

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended March 31, 2026	2025	Change
Crude oil:			
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 71.92	$ 71.42	1 %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 98.65	$ 102.47	(4) %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 79.22	$ 84.30	(6) %
Edmonton Par (C$/bbl)[3]	$ 93.40	$ 95.30	(2) %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 97.70	$ 99.65	(2) %
WCS Differential:			
to WTI (US$/bbl)	$ (14.16)	$ (12.67)	12 %
to WTI (C$/bbl)	$ (19.43)	$ (18.17)	7 %
Edmonton Par Differential:			
to WTI (US$/bbl)	$ (3.76)	$ (4.98)	(24) %
to WTI (C$/bbl)	$ (5.25)	$ (7.17)	(27) %
Natural gas:			
AECO (C$/GJ)[5][6]	$ 1.90	$ 2.05	(7) %
Foreign exchange:			
USD : CAD	1.3716	1.4347	(4) %

Primary benchmark for:
(1) Light Oil pricing in North America.
(2) Athabasca's Heavy oil (i.e. blended bitumen) sales.
(3) Light oil (i.e. light and medium crude oil and tight oil) sales in Duvernay Energy.
(4) Natural gas liquids condensate sales in Duvernay Energy and for diluent purchases in Thermal Oil.
(5) Natural gas consumed by Athabasca in order to generate steam in Thermal Oil.
(6) Natural gas (i.e. shale gas and conventional natural gas) sales in Duvernay Energy.

OUTLOOK

2026 Operational & Financial Guidance ($ millions, unless otherwise noted)	Athabasca (Thermal Oil)	Duvernay Energy(4)(5)	Corporate Consolidated(2)(5)
Production (boe/d)(1)(3)	32,000-34,000	~5,000	37,000-39,000
Adjusted Funds Flow(1)			~$550-$575
Capital Expenditures	$273	$79	$352

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP measures and production disclosure.
(2) May 6, 2026 commodity price guidance: 2026 strip pricing (April 27), US$80.96 WTI, US$14.48 WCS heavy differential, C$1.65 AECO, and 0.73 C$/US$ FX.
(3) Production is inclusive of an approximately 2,500 boe/d annual impact due to planned turnarounds across its assets.
(4) Duvernay Energy's capital expenditures are funded independently through its Adjusted Funds Flow and balance sheet.
(5) Duvernay Energy and Corporate Consolidated reflect gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.

Athabasca's (Thermal Oil) production and capital expenditures guidance remains unchanged. Duvernay Energy is accelerating the timing of a three-well 100% working interest pad into the third quarter of 2026. The capital budget for Duvernay Energy has increased to $79 million (up from $38 million).

Production growth will materialize in the second half of 2026 with an increased exit rate of approximately 45,000 boe/d, supported by the Leismer expansion project and additional Duvernay activity. Annual production is expected to be at the high end of guidance of 37,000 – 39,000 boe/d (98% Liquids), inclusive of an approximately 2,500 boe/d impact of planned turnarounds across its assets.

The Company has increased its consolidated 2026 Adjusted Funds Flow forecast to $550 – $575 million reflecting higher oil prices. With operational momentum into 2027, Adjusted Funds Flow and Free Cash Flow are expected to grow significantly year over year.

CORPORATE CONSOLIDATED OPERATING RESULTS

For analysis of operating results see the Athabasca (Thermal Oil) and Duvernay Energy sections within this MD&A. Corporate Consolidated results reflect gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.

	Three months ended March 31, 2026	2025
PRODUCTION		
Bitumen (bbl/d)	35,629	34,742
Oil and condensate (bbl/d)[1]	3,328	1,839
Natural gas (Mcf/d)[1]	5,227	4,844
Other natural gas liquids (bbl/d)[1]	413	326
Total (boe/d)[1]	40,242	37,714

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP measures and production disclosure.

($ Thousands, unless otherwise noted)	Three months ended March 31, 2026	2025
Petroleum, natural gas and midstream sales[1]	$ 422,398	$ 379,994
Royalties	(18,894)	(18,725)
Cost of diluent[1]	(158,752)	(152,132)
Operating expenses	(48,552)	(42,180)
Transportation and marketing[2]	(23,984)	(21,367)
Operating Income[3]	172,216	145,590
Realized gain (loss) on commodity risk mgmt. contracts	800	(1,643)
OPERATING INCOME NET OF REALIZED HEDGING[3]	$ 173,016	$ 143,947
REALIZED PRICES[3]		
Heavy oil (Blended bitumen) ($/bbl)[3]	$ 79.95	$ 81.48
Oil and condensate ($/bbl)[3]	88.79	93.44
Natural gas ($/Mcf)[3]	2.36	2.33
Other natural gas liquids ($/bbl)[3]	22.14	38.77
Realized price (net of cost of diluent) ($/boe)[3]	70.34	68.98
Royalties ($/boe)[3]	(5.04)	(5.67)
Operating expenses ($/boe)[3]	(12.95)	(12.77)
Transportation and marketing ($/boe)[2][3]	(6.40)	(6.47)
Operating Netback ($/boe)[3]	45.95	44.07
Realized gain (loss) on commodity risk mgmt. contracts ($/boe)[3]	0.21	(0.50)
OPERATING NETBACK NET OF REALIZED HEDGING ($/boe)[3]	$ 46.16	$ 43.57

(1) Non-GAAP measure includes intercompany NGLs (i.e. condensate) sold by the Duvernay Energy segment to the Athabasca (Thermal Oil) segment for use as diluent that is eliminated on consolidation.
(2) Transportation and marketing excludes non-cash costs of $0.6 million for the three months ended March 31, 2026 (three months ended March 31, 2025 - $0.6 million).
(3) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Corporate Consolidated Capital Expenditures

($ Thousands)	Three months ended March 31, 2026	2025
Athabasca (Thermal Oil)	$ 92,125	$ 50,376
Duvernay Energy	21,837	12,957
CORPORATE CONSOLIDATED CAPITAL EXPENDITURES[1][2]	$ 113,962	$ 63,333

(1) For the three months ended March 31, 2026, expenditures include capitalized staff costs of $2.7 million (three months ended March 31, 2025 - $2.4 million).
(2) Excludes non-cash capitalized costs related to stock-based compensation and decommissioning obligation assets.

ATHABASCA (THERMAL OIL)

Athabasca's Thermal Oil assets consist of its cornerstone producing Leismer asset, its producing Hangingstone asset, the high-quality Corner lease which is an extension of the Leismer field and the Dover West exploration asset in the Athabasca region of northeastern Alberta. The Thermal Oil assets underpin the Company's low corporate production decline and low relative sustaining capital requirements, supporting free cash flow generation in the current environment.

Athabasca has a 100% working interest in the producing Leismer Thermal Oil Project (the "Leismer Project") and the delineated Corner lease. The Leismer Project was commissioned in 2010 and has a reserve life index of approximately 65 years (proved plus probable) at current production levels. The Leismer Project has Proved plus Probable Reserves of approximately 687 MMbbl(1) and Best Estimate Development Pending Contingent Resources of 418 MMbbl (risked)(1) (464 MMbbl unrisked)(1). The Corner lease has Proved plus Probable Reserves of approximately 353 MMbbl(1) and Best Estimate Development Pending Contingent Resources of 416 MMbbl (risked)(1) (520 MMbbl unrisked)(1). The Leismer and Corner development application has regulatory approval for future development phases of up to a combined 80,000 bbl/d.

Athabasca also has a 100% working interest in the producing Hangingstone Thermal Oil Project (the "Hangingstone Project"). The Hangingstone Project was commissioned in 2015 and has a reserve life index of approximately 50 years (proved plus probable) at current production levels. Hangingstone has Proved plus Probable Reserves of approximately 161 MMbbl(1).

<u>Royalty</u>

Athabasca has granted Contingent Bitumen Royalties (the "Royalty") on its Thermal Oil assets. The Royalty structure ensures the Thermal Oil assets are not encumbered at low commodity prices while allowing strong participation at high commodity prices. The Royalty on the Leismer and Hangingstone projects is based on a scale from 0% – 15% with a Western Canadian Select ("WCS") heavy benchmark. At prices below US$60 WCS the rate is 0%. The minimum 2.5% rate is triggered at US$60 WCS with a sliding scale up to 15% at US$100 WCS. The Royalty is applied to Athabasca's realized bitumen price (C$), which is determined net of storage and transportation costs.

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2025. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.

Leismer Operating Results

	Three months ended March 31, 2026	2025
VOLUMES		
Bitumen production (bbl/d)	26,683	27,025
Bitumen sales (bbl/d)	27,212	26,519
Heavy oil (blended bitumen) sales (bbl/d)	40,123	38,884

($ Thousands, unless otherwise noted)	Three months ended March 31, 2026	2025
Heavy oil (blended bitumen) sales	$ 285,550	$ 286,133
Cost of diluent	(116,575)	(121,012)
Total bitumen sales	168,975	165,121
Royalties	(12,112)	(12,681)
Operating expenses - non-energy	(21,132)	(19,202)
Operating expenses - energy	(10,507)	(9,668)
Transportation and marketing	(14,123)	(13,206)
LEISMER OPERATING INCOME[(1)]	$ 111,101	$ 110,364
REALIZED PRICE[(1)]		
Heavy oil (blended bitumen) sales ($/bbl)[(1)]	$ 79.08	$ 81.76
Bitumen sales ($/bbl)[(1)]	$ 69.00	$ 69.18
Royalties ($/bbl)[(1)]	(4.95)	(5.31)
Operating expenses - non-energy ($/bbl)[(1)]	(8.63)	(8.05)
Operating expenses - energy ($/bbl)[(1)]	(4.29)	(4.05)
Transportation and marketing ($/bbl)[(1)]	(5.77)	(5.53)
LEISMER OPERATING NETBACK ($/bbl)[(1)]	$ 45.36	$ 46.24

(1) Refer to the “Advisories and Other Guidance” section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Leismer’s bitumen production for the three months ended March 31, 2026 was 26,683 bbl/d. Total operating expenses were $12.92/bbl in the first quarter of 2026, compared to $12.10/bbl for the same period in 2025. The increase on a per barrel basis is largely the result of higher maintenance costs and slightly lower production. Leismer’s Operating Netback was $45.36/bbl for the three months ended March 31, 2026.

Hangingstone Operating Results

	Three months ended March 31, 2026	2025
VOLUMES		
Bitumen production (bbl/d)	8,946	7,717
Bitumen sales (bbl/d)	9,822	7,214
Heavy oil (blended bitumen) sales (bbl/d)	14,616	10,529

($ Thousands, unless otherwise noted)	Three months ended March 31, 2026	2025
Heavy oil (blended bitumen) and midstream sales	$ 108,313	$ 76,242
Cost of diluent	(42,177)	(31,120)
Total bitumen and midstream sales	66,136	45,122
Royalties	(3,989)	(3,283)
Operating expenses - non-energy	(6,150)	(5,685)
Operating expenses - energy	(5,461)	(3,839)
Transportation and marketing[(1)]	(8,978)	(7,363)
HANGINGSTONE OPERATING INCOME[(2)]	$ 41,558	$ 24,952
REALIZED PRICE[(2)]		
Heavy oil (blended bitumen) and midstream sales ($/bbl)[(2)]	$ 82.34	$ 80.46
Bitumen and midstream sales ($/bbl)[(2)]	$ 74.82	$ 69.50
Royalties ($/bbl)[(2)]	(4.51)	(5.06)
Operating expenses - non-energy ($/bbl)[(2)]	(6.96)	(8.76)
Operating expenses - energy ($/bbl)[(2)]	(6.18)	(5.91)
Transportation and marketing ($/bbl)[(1)(2)]	(10.16)	(11.34)
HANGINGSTONE OPERATING NETBACK ($/bbl)[(2)]	$ 47.01	$ 38.43

(1) Transportation and marketing excludes non-cash costs of $0.6 million for the three months ended March 31, 2026 (three months ended March 31, 2025 - $0.6 million).
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Hangingstone's bitumen production for the three months ended March 31, 2026 was 8,946 bbl/d, an increase of 16% compared to the corresponding period in 2025. The production increase is attributed to production from two new well pairs commencing in March 2025.

Total operating expenses were $13.14/bbl in the first quarter of 2026, compared to $14.67/bbl for the same period in 2025, with the decrease primarily the result of higher production.

Hangingstone's Operating Netback was $47.01/bbl for the three months ended March 31, 2026, representing an increase of $8.58/bbl compared with the same period in 2025. The increase on a per bbl basis is largely the result of higher realized prices, higher production volumes which attributed to lower operating expenses and transportation and marketing costs and lower royalties.

Athabasca (Thermal Oil) Operating Results

	Three months ended March 31, 2026	2025
VOLUMES		
Bitumen production (bbl/d)	35,629	34,742
Bitumen sales (bbl/d)	37,034	33,733
Heavy oil (blended bitumen) sales (bbl/d)	54,739	49,413

($ Thousands, unless otherwise noted)	Three months ended March 31, 2026	2025
Heavy oil (blended bitumen) and midstream sales	$ 393,863	$ 362,375
Cost of diluent	(158,752)	(152,132)
Total bitumen and midstream sales	235,111	210,243
Royalties	(16,101)	(15,964)
Operating expenses - non-energy	(27,282)	(24,887)
Operating expenses - energy	(15,968)	(13,507)
Transportation and marketing(1)	(23,101)	(20,569)
ATHABASCA (THERMAL OIL) OPERATING INCOME(2)	$ 152,659	$ 135,316
REALIZED PRICE(2)		
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 79.95	$ 81.48
Bitumen and midstream sales ($/bbl)(2)	$ 70.54	$ 69.25
Royalties ($/bbl)(2)	(4.83)	(5.26)
Operating expenses - non-energy ($/bbl)(2)	(8.19)	(8.20)
Operating expenses - energy ($/bbl)(2)	(4.79)	(4.45)
Transportation and marketing ($/bbl)(1)(2)	(6.93)	(6.78)
ATHABASCA (THERMAL OIL) OPERATING NETBACK ($/bbl)(2)	$ 45.80	$ 44.56

(1) Transportation and marketing excludes non-cash costs of $0.6 million for the three months ended March 31, 2026 (three months ended March 31, 2025 - $0.6 million).
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Seasonality can have an impact on Operating Income generated by the Thermal Oil business. In the first and fourth quarters of a given year, dilution costs will generally increase as more diluent is required to meet pipeline specifications.

Athabasca (Thermal Oil) Capital Expenditures

($ Thousands)	Three months ended March 31, 2026	2025
Leismer Project	$ 80,593	$ 43,704
Hangingstone Project	3,157	6,308
Corner Project and Other	8,375	364
ATHABASCA (THERMAL OIL) CAPITAL EXPENDITURES(1)	$ 92,125	$ 50,376

(1) For the three months ended March 31, 2026, capital expenditures include $2.0 million of capitalized staff costs (three months ended March 31, 2025 - $1.6 million).

Thermal Oil capital expenditures were $92.1 million for the three months ended March 31, 2026. At Leismer, the Company continued to advance its next expansion project, with field activity including facilities and pipeline construction on Pad 10 and 11, drilling and commencing completion activities on Pad 10. At Corner, work continued on advancing the project which included regulatory, engineering of the central processing facility, road access and lease site construction.

DUVERNAY ENERGY[1]

Duvernay Energy, a privately held subsidiary of Athabasca, commenced operations on February 6, 2024 following the transfer of certain assets, pursuant to an agreement involving Athabasca and Cenovus Energy ("Cenovus") (the "Transaction"). Athabasca received a 70% equity interest in exchange for cash, petroleum and natural gas assets and the transferred interest of its wholly owned Kaybob partnership. Cenovus received a 30% equity interest in exchange for cash and petroleum and natural gas assets. Duvernay Energy is managed by Athabasca through a management and operating services agreement. With Duvernay Energy operating as a subsidiary under Athabasca's control it is consolidated within the Consolidated Financial Statements.

Duvernay Energy produces light oil and liquids-rich natural gas from unconventional reservoirs. Development has been focused on the Duvernay shale play in the Greater Kaybob area near the town of Fox Creek, Alberta. As at December 31, 2025, the Greater Kaybob assets had approximately 79 MMboe of Proved plus Probable Reserves[2]. The Duvernay Energy assets are supported by operated regional infrastructure consisting of two batteries and a network of gas pipelines which connect the facilities to two regional third party gas processing plants.

In Greater Kaybob, Duvernay Energy has approximately 200,000 gross acres of commercially prospective Duvernay lands with exposure to both Liquids-rich gas and volatile oil opportunities. This land is comprised of a 100% operated interest in approximately 46,000 gross acres and a 30% non-operated interest in approximately 155,000 gross acres with an estimated inventory of 432[3] gross drilling locations.

(1) Duvernay Energy reflects gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.
(2) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2025. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.
(3) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information regarding the Company's drilling locations.

Duvernay Energy Operating Results

	Three months ended March 31, 2026	2025
PRODUCTION[1]		
Oil and condensate (bbl/d)	3,328	1,839
Natural gas (Mcf/d)	5,227	4,844
Other natural gas liquids (bbl/d)	413	326
Total (boe/d)	4,613	2,972
% Liquids	81%	73%

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on production disclosure.

($ Thousands, unless otherwise noted)	Three months ended March 31, 2026	2025
Petroleum and natural gas sales	$ 28,535	$ 17,619
Royalties	(2,793)	(2,761)
Operating expenses	(5,302)	(3,786)
Transportation and marketing	(883)	(798)
DUVERNAY ENERGY OPERATING INCOME[1]	$ 19,557	$ 10,274
REALIZED PRICES[1]		
Oil and condensate ($/bbl)[1]	$ 88.79	$ 93.44
Natural gas ($/Mcf)[1]	2.36	2.33
Other natural gas liquids ($/bbl)[1]	22.14	38.77
Realized price ($/boe)[1]	68.73	65.87
Royalties ($/boe)[1]	(6.73)	(10.32)
Operating expenses ($/boe)[1]	(12.77)	(14.15)
Transportation and marketing ($/boe)[1]	(2.13)	(2.98)
DUVERNAY ENERGY OPERATING NETBACK ($/boe)[1]	$ 47.10	$ 38.42

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Duvernay Energy's production for the three months ended March 31, 2026 was 4,613 boe/d, an increase of 55% compared to the corresponding period in 2025. The production growth in the first quarter is primarily attributed to the seven gross (4.2 net) development wells that were placed on production in 2025.

Total operating expenses were $12.77/boe in the first quarter of 2026, compared to $14.15/boe for the same period in 2025. The decrease on a per boe basis is the result of higher production.

Duvernay Energy's Operating Netback was $47.10/boe in the first quarter of 2026, compared to $38.42/boe for the same period in 2025. The increase on a per boe basis from the comparable 2025 period is largely the result of having a higher percentage of liquids production resulting in a higher realized price, lower royalties and higher production volumes which attributed to lower operating expenses and transportation and marketing costs on a boe basis.

Duvernay Energy Capital Expenditures

($ Thousands)	Three months ended March 31, 2026	2025
DUVERNAY ENERGY CAPITAL EXPENDITURES[1]	$ 21,837	$ 12,957

(1) For the three months ended March 31, 2026, capital expenditures include $0.7 million of capitalized staff costs (three months ended March 31, 2025 - $0.8 million).

For the three months ended March 31, 2026, Duvernay Energy's capital expenditures were $21.8 million. Activity focused on completion operations on a four well pad (30% working interest) brought on production early in the second quarter of 2026 and the drilling of a land retention well (100% working interest). Capital expenditures also included the ongoing expansion of the operated Kaybob facilities, supporting future development activity.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

For the balance of 2026, it is anticipated that Athabasca's capital and operating activities will be funded through cash flow from operating activities and existing credit facilities and cash and cash equivalents. The Company is directing Free Cash Flow to share buybacks and high return growth projects. Maintaining sufficient liquidity and a commodity risk management program is expected to allow the Company to manage periods of volatility.

As at March 31, 2026, Athabasca had Liquidity of $405.6 million which included $290.5 million of cash and cash equivalents, all within Athabasca (Thermal Oil), and $115.1 million of available capacity on its credit facilities (comprised of $78.2 million Athabasca (Thermal Oil) and $36.9 million Duvernay Energy).

Indebtedness

Athabasca had the following debt instruments and credit facilities in place as at March 31, 2026:

Term Debt

On August 9, 2024, Athabasca issued $200 million Senior Unsecured Notes ("2029 Notes"). The 2029 Notes bear interest at 6.75% per annum, payable semi-annually, and have a five year term maturing on August 9, 2029.

The 2029 Notes are unsecured, ranking equal in right of payment to all existing and future unsecured indebtedness, and are not subject to any maintenance or financial covenants. The 2029 Notes contain certain covenants that limit the Company's ability to, among other things, incur additional indebtedness, create or permit liens to exist, and make certain restricted payments, dispositions and transfers of assets. As at March 31, 2026, the Company is in compliance with all covenants.

Athabasca may redeem all or part of the 2029 Notes at any time prior to August 9, 2026 at 100% of the principal amount plus an applicable premium, as set out in the 2029 Notes indenture. On or after August 9, 2026, Athabasca may redeem all or part of the 2029 Notes at 103.375% from August 9, 2026 to August 8, 2027, at 101.688% from August 9, 2027 to August 8, 2028, and at 100% from August 9, 2028 onwards.

Credit Facility

Athabasca has a $110.0 million reserve-based credit facility (the "Credit Facility"). The Credit Facility is a committed facility available on a revolving basis until May 31, 2027, at which point in time it may be extended at the lender's option. The Credit Facility is subject to an annual borrowing base review, occurring by May 31 of each year. The borrowing base is determined based on the lender's evaluation of the Company's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal. As at March 31, 2026 and December 31, 2025, the Company had no amounts drawn and $41.1 million of letters of credit outstanding under the Credit Facility.

Unsecured Letter of Credit Facility

Athabasca maintains a $75.0 million unsecured letter of credit facility (the "Unsecured Letter of Credit Facility") with a Canadian bank that is supported by a performance security guarantee from Export Development Canada. The facility is available on a demand basis and letters of credit issued under this facility incur an issuance and performance guarantee fee of 3.25%. As at

March 31, 2026 and December 31, 2025, the Company had $65.7 million of letters of credit outstanding under the Unsecured Letter of Credit Facility.

Duvernay Energy Credit Facility

Duvernay Energy has a $50.0 million reserve-based credit facility (the “Duvernay Credit Facility”). The Duvernay Credit Facility is a committed facility available on a revolving basis until November 30, 2026, at which point in time it may be extended at the lender's option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and any amounts outstanding would be repayable at the end of the non-revolving term, being November 30, 2027. The Duvernay Credit Facility is subject to a semi-annual borrowing base review, occurring by May 31 and November 30 of each year. The borrowing base is determined based on the lender's evaluation of Duvernay Energy's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal. As at March 31, 2026, the Company had $12.7 million drawn and $0.4 million of letters of credit outstanding under the Duvernay Credit Facility. As at December 31, 2025, the Company had $1.2 million drawn and $0.4 million of letters of credit outstanding under the Duvernay Credit Facility.

Financing and Interest

($ Thousands)	Three months ended March 31, 2026	2025
Financing and interest expense on indebtedness	$ 4,714	$ 4,686
Accretion of 2029 Notes	204	189
Accretion of provisions	2,180	2,106
Interest expense on lease liability	85	79
TOTAL FINANCING AND INTEREST	$ 7,183	$ 7,060

For the three months ended March 31, 2026 and 2025, financing and interest expense on indebtedness were primarily attributable to the Company's 2029 Notes. Accretion of provisions of $2.2 million for the three months ended March 31, 2026 (March 31, 2025 - $2.1 million) primarily relates to accretion on the Company’s decommissioning obligations.

Foreign Exchange Gain (Loss), Net

As at March 31, 2026, Athabasca’s net foreign exchange risk exposure was a US$258.0 million asset (December 31, 2025 - US$267.5 million asset), and a 5.0% change in the foreign exchange rate (USD:CAD) would result in a $18.0 million change in the foreign exchange gain/loss (December 31, 2025 - $18.3 million).

The following table provides a breakdown of the foreign exchange gain (loss):

($ Thousands)	Three months ended March 31, 2026	2025
Unrealized foreign exchange gain (loss)	$ 5,783	$ (777)
Realized foreign exchange gain	287	152
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 6,070	$ (625)

Athabasca is exposed to foreign currency risk on its US dollar denominated cash, cash equivalents, receivables and payables.

Risk Management Contracts

The Company may utilize financial and/or physical delivery contracts to fix the commodity price associated with a portion of its future production in order to manage its exposure to fluctuations in commodity prices.

Financial commodity risk management contracts are valued on the consolidated balance sheet at each period end by multiplying the contractual volumes by the differential between the anticipated market price (i.e. forecasted strip price) and the contractual fixed price at each future settlement date. The corresponding change in the asset or liability is recognized as an unrealized gain or loss in the consolidated statements of income (loss). As the commodity derivatives are unwound (i.e. settled in cash), the Company recognizes a corresponding realized gain or loss in the consolidated statements of income (loss). Physical delivery contracts are not considered financial instruments and therefore, no asset or liability is recognized on the consolidated balance sheet.

Financial commodity risk management contracts

At March 31, 2026, the following financial commodity risk management contracts were in place for Athabasca (Thermal Oil):

Instrument	Period	Volume		C$ Average Price(1)		US$ Average Price(1)
Sales contracts				*C$/bbl*		*US$/bbl*
WTI fixed price swaps	July - September 2026	10,000 bbl/d	$	97.57	$	70.00
WTI fixed price swaps	October - December 2026	10,000 bbl/d	$	97.99	$	70.30
WTI collars	July - December 2026	13,850 bbl/d	$	97.57 - 107.78	$	70.00 - 77.32
Purchase contracts				*C$/GJ/bbl*		*US$/GJ/bbl*
C5+ differentials	April - December 2026(2)	3,000 bbl/d	$	(2.56)	$	(1.83)
AECO fixed price swaps	April - December 2026(2)	25,000 GJ/d	$	2.79	$	2.00
C5+ fixed price purchases	July - September 2026	6,000 bbl/d	$	97.22	$	69.75
C5+ fixed price purchases	October - December 2026	6,000 bbl/d	$	96.64	$	69.33

(1) The implied C$ or US$ average price per bbl or GJ, as applicable, was calculated using the March 31, 2026 exchange rate of US$1.00 = C$1.3939.
(2) Excludes May 2026 due to the planned Thermal Oil turnarounds.

In 2021, Athabasca (Thermal Oil) entered into a seven-year marketing agreement with an industry counterparty that diversifies the Company's sales to the US Gulf Coast through the Keystone pipeline system. The marketing agreement has a pricing derivative that provides exposure to WCS Gulf Coast pricing. As at March 31, 2026, the pricing derivative had a liability value of $2.4 million (December 31, 2025 - liability value of $3.0 million).

The following table summarizes the sensitivity to price changes for the Company's commodity risk management contracts for Athabasca (Thermal Oil):

As at March 31, 2026	Change in WTI		Change in AECO		Change in C5 differential		Change in C5+	
	Increase of US$5.00/bbl	Decrease of US$5.00/bbl	Increase of C$1.00/GJ	Decrease of C$1.00/GJ	Increase of US$1.00/bbl	Decrease of US$1.00/bbl	Increase of US$5.00/bbl	Decrease of US$5.00/bbl
Increase (decrease) to fair value of commodity risk management contracts	$ (14,173)	$ 13,150	$ 5,963	$ (5,918)	$ 2,401	$ (2,401)	$ 7,588	$ (7,534)

Subsequent to March 31, 2026 Athabasca (Thermal Oil) entered into WTI calls at US$100/bbl for 17,000 bbl/d from July through December 2026.

At March 31, 2026, the following financial commodity risk management contracts were in place for Duvernay Energy:

Instrument	Period	Volume		C$ Average Price(1)		US$ Average Price(1)
Sales contracts				*C$/bbl*		*US$/bbl*
WTI fixed price swaps	April - June 2026	1,525 bbl/d	$	87.78	$	62.97
WTI fixed price swaps	July - September 2026	1,175 bbl/d	$	88.04	$	63.16
WTI fixed price swaps	October - December 2026	450 bbl/d	$	87.63	$	62.87
WTI collars	April - June 2026	1,325 bbl/d	$	83.63 - 93.05	$	60.00 - 66.76
WTI collars	July - September 2026	1,175 bbl/d	$	83.63 - 91.84	$	60.00 - 65.89
WTI collars	October - December 2026	450 bbl/d	$	83.63 - 89.67	$	60.00 - 64.33

(1) The implied C$ or US$ average price per bbl was calculated using the March 31, 2026 exchange rate of US$1.00 = C$1.3939.

The following table summarizes the sensitivity to price changes for the Company's commodity risk management contracts for Duvernay Energy:

As at March 31, 2026		Change in WTI Increase of US$5.00/bbl		Decrease of US$5.00/bbl
Increase (decrease) to fair value of commodity risk management contracts	$	(3,804)	$	3,804

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three months ended March 31, 2026 and 2025:

($ Thousands)		Three months ended March 31, 2026		2025
Unrealized gain (loss) on commodity risk mgmt. contracts	$	(25,397)	$	2,486
Realized gain (loss) on commodity risk mgmt. contracts		800		(1,643)
GAIN (LOSS) ON COMMODITY RISK MGMT. CONTRACTS, NET	$	(24,597)	$	843

Commitments

The following table summarizes Athabasca's estimated future unrecognized minimum commitments as at March 31, 2026 for the following five years and thereafter:

($ Thousands)		Remaining 2026		2027		2028		2029		2030		Thereafter		Total
Transportation and processing(1)	$	92,151	$	149,594	$	137,951	$	120,468	$	120,027	$	1,571,511	$	2,191,702
Interest expense on 2029 Notes		10,125		13,500		13,500		8,174		—		—		45,299
Purchase commitments and other(1)		33,152		5,609		—		—		—		—		38,761
TOTAL COMMITMENTS	$	135,428	$	168,703	$	151,451	$	128,642	$	120,027	$	1,571,511	$	2,275,762

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the March 31, 2026 exchange rate of US$1.00 = C$1.3939.

Credit Risk

Credit risk is the risk of financial loss to Athabasca if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from Athabasca's cash balances, accounts receivables from petroleum and natural gas marketers, joint interest partners and risk management contract counterparties.

Athabasca's cash and cash equivalents are held with two counterparties, which are large reputable financial institutions, and management has therefore concluded that credit risk associated with the investments is low. Management concluded that collection risk of the outstanding accounts receivables is low given the high credit quality of the Company's material counterparties. No material receivables were past due as at March 31, 2026. Athabasca's risk management contracts are held with three counterparties, all of which are large reputable financial institutions, and management has therefore concluded that credit risk associated with these risk management contracts is low.

Interest Rate Risk

The Company has exposure to interest rate fluctuations on its floating rate cash and cash equivalents balance at March 31, 2026 of $290.5 million (December 31, 2025 - $316.4 million). A 1.0% change in interest rates would have an annualized impact of approximately $2.9 million (year ended December 31, 2025 - $3.2 million) on interest income. The 2029 Notes and letters of credit issued are subject to fixed interest rates and are not exposed to changes in interest rates.

Duvernay Energy is exposed to interest rate fluctuations on its floating rate long-term debt balance at March 31, 2026 of $12.7 million (December 31, 2025 - $1.2 million). Amounts borrowed under the Duvernay Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, SOFR or CORRA, plus a margin of 2.00% to 3.00%. Changes in interest rates could result in an increase or decrease in the amount Duvernay Energy pays to service the Duvernay Credit Facility. Letters of credit are subject to fixed interest rates and are not exposed to changes in interest rates. A 1.0% change in interest rates would have an annualized impact of approximately $0.1 million (December 31, 2025 - $0.1 million) on financing and interest expense.

Other Corporate Items

General and Administrative ("G&A")

($ Thousands, unless otherwise noted)		Three months ended March 31, 2026		2025
TOTAL GENERAL AND ADMINISTRATIVE	$	6,188	$	6,047
G&A per boe[1]	$	1.71	$	1.78

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Stock-Based Compensation

During the three months ended March 31, 2026, Athabasca's stock-based compensation expense was $38.0 million, compared to $7.7 million in the prior year period. Stock-based compensation expense is impacted by the changes in the fair value of the cash settled stock-based compensation plans as a result of the share price changes in the respective periods. During the first quarter of 2026, Athabasca's share price increased by 60% or $4.22 per share.

Depletion and Depreciation

For the three months ended March 31, 2026, Athabasca's depletion and depreciation expense was $34.5 million compared to $31.2 million in the prior year period. The year over year increase is primarily a result of higher production at Duvernay Energy.

Loss on Revaluation of Provisions and Other

($ Thousands)		Three months ended March 31, 2026		2025
Change in fair value of warrant liability	$	(9,673)	$	(1,569)
LOSS ON REVALUATION OF PROVISIONS AND OTHER	$	(9,673)	$	(1,569)

The warrants are classified as a financial liability due to the cashless exercise provision and are therefore revalued quarterly. The changes in the fair value of the warrant liability in 2026 and 2025 primarily relate to changes in the share price.

Income Taxes

In the first three months of 2026, as a result of net income before tax of $60.3 million, $16.1 million of deferred income tax expense was recorded (first three months of 2025 - $21.5 million expense). At March 31, 2026, the Company recognized a deferred tax asset of $220.8 million (December 31, 2025 - $234.1 million) and a deferred tax liability of $44.2 million (December 31, 2025 - $46.6 million). The deferred tax liability is recognized as a result of the assets transferred in the Duvernay Energy Transaction. Management has concluded that based on current cash flow projections, it is probable Athabasca will generate sufficient taxable profits against which the deferred tax asset can be utilized. As at March 31, 2026, the Company has approximately $2.1 billion in tax pools, including approximately $1.5 billion in non-capital loss tax pools available for immediate deduction against future income.

Environmental and Regulatory Risks Impacting Athabasca

Athabasca operates in jurisdictions that have regulated greenhouse gas ("GHG") emissions and other air pollutants. While some regulations are in effect, further changes and amendments are at various stages of review, discussion and implementation. There is uncertainty around how any future federal legislation will harmonize with provincial regulation, as well as the timing and effects of regulations. Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the crude oil and natural gas industry in Canada. Such regulations impose certain costs and risks on the industry, and there remains uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as such Athabasca is unable to predict additional legislation or amendments that governments may enact in the future. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's assets, operations and cash flow.

Off Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements that have or are reasonably likely to have a material current or future effect on the Company’s consolidated financial statements.

Outstanding Share Data

As at March 31, 2026, there were 483.7 million common shares outstanding, 3.6 million restricted share units outstanding, 3.3 million performance share units outstanding, 2.4 million stock options outstanding and 1.0 million potential shares issuable under warrants agreements (4,324 warrants outstanding).

In the first quarter of 2026, the Company renewed its NCIB with approval to purchase up to 47.0 million common shares during the twelve-month period commencing March 18, 2026 and ending March 17, 2027. The Company repurchased and cancelled on its previous NCIB a total of 32.7 million common shares for the twelve-month period ended March 17, 2026.

During the first three months of 2026, the Company repurchased for cancellation 2.4 million common shares under its NCIB program. Subsequent to March 31, 2026, the Company repurchased for cancellation an additional 1.5 million common shares under its NCIB program.

As at May 6, 2026, there were 484.0 million common shares outstanding, 2.8 million restricted share units outstanding, 2.4 million performance share units outstanding, 2.4 million stock options outstanding and 1.0 million potential shares issuable under warrants agreements (4,324 warrants outstanding).

SUMMARY OF QUARTERLY RESULTS

The following table summarizes selected consolidated financial information for the Company for the preceding eight quarters:

	2026	2025				2024		
($ Thousands, unless otherwise noted)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	71.92	59.14	64.93	63.74	71.42	70.27	75.09	80.57
WTI (C$/bbl)	98.65	82.49	89.43	88.21	102.47	98.29	102.39	110.25
Western Canadian Select (C$/bbl)	79.22	66.89	75.11	73.96	84.30	80.74	83.91	91.59
Edmonton Par (C$/bbl)	93.40	76.39	86.18	84.13	95.30	94.91	97.85	105.32
Edmonton Condensate (C5+) (C$/bbl)	97.70	79.16	86.43	87.42	99.65	98.25	96.49	104.85
AECO (C$/GJ)	1.90	2.11	0.60	1.60	2.05	1.40	0.65	1.12
Foreign exchange (USD : CAD)	1.37	1.39	1.38	1.38	1.43	1.40	1.36	1.37
CORPORATE CONSOLIDATED(1)								
Petroleum and natural gas production (boe/d)(2)	40,242	41,061	39,599	39,088	37,714	37,236	38,909	37,621
Realized price (net of cost of diluent) ($/boe)(2)	70.34	54.20	62.53	60.70	68.98	67.27	72.90	79.93
Petroleum, natural gas and midstream sales ($)(3)	422,398	324,863	345,382	368,686	379,994	366,895	397,362	422,028
Operating Income ($)(2)	172,216	128,231	151,835	141,707	145,590	155,022	180,184	179,751
Operating Income Net of Realized Hedging ($)(2)	173,016	132,608	144,650	142,101	143,947	153,119	175,755	178,176
Operating Netback ($/boe)(2)	45.95	34.50	42.50	38.81	44.07	45.53	49.12	52.46
Operating Netback Net of Realized Hedging ($/boe)(2)	46.16	35.68	40.49	38.92	43.57	44.97	47.91	52.00
Capital expenditures ($)	113,962	89,955	96,190	73,066	63,333	92,944	50,634	48,453
Cash flow from operating activities ($)	102,027	138,259	157,414	101,432	123,353	158,677	187,143	135,083
Adjusted Funds Flow ($)(2)	128,025	117,473	129,197	127,591	129,675	143,737	163,680	165,746
ATHABASCA (THERMAL OIL)								
Bitumen production (bbl/d)	35,629	35,795	36,590	36,476	34,742	33,849	34,853	33,765
Bitumen sales volumes (bbl/d)	37,034	35,134	35,818	37,511	33,733	33,628	35,813	33,794
Realized bitumen price ($/bbl)(2)	70.54	53.73	62.98	60.96	69.25	67.52	73.65	80.36
Heavy Oil (blended bitumen) and midstream sales ($)	393,863	297,101	329,542	355,160	362,375	346,716	372,634	395,279
Operating Income ($)(2)	152,659	109,651	142,631	135,803	135,316	143,246	163,694	161,694
Operating Netback ($/bbl)(2)	45.80	33.93	43.28	39.79	44.56	46.30	49.68	52.59
Capital expenditures ($)	92,125	76,173	64,965	56,110	50,376	74,268	44,431	34,084
Adjusted Funds Flow ($)(2)	112,240	99,925	121,131	122,097	121,353	133,398	150,088	149,413
Free Cash Flow ($)(2)	20,115	23,752	56,166	65,987	70,977	59,130	105,657	115,329
DUVERNAY ENERGY(1)								
Petroleum and natural gas production (boe/d)(2)	4,613	5,266	3,009	2,612	2,972	3,387	4,056	3,856
Realized price ($/boe)(2)	68.73	57.30	57.22	56.91	65.87	64.76	66.27	76.23
Petroleum and natural gas sales ($)(3)	28,535	27,762	15,840	13,526	17,619	20,179	24,728	26,749
Operating Income ($)(2)	19,557	18,580	9,204	5,904	10,274	11,776	16,490	18,057
Operating Netback ($/boe)(2)	47.10	38.35	33.25	24.84	38.42	37.79	44.20	51.46
Capital expenditures ($)	21,837	13,782	31,225	16,956	12,957	18,676	6,203	14,369
Adjusted Funds Flow ($)(2)	15,785	17,548	8,066	5,494	8,322	10,339	13,592	16,333
Free Cash Flow ($)(2)	(6,052)	3,766	(23,159)	(11,462)	(4,635)	(8,337)	7,389	1,964
OPERATING RESULTS								
Net income ($)(4)	46,285	46,596	69,640	56,870	72,004	264,336	68,722	96,076
Net income per share - basic ($)(4)	0.10	0.10	0.14	0.11	0.14	0.50	0.13	0.17
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	290,522	316,366	334,550	304,048	304,538	344,836	334,851	303,360
Total assets ($)	2,672,785	2,550,739	2,532,553	2,475,675	2,457,126	2,474,609	2,234,651	2,230,648
Long-term debt ($)	209,573	197,832	198,084	196,217	196,022	195,833	195,642	190,986
Shareholders' equity ($)	1,964,054	1,893,307	1,898,145	1,889,887	1,866,431	1,863,732	1,674,942	1,687,741

(1) Corporate Consolidated and Duvernay Energy reflect gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.
(3) Includes intercompany NGLs (i.e. condensate) sold by the Duvernay Energy segment to the Athabasca (Thermal Oil) segment for use as diluent that is eliminated on consolidation.
(4) Net income per share amounts are based on net income attributable to shareholders of the Parent Company.

Refer to the Results of Operations and other sections of this MD&A for detailed financial and operational variances between reporting periods as well as to Athabasca's previously issued annual and quarterly MD&As for changes in prior periods.

ACCOUNTING POLICIES AND ESTIMATES

During the three months ended March 31, 2026, there were no changes to Athabasca's accounting policies or use of estimates and judgments in the preparation of the Consolidated Financial Statements and the notes thereto. A summary of the significant accounting policies, including the use of estimates and judgments, used by Athabasca can be found in Note 3 of the December 31, 2025 audited consolidated financial statements. All of the estimates and judgments are subject to measurement uncertainty and changes in these estimates could materially impact the consolidated financial statements of future periods and have a significant impact on net income (loss) and comprehensive income (loss).

ADVISORIES AND OTHER GUIDANCE

Non-GAAP and Other Financial Measures, and Production Disclosure

The "Corporate Consolidated Adjusted Funds Flow", "Corporate Consolidated Adjusted Funds Flow per Share", "Athabasca (Thermal Oil) Adjusted Funds Flow", "Duvernay Energy Adjusted Funds Flow", "Corporate Consolidated Free Cash Flow", "Athabasca (Thermal Oil) Free Cash Flow", "Duvernay Energy Free Cash Flow", "Corporate Consolidated Operating Income", "Corporate Consolidated Operating Income Net of Realized Hedging", "Athabasca (Thermal Oil) Operating Income", "Duvernay Energy Operating Income", "Corporate Consolidated Operating Netback", "Corporate Consolidated Operating Netback Net of Realized Hedging", "Athabasca (Thermal Oil) Operating Netback", "Duvernay Energy Operating Netback", "Realized Prices" and "Cash Transportation and Marketing Expense" financial measures contained in this MD&A do not have standardized meanings which are prescribed by IFRS and they are considered to be non-GAAP financial measures or ratios. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS. The Liquidity and the per boe or per bbl disclosures for each segment's royalties, operating expenses, transportation and marketing, realized gain (loss) on commodity risk management contracts and G&A are supplementary financial measures. The Leismer and Hangingstone operating results are supplementary financial measures that when aggregated combine to the Athabasca (Thermal Oil) segment results.

<u>Adjusted Funds Flow, Adjusted Funds Flow Per Share and Free Cash Flow</u>

Adjusted Funds Flow and Free Cash Flow are non-GAAP financial measures and are not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Adjusted Funds Flow and Free Cash Flow measures allow management and others to evaluate the Company's ability to fund its capital programs and meet its ongoing financial obligations using cash flow internally generated from ongoing operating related activities. Adjusted Funds Flow per share is a non-GAAP financial ratio calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding.

Adjusted Funds Flow and Free Cash Flow are calculated as follows:

	Three months ended March 31, 2026		
($ Thousands)	Athabasca (Thermal Oil)	Duvernay Energy(1)	Corporate Consolidated(1)
Cash flow from operating activities	$ 87,625	$ 14,402	$ 102,027
Changes in non-cash working capital	22,538	1,278	23,816
Settlement of provisions	2,077	105	2,182
ADJUSTED FUNDS FLOW	112,240	15,785	128,025
Capital expenditures	(92,125)	(21,837)	(113,962)
FREE CASH FLOW	$ 20,115	$ (6,052)	$ 14,063

(1) Duvernay Energy and Corporate Consolidated reflect gross financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.

($ Thousands)		Three months ended March 31, 2025 Athabasca (Thermal Oil)	Duvernay Energy[1]	Corporate Consolidated[1]
Cash flow from operating activities	$	113,427 $	9,926 $	123,353
Changes in non-cash working capital		7,230	(1,612)	5,618
Settlement of provisions		696	8	704
ADJUSTED FUNDS FLOW		121,353	8,322	129,675
Capital expenditures		(50,376)	(12,957)	(63,333)
FREE CASH FLOW	$	70,977 $	(4,635) $	66,342

(1) Duvernay Energy and Corporate Consolidated reflect gross financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.

Operating Income and Operating Netback

The non-GAAP measure Operating Income in this MD&A is calculated by subtracting the cost of diluent, royalties, operating expenses and cash transportation & marketing expenses from petroleum, natural gas and midstream sales which is the most directly comparable GAAP measure. The Operating Netback per boe is a non-GAAP financial ratio measure calculated by dividing the respective projects Operating Income by its respective sales volumes. The Operating Income and Operating Netback measures allow management and others to evaluate the production results from the Company's assets.

The non-GAAP measure Corporate Consolidated Operating Income Net of Realized Hedging in this MD&A is calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, royalties, the cost of diluent, operating expenses and cash transportation & marketing expenses from petroleum, natural gas and midstream sales which is the most directly comparable GAAP measure. The Corporate Consolidated Operating Netback Net of Realized Hedging measure per boe is a non-GAAP financial ratio calculated by dividing Corporate Consolidated Operating Income Net of Realized Hedging by the total sales volumes. The Corporate Consolidated Operating Income Net of Realized Hedging and the Corporate Consolidated Operating Netback Net of Realized Hedging measures allow management and others to evaluate the production results from the Company's Duvernay Energy and Athabasca (Thermal Oil) assets combined together including the impact of realized commodity risk management gains or losses.

Realized Prices

The realized price financial measures contained in this MD&A are calculated by subtracting the cost of diluent from the petroleum, natural gas and midstream sales for the respective segment and are considered to be non-GAAP financial ratios.

Cash Transportation and Marketing Expense

The Cash Transportation and Marketing Expense financial measures contained in this MD&A are calculated by subtracting the non-cash transportation and marketing expense as reported in the Consolidated Statement of Cash Flows from the transportation and marketing expense as reported in the Consolidated Statement of Income (Loss) and are considered to be non-GAAP financial measures.

Supplementary Financial Measures

The supplementary financial measure Liquidity is defined as cash and cash equivalents plus available credit capacity.

Per boe or per bbl disclosures for each segment's royalties, operating expenses, transportation and marketing, realized gain (loss) on commodity risk management contracts and G&A are supplementary financial measures that are calculated by dividing the respective GAAP measure by its respective sales volumes.

Production volumes details

Production[1]		Three months ended March 31, 2026	2025
Duvernay Energy:			
Oil and condensate NGLs[2]	bbl/d	3,328	1,839
Other NGLs	bbl/d	413	326
Natural gas[3]	mcf/d	5,227	4,844
Total Duvernay Energy	boe/d	4,613	2,972
Total Thermal Oil bitumen	bbl/d	35,629	34,742
Total Company production	boe/d	40,242	37,714

(1) Duvernay Energy and Total Company production reflect gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.
(2) Comprised of 99% or greater of tight oil, with the remaining being light and medium crude oil.
(3) Comprised of 99% or greater of shale gas, with the remaining being conventional natural gas.

Liquids[1]		Three months ended March 31, 2026	2025
Total Duvernay Energy:			
Oil and condensate NGLs	bbl/d	3,328	1,839
Other NGLs	bbl/d	413	326
Total Duvernay Energy Liquids	bbl/d	3,741	2,165
as % of Duvernay Energy production		81%	73%
Total Company:			
Total Duvernay Energy Liquids	bbl/d	3,741	2,165
Total Thermal Oil bitumen	bbl/d	35,629	34,742
Total Company Liquids	bbl/d	39,370	36,907
as % of Company production		98%	98%

(1) Duvernay Energy and Total Company reflect gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.

This MD&A also makes reference to Athabasca's forecasted total average daily Thermal Oil production of 32,000 - 34,000 bbl/d for 2026. Athabasca expects that 100% of that production will be comprised of bitumen. Duvernay Energy's forecasted total average daily production of approximately 5,000 boe/d for 2026 is expected to be comprised of approximately 69% tight oil, 22% shale gas and 9% NGLs.

Disclosure Control and Procedures

Athabasca is required to comply with National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). NI 52-109 requires that Athabasca disclose in its interim MD&A any material weaknesses in Athabasca's internal control over financial reporting and/or any changes in Athabasca's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect, Athabasca's internal controls over financial reporting. Athabasca confirms that no material weaknesses or such changes were identified in Athabasca's internal controls over financial reporting during the first quarter of 2026.

Risks

Factors currently influencing the Company's ability to succeed include, but are not limited to, the following:

Operational risks

- the performance of the Company's assets;
- reservoir impairment when shutting in or curtailing production from oil and gas assets;
- Athabasca's exploration and development budget and Athabasca's capital expenditure programs;
- failure to realize anticipated benefits of acquisitions or divestments;
- uncertainties inherent in estimating quantities of Proved Reserves, Probable Reserves and Contingent Resources;

- the timing of certain of Athabasca's operations and projects, including the commencement of its planned Thermal Oil development projects, the exploration and development of its Duvernay Energy assets and the levels and timing of anticipated production;
- dependence upon Murphy as the operator of the joint development Greater Kaybob assets;
- risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of reserves and resources;
- risks related to gathering and processing facilities and pipeline systems;
- reliance on third party infrastructure;
- supply chain disruption;
- seasonality and weather conditions, which may be impacted by climate change;
- risks associated with events of force majeure; and
- expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits.

Planning risks

- the business strategy, objectives and business strengths of Athabasca;
- Athabasca's growth strategy and opportunities;
- Athabasca's plans to submit additional regulatory applications;
- Athabasca's drilling plans and plans and results regarding the completion of wells that have been drilled and other exploration and development activities;
- Athabasca's environment, social and governance goals;
- failure to accurately estimate abandonment and reclamation costs; and
- the potential for management estimates and assumptions to be inaccurate.

Financial and market risks

- general economic, market and business conditions in Canada, the United States and globally;
- future commodity market prices;
- Canadian heavy and light oil export capacity constraints and the resulting impact on realized pricing;
- Athabasca's projections of commodity prices, costs and netbacks;
- the substantial capital requirements of Athabasca's projects and the Company's ability to raise capital;
- risk of reduced capital availability due to environmental and climate related reputational issues for industry;
- the potential for future joint venture arrangements;
- insurance risks;
- hedging risks;
- variations in foreign exchange and interest rates;
- risks related to the Company's indebtedness;
- risks related to the Common Shares; and
- risks of cybersecurity threats including the possibility of potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems.

Legal and compliance risks

- the regulatory framework governing royalties, taxes, environmental matters and foreign investment in the jurisdictions in which Athabasca conducts and will conduct its business;
- risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments;
- risks related to climate change and carbon pricing;
- actions taken by the American administration on the imposition of taxes on the importation of goods into the United States;
- aboriginal claims;
- risks associated with establishing and maintaining systems of internal controls;
- inaccuracy of forward-looking information; and
- risks related to the Government of Canada amendments to the deceptive marketing practices provisions of the *Competition Act* (Canada) that specifically address greenwashing.

For additional information regarding the risks and uncertainties to which the Company and its business are subject, please see the information under the headings "Forward Looking Information" below, and under the headings "Forward Looking Statements" and "Risk Factors" in the Company's most recent AIF, on the Company's SEDAR profile at www.sedarplus.ca.

Forward Looking Information

This MD&A contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words “anticipate”, "intend", “plan”, "outlook", "guidance", "estimate”, “expect”, “may”, “will”, “target”, “believe”, “predict”, “potential” and similar expressions are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company’s current plans, objectives, goals, strategies, estimates, assumptions and projections about the Company’s industry, business and future financial results. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this MD&A should not be unduly relied upon. This information speaks only as of the date of this MD&A. In particular, this MD&A may contain forward-looking information pertaining to the following: the Company's future growth outlook and how that growth outlook is funded; estimates of Thermal Oil and Duvernay Energy production levels; reserve life index; on stream timing of wells and timing of expansion projects; the Company's anticipated sources of funding for 2026 and beyond; the Company's estimated future minimum commitments; the future allocation of capital; the Company’s ability to manage periods of volatility; Adjusted Funds Flow; Free Cash Flow; capital expenditures and other matters.

In addition, information and statements in this MD&A relating to “Reserves” and “Resources” are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future. Certain assumptions related to the Company’s Reserves and Resources are contained in the report of McDaniel & Associates Consultants Ltd. ("McDaniel") evaluating Athabasca’s Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2025 (which is respectively referred to herein as the "McDaniel Report”).

With respect to forward-looking information contained in this MD&A, assumptions have been made regarding, among other things: commodity prices; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct business and the effects that such regulatory framework will have on the Company, including on the Company’s financial condition and results of operations; the Company’s financial and operational flexibility; the Company’s financial sustainability; the Company’s ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the applicability of technologies for the recovery and production of the Company’s reserves and resources; future capital expenditures to be made by the Company; future sources of funding for the Company’s capital programs; the Company’s future debt levels; future production levels; the Company’s ability to obtain financing and/or enter into joint venture arrangements, on acceptable terms; operating costs; compliance of counterparties with the terms of contractual arrangements; impact of increasing competition globally; collection risk of outstanding accounts receivable from third parties; geological and engineering estimates in respect of the Company’s reserves and resources; recoverability of reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities and the quality of its assets.

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company’s most recent AIF available on SEDAR at www.sedarplus.ca, including, but not limited to: weakness in the oil and gas industry; exploration, development and production risks; prices, markets and marketing; market conditions; trade relations and tariffs; climate change and carbon pricing risk; statutes and regulations regarding the environment; regulatory environment and changes in applicable law; gathering and processing facilities, pipeline systems and rail; reputation and public perception of the oil and gas sector; environment, social and governance goals; political uncertainty; state of capital markets; ability to finance capital requirements; access to capital and insurance; abandonment and reclamation costs; changing demand for oil and natural gas products; anticipated benefits of acquisitions and dispositions; royalty regimes; foreign exchange rates and interest rates; reserves; hedging; operational dependence; operating costs; project risks; supply chain disruption; financial assurances; diluent supply; third party credit risk; indigenous claims; reliance on key personnel and operators; income tax; cybersecurity; advanced technologies; hydraulic fracturing; liability management; seasonality and weather conditions; unexpected events; internal controls; evolving corporate governance, sustainability and reporting framework; limitations of insurance; litigation; natural gas overlying bitumen resources; competition; chain of title and expiration of licenses and leases; breaches of confidentiality; new industry related activities or new geographical areas; water use restrictions and/or limited access to water; relationship with Duvernay Energy Corporation; management estimates and assumptions; third-party claims; conflicts of interest; inflation and cost management; credit ratings; growth management; impact of pandemics; ability of investors resident in the United States to enforce civil remedies in Canada; and risks related to our debt and securities.

The risks and uncertainties referred to above are described in more detail in Athabasca's most recent AIF, which is available on the Company's SEDAR profile at www.sedarplus.ca. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. The forward-looking information included in this MD&A is expressly qualified by this cautionary statement and is made as of the date of this MD&A. The Company does not undertake any obligation to publicly update or revise any forward-looking information except as required by applicable securities laws.

The Company's financial condition and results of operations discussed in this MD&A will not necessarily be indicative of the Company's future performance, particularly considering that many of the Company's activities are currently in the early stages of their planned exploration and/or development.

Reserves and Resource Information

The McDaniel Report was prepared using the assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities,* effective December 31, 2025. There are numerous uncertainties inherent in estimating quantities of bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale 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 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 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. There is no certainty that it will be commercially viable to produce any portion of the resources. Reserves and Contingent Resources figures described herein have been rounded to the nearest MMbbl or MMboe. For additional information regarding the consolidated reserves and resources of the Company as evaluated by McDaniel in the McDaniel Report, please refer to the Company's AIF that is available on SEDAR at www.sedarplus.ca.

Oil and Gas Information

"Boe" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (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. 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.

Drilling Locations

The 432 gross Duvernay drilling locations referenced in this MD&A include: 95 proved undeveloped locations and 88 probable undeveloped locations for a total of 183 booked locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by McDaniel as of December 31, 2025 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur over the next two decades 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, commodity prices, provincial fiscal and royalty policies, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Definitions

"Best Estimate" is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

“**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. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as “Contingent Resources” the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources may be divided into the following project maturity sub-classes: “Development Pending” is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development); “Development On Hold” is assigned to Contingent Resources for a particular project where 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; “Development Unclarified” is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined; “Development Not Viable” is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development. As at December 31, 2025, the Company reported Contingent Resources on a risked and unrisked basis located in its Leismer and Corner asset areas in the Development Pending project maturity sub-class.

“Liquids” includes bitumen, light oil and medium oil, tight oil and NGLs, as applicable.

“Proved Reserves” are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves.

“Probable Reserves” are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved Reserves plus Probable Reserves.

"Reserve Life Index" is a measure of the estimated length of time it will take to deplete the Company's oil and gas reserves (typically reported in number of years).

“**Risked**” or **"risked"** means the applicable reported volumes or revenues have been risked (or adjusted) based on the chance of commerciality of such resources in accordance with the COGE Handbook. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore, risked reported volumes and values of contingent resources reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

“**Unrisked**” or **"unrisked"** means applicable reported volumes or values of resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore, unrisked reported volumes and values of contingent resources do not reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

Abbreviations

AECO	physical storage and trading hub for natural gas on the TC Alberta transmission system which is the delivery point for various benchmark Alberta index prices.
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian Dollars
COGE	Canadian Oil and Gas Evaluation
GAAP	Generally Accepted Accounting Principles
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
Mgmt.	management
MMbbl	millions of barrels
MMboe	millions of barrels of oil equivalent
MMBtu	million British thermal units
NGL	Natural gas liquids
SAGD	steam assisted gravity drainage
US$	United States Dollars
WTI	West Texas Intermediate
WCS	Western Canadian Select