Management's Discussion and Analysis

December 31, 2023

ATHABASCA OIL CORPORATION

This Management's Discussion and Analysis of the financial condition and results of operations ("MD&A") of Athabasca Oil Corporation ("Athabasca" or the "Company") is dated February 29, 2024 and should be read in conjunction with the audited consolidated financial statements ("Consolidated Financial Statements") as at and for the years ended December 31, 2023 and 2022 ("Consolidated Financial Statements"). 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
- Light Oil: Self-funded, Liquids Rich Development in Duvernay Energy Corporation
- Financial Sustainability: Low Leverage, Flexible Capital, Prudent Risk Management

Athabasca 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 Light Oil development opportunities. This balanced portfolio provides shareholders with differentiated exposure to liquids weighted production and significant long reserve life assets.

HIGHLIGHTS FOR THE QUARTER AND YEAR ENDED DECEMBER 31, 2023

Corporate

- Fourth quarter production of 33,127 boe/d (98% Liquids(1)) and 2023 production of 34,490 boe/d (95% Liquids(1)).
- Petroleum, natural gas and midstream sales of $315.9 million in the fourth quarter and $1.3 billion for 2023.
- Operating Income(1) and Operating Netback(1) of $97.0 million ($30.44/boe) in the fourth quarter and $417.0 million ($32.57/boe) for 2023.
- Fourth quarter Adjusted Funds Flow(1) of $81.8 million and $295.2 million for 2023 (cash flow from operating activities of $103.2 and $305.5 million respectively).
- Fourth quarter Free Cash Flow(1) of $43.1 million and $155.4 million for 2023, supporting return of capital commitments.
- In 2023 completed $158.6 million in share buybacks and reduced the fully diluted share count by 44.2 million (average price of $3.58 per share); exceeding its commitment of returning a minimum of 75% of Excess Cash Flow(1) ("ECF") to shareholders.
- Strong Liquidity(1) of $428.8 million, including $343.3 million of cash as at December 31, 2023.
- On December 19, 2023, the Company entered into transaction agreements to create Duvernay Energy Corporation ("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.

Thermal Oil Division

- Fourth quarter production of 31,059 bbl/d and 2023 production of 30,246 bbl/d.
- Petroleum, natural gas and midstream sales of $309.1 million in the fourth quarter and $1.2 billion for 2023.
- Operating Income(1) and Operating Netback(1) of $92.2 million ($30.78/bbl) for the fourth quarter and $370.7 million ($32.93/bbl) for 2023.
- Capital expenditures of $113.1 million for 2023 with activity focused on advancing the Leismer expansion project to 28,000 bbl/d by mid-2024 and operational planning at Hangingstone for sustaining well pairs in 2024; at Leismer activity included the ramp-up of five well pairs at Pad 8M, drilling and completions operations of four well pairs on Pad 8S and four infill wells on Pad 7 that commenced steaming in the fourth quarter of 2023.

Light Oil Division

- Fourth quarter production of 2,068 boe/d (71% Liquids(1)) and 2023 production of 4,244 boe/d (58% Liquids(1)). Volumes were impacted by the closing of a non-core asset sale on September 14, 2023.
- Petroleum, natural gas and midstream sales of $12.7 million in the fourth quarter and $91.1 million for 2023.
- Operating Income(1) and Operating Netback(1) of $4.8 million ($25.02/boe) for the fourth quarter and $46.3 million ($29.89/boe) for 2023.
- Capital expenditures of $20.9 million for 2023 were focused on the drilling and operational readiness for the upcoming Duvernay program at Greater Kaybob with two wells spud in the fourth quarter of 2023.

(1) 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 December 31, 2023	2022	Year ended December 31, 2023	2022
CONSOLIDATED				
Petroleum and natural gas production (boe/d)[1]	33,127	35,850	34,490	35,262
Petroleum, natural gas and midstream sales	$ 315,929	$ 282,524	$ 1,268,525	$ 1,504,685
Operating Income (Loss)[1]	$ 96,960	$ 70,319	$ 417,023	$ 530,295
Operating Income (Loss) Net of Realized Hedging[1][2]	$ 91,443	$ 62,131	$ 381,088	$ 378,695
Operating Netback ($/boe)[1]	$ 30.44	$ 23.17	$ 32.57	$ 41.65
Operating Netback Net of Realized Hedging ($/boe)[1][2]	$ 28.71	$ 20.47	$ 29.76	$ 29.74
Capital expenditures	$ 38,752	$ 13,029	$ 139,832	$ 147,449
THERMAL OIL DIVISION				
Bitumen production (bbl/d)[1]	31,059	30,210	30,246	28,989
Petroleum, natural gas and midstream sales	$ 309,078	$ 255,749	$ 1,204,245	$ 1,382,627
Operating Income (Loss)[1]	$ 92,199	$ 50,691	$ 370,732	$ 420,511
Operating Netback ($/bbl)[1]	$ 30.78	$ 20.15	$ 32.93	$ 40.26
Capital expenditures	$ 29,260	$ 10,895	$ 113,077	$ 110,582
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)[1]	2,068	5,640	4,244	6,273
Percentage Liquids (%)[1]	71%	56%	58%	57%
Petroleum, natural gas and midstream sales	$ 12,659	$ 36,356	$ 91,062	$ 175,279
Operating Income (Loss)[1]	$ 4,761	$ 19,628	$ 46,291	$ 109,784
Operating Netback ($/boe)[1]	$ 25.02	$ 37.83	$ 29.89	$ 47.95
Capital expenditures	$ 9,381	$ 1,594	$ 20,857	$ 11,662
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 103,196	$ 69,368	$ 305,526	$ 315,618
per share - basic	$ 0.18	$ 0.12	$ 0.52	$ 0.56
Adjusted Funds Flow[1]	$ 81,830	$ 46,074	$ 295,236	$ 308,004
per share - basic	$ 0.14	$ 0.08	$ 0.51	$ 0.54
Free Cash Flow[1]	$ 43,078	$ 33,045	$ 155,404	$ 160,555
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ 27,506	$ 489,654	$ (51,220)	$ 572,271
per share - basic	$ 0.05	$ 0.83	$ (0.09)	$ 1.01
per share - diluted[3]	$ 0.03	$ 0.81	$ (0.09)	$ 0.98
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	574,412,564	586,468,394	583,757,575	568,035,589
Weighted average shares outstanding - diluted	588,498,448	604,911,603	583,757,575	586,913,328

As at ($ Thousands)	December 31, 2023	December 31, 2022
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 343,309	$ 197,525
Available credit facilities[4]	$ 85,488	$ 87,838
Face value of term debt[5]	$ 207,648	$ 237,231

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.
(2) Includes realized commodity risk management loss of $5.5 million and $35.9 million for the three months and year ended December 31, 2023 (the three months and year ended December 31, 2022 – loss of $8.2 million and $151.6 million).
(3) In the calculation of diluted earnings per share for the three months ended December 31, 2023 earnings were reduced by $11.3 million to account for the impact to net income had the outstanding warrants been converted to equity.
(4) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility.
(5) The face value of the term debt at December 31, 2023 was US$157 million (December 31, 2022 – US$175 million) translated into Canadian dollars at the December 31, 2023 exchange rate of US$1.00 = C$1.3226 (December 31, 2022 – C$1.3544).

INDEPENDENT RESERVES EVALUATION

The Company's qualified independent reserve evaluators, McDaniel & Associates Consultants Ltd. ("McDaniel"), completed independent reserve evaluations effective December 31, 2023 and 2022. Athabasca's light and medium oil, tight oil, shale gas, conventional natural gas, condensate natural gas liquids and other natural gas liquids reserves are located in the Company's Light Oil Division. The Company's bitumen reserves are located in the Company's Thermal Oil Division.

Refer to the "Advisories and Other Guidance" section within this MD&A and the Company's AIF dated February 29, 2024, for further details relating to Athabasca's reserves.

Reserves

At December 31, 2023, the Company had 1,243 MMboe of Proved plus Probable Reserves (December 31, 2022 - 1,290 MMboe). The following table shows the Company's reserves by division (tables may not add due to rounding):

	December 31, 2023			December 31, 2022		
Reserves	Proved Developed Producing	Proved	Proved plus Probable	Proved Developed Producing	Proved	Proved plus Probable
Thermal Oil Division[1]						
Leismer (MMbbl)	51	331	697	35	327	698
Corner (MMbbl)	—	—	351	—	—	353
Hangingstone (MMbbl)	27	73	167	31	76	170
Total Thermal Oil Division (MMbbl)	77	404	1,216	66	403	1,220
Light Oil Division[2]						
Greater Placid (MMboe)	—	—	—	6	22	46
Greater Kaybob (MMboe)	4	11	27	6	7	24
Total Light Oil Division (MMboe)	4	11	27	12	29	70
Consolidated reserves (MMboe)	**82**	**415**	**1,243**	**78**	**433**	**1,290**

(1) Thermal Oil reserves are comprised of bitumen.
(2) Light Oil reserves are comprised of light and medium oil, tight oil, shale gas, conventional natural gas, condensate natural gas liquids and other natural gas liquids.

In the Thermal Oil Division, the Proved Developed Producing ("PDP") reserves increased by 17% to 77 MMbbl. The increase is due to the Proved Undeveloped transfers to PDP in Leismer more than replacing the 2023 production. Proved plus Probable ("2P") reserves were relatively consistent with 1,216 MMbbl at December 31, 2023 and 1,220 MMbbl at December 31, 2022.

In the Light Oil Division, the 2P reserves at December 31, 2023 were 27 MMboe (December 31, 2022 - 70 MMboe). The decrease is due to the Greater Placid Non-Core Light Oil Asset Sale during the year.

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended December 31, 2023	2022	Change	Year ended December 31, 2023	2022	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[(1)]	$ 78.32	$ 82.65	(5) %	$ 77.62	$ 94.23	(18) %
West Texas Intermediate (WTI) (C$/bbl)[(1)]	$ 106.65	$ 112.21	(5) %	$ 104.73	$ 122.56	(15) %
Western Canadian Select (WCS) (C$/bbl)[(2)]	$ 76.92	$ 77.36	(1) %	$ 79.54	$ 98.46	(19) %
Edmonton Par (C$/bbl)[(3)]	$ 99.71	$ 110.13	(9) %	$ 100.56	$ 120.09	(16) %
Edmonton Condensate (C5+) (C$/bbl)[(4)]	$ 102.83	$ 111.82	(8) %	$ 102.11	$ 120.81	(15) %
WCS Differential:						
to WTI (US$/bbl)	$ (21.89)	$ (25.66)	(15) %	$ (18.66)	$ (18.22)	2 %
to WTI (C$/bbl)	$ (29.73)	$ (34.85)	(15) %	$ (25.19)	$ (24.10)	5 %
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (5.19)	$ (1.61)	222 %	$ (3.22)	$ (1.78)	81 %
to WTI (C$/bbl)	$ (6.94)	$ (2.08)	234 %	$ (4.17)	$ (2.47)	69 %
Natural gas:						
AECO (C$/GJ)[(5)(6)]	$ 2.18	$ 4.85	(55) %	$ 2.51	$ 5.04	(50) %
Foreign exchange:						
USD : CAD	1.3617	1.3576	— %	1.3493	1.3006	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 the Company's Light Oil Division.
(4) Natural gas liquids condensate sales in the Company's Light Oil Division and for diluent purchases in the Thermal Oil Division.
(5) Natural gas consumed by Athabasca in order to generate steam in the Thermal Oil Division.
(6) Natural gas (i.e. shale gas and conventional natural gas) sales in the Company's Light Oil Division.

OUTLOOK

2024 Operational & Financial Guidance ($ millions, unless otherwise noted)	Athabasca Oil 100% Thermal Oil	Duvernay Energy Corporation(3)(4)
Production (boe/d)(1)	32,000-33,000	3,000
Adjusted Funds Flow(1)(2)	~$460	~$50
Free Cash Flow(1)(2)	~$325	—
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 February 29, 2024 guidance: US$80 WTI, US$15 Western Canadian Select "WCS" heavy differential, C$3 AECO, and $0.75 C$/US$ FX.
(3) Duvernay Energy reflects gross production and financial metrics before taking into consideration Athabasca's 70% equity interest.
(4) Duvernay Energy capital program funded by seed capital and Adjusted Funds Flow forecast.

Athabasca's Thermal Oil division underpins 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 is on track to be commissioned during the first quarter of 2024 with production expected to reach approximately 28,000 bbl/d mid-year following the tie-in of behind pipe wells. Two 1,400 meter well pairs are planned to be drilled at Hangingstone in the second half of 2024 with the objective of ensuring the project continues to deliver meaningful cash flow to the Company.

Duvernay Energy Corporation's 2024 capital program of $82 million (gross) includes the drilling of 12 gross (7.1 net) Duvernay wells. Capital will be funded through cash balances and cash flow from operations. 2024 production guidance is approximately 3,000 boe/d (75% Liquids). Development plans are expected to drive strong production momentum into 2025 with estimated production of approximately 6,000 boe/d.

Excluding its 70% equity interest in Duvernay Energy Corporation, the Company forecasts Adjusted Funds Flow of approximately $460 million in 2024. Athabasca's 2024 Free Cash Flow forecast is approximately $325 million. The Company has $2.8 billion in corporate tax pools and Athabasca is not forecasted to pay cash taxes for approximately seven years.

The Company will release its annual Environmental, Social and Governance update in May of 2024. In 2023, the Company maintained a strong safety record with a 0.31 Total Recordable Injury Frequency and no reportable hydrocarbon spills.

2023 Guidance Review

The Company's 2023 corporate production was in line with guidance of approximately 34,500 boe/d. The impact of the non-core Light Oil Asset Sale on September 14, 2023 was partially offset by growth at Leismer. The cashflow metrics guidance was updated throughout the year to reflect realized commodity prices and the outlook for prices for the balance of the year.

2023 Guidance ($ millions, unless otherwise noted)	Original Guidance Dec. 7, 2022	Updated Guidance May 10, 2023	Jul. 26, 2023	Nov. 1, 2023	Actual Full year
Production (boe/d)(1)	34,500-36,000	34,500-36,000	34,500-36,000	~34,500	34,490
Adjusted Funds Flow(1)	$415	$325-400	$310-365	$310-335	$295
Free Cash Flow(1)	$270	$180-255	$165-220	$165-190	$155
Capital Expenditures	$145	$145	$145	$145	$140

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

CONSOLIDATED RESULTS

For analysis of operating results see the Thermal Oil Division and Light Oil Division sections within this MD&A. For further details related to commodity risk management gains/losses see the Risk Management Contracts section.

Consolidated Operating Results

	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
PRODUCTION				
Bitumen (bbl/d)	31,059	30,210	30,246	28,989
Oil and condensate (bbl/d)(1)	1,208	2,550	1,924	2,848
Natural gas (Mcf/d)(1)	3,612	14,785	10,769	16,169
Other natural gas liquids (bbl/d)(1)	258	626	525	730
Total (boe/d)(1)	33,127	35,850	34,490	35,262

(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 December 31, 2023	2022	Year ended December 31, 2023	2022
Petroleum, natural gas and midstream sales(1)	$ 321,737	$ 292,105	$ 1,295,307	$ 1,557,906
Royalties	(17,875)	(19,957)	(73,448)	(158,742)
Cost of diluent(1)	(137,438)	(128,713)	(518,219)	(548,553)
Operating expenses	(46,427)	(50,767)	(193,882)	(226,630)
Transportation and marketing(2)	(23,037)	(22,349)	(92,735)	(93,686)
Operating Income (Loss)(3)	96,960	70,319	417,023	530,295
Realized gain (loss) on commodity risk mgmt. contracts	(5,517)	(8,188)	(35,935)	(151,600)
OPERATING INCOME (LOSS) NET OF REALIZED HEDGING(3)	$ 91,443	$ 62,131	$ 381,088	$ 378,695
REALIZED PRICES(3)				
Heavy oil (Blended bitumen) ($/bbl)(3)	$ 72.95	$ 72.24	$ 75.98	$ 94.15
Oil and condensate ($/bbl)(3)	98.29	108.33	98.78	118.27
Natural gas ($/Mcf)(3)	3.00	5.48	3.12	5.73
Other natural gas liquids ($/bbl)(3)	31.07	60.52	49.09	69.57
Realized price (net of cost of diluent) ($/boe)(3)	57.86	53.84	60.69	79.28
Royalties ($/boe)(3)	(5.61)	(6.58)	(5.74)	(12.47)
Operating expenses ($/boe)(3)	(14.58)	(16.73)	(15.14)	(17.80)
Transportation and marketing ($/boe)(2)(3)	(7.23)	(7.36)	(7.24)	(7.36)
Operating Netback ($/boe)(3)	30.44	23.17	32.57	41.65
Realized gain (loss) on commodity risk mgmt. contracts ($/boe)(3)	(1.73)	(2.70)	(2.81)	(11.91)
OPERATING NETBACK NET OF REALIZED HEDGING ($/boe)(3)	$ 28.71	$ 20.47	$ 29.76	$ 29.74

(1) Non-GAAP measure includes intercompany NGLs (i.e. condensate) sold by the Light Oil segment to the Thermal Oil segment for use as diluent that is eliminated on consolidation.
(2) Transportation and marketing excludes non-cash costs of $0.6 million and $2.2 million for the three months and year ended December 31, 2023 (the three months and year ended December 31, 2022 - $0.6 million and $2.2 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.

Consolidated Segments Income

($ Thousands)	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Operating Income (Loss) Net of Realized Hedging[1]	$ 91,443	$ 62,131	$ 381,088	$ 378,695
Non-cash transportation and marketing	(558)	(558)	(2,230)	(2,230)
Unrealized gain (loss) on commodity risk mgmt. contracts	1,435	(4,175)	6,390	27,261
Impairment reversal (expense)	—	80,000	—	80,000
Depletion and depreciation	(24,119)	(29,512)	(108,983)	(116,641)
Gain (loss) on sale of assets	(4,810)	37	(179,382)	440
Exploration expenses	(532)	(630)	(1,412)	(3,117)
CONSOLIDATED SEGMENTS INCOME (LOSS)	$ 62,859	$ 107,293	$ 95,471	$ 364,408

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

Consolidated Capital Expenditures

($ Thousands)	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Thermal Oil Division	$ 29,260	$ 10,895	$ 113,077	$ 110,582
Light Oil Division	9,381	1,594	20,857	11,662
Corporate assets	111	540	5,898	25,205
CAPITAL EXPENDITURES[1][2][3]	$ 38,752	$ 13,029	$ 139,832	$ 147,449

(1) For the three months and year ended December 31, 2023, expenditures include capitalized cash based stock-based compensation costs of $0.1 million and $1.6 million (the three months and year ended December 31, 2022 - $0.4 million and $3.0 million).

(2) For the three months and year ended December 31, 2023, expenditures include capitalized staff costs of $1.9 million and $7.6 million (the three months and year ended December 31, 2022 - $1.8 million and $7.2 million).

(3) Excludes non-cash capitalized costs related to stock-based compensation, decommissioning obligation assets and leased asset modifications.

THERMAL OIL DIVISION

Athabasca's Thermal Oil Division 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 Division underpins 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 December 31, 2023	2022	Year ended December 31, 2023	2022
VOLUMES				
Bitumen production (bbl/d)	23,764	21,774	22,497	20,135
Bitumen sales (bbl/d)	24,084	20,469	22,816	19,884
Heavy oil (blended bitumen) sales (bbl/d)	34,277	28,850	32,170	27,867

($ Thousands, unless otherwise noted)	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Heavy oil (blended bitumen) sales	$ 229,563	$ 190,692	$ 889,825	$ 946,609
Cost of diluent	(104,762)	(97,665)	(389,410)	(378,427)
Total bitumen sales	124,801	93,027	500,415	568,182
Royalties	(12,234)	(9,785)	(46,773)	(92,094)
Operating expenses - non-energy	(17,962)	(12,864)	(64,815)	(56,798)
Operating expenses - energy	(11,291)	(17,470)	(50,691)	(68,219)
Transportation and marketing	(12,677)	(12,613)	(50,064)	(50,663)
LEISMER OPERATING INCOME (LOSS)(1)	$ 70,637	$ 40,295	$ 288,072	$ 300,408
REALIZED PRICE(1)				
Heavy oil (blended bitumen) sales ($/bbl)(1)	$ 72.80	$ 71.84	$ 75.78	$ 93.06
Bitumen sales ($/bbl)(1)	$ 56.33	$ 49.40	$ 60.09	$ 78.29
Royalties ($/bbl)(1)	(5.52)	(5.20)	(5.62)	(12.69)
Operating expenses - non-energy ($/bbl)(1)	(8.11)	(6.83)	(7.78)	(7.83)
Operating expenses - energy ($/bbl)(1)	(5.10)	(9.28)	(6.09)	(9.40)
Transportation and marketing ($/bbl)(1)	(5.72)	(6.70)	(6.01)	(6.98)
LEISMER OPERATING NETBACK ($/bbl)(1)	$ 31.88	$ 21.39	$ 34.59	$ 41.39

(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 and year ended December 31, 2023 was 23,764 bbl/d and 22,497 bbl/d, an increase of 9% and 12%, respectively, compared to the corresponding periods in 2022. Production increases are primarily attributed to the ramp-up of Pad 8 (five initial well pairs) through 2022 and new production from five additional well pairs on Pad 8M.

Leismer’s Operating Netback was $31.88/bbl for the three months ended December 31, 2023, representing an increase of $10.49/bbl compared with the same period in 2022. The increase is primarily a result of higher realized oil prices and lower energy operating expenses. For the year ended December 31, 2023 Leismer’s Operating Netback was $34.59/bbl, representing a decrease of $6.80/bbl compared with the same period in 2022. The decrease is primarily due to lower WCS benchmark oil prices, partially offset by a decrease in royalties due to lower oil prices and lower energy operating expenses.

Total operating expenses were $13.21/bbl in the fourth quarter of 2023 and $13.87/bbl in the year ended December 31, 2023, compared to $16.11/bbl and $17.23/bbl in the comparable periods of 2022. The decrease on a per barrel basis is largely the result of higher production and lower energy costs in the year ended December 31, 2023.

Hangingstone Operating Results

	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
VOLUMES				
Bitumen production (bbl/d)	7,295	8,436	7,749	8,854
Bitumen sales (bbl/d)	8,468	6,877	8,020	8,725
Heavy oil (blended bitumen) sales (bbl/d)	11,777	9,632	11,251	12,365

($ Thousands, unless otherwise noted)	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Heavy oil (blended bitumen) and midstream sales	$ 79,515	$ 65,057	$ 314,420	$ 436,018
Cost of diluent	(32,676)	(31,048)	(128,809)	(170,126)
Total bitumen and midstream sales	46,839	34,009	185,611	265,892
Royalties	(3,461)	(3,471)	(14,092)	(41,040)
Operating expenses - non-energy	(5,805)	(4,198)	(22,301)	(24,521)
Operating expenses - energy	(6,360)	(8,444)	(31,078)	(46,403)
Transportation and marketing(1)	(9,651)	(7,500)	(35,480)	(33,825)
HANGINGSTONE OPERATING INCOME (LOSS)(2)	$ 21,562	$ 10,396	$ 82,660	$ 120,103
REALIZED PRICE(2)				
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 73.39	$ 73.41	$ 76.56	$ 96.61
Bitumen and midstream sales ($/bbl)(2)	$ 60.12	$ 53.75	$ 63.41	$ 83.49
Royalties ($/bbl)(2)	(4.44)	(5.49)	(4.81)	(12.89)
Operating expenses - non-energy ($/bbl)(2)	(7.45)	(6.64)	(7.62)	(7.70)
Operating expenses - energy ($/bbl)(2)	(8.16)	(13.35)	(10.62)	(14.57)
Transportation and marketing ($/bbl)(1)(2)	(12.39)	(11.85)	(12.12)	(10.62)
HANGINGSTONE OPERATING NETBACK ($/bbl)(2)	$ 27.68	$ 16.42	$ 28.24	$ 37.71

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $2.2 million for the three months and year ended December 31, 2023 (three months and year ended December 31, 2022 - $0.6 million and $2.2 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 and year ended December 31, 2023 decreased compared to the same periods in 2022 as a result of natural declines.

The Hangingstone Operating Netback was $27.68/bbl for the three months ended December 31, 2023, representing an increase of $11.26/bbl compared with the same period in 2022. The increase is primarily a result of higher realized oil prices and lower energy operating expenses. For the year ended December 31, 2023 Hangingstone's Operating Netback was $28.24/bbl, representing a decrease of $9.47/bbl compared with the same period in 2022. The decrease is primarily due to lower WCS benchmark oil prices, partially offset by a decrease in royalties due to lower oil prices and lower energy operating expenses.

Total operating expenses were $15.61/bbl in the fourth quarter of 2023 and $18.24/bbl in the year ended December 31, 2023, compared to $19.99/bbl and $22.27/bbl in the comparable periods of 2022. The decrease on a per barrel is the result of lower energy costs and a lower steam oil ratio in the year ended December 31, 2023, partially offset by lower production.

Consolidated Thermal Oil Operating Results

	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
VOLUMES				
Bitumen production (bbl/d)	31,059	30,210	30,246	28,989
Bitumen sales (bbl/d)	32,552	27,346	30,836	28,609
Heavy oil (blended bitumen) sales (bbl/d)	46,054	38,482	43,421	40,232

($ Thousands, unless otherwise noted)	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Heavy oil (blended bitumen) and midstream sales	$ 309,078	$ 255,749	$ 1,204,245	$ 1,382,627
Cost of diluent	(137,438)	(128,713)	(518,219)	(548,553)
Total bitumen and midstream sales	171,640	127,036	686,026	834,074
Royalties	(15,695)	(13,256)	(60,865)	(133,134)
Operating expenses - non-energy	(23,767)	(17,062)	(87,116)	(81,319)
Operating expenses - energy	(17,651)	(25,914)	(81,769)	(114,622)
Transportation and marketing[1]	(22,328)	(20,113)	(85,544)	(84,488)
THERMAL OIL OPERATING INCOME (LOSS)[2]	$ 92,199	$ 50,691	$ 370,732	$ 420,511
REALIZED PRICE[2]				
Heavy oil (blended bitumen) and midstream sales ($/bbl)[2]	$ 72.95	$ 72.24	$ 75.98	$ 94.15
Bitumen and midstream sales ($/bbl)[2]	$ 57.31	$ 50.49	$ 60.95	$ 79.87
Royalties ($/bbl)[2]	(5.24)	(5.27)	(5.41)	(12.75)
Operating expenses - non-energy ($/bbl)[2]	(7.94)	(6.78)	(7.74)	(7.79)
Operating expenses - energy ($/bbl)[2]	(5.89)	(10.30)	(7.27)	(10.98)
Transportation and marketing ($/bbl)[1][2]	(7.46)	(7.99)	(7.60)	(8.09)
THERMAL OIL OPERATING NETBACK ($/bbl)[2]	$ 30.78	$ 20.15	$ 32.93	$ 40.26

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $2.2 million for the three months and year ended December 31, 2023 (three months and year ended December 31, 2022 - $0.6 million and $2.2 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 (Loss) 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.

Thermal Oil Segment Income

($ Thousands)	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Thermal Oil Operating Income (Loss)[1]	$ 92,199	$ 50,691	$ 370,732	$ 420,511
Non-cash transportation and marketing	(558)	(558)	(2,230)	(2,230)
Depletion and depreciation	(19,918)	(19,464)	(77,152)	(75,299)
Gain (loss) on sale of assets	—	37	—	440
Exploration expenses	(532)	(630)	(1,412)	(3,117)
THERMAL OIL SEGMENT INCOME (LOSS)	$ 71,191	$ 30,076	$ 289,938	$ 340,305

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

Depletion and depreciation increased $1.9 million during the year ended December 31, 2023, compared to the same period in the prior year primarily due to higher production volumes at Leismer.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Leismer Project	$ 24,999	$ 9,020	$ 99,007	$ 102,668
Hangingstone Project	4,026	1,740	13,351	7,457
Other Thermal Oil exploration	235	135	719	457
THERMAL OIL CAPITAL EXPENDITURES(1)	$ 29,260	$ 10,895	$ 113,077	$ 110,582

(1) For the three months and year ended December 31, 2023, capital expenditures include $1.5 million and $6.0 million of capitalized staff costs (three months and year ended December 31, 2022 - $1.4 million and $5.5 million).

Thermal Oil capital expenditures for the year ended December 31, 2023 of $113.1 million were primarily focused at Leismer along with routine pump replacements across both assets. At Leismer, the Company focused on advancing the Leismer expansion project to 28,000 bbl/d by mid-2024 and activity included the ramp-up of five well pairs at Pad 8M, facilities completion of four well pairs on Pad 8S and four infill wells on Pad 7. These additional new wells commenced steaming during the fourth quarter of 2023 and are expected to support production in 2024 and beyond. At Hangingstone, Athabasca commenced the Pad AA extension for future sustaining well pairs.

In comparison, capital expenditures for the year ended December 31, 2022 of $110.6 million were primarily related to sustaining operations and a planned facility turnaround at Leismer, along with routine pump replacements across both assets. At Leismer, the Company converted five Pad 8 wells to production, two Pad 6 infill wells were placed on production and rig released the Pad 8M expansion (five additional well pairs).

LIGHT OIL DIVISION

Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs. Development has been focused on the Duvernay 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[1]. Athabasca's Light Oil Division 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, Athabasca 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[2] gross drilling locations.

Light Oil Non-Core Asset Sale

Athabasca completed the sale of its 70% operated working interest in Placid targeting the Montney, its 30% non-operated working interest in Saxon and Simonette targeting the Duvernay and other associated non-core Placid Montney assets to a private company for $160 million in cash before closing adjustments and transaction costs ($149.2 million net). The deal closed on September 14, 2023 with an effective date of March 1, 2023. Athabasca de-recognized $333.9 million of PP&E and $6.0 million in decommissioning obligations resulting in a loss of $178.7 million on the asset sale.

The transaction was completed at attractive and accretive metrics, and crystallized value of assets that became non-core due to the smaller scale, lower liquids content and lower relative returns versus core assets within the Company's portfolio. During the first half of 2023, these assets collectively averaged approximately 3,000 boe/d (approximately 45% Liquids).

(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.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information regarding the Company's drilling locations.

Duvernay Energy Corporation

On December 19, 2023 Athabasca announced that it entered into transaction agreements ("Transaction") to create Duvernay Energy Corporation ("Duvernay Energy") with Cenovus Energy Inc. ("Cenovus"). The Transaction closed February 6, 2024 with an effective date of January 1, 2024. Duvernay Energy is a privately held subsidiary of Athabasca. Athabasca and Cenovus have contributed assets into Duvernay Energy combining Athabasca's existing Duvernay assets, Athabasca's new 100% working interest Duvernay assets and Cenovus' 100% working interest Kaybob Duvernay assets. Athabasca owns a 70% equity interest in Duvernay Energy with Cenovus owning the remaining 30% equity interest. Duvernay Energy will be managed by Athabasca through a management and operating services agreement. Duvernay Energy's Board of Directors will include three members nominated by Athabasca and one member nominated by Cenovus. Duvernay Energy has a $50 million undrawn credit facility. With the completion of the Transaction, Duvernay Energy will operate as a subsidiary under Athabasca's control and will be included in the Consolidated Financial Statements.

Light Oil Operating Results

	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
PRODUCTION(1)				
Oil and condensate (bbl/d)	1,208	2,550	1,924	2,848
Natural gas (Mcf/d)	3,612	14,785	10,769	16,169
Other natural gas liquids (bbl/d)	258	626	525	730
Total (boe/d)	2,068	5,640	4,244	6,273
Consisting of:				
Greater Placid area (boe/d)	—	2,913	1,904	3,232
% Liquids	0%	41%	41%	42%
Greater Kaybob area (boe/d)	2,068	2,727	2,340	3,041
% Liquids	71%	72%	71%	72%

(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 December 31, 2023	2022	Year ended December 31, 2023	2022
Petroleum and natural gas sales	$ 12,659	$ 36,356	$ 91,062	$ 175,279
Royalties	(2,180)	(6,701)	(12,583)	(25,608)
Operating expenses	(5,009)	(7,791)	(24,997)	(30,689)
Transportation and marketing	(709)	(2,236)	(7,191)	(9,198)
LIGHT OIL OPERATING INCOME (LOSS)(1)	$ 4,761	$ 19,628	$ 46,291	$ 109,784
REALIZED PRICES(1)				
Oil and condensate ($/bbl)(1)	$ 98.29	$ 108.33	$ 98.78	$ 118.27
Natural gas ($/Mcf)(1)	3.00	5.48	3.12	5.73
Other natural gas liquids ($/bbl)(1)	31.07	60.52	49.09	69.57
Realized price ($/boe)(1)	66.54	70.07	58.79	76.55
Royalties ($/boe)(1)	(11.46)	(12.91)	(8.12)	(11.18)
Operating expenses ($/boe)(1)	(26.33)	(15.02)	(16.14)	(13.40)
Transportation and marketing ($/boe)(1)	(3.73)	(4.31)	(4.64)	(4.02)
LIGHT OIL OPERATING NETBACK ($/boe)(1)	$ 25.02	$ 37.83	$ 29.89	$ 47.95

(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 Light Oil production for the three months and year ended December 31, 2023 decreased as a result of natural declines and the September 14, 2023 closing of the Light Oil Non-Core Asset Sale.

The Operating Netback was $25.02/boe and $29.89/boe for the three months and year ended December 31, 2023, respectively. The decrease from the prior year is primarily due to lower commodity prices and higher operating expenses on a per boe basis correlated to lower production volumes, partially offset by a decrease in royalties primarily due to lower commodity prices and an annual gas cost allowance adjustment from the Crown.

Light Oil Segment Income (Loss)

($ Thousands)		Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Light Oil Operating Income (Loss)[1]	$	4,761 $	19,628 $	46,291 $	109,784
Impairment reversal (expense)		—	80,000	—	80,000
Depletion and depreciation		(4,201)	(10,048)	(31,831)	(41,342)
Gain (loss) on sale of assets		(4,810)	—	(179,382)	—
LIGHT OIL SEGMENT INCOME (LOSS)	$	(4,250) $	89,580 $	(164,922) $	148,442

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

In 2023, no indicators of impairment or impairment reversal were identified. This assessment included an analysis of current market and regulatory conditions as well as a review of the Company's assets, future development plans and pending land expiries. In the fourth quarter of 2022 Athabasca completed an impairment test on the Light Oil CGU due to higher commodity price forecasts and increasing interest rates, which resulted in the reversal of previous Light Oil impairments of $80.0 million.

Depletion and depreciation decreased $5.8 million and $9.5 million during the three months and year ended December 31, 2023, respectively, compared to the same periods in the prior year primarily due to lower production volumes. During the year ended December 31, 2023, Athabasca recorded a loss on sale of assets of $179.4 million primarily related to the Light Oil Non-Core Asset Sale.

Light Oil Capital Expenditures

($ Thousands)		Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
LIGHT OIL CAPITAL EXPENDITURES[1]	$	9,381 $	1,594 $	20,857 $	11,662

(1) For the three months and year ended December 31, 2023, capital expenditures include $0.4 million and $1.6 million of capitalized staff costs (three months and year ended December 31, 2022 - $0.4 million and $1.7 million).

For the year ended December 31, 2023, Light Oil capital expenditures of $20.9 million were focused on drilling and operational readiness for the upcoming Duvernay program at Greater Kaybob with two wells spud in the fourth quarter of 2023.

In comparison, for the year ended December 31, 2022, Light Oil capital expenditures were primarily incurred at Greater Kaybob for the completion and infrastructure work for three gross wells drilled in 2019 and two facility turnarounds at Kaybob West and Kaybob East.

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 a portion of its forecasted Free Cash Flow in 2024 to share buybacks with flexibility for further debt reduction 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 December 31, 2023, Athabasca had Liquidity of $428.8 million which included $343.3 million of cash and cash equivalents and $85.5 million of available capacity on its credit facilities.

Indebtedness

Athabasca had the following debt instruments and credit facilities in place as at December 31, 2023:

Term Debt

As at December 31, 2023, the principal balance on Athabasca's senior secured second lien notes ("2026 Notes" or "Notes") was $207.6 million (US$157 million). During the year ended 2023 the Company redeemed $24.9 million (US$18.2 million) of the Notes and achieved a 55% reduction in the principal balance from the original US$350 million Notes issuance in the fourth quarter of 2021. During the first quarter of 2023 the Excess Cash Flow ("ECF") feature was terminated within the indenture as the principal balance fell below US$175 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 December 31, 2023, the Company had no amounts drawn and $27.1 million of letters of credit outstanding under the Credit Facility. As at December 31, 2022, the Company had no amounts drawn and $34.4 million of letters of credit outstanding under the Credit Facility.

Unsecured Letter of Credit Facility

Athabasca maintains 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, 2022 - $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 December 31, 2023, the Company had $57.5 million of letters of credit outstanding under the Unsecured Letter of Credit Facility (December 31, 2022 - $47.8 million).

Financing and Interest

($ Thousands)	Three months ended December 31, 2023	Three months ended December 31, 2022	Year ended December 31, 2023	Year ended December 31, 2022
Financing and interest expense on indebtedness	$ 6,072	$ 10,012	$ 26,648	$ 49,744
Accretion of 2026 Notes	1,923	9,201	3,155	28,334
Accretion of warrants	415	85	1,013	2,605
Accretion of provisions	1,911	2,644	7,780	10,519
Interest expense on lease liability	127	197	588	909
TOTAL FINANCING AND INTEREST	$ 10,448	$ 22,139	$ 39,184	$ 92,111

During the three months and year ended December 31, 2023 and 2022, total financing and interest expenses were primarily attributable to the financing, interest and accretion expenses related to the Company's Notes. Accretion of the 2026 Notes decreased in the year ended December 31, 2023 as a result of the termination of the ECF feature in the first quarter of 2023.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Unrealized foreign exchange gain (loss)	$ (3,267)	$ 3,523	$ (1,141)	$ (900)
Realized foreign exchange gain (loss)	(1,153)	(3,616)	(1,293)	(3,991)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ (4,420)	$ (93)	$ (2,434)	$ (4,891)

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 December 31, 2023, 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	January - March 2024	9,040 bbl/d	$ 66.13 - 166.54	$ 50.00 - 125.92
Purchase contracts			C$/GJ/bbl	US$/GJ/bbl
AECO collar	January - December 2024	20,000 GJ/d	$ 2.35 - 2.84	$ 1.78 - 2.15

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the December 31, 2023 exchange rate of US$1.00 = C$1.3226.

In 2021, Athabasca entered into a seven-year marketing agreement for 15,000 bbl/d 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 December 31, 2023, the pricing derivative had an asset value of $2.0 million (December 31, 2022 - $0.8 million).

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three months and year ended December 31, 2023 and 2022:

($ Thousands)	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Unrealized gain (loss) on commodity risk mgmt. contracts	$ 1,435	$ (4,175)	$ 6,390	$ 27,261
Realized gain (loss) on commodity risk mgmt. contracts	(5,517)	(8,188)	(35,935)	(151,600)
GAIN (LOSS) ON COMMODITY RISK MGMT. CONTRACTS, NET	$ (4,082)	$ (12,363)	$ (29,545)	$ (124,339)

At December 31, 2023, 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 December 31, 2023	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	$ 1,739	$ (7,208)

Additional financial commodity risk management has taken place subsequent to December 31, 2023 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	January - March 2024	13,120 bbl/d	$ 66.13 - 122.23	$ 50.00 - 92.42
WTI collar	April - June 2024	9,725 bbl/d	$ 66.13 - 127.29	$ 50.00 - 96.24

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the December 31, 2023 exchange rate of US$1.00 = C$1.3226.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future unrecognized minimum commitments as at December 31, 2023 for the following five years and thereafter:

($ Thousands)	2024	2025	2026	2027	2028	Thereafter	Total
Transportation and processing[1]	$ 109,706	$ 107,391	$ 107,166	$ 105,561	$ 75,453	$ 1,014,725	$ 1,520,002
Interest expense on term debt[1]	20,246	20,246	16,871	—	—	—	57,363
Purchase commitments and other[1]	10,521	—	—	—	—	—	10,521
TOTAL COMMITMENTS	$ 140,473	$ 127,637	$ 124,037	$ 105,561	$ 75,453	$ 1,014,725	$ 1,587,886

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the December 31, 2023 exchange rate of US$1.00 = C$1.3226.

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 December 31, 2023. 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 December 31, 2023 of $343.3 million (December 31, 2022 - $197.5 million), from a 1.0% change in interest rates, would have an annualized impact of approximately $3.4 million (December 31, 2022 - $2.0 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 December 31, 2023	2022	Year ended December 31, 2023	2022
TOTAL GENERAL AND ADMINISTRATIVE	$ 6,285	$ 6,024	$ 20,646	$ 20,768
G&A per boe[1]	$ 2.06	$ 1.83	$ 1.64	$ 1.61

(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 and year ended December 31, 2023, Athabasca's stock-based compensation expense was $1.8 million and $54.2 million, respectively, compared to $6.2 million and $27.4 million in the respective prior year periods. The increase year to date is due to the increase in the fair value of the cash settled stock-based compensation plans as a result of the share price increase in 2023. In addition, 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 the second quarter of 2023. The PSUs, PUPs and DSUs plans are accounted for as cash-settled stock-based compensation plans and are recognized as liabilities on the Consolidated Balance Sheet. The liabilities under cash settled plans are revalued at each reporting date based on the Company's closing share price.

Gain (Loss) on Revaluation of Provisions and Other

($ Thousands)	Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Change in fair value of warrant liability	$ 11,725	$ (7,697)	$ (25,801)	$ (68,930)
Change in estimated decommissioning obligations related to fully impaired E&E assets	(94)	9,672	(94)	6,599
Other	—	515	—	1,742
GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER	$ 11,631	$ 2,490	$ (25,895)	$ (60,589)

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 2022 and 2023 primarily relate to changes in the share price and warrant exercises.

Income Taxes

For the year ended December 31, 2023, a $14.1 million deferred income tax expense was recorded (December 31, 2022 - $413.3 million recovery) resulting in a December 31, 2023 deferred income tax asset of $403.5 million (December 31, 2022 - $413.3 million). The Company has approximately $2.8 billion in tax pools, including approximately $2.3 billion in non-capital losses and exploration tax pools available for immediate deduction against future income.

From time to time, Athabasca undergoes income tax audits in the normal course of business. In 2018, the Company received a notice of reassessment from the Canada Revenue Agency ("CRA") and Alberta Finance with regards to its 2012 taxation year resulting in a $12.6 million deposit posted with the CRA. In the second quarter of 2023, Athabasca received confirmation that its appeal had been successful and the $12.6 million was refunded.

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 December 31, 2023, there were 572.4 million common shares outstanding, an aggregate of 11.9 million restricted share units and performance share units outstanding, 3.6 million stock options outstanding and 6.7 million (5.1 million assuming cashless exercise at December 31, 2023 share price) potential shares issuable under warrants agreements (29,324 warrants outstanding).

As at December 31, 2023, the Company repurchased for cancellation 44.2 million common shares under its NCIB program, for total consideration of $158.6 million. Subsequent to December 31, 2023, the Company repurchased for cancellation 5.4 million common shares under its NCIB program, for total consideration of $23.7 million.

As at February 29, 2024, there were 567.0 million common shares outstanding, an aggregate of 11.9 million restricted share units and performance share units outstanding, 3.6 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:

	2023				2022			
($ Thousands, unless otherwise noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	78.32	82.26	73.78	76.13	82.65	91.55	108.41	94.29
WTI (C$/bbl)	106.65	110.29	99.09	102.92	112.21	119.54	138.39	119.38
Western Canadian Select (C$/bbl)	76.92	93.00	78.80	69.42	77.36	93.48	122.04	100.96
Edmonton Par (C$/bbl)	99.71	107.85	95.33	99.34	110.13	116.79	137.83	115.62
Edmonton Condensate (C5+) (C$/bbl)	102.83	104.05	96.10	105.44	111.82	112.87	137.70	120.84
AECO (C$/GJ)	2.18	2.46	2.32	3.05	4.85	3.95	6.86	4.49
Foreign exchange (USD : CAD)	1.36	1.34	1.34	1.35	1.36	1.31	1.28	1.27
CONSOLIDATED								
Petroleum and natural gas production (boe/d)(1)	33,127	36,176	33,971	34,683	35,850	37,240	33,247	34,679
Realized price (net of cost of diluent) ($/boe)(1)	57.86	80.85	59.25	44.74	53.84	75.10	105.99	83.53
Petroleum, natural gas and midstream sales ($)(2)	321,737	385,269	289,310	298,991	292,105	406,794	453,618	405,389
Operating Income (Loss) ($)(1)	96,960	168,410	95,118	56,535	70,319	140,081	169,255	150,640
Operating Income (Loss) Net of Realized Hedging ($)(1)	91,443	164,643	90,522	34,480	62,131	110,021	103,549	102,994
Operating Netback ($/boe)(1)	30.44	50.84	32.23	16.85	23.17	39.17	57.51	47.40
Operating Netback Net of Realized Hedging ($/boe)(1)	28.71	49.70	30.67	10.27	20.47	30.76	35.18	32.41
Capital expenditures ($)	38,752	33,286	41,432	26,362	13,029	52,300	51,191	30,929
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	31,059	31,691	29,016	29,179	30,210	31,023	26,768	27,909
Bitumen sales volumes (bbl/d)	32,552	31,527	27,482	31,765	27,346	32,650	25,863	28,545
Realized bitumen price ($/bbl)(1)	57.31	83.90	60.33	42.03	50.49	76.09	109.67	85.78
Heavy Oil (blended bitumen) and midstream sales ($)	309,078	360,761	265,304	269,102	255,749	366,804	399,793	360,281
Operating Income (Loss) ($)(1)	92,199	155,415	81,621	41,497	50,691	117,916	131,067	120,837
Operating Netback ($/bbl)(1)	30.78	53.59	32.64	14.52	20.15	39.25	55.68	47.04
Capital expenditures ($)	29,260	31,069	29,912	22,836	10,895	35,412	43,093	21,182
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)(1)	2,068	4,485	4,955	5,504	5,640	6,217	6,479	6,770
Realized price ($/boe)(1)	66.54	59.40	53.24	60.34	70.07	69.92	91.29	74.03
Petroleum and natural gas sales ($)(2)	12,659	24,508	24,006	29,889	36,356	39,990	53,825	45,108
Operating Income (Loss) ($)(1)	4,761	12,995	13,497	15,038	19,628	22,165	38,188	29,803
Operating Netback ($/boe)(1)	25.02	31.50	29.92	30.35	37.83	38.76	64.77	48.92
Capital expenditures ($)	9,381	(1,153)	10,753	1,876	1,594	860	1,221	7,987
OPERATING RESULTS								
Cash flow from operating activities ($)	103,196	134,879	46,914	20,537	69,368	117,853	68,535	59,862
Adjusted Funds Flow ($)(1)	81,830	141,138	81,664	(9,396)	46,074	102,370	84,799	74,761
Free Cash Flow ($)(1)	43,078	107,852	40,232	(35,758)	33,045	50,070	33,608	43,832
Net income (loss) ($)	27,506	(79,212)	57,121	(56,635)	489,654	155,097	47,121	(119,601)
Net income (loss) per share - basic ($)	0.05	(0.14)	0.10	(0.10)	0.83	0.27	0.08	(0.23)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	343,309	337,125	132,491	173,280	197,525	200,100	154,172	213,534
Total assets ($)	2,048,635	2,102,338	2,162,091	2,210,487	2,230,354	1,803,624	1,815,390	1,814,662
Term debt ($)(3)	179,705	182,398	181,577	184,509	206,133	240,078	250,756	355,328
Shareholders' equity ($)	1,583,453	1,580,312	1,682,906	1,655,044	1,710,497	1,218,174	1,057,355	909,852

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.
(2) Includes intercompany NGLs (i.e. condensate) sold by the Light Oil segment to the Thermal Oil segment for use as diluent that is eliminated on consolidation.
(3) 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.

SELECTED ANNUAL INFORMATION

The following table provides a summary of selected annual information for the years ended 2023, 2022 and 2021:

($ Thousands, unless otherwise noted)	December 31, 2023	December 31, 2022	December 31, 2021
Petroleum and natural gas production (boe/d)[(1)]	34,490	35,262	34,618
Petroleum, natural gas and midstream sales	$ 1,268,525	$ 1,504,685	$ 1,016,323
Net income (loss) and comprehensive income (loss)	$ (51,220)	$ 572,271	$ 457,608
per share (basic)	$ (0.09)	$ 1.01	$ 0.86
Cash flow from operating activities	$ 305,526	$ 315,618	$ 194,253
per share (basic)	$ 0.52	$ 0.56	$ 0.37
Adjusted Funds Flow[(1)]	$ 295,236	$ 308,004	$ 184,065
per share (basic)	$ 0.51	$ 0.54	$ 0.35
Free Cash Flow[(1)]	$ 155,404	$ 160,555	$ 91,923
Capital expenditures	$ 139,832	$ 147,449	$ 92,142
Total assets	$ 2,048,635	$ 2,230,354	$ 1,742,131
Face value of term debt[(2)]	$ 207,648	$ 237,231	$ 443,730
Weighted average shares outstanding (basic)	583,757,575	568,035,589	530,692,724
Weighted average shares outstanding (diluted)	583,757,575	586,913,328	546,717,181

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

(2) The face value of the term debt at December 31, 2023 is US$157 million (December 31, 2022 - US$175 million; December 31, 2021 - US$350 million) and was translated into Canadian dollars at the December 31, 2023 exchange rate of US$1.00 = C$1.3226 (December 31, 2022 - C$1.3544; December 31, 2021 - C$1.2678).

ACCOUNTING POLICIES AND ESTIMATES

During the year ended December 31, 2023, 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 3 of the Consolidated Financial Statements. A summary of the material accounting policy information, 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).

Material Accounting Estimates and Judgments

The preparation of the Consolidated Financial Statements requires management to use estimates, judgments and assumptions. These judgments and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the applicable reporting period. These estimates relate to unsettled transactions and events as of the date of the Consolidated Financial Statements and may differ from actual results as future confirming events occur. Estimates and underlying assumptions are reviewed by management on an ongoing basis. Revisions to accounting estimates are recognized prospectively in the year in which the estimates are revised. Changes in the Company’s accounting estimates and judgments could have a significant impact on net income (loss).

Included in the carrying value of property, plant and equipment ("PP&E") are accumulated depletion, depreciation and impairment charges/reversals that are determined, in part, by utilizing estimates based on Athabasca's reserves, resources, relevant market transactions and land acreage values. The estimates of reserves and resources include estimates of the recoverable volumes of bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and Natural Gas Liquids (“NGLs”), future commodity prices and future costs required to develop and produce the assets. Reserve and resource estimates and future cash flows could be revised either upwards or downwards based on updated information from drilling and operating results as well as changes to future commodity price estimates, changes in cost estimates and changes to the anticipated timing of project development. The rates used to discount future cash flows are based on judgment of economic, regulatory and operating factors. Changes in these factors could increase or decrease the discount rate which may result in material changes to the estimated recoverable amount of the assets. Exploration and evaluation assets ("E&E") require judgment as to whether future economic benefits exist, including the estimated recoverability of reserves and contingent resources, technology uncertainty, government regulation uncertainty and the ability to finance exploration and evaluation projects, where technical feasibility and commercial viability has not yet been determined.

For purposes of impairment testing, PP&E and E&E are aggregated into cash-generating units ("CGUs") based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations. CGUs are not larger than an operating segment. Impairment test calculations require the use of estimates and assumptions and are subject to change as new information becomes available. Factors that are subject to change include estimates of future commodity prices, expected production volumes, development timing, land values, tax pools, directly comparable market transactions, quantity of reserves and resources, discount rates, recovery rates, timing of anticipated ramp-up of production, and future development, regulatory, carbon and operating costs. Changes in assumptions used in determining the recoverable amount could have a prospective material effect on the carrying value of the related PP&E and E&E CGUs.

The provision for decommissioning obligations is based upon numerous assumptions including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Actual costs and cash outflows could differ from the estimates as a result of changes in any of the above noted assumptions.

Deferred tax assets are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in net income (loss) in the period in which the change occurs. Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in net income (loss) both in the period of change, which would include any impact on cumulative provisions, and in future periods. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations of the standards which may result in a material increase or decrease in the Company's provision for income taxes.

In 2023, crude oil prices were impacted by various factors. These included geopolitical instability, uncertainties surrounding the production levels of key oil-producing nations, strategic supply adjustments by OPEC, and recessionary fears caused by central banks raising interest rates. Athabasca uses forward commodity price curves as an input in assessing the value of its crude oil and natural gas assets and these inputs could be affected by the unknown future impact of the factors above. Refer to Note 9 of the December 31, 2023 audited Consolidated Financial Statements. At December 31, 2023, Management has incorporated the anticipated impacts of the factors above in its estimates and judgments in preparation of these Consolidated Financial Statements.

All of these 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).

ADVISORIES AND OTHER GUIDANCE

Non-GAAP and Other Financial Measures, and Production Disclosure

The "Adjusted Funds Flow", "Adjusted Funds Flow per Share", "Free Cash Flow", "Light Oil Operating Income", "Light Oil Operating Netback", "Thermal Oil Operating Income", "Thermal Oil Operating Netback", "Consolidated Operating Income", "Consolidated Operating Netback", "Consolidated Operating Income Net of Realized Hedging", "Consolidated Operating Netback Net of Realized Hedging", "Realized Prices", "Cash Transportation & Marketing Expenses", "Excess Cash Flow" and "Sustaining Capital" 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 Thermal Oil segment results and the Greater Placid and Greater Kaybob operating results are supplementary financial measures that when aggregated, combine to the Light 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:

	Three months ended December 31,		Year ended December 31,	
($ Thousands)	2023	2022	2023	2022
Cash flow from operating activities	$ 103,196	$ 69,368	$ 305,526	$ 315,618
Changes in non-cash working capital	(21,973)	(23,356)	525	(8,970)
Settlement of provisions	607	62	1,762	1,356
Long-term deposit	—	—	(12,577)	—
ADJUSTED FUNDS FLOW	81,830	46,074	295,236	308,004
Capital expenditures	(38,752)	(13,029)	(139,832)	(147,449)
FREE CASH FLOW	$ 43,078	$ 33,045	$ 155,404	$ 160,555

Operating Income (Loss) 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 table on page 13 reconciles Light Oil Operating Income to its segmented income in *Note 17 - Segmented Information* of the Consolidated Financial Statements for the three months and year ended December 31, 2023. The table on page 10 reconciles Thermal Oil Operating Income to its segmented income in *Note 17 - Segmented Information* of the Consolidated Financial Statements for the three months and year ended December 31, 2023.

The non-GAAP measure 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 Consolidated Operating Netback Net of Realized Hedging measure per boe is a non-GAAP financial ratio calculated by dividing Consolidated Operating Income Net of Realized Hedging by the total sales volumes. The Consolidated Operating Income Net of Realized Hedging and the Consolidated Operating Netback Net of Realized Hedging measures allow management and others to evaluate the production results from the Company’s Light Oil and Thermal Oil assets combined together including the impact of realized commodity risk management gains or losses. The table on page 7 reconciles Consolidated Operating Income Net of Realized Hedging to Consolidated segment income in *Note 17 - Segmented Information* of the Consolidated Financial Statements for the three months and year ended December 31, 2023.

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 & Marketing Expenses

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

Excess Cash Flow and Sustaining Capital

The Excess Cash Flow and Sustaining Capital measures allow management and others to evaluate the Company’s ability to return capital to Shareholders. Sustaining Capital is managements' assumption of the required capital to maintain the Company’s production base. The Excess Cash Flow measure is calculated by Adjusted Funds Flow less Sustaining Capital.

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 December 31, 2023	2022	Year ended December 31, 2023	2022
Greater Placid:					
Condensate NGLs	bbl/d	—	843	528	962
Other NGLs	bbl/d	—	360	256	411
Natural gas[1]	mcf/d	—	10,259	6,720	11,149
Total Greater Placid	boe/d	—	2,913	1,904	3,232
Greater Kaybob:					
Oil[2]	bbl/d	1,208	1,707	1,396	1,886
Other NGLs	bbl/d	258	266	269	319
Natural gas[1]	mcf/d	3,612	4,526	4,049	5,020
Total Greater Kaybob	boe/d	2,068	2,727	2,340	3,041
Light Oil:					
Oil[2]	bbl/d	1,208	1,707	1,396	1,886
Condensate NGLs	bbl/d	—	843	528	962
Oil and condensate NGLs	bbl/d	1,208	2,550	1,924	2,848
Other NGLs	bbl/d	258	626	525	730
Natural gas[1]	mcf/d	3,612	14,785	10,769	16,169
Total Light Oil division	boe/d	2,068	5,640	4,244	6,273
Total Thermal Oil division bitumen	bbl/d	31,059	30,210	30,246	28,989
Total Company production	boe/d	33,127	35,850	34,490	35,262

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

Liquids:		Three months ended December 31, 2023	2022	Year ended December 31, 2023	2022
Greater Placid:					
Condensate NGLs	bbl/d	—	843	528	962
Other NGLs	bbl/d	—	360	256	411
Total Greater Placid Liquids	bbl/d	—	1,203	784	1,373
as % of Greater Placid production		—	41%	41%	42%
Greater Kaybob:					
Oil	bbl/d	1,208	1,707	1,396	1,886
Other NGLs	bbl/d	258	266	269	319
Total Greater Kaybob Liquids	bbl/d	1,466	1,973	1,665	2,205
as % of Greater Kaybob production		71%	72%	71%	73%
Total Light Oil:					
Oil and condensate NGLs	bbl/d	1,208	2,550	1,924	2,848
Other NGLs	bbl/d	258	626	525	730
Total Light Oil division Liquids	bbl/d	1,466	3,176	2,449	3,578
as % of Light Oil production		71%	56%	58%	57%
Total Company:					
Total Light Oil division Liquids	bbl/d	1,466	3,176	2,449	3,578
Total Thermal Oil division bitumen	bbl/d	31,059	30,210	30,246	28,989
Total Company Liquids	bbl/d	32,525	33,386	32,695	32,567
as % of Company production		98%	93%	95%	92%

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").

Disclosure controls and procedures ("DC&P") are designed to provide reasonable assurance that the information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under the applicable Canadian securities regulatory requirements.

Part 1 of NI 52-109 defines DC&P as "Controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure".

For the year ended December 31, 2023, an evaluation was carried out under the supervision of and with the participation of Athabasca's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Company's DC&P. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer of the Company concluded that the design and operation of the Company's DC&P were effective to ensure that the information required by Canadian securities regulatory authorities, will be recorded, processed, summarized and reported within the prescribed timelines.

Management's Report on Internal Controls Over Financial Reporting

Management of Athabasca is responsible for establishing and maintaining adequate "internal control over financial reporting" as such term is defined in the applicable Canadian securities regulations. The Company's policies and procedures regarding internal controls over financial reporting were designed by the Company's management, with the oversight of the Chief Executive Officer and the Chief Financial Officer, to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of the Company's financial statements in accordance with IFRS.

The Company has policies and procedures with respect to internal control over financial reporting that:

- pertain to the maintenance of records, to ensure that dispositions of assets and other material transactions involving the Company are accurately and fairly reflected in a reasonable level of detail in the Company's records;
- provide reasonable assurance that transactions are recorded as necessary to ensure that the preparation of the financial statements is done in accordance with IFRS; and
- provide reasonable assurance regarding the timely detection and prevention of unauthorized acquisitions, uses or dispositions of the Company's assets which could have a material impact on the Company and its financial statements.

Athabasca's policies and procedures regarding internal control over financial reporting may not detect or prevent all inaccuracies, omissions or misstatements. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management, including the Chief Executive Officer and Chief Financial Officer, must assess the effectiveness of the Company's internal control over financial reporting as of December 31, 2023, based on the Internal Control - Integrated Framework (the "Framework") established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In making its assessment, Management used the COSO 2013 Framework in order to evaluate the design and effectiveness of internal control over financial reporting. Based upon management's assessment, the Company has maintained effective internal control over financial reporting as of December 31, 2023.

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 Division development projects, the exploration and development of Athabasca’s Light Oil assets and the levels and timing of anticipated production;
- dependence upon Murphy as a working interest participant in its Light Oil 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 corporate, Thermal Oil and Light Oil production levels; reserve life index; on stream timing of additional well pairs and timing of expansion projects at Leismer; the Company's anticipated sources of funding for 2024 and beyond; the Company’s use of Excess Cash Flow, including in respect of share buybacks; 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