Management's Discussion and Analysis

Q1 2024

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 8, 2024 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, 2024, and the MD&A and audited consolidated financial statements of the Company for the year ended December 31, 2023. 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 February 29, 2024 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "ATH".

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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 2024 HIGHLIGHTS

Corporate Consolidated(1)

- Production of 33,470 boe/d (98% Liquids(2)).
- Petroleum, natural gas and midstream sales of $311.1 million.
- Operating Income(2) and Operating Netback(2) of $105.1 million ($35.78/boe).
- Adjusted Funds Flow(2) of $87.8 million (cash flow from operating activities of $76.6 million).
- Strong Liquidity(2) of $432.9 million, including $306.5 million of cash as at March 31, 2024.
- Fully completed the Company's inaugural annual Normal Course Issuer Bid ("NCIB") which expired on March 15, 2024; returned $225.2 million to shareholders through repurchasing and cancelling 58.0 million common shares at an average price of $3.88 per share.
- Renewed the Company's annual NCIB with authorization to purchase up to 55.4 million common shares during the twelve-month period commencing on March 18, 2024 and ending March 17, 2025.
- On December 19, 2023, the Company entered into a transaction to create Duvernay Energy with Cenovus Energy Inc. Duvernay Energy is designed to enhance value for Athabasca's shareholders by providing a clear path for self-funded production and cash flow growth in the Kaybob Duvernay resource play. The transaction closed on February 6, 2024.

Athabasca (Thermal Oil)

- Production of 31,536 bbl/d.
- Petroleum, natural gas and midstream sales of $305.0 million.
- Operating Income(2) and Operating Netback(2) of $100.4 million ($36.36/bbl).
- Adjusted Funds Flow(2) of $83.7 million; Free Cash Flow(2) of $41.6 million supporting return of capital commitments.
- Capital expenditures of $42.1 million, with activity focused on completing the Leismer expansion project that will support growth to approximately 28,000 bbl/d mid-year following the tie-in of well pairs currently steaming.

Duvernay Energy(1)

- Production of 1,934 boe/d (72% Liquids(2)).
- Petroleum, natural gas and midstream sales of $11.5 million.
- Operating Income(2) and Operating Netback(2) of $4.7 million ($26.63/boe).
- Capital expenditures of $33.9 million included rig releasing two multi well pads, completions operations on a two well pad and readiness capital for the development program; new production from the winter program is expected in the second quarter of 2024.

(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, 2024		2023
CORPORATE CONSOLIDATED[1]				
Petroleum and natural gas production (boe/d)[2]		33,470		34,683
Petroleum, natural gas and midstream sales	$	311,116	$	290,741
Operating Income[2]	$	105,135	$	56,535
Operating Income Net of Realized Hedging[2][3]	$	106,580	$	34,480
Operating Netback ($/boe)[2]	$	35.78	$	16.85
Operating Netback Net of Realized Hedging ($/boe)[2][3]	$	36.27	$	10.27
Capital expenditures	$	76,011	$	26,362
Cash flow from operating activities	$	76,638	$	20,537
per share - basic	$	0.14	$	0.04
Adjusted Funds Flow[2]	$	87,772	$	(9,396)
per share - basic	$	0.15	$	(0.02)
ATHABASCA (THERMAL OIL)				
Bitumen production (bbl/d)[2]		31,536		29,179
Petroleum, natural gas and midstream sales	$	305,041	$	269,102
Operating Income[2]	$	100,449	$	41,497
Operating Netback ($/bbl)[2]	$	36.36	$	14.52
Capital expenditures	$	42,119	$	24,486
Adjusted Funds Flow[2]	$	83,713		
Free Cash Flow[2]	$	41,594		
DUVERNAY ENERGY[1]				
Petroleum and natural gas production (boe/d)[2]		1,934		5,504
Percentage Liquids (%)[2]		72%		57%
Petroleum, natural gas and midstream sales	$	11,538	$	29,889
Operating Income[2]	$	4,686	$	15,038
Operating Netback ($/boe)[2]	$	26.63	$	30.35
Capital expenditures	$	33,892	$	1,876
Adjusted Funds Flow[2]	$	4,059		
Free Cash Flow[2]	$	(29,833)		
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)[4]	$	38,609	$	(56,635)
per share - basic[4]	$	0.07	$	(0.10)
per share - diluted[4]	$	0.07	$	(0.10)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic		567,076,940		586,631,143
Weighted average shares outstanding - diluted		577,106,504		586,631,143

As at ($ Thousands)		March 31, 2024		December 31, 2023
LIQUIDITY AND BALANCE SHEET				
Cash and cash equivalents	$	306,503	$	343,309
Available credit facilities[5]	$	126,425	$	85,488
Face value of term debt[6]	$	212,735	$	207,648

(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 $1.4 million for the three months ended March 31, 2024 (three months ended March 31, 2023 – loss of $22.1 million).
(4) Net income (loss) and comprehensive income (loss) per share amounts are based on net income (loss) and comprehensive income (loss) 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.
(6) The face value of the term debt at March 31, 2024 was US$157 million (December 31, 2023 – US$157 million) translated into Canadian dollars at the March 31, 2024 exchange rate of US$1.00 = C$1.3550 (December 31, 2023 – C$1.3226).

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended March 31, 2024	2023	Change
Crude oil:			
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 76.96	$ 76.13	1 %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 103.80	$ 102.92	1 %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 77.73	$ 69.42	12 %
Edmonton Par (C$/bbl)[3]	$ 92.21	$ 99.34	(7) %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 97.36	$ 105.44	(8) %
WCS Differential:			
to WTI (US$/bbl)	$ (19.31)	$ (24.77)	(22) %
to WTI (C$/bbl)	$ (26.07)	$ (33.50)	(22) %
Edmonton Par Differential:			
to WTI (US$/bbl)	$ (8.65)	$ (2.86)	202 %
to WTI (C$/bbl)	$ (11.59)	$ (3.58)	224 %
Natural gas:			
AECO (C$/GJ)[5][6]	$ 2.36	$ 3.05	(23) %
Foreign exchange:			
USD : CAD	1.3488	1.3519	— %

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

2024 Operational & Financial Guidance ($ millions, unless otherwise noted)	Athabasca (Thermal Oil)	Duvernay Energy[3][4]
Production (boe/d)[1]	32,000-33,000	~3,000
Adjusted Funds Flow[1][2]	~$500	~$50
Free Cash Flow[1][2]	~$365	—
Capital Expenditures	$135	$82

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP measures and production disclosure.
(2) Pricing assumptions for May 8, 2024 guidance: 2024 annual average prices of US$80 WTI, US$15 Western Canadian Select "WCS" heavy differential, C$3 AECO, and $0.73 C$/US$ FX with Q1 2024 pricing actualized.
(3) Duvernay Energy reflects gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.
(4) Duvernay Energy capital program funded by seed capital and Adjusted Funds Flow forecast.

Athabasca's Thermal Oil assets underpin the Company's strong Free Cash Flow outlook, with an unchanged $135 million capital budget and production guidance of 32,000 – 33,000 bbl/d. The facility expansion at Leismer was completed in late February with additional wells currently being brought onstream. The Company remains on track to reach approximately 28,000 bbl/d at Leismer mid-year. At Hangingstone the Company is preparing to spud two approximately 1,400 meter well pairs in the third quarter of 2024. These sustaining well pairs will support base production in 2025 and beyond with the objective of ensuring Hangingstone continues to deliver meaningful cash flow contributions to the Company and maintaining competitive netbacks.

Duvernay Energy recently brought on production a two well pad (100% working interest) at 03-18-64-17W5 with an average horizontal length of approximately 4,150 meters per well. A second three well pad at 02-03-65-20W5 (30% working interest) is expected to be placed on stream in June. The Company's 2024 capital program of $82 million (gross) includes four multi-well pads supporting production momentum with volumes expected to average approximately 6,000 boe/d in 2025.

ATHABASCA (THERMAL OIL)

Athabasca's Thermal Oil assets consists 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 significant 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 proven reserves in place to support a flat production profile for approximately 40 years and a reserve life index of approximately 80 years (proved plus probable). The Leismer Project has Proved plus Probable Reserves of approximately 697 MMbbl(1) and Best Estimate Development Pending Contingent Resources of 346 MMbbl (risked)(1) (384 MMbbl unrisked)(1). The Corner lease has Proved plus Probable Reserves of approximately 351 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 proven reserves in place to support a flat production profile for approximately 30 years and a reserve life index of approximately 65 years (proved plus probable). Hangingstone has Proved plus Probable Reserves of approximately 167 MMbbl(1).

Royalty

Athabasca has granted Contingent Bitumen Royalties 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 are 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, 2023. 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, 2024	2023
VOLUMES		
Bitumen production (bbl/d)	24,143	20,697
Bitumen sales (bbl/d)	24,077	22,165
Heavy oil (blended bitumen) sales (bbl/d)	35,232	31,756

($ Thousands, unless otherwise noted)	Three months ended March 31, 2024	2023
Heavy oil (blended bitumen) sales	$ 240,035	$ 185,560
Cost of diluent	(108,272)	(105,374)
Total bitumen sales	131,763	80,186
Royalties	(9,214)	(4,821)
Operating expenses - non-energy	(18,302)	(16,860)
Operating expenses - energy	(11,743)	(14,077)
Transportation and marketing	(12,283)	(14,092)
LEISMER OPERATING INCOME(1)	$ 80,221	$ 30,336
REALIZED PRICE(1)		
Heavy oil (blended bitumen) sales ($/bbl)(1)	$ 74.87	$ 64.93
Bitumen sales ($/bbl)(1)	$ 60.14	$ 40.20
Royalties ($/bbl)(1)	(4.21)	(2.42)
Operating expenses - non-energy ($/bbl)(1)	(8.35)	(8.45)
Operating expenses - energy ($/bbl)(1)	(5.36)	(7.06)
Transportation and marketing ($/bbl)(1)	(5.61)	(7.06)
LEISMER OPERATING NETBACK ($/bbl)(1)	$ 36.61	$ 15.21

(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, 2024 was 24,143 bbl/d, an increase of 17% compared to the corresponding period in 2023. Production increases are primarily attributed to the tie-in of new wells including Pad 8 (ten sustaining well pairs) and Pad 7 (four infill wells).

Leismer’s Operating Netback was $36.61/bbl for the three months ended March 31, 2024, representing an increase of $21.40/bbl compared with the same period in 2023. The increase is primarily a result of higher realized oil prices and lower energy operating expenses.

Total operating expenses were $13.71/bbl in the first quarter of 2024 compared to $15.51/bbl in the same period in 2023. The decrease on a per barrel basis is largely the result of stronger margins due to higher production and lower energy costs in the first quarter of 2024.

Hangingstone Operating Results

	Three months ended March 31, 2024	2023
VOLUMES		
Bitumen production (bbl/d)	7,393	8,482
Bitumen sales (bbl/d)	6,281	9,600
Heavy oil (blended bitumen) sales (bbl/d)	8,959	13,754

($ Thousands, unless otherwise noted)	Three months ended March 31, 2024	2023
Heavy oil (blended bitumen) and midstream sales	$ 65,006	$ 83,542
Cost of diluent	(25,588)	(43,559)
Total bitumen and midstream sales	39,418	39,983
Royalties	(2,323)	(1,792)
Operating expenses - non-energy	(4,823)	(6,080)
Operating expenses - energy	(4,815)	(10,752)
Transportation and marketing(1)	(7,229)	(10,198)
HANGINGSTONE OPERATING INCOME(2)	$ 20,228	$ 11,161
REALIZED PRICE(2)		
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 79.74	$ 67.49
Bitumen and midstream sales ($/bbl)(2)	$ 68.96	$ 46.28
Royalties ($/bbl)(2)	(4.06)	(2.07)
Operating expenses - non-energy ($/bbl)(2)	(8.44)	(7.04)
Operating expenses - energy ($/bbl)(2)	(8.42)	(12.44)
Transportation and marketing ($/bbl)(1)(2)	(12.65)	(11.80)
HANGINGSTONE OPERATING NETBACK ($/bbl)(2)	$ 35.39	$ 12.93

(1) Transportation and marketing excludes non-cash costs of $0.6 million for the three months ended March 31, 2024 (three months ended March 31, 2023 - $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.

Average Hangingstone bitumen production for the three months ended March 31, 2024 decreased compared to the same period in 2023 as a result of natural declines.

The Hangingstone Operating Netback was $35.39/bbl for the three months ended March 31, 2024, representing an increase of $22.46/bbl compared with the same period in 2023. The increase is primarily a result of higher realized oil prices and lower energy operating expenses.

Total operating expenses were $16.86/bbl in the first quarter of 2024 compared to $19.48/bbl in the same period in 2023. The decrease on a per barrel basis is the result of lower energy costs and a lower steam oil ratio in the first quarter of 2024 partially offset by lower production.

Athabasca (Thermal Oil) Operating Results

		Three months ended March 31, 2024		2023
VOLUMES				
Bitumen production (bbl/d)		31,536		29,179
Bitumen sales (bbl/d)		30,358		31,765
Heavy oil (blended bitumen) sales (bbl/d)		44,191		45,510

($ Thousands, unless otherwise noted)		Three months ended March 31, 2024		2023
Heavy oil (blended bitumen) and midstream sales	$	305,041	$	269,102
Cost of diluent		(133,860)		(148,933)
Total bitumen and midstream sales		171,181		120,169
Royalties		(11,537)		(6,613)
Operating expenses - non-energy		(23,125)		(22,940)
Operating expenses - energy		(16,558)		(24,829)
Transportation and marketing(1)		(19,512)		(24,290)
ATHABASCA (THERMAL OIL) OPERATING INCOME(2)	$	100,449	$	41,497
REALIZED PRICE(2)				
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$	75.85	$	65.70
Bitumen and midstream sales ($/bbl)(2)	$	61.96	$	42.03
Royalties ($/bbl)(2)		(4.18)		(2.31)
Operating expenses - non-energy ($/bbl)(2)		(8.37)		(8.02)
Operating expenses - energy ($/bbl)(2)		(5.99)		(8.68)
Transportation and marketing ($/bbl)(1)(2)		(7.06)		(8.50)
ATHABASCA (THERMAL OIL) OPERATING NETBACK ($/bbl)(2)	$	36.36	$	14.52

(1) Transportation and marketing excludes non-cash costs of $0.6 million for the three months ended March 31, 2024 (three months ended March 31, 2023 - $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, 2024		2023
Leismer Project	$	33,781	$	19,413
Hangingstone Project		6,874		3,226
Other		1,464		1,847
ATHABASCA (THERMAL OIL) CAPITAL EXPENDITURES(1)	$	42,119	$	24,486

(1) For the three months ended March 31, 2024, capital expenditures include $1.5 million of capitalized staff costs (three months ended March 31, 2023 - $1.5 million).

Thermal Oil capital expenditures for the three months ended March 31, 2024 of $42.1 million were primarily focused at Leismer along with routine pump replacements across both assets. At Leismer, the Company is focused on completing the expansion project that will support growth to approximately 28,000 bbl/d mid-year. Activity during the quarter included commencing steaming on four well pairs on Pad 8S, commencing steaming of three redrills on Pad 4 and the tie-in of four infill wells on Pad 7. At Hangingstone, Athabasca commenced the Pad AA extension for future sustaining well pairs.

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 (the "Transaction") involving Athabasca and Cenovus Energy ("Cenovus"). 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. Duvernay Energy's Board of Directors includes three members nominated by Athabasca and one member nominated by Cenovus. With the completion of the Transaction, the former Light Oil operating segment has been renamed Duvernay Energy and 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, 2023, the Greater Kaybob assets had approximately 27 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 inventory of approximately 500[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, 2023. 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, 2024	2023
PRODUCTION[1]		
Oil and condensate (bbl/d)	1,205	2,390
Natural gas (Mcf/d)	3,291	14,358
Other natural gas liquids (bbl/d)	180	721
Total (boe/d)	1,934	5,504
% Liquids	72%	57%

(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, 2024	2023
Petroleum and natural gas sales	$ 11,538	$ 29,889
Royalties	(2,314)	(5,556)
Operating expenses	(3,640)	(6,929)
Transportation and marketing	(898)	(2,366)
DUVERNAY ENERGY OPERATING INCOME[1]	$ 4,686	$ 15,038
REALIZED PRICES[1]		
Oil and condensate ($/bbl)[1]	$ 92.32	$ 99.47
Natural gas ($/Mcf)[1]	2.82	3.72
Other natural gas liquids ($/bbl)[1]	34.73	56.79
Realized price ($/boe)[1]	65.56	60.34
Royalties ($/boe)[1]	(13.15)	(11.22)
Operating expenses ($/boe)[1]	(20.68)	(13.99)
Transportation and marketing ($/boe)[1]	(5.10)	(4.78)
DUVERNAY ENERGY OPERATING NETBACK ($/boe)[1]	$ 26.63	$ 30.35

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

Average Duvernay Energy production for the three months ended March 31, 2024 decreased primarily as a result of the closing of the Light Oil Non-Core Asset Sale in the third quarter of 2023 and natural declines.

The Operating Netback was $26.63/boe for the three months ended March 31, 2024, the decrease is primarily due to higher operating expenses on a per boe basis correlated to lower production volumes.

Duvernay Energy Capital Expenditures

($ Thousands)	Three months ended March 31, 2024	2023
DUVERNAY ENERGY CAPITAL EXPENDITURES[1]	$ 33,892	$ 1,876

(1) For the three months ended March 31, 2024, capital expenditures include $0.4 million of capitalized staff costs (three months ended March 31, 2023 - $0.4 million).

For the three months ended March 31, 2024, Duvernay Energy's capital expenditures of $33.9 million were primarily focused on commencing the development program and included drilling and rig releasing 4 (2.6 net) wells and completions operations on 2 (2.0 net) wells. New production from the winter program is expected in the second quarter of 2024.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

For 2024, Athabasca's capital and operating activities will be funded through cash flow from operating activities and existing cash and cash equivalents. The Company is directing forecasted Free Cash Flow in 2024 to share buybacks and high return growth projects. An active commodity risk management program and maintaining sufficient liquidity is expected to allow the Company to manage periods of volatility.

As at March 31, 2024, Athabasca had Liquidity of $432.9 million which included $306.5 million of cash and cash equivalents and $126.4 million of available capacity on its credit facilities.

Indebtedness

Athabasca had the following debt instruments and credit facilities in place as at March 31, 2024:

Term Debt

As at March 31, 2024, the principal balance on Athabasca's senior secured second lien notes ("2026 Notes" or "Notes") was $212.7 million (US$157 million).

The Notes are due November 1, 2026 and bear interest at 9.75% per annum. Athabasca may redeem all or part of the 2026 Notes at any time prior to November 1, 2024 at 100% of the principal amount plus an applicable premium, as set out in the 2026 Notes indenture. On or after November 1, 2024, Athabasca may redeem all or part of the 2026 Notes at 104.875% from November 1, 2024 to November 1, 2025 and at 100% from November 1, 2025 to November 1, 2026.

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, 2024, at which point in time it may be extended at the lenders' 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 May 31, 2025. The Credit Facility is subject to a semi-annual borrowing base review, occurring by May 31 and November 30 of each year. In the fourth quarter of 2023, the semi-annual borrowing base review was completed and the borrowing base was confirmed at $110.0 million. The borrowing base is determined based on the lenders' 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, 2024, the Company had no amounts drawn and $34.9 million of letters of credit outstanding under the Credit Facility. As at December 31, 2023, the Company had no amounts drawn and $27.1 million of letters of credit outstanding under the Credit Facility.

Unsecured Letter of Credit Facility

Athabasca has a $60.0 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 (December 31, 2023 - $60.0 million). The facility is available on a demand basis and letters of credit issued under this facility incur an issuance and performance guarantee fee of 3.0%. As at March 31, 2024, the Company had $58.3 million of letters of credit outstanding under the Unsecured Letter of Credit Facility (December 31, 2023 - $57.5 million).

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, 2024, at which point in time it may be extended at the lenders' 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, 2025. 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 lenders' 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, 2024, the Company had no amounts drawn and $0.4 million of letters of credit outstanding under the Duvernay Credit Facility.

Financing and Interest

($ Thousands)		Three months ended March 31, 2024		2023
Financing and interest expense on indebtedness	$	6,287	$	7,510
Accretion of 2026 Notes		1,981		(3,402)
Accretion of warrants		16		78
Accretion of provisions		1,940		1,919
Interest expense on lease liability		116		177
TOTAL FINANCING AND INTEREST	$	10,340	$	6,282

During the three months ended March 31, 2024 and 2023, total financing and interest expenses were primarily attributable to the financing, interest and accretion expenses related to the Company's Notes.

Foreign Exchange Gain (Loss), Net

($ Thousands)		Three months ended March 31, 2024		2023
Unrealized foreign exchange gain	$	2,317	$	2,656
Realized foreign exchange gain (loss)		1,120		(1,194)
FOREIGN EXCHANGE GAIN, NET	$	3,437	$	1,462

Athabasca is exposed to foreign currency risk primarily on the principal and interest components of its US dollar denominated term debt, partially offset by its US dollar cash balances.

Risk Management Contracts

Under the Company's commodity risk management program, Athabasca 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 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 net income (loss). As the commodity derivatives are unwound (i.e. settled in cash), Athabasca recognizes a corresponding realized gain or loss in net 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

As at March 31, 2024, the following financial commodity risk management contracts were in place:

Instrument	Period	Volume		C$ Average Price(1)		US$ Average Price(1)
Sales contracts				*C$/bbl*		*US$/bbl*
WTI collar	April - June 2024	9,725 bbl/d	$	67.75 - 130.40	$	50.00 - 96.24
Purchase contracts				*C$/GJ/bbl*		*US$/GJ/bbl*
AECO collar	April - December 2024	20,000 GJ/d	$	2.35 - 2.84	$	1.74 - 2.10

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the March 31, 2024 exchange rate of US$1.00 = C$1.3550.

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three months ended March 31, 2024 and 2023:

($ Thousands)		Three months ended March 31, 2024		2023
Unrealized loss on commodity risk mgmt. contracts	$	(1,279)	$	(4,965)
Realized gain (loss) on commodity risk mgmt. contracts		1,445		(22,055)
GAIN (LOSS) ON COMMODITY RISK MGMT. CONTRACTS, NET	$	166	$	(27,020)

At March 31, 2024, a US$5 increase/decrease in the price of WTI has a nil impact on the WTI collar contracts. The following table summarizes the sensitivity to price changes for Athabasca's other commodity risk management contracts:

As at March 31, 2024	Change in AECO Increase of C$1.00/GJ	Decrease of C$1.00/GJ
Increase (decrease) to fair value of commodity risk management contracts	$ 953	$ (5,351)

Additional financial commodity risk management has taken place subsequent to March 31, 2024 as noted in the table below:

Instrument	Period	Volume	C$ Average Price(1)	US$ Average Price(1)
Sales contracts			*C$/bbl*	*US$/bbl*
WTI collar	April - June 2024	13,059 bbl/d	$ 67.75 - 151.64	$ 50.00 - 111.91
WTI collar	July - September 2024	8,184 bbl/d	$ 67.75 - 174.58	$ 50.00 - 128.84

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the March 31, 2024 exchange rate of US$1.00 = C$1.3550.

Commitments

The following table summarizes Athabasca's estimated future unrecognized minimum commitments as at March 31, 2024 for the following five years and thereafter:

($ Thousands)	Remaining 2024	2025	2026	2027	2028	Thereafter	Total
Transportation and processing(1)	$ 82,057	$ 107,728	$ 107,503	$ 105,898	$ 75,707	$ 1,014,991	$ 1,493,884
Interest expense on term debt(1)	15,556	20,742	17,285	—	—	—	53,583
Purchase commitments and other(1)	23,686	4,160	—	—	—	—	27,846
TOTAL COMMITMENTS	$ 121,299	$ 132,630	$ 124,788	$ 105,898	$ 75,707	$ 1,014,991	$ 1,575,313

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the March 31, 2024 exchange rate of US$1.00 = C$1.3550.

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 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, 2024. Athabasca's risk management contracts are held with three counterparties, all of which are large reputable financial institutions, and management concluded that credit risk associated with these risk management contracts is low.

Interest rate Risk

The Company's exposure to interest rate fluctuations on interest earned on its floating rate cash and cash equivalents balance at March 31, 2024 of $306.5 million (December 31, 2023 - $343.3 million), from a 1.0% change in interest rates, would have an annualized impact of approximately $3.1 million (December 31, 2023 - $3.4 million). The 2026 Notes and letters of credit issued are subject to fixed interest rates and are not exposed to changes in interest rates.

Other Corporate Items

General and Administrative ("G&A")

($ Thousands, unless otherwise noted)		Three months ended March 31, 2024		2023
TOTAL GENERAL AND ADMINISTRATIVE	$	5,762	$	5,747
G&A per boe[1]	$	1.89	$	1.84

(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, 2024, Athabasca's stock-based compensation expense was $14.2 million compared to $35.0 million in the respective prior year period. During the first quarter of 2023, the Company elected for the 2020 PSUs vesting April 1, 2023 to be settled in cash to reduce share dilution in advance of its proposed share buyback program which commenced in April 2023 and this election resulted in a $24.2 million cash based stock-based compensation expense. The expenses are also driven by the increases in the fair value of the cash settled stock-based compensation plans as a result of the share price increases in the respective quarters.

Depletion and Depreciation

In the first quarter of 2024, Athabasca's depletion and depreciation expense was $23.7 million compared to $29.2 million in the respective prior year period. The decrease primarily relates to lower depletion expense as a result of the closing of the Light Oil Non-Core Asset Sale in the third quarter of 2023.

Loss on Revaluation of Provisions and Other

($ Thousands)		Three months ended March 31, 2024		2023
Change in fair value of warrant liability	$	(6,929)	$	(23,814)
LOSS ON REVALUATION OF PROVISIONS AND OTHER	$	(6,929)	$	(23,814)

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 2023 and 2024 primarily relate to changes in the share price.

Income Taxes

In the first quarter of 2024, as a result of net income before tax of $51.5 million a $13.0 million deferred income tax expense was recorded (first quarter of 2023 - $10.1 million recovery). At March 31, 2024, the Company has a deferred tax asset of $433.2 million (December 31, 2023 - $403.5 million) and a deferred tax liability of $39.8 million (December 31, 2023 - nil). The liability has been recognized as a result of the assets transferred in the Duvernay Energy Transaction. The Company has approximately $2.6 billion in tax pools, including approximately $2.1 billion in non-capital losses and exploration 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 some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as 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, 2024, there were 557.6 million common shares outstanding, an aggregate of 11.9 million restricted share units and performance share units outstanding, 2.9 million stock options outstanding and 6.7 million potential shares issuable under warrants agreements (29,324 warrants outstanding).

In the first quarter of 2024, the Company renewed its NCIB to purchase up to 55.4 million common shares during the twelve-month period commencing on March 18, 2024 and ending March 17, 2025. The Company fully completed its previous NCIB and purchased and cancelled a total of 58.0 million common shares for the twelve-month period ended March 15, 2024.

During the first quarter of 2024, the Company repurchased for cancellation 14.8 million common shares under its NCIB program. Subsequent to March 31, 2024, the Company repurchased for cancellation 4.9 million common shares under its NCIB program.

As at May 8, 2024, there were 559.0 million common shares outstanding, an aggregate of 7.8 million restricted share units and performance share units outstanding, 2.9 million stock options outstanding and 6.7 million potential shares issuable under warrants agreements (29,324 warrants outstanding).

SUMMARY OF QUARTERLY RESULTS

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

	2024	2023				2022		
($ Thousands, unless otherwise noted)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	76.96	78.32	82.26	73.78	76.13	82.65	91.55	108.41
WTI (C$/bbl)	103.80	106.65	110.29	99.09	102.92	112.21	119.54	138.39
Western Canadian Select (C$/bbl)	77.73	76.92	93.00	78.80	69.42	77.36	93.48	122.04
Edmonton Par (C$/bbl)	92.21	99.71	107.85	95.33	99.34	110.13	116.79	137.83
Edmonton Condensate (C5+) (C$/bbl)	97.36	102.83	104.05	96.10	105.44	111.82	112.87	137.70
AECO (C$/GJ)	2.36	2.18	2.46	2.32	3.05	4.85	3.95	6.86
Foreign exchange (USD : CAD)	1.35	1.36	1.34	1.34	1.35	1.36	1.31	1.28
CORPORATE CONSOLIDATED(1)								
Petroleum and natural gas production (boe/d)(2)	33,470	33,127	36,176	33,971	34,683	35,850	37,240	33,247
Realized price (net of cost of diluent) ($/boe)(2)	62.18	57.86	80.85	59.25	44.74	53.84	75.10	105.99
Petroleum, natural gas and midstream sales ($)(3)	316,579	321,737	385,269	289,310	298,991	292,105	406,794	453,618
Operating Income ($)(2)	105,135	96,960	168,410	95,118	56,535	70,319	140,081	169,255
Operating Income Net of Realized Hedging ($)(2)	106,580	91,443	164,643	90,522	34,480	62,131	110,021	103,549
Operating Netback ($/boe)(2)	35.78	30.44	50.84	32.23	16.85	23.17	39.17	57.51
Operating Netback Net of Realized Hedging ($/boe)(2)	36.27	28.71	49.70	30.67	10.27	20.47	30.76	35.18
Capital expenditures ($)	76,011	38,752	33,286	41,432	26,362	13,029	52,300	51,191
Cash flow from operating activities ($)	76,638	103,196	134,879	46,914	20,537	69,368	117,853	68,535
Adjusted Funds Flow ($)(2)	87,772	81,830	141,138	81,664	(9,396)	46,074	102,370	84,799
ATHABASCA (THERMAL OIL)								
Bitumen production (bbl/d)	31,536	31,059	31,691	29,016	29,179	30,210	31,023	26,768
Bitumen sales volumes (bbl/d)	30,358	32,552	31,527	27,482	31,765	27,346	32,650	25,863
Realized bitumen price ($/bbl)(2)	61.96	57.31	83.90	60.33	42.03	50.49	76.09	109.67
Heavy Oil (blended bitumen) and midstream sales ($)	305,041	309,078	360,761	265,304	269,102	255,749	366,804	399,793
Operating Income ($)(2)	100,449	92,199	155,415	81,621	41,497	50,691	117,916	131,067
Operating Netback ($/bbl)(2)	36.36	30.78	53.59	32.64	14.52	20.15	39.25	55.68
Capital expenditures ($)	42,119	29,371	34,439	30,679	24,486	11,435	51,440	49,970
Adjusted Funds Flow ($)(2)	83,713							
Free Cash Flow ($)(2)	41,594							
DUVERNAY ENERGY(1)								
Petroleum and natural gas production (boe/d)(2)	1,934	2,068	4,485	4,955	5,504	5,640	6,217	6,479
Realized price ($/boe)(2)	65.56	66.54	59.40	53.24	60.34	70.07	69.92	91.29
Petroleum and natural gas sales ($)(3)	11,538	12,659	24,508	24,006	29,889	36,356	39,990	53,825
Operating Income ($)(2)	4,686	4,761	12,995	13,497	15,038	19,628	22,165	38,188
Operating Netback ($/boe)(2)	26.63	25.02	31.50	29.92	30.35	37.83	38.76	64.77
Capital expenditures ($)	33,892	9,381	(1,153)	10,753	1,876	1,594	860	1,221
Adjusted Funds Flow ($)(2)	4,059							
Free Cash Flow ($)(2)	(29,833)							
OPERATING RESULTS								
Net income (loss) ($)(4)	38,609	27,506	(79,212)	57,121	(56,635)	489,654	155,097	47,121
Net income (loss) per share - basic ($)(4)	0.07	0.05	(0.14)	0.10	(0.10)	0.83	0.27	0.08
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	306,503	343,309	337,125	132,491	173,280	197,525	200,100	154,172
Total assets ($)	2,208,094	2,048,635	2,102,338	2,162,091	2,210,487	2,230,354	1,803,624	1,815,390
Term debt ($)(5)	186,773	179,705	182,398	181,577	184,509	206,133	240,078	250,756
Shareholders' equity ($)	1,665,552	1,583,453	1,580,312	1,682,906	1,655,044	1,710,497	1,218,174	1,057,355

(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 (loss) and comprehensive income (loss) per share amounts are based on net income (loss) and comprehensive income (loss) attributable to shareholders of the Parent Company.
(5) Balances include the current and long-term portions as reported in the consolidated balance sheets.

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, 2024, 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, except as disclosed in Note 5 of the Consolidated Financial Statements. 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, 2023 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). Certain comparative figures have been restated to conform to the current period presentation.

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", "Cash Transportation and Marketing Expense", "Cash Financing and Interest Expense", "Cash Stock-Based Compensation Expense" and "Realized Foreign Exchange" 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.

Adjusted Funds Flow, Adjusted Funds Flow Per Share and Free Cash Flow

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:

($ Thousands)	Three months ended March 31, 2024 Athabasca (Thermal Oil)	Duvernay Energy[(1)]	Corporate Consolidated[(1)]	Three months ended March 31, 2023 Corporate Consolidated
Operating Income	$ 100,449	$ 4,686	$ 105,135	$ 56,535
Realized gain (loss) on commodity risk mgmt contracts	1,445	—	1,445	(22,055)
General and administrative	(4,934)	(828)	(5,762)	(5,747)
Interest income	4,207	283	4,490	3,270
Cash Financing and Interest	(6,321)	(82)	(6,403)	(6,959)
Cash Stock-Based Compensation	(12,186)	—	(12,186)	(34,763)
Realized Foreign Exchange	1,120	—	1,120	635
Exploration expenses	(67)	—	(67)	(312)
ADJUSTED FUNDS FLOW	83,713	4,059	87,772	(9,396)
Capital expenditures	(42,119)	(33,892)	(76,011)	(26,362)
FREE CASH FLOW	$ 41,594	$ (29,833)	$ 11,761	$ (35,758)

(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.

Cash Financing and Interest Expense

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

Cash Stock-Based Compensation Expense

The Cash Stock-Based Compensation Expense financial measures contained in this MD&A are calculated by subtracting the net non-cash stock-based compensation expense as reported in the Consolidated Statement of Cash Flows from the stock-based compensation expense as reported in the Consolidated Statement of Income (Loss) and are considered to be non-GAAP financial measures.

Realized Foreign Exchange

The Realized Foreign Exchange financial measures contained in this MD&A are calculated by subtracting the realized foreign exchange (gain) loss on redemption of US dollar debt as reported in the Consolidated Statement of Cash Flows from the realized foreign exchange gain (loss) as reported in Note 19 of the Consolidated Financial Statements 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		Three months ended March 31, 2024	2023
Duvernay Energy:			
Oil(1)	bbl/d	1,205	1,576
Condensate NGLs	bbl/d	—	814
Oil and condensate NGLs	bbl/d	1,205	2,390
Other NGLs	bbl/d	180	721
Natural gas(2)	mcf/d	3,291	14,358
Total Duvernay Energy	boe/d	1,934	5,504
Total Thermal Oil bitumen	bbl/d	31,536	29,179
Total Company production	boe/d	33,470	34,683

(1) Comprised of 98% or greater of tight oil, with the remaining being light and medium crude oil.
(2) Comprised of 99% or greater of shale gas, with the remaining being conventional natural gas.

Liquids:		Three months ended March 31, 2024	2023
Total Duvernay Energy:			
Oil and condensate NGLs	bbl/d	1,205	2,390
Other NGLs	bbl/d	180	721
Total Duvernay Energy Liquids	bbl/d	1,385	3,111
as % of Duvernay Energy production		72%	57%
Total Company:			
Total Duvernay Energy Liquids	bbl/d	1,385	3,111
Total Thermal Oil bitumen	bbl/d	31,536	29,179
Total Company Liquids	bbl/d	32,921	32,290
as % of Company production		98%	93%

This MD&A also makes reference to Athabasca's forecasted total average daily Thermal Oil production of approximately 32,000 - 33,000 bbl/d for 2024. Athabasca expects that 100% of that production will be comprised of bitumen. Duvernay Energy’s forecasted total average daily production of approximately 3,000 boe/d for 2024 is expected to be comprised of approximately 66% tight oil, 24% shale gas and 10% 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 2024.

Risk Factors

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 a working interest participant in its Duvernay Energy assets and as operator of the 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; and
- inaccuracy of forward-looking information.

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 2024 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, 2023 (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; 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; 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, 2023. 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 500 gross Duvernay drilling locations referenced in this MD&A include: 37 proved undeveloped locations and 76 probable undeveloped locations for a total of 113 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, 2023 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, 2023, 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