Management's Discussion and Analysis

Q3 2022

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 November 2, 2022 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2021 and 2020 ("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.sedar.com, including the Company's most recent Annual Information Form dated March 2, 2022 ("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 most active resource plays (Oil Sands, Montney, Duvernay). The Company's strategy is guided by:

- Thermal Oil: Predictable, Low Decline Production
- Light Oil - Montney at Placid and Duvernay at Kaybob: De-risked High Margin Liquids Rich Development
- Financial Sustainability: Low Leverage, Flexible Capital, Prudent Risk Management

Athabasca is currently focused on maximizing corporate free cash flow and maintaining its production base with low sustaining capital requirements. 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.

THIRD QUARTER 2022 AND RECENT HIGHLIGHTS

Corporate

- Production of 37,240 boe/d (93% Liquids[(1)]).
- Petroleum, natural gas & midstream sales of $397.1 million.
- Operating Income[(1)] of $140.1 million ($110.0 million Operating Income Net of Realized Hedging[(1)]).
- Adjusted Funds Flow[(1)] of $102.4 million (cash flow from operating activities $117.9 million).
- Free Cash Flow[(1)] of $50.1 million.
- Liquidity[(1)] of $277.9 million, including $200.1 million of cash as at September 30, 2022.
- Redeemed a total of $222.9 million (US$171.6 million) of the 2026 Notes year-to-date, which represents 98% of the Company's debt reduction target of US$175 million or 50% from the original US$350 million Notes issuance in October 2021.

Thermal Oil Division

- Production of 31,023 bbl/d.
- Petroleum, natural gas & midstream sales of $366.8 million.
- Operating Income[(1)] of $117.9 million and Operating Netback[(1)] of $39.25/bbl.
- Capital expenditures of $35.4 million were focused on projects at Leismer, including the start-up of two infill wells on Pad 6 in September and rig releasing five additional sustaining well pairs on Pad 8 which are expected to be on production in 2023.

Light Oil Division

- Production of 6,217 boe/d (57% Liquids[(1)]).
- Petroleum, natural gas & midstream sales of $40.0 million.
- Operating Income[(1)] of $22.2 million and Operating Netback[(1)] of $38.76/boe.
- Capital expenditures of $0.9 million.

(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 September 30, 2022	2021	Nine months ended September 30, 2022	2021
CONSOLIDATED				
Petroleum and natural gas production (boe/d)(1)	37,240	34,255	35,064	34,439
Petroleum, natural gas and midstream sales	$ 397,059	$ 280,151	$ 1,222,161	$ 723,918
Operating Income (Loss)(1)	$ 140,081	$ 120,581	$ 459,976	$ 279,705
Operating Income (Loss) Net of Realized Hedging(1)(2)	$ 110,021	$ 92,742	$ 316,564	$ 212,929
Operating Netback ($/boe)(1)	$ 39.17	$ 36.02	$ 47.43	$ 29.54
Operating Netback Net of Realized Hedging ($/boe)(1)(2)	$ 30.76	$ 27.70	$ 32.64	$ 22.49
Capital expenditures	$ 52,300	$ 15,608	$ 134,420	$ 73,790
Free Cash Flow(1)	$ 50,070	$ 56,625	$ 127,510	$ 67,632
THERMAL OIL DIVISION				
Bitumen production (bbl/d)(1)	31,023	26,729	28,578	26,374
Petroleum, natural gas and midstream sales	$ 366,804	$ 254,769	$ 1,126,878	$ 648,982
Operating Income (Loss)(1)	$ 117,916	$ 94,796	$ 369,820	$ 204,532
Operating Netback ($/bbl)(1)	$ 39.25	$ 35.71	$ 46.66	$ 28.16
Capital expenditures	$ 35,412	$ 15,228	$ 99,687	$ 69,630
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)(1)	6,217	7,526	6,486	8,065
Percentage Liquids (%)(1)	57%	55%	57%	56%
Petroleum, natural gas and midstream sales	$ 39,990	$ 36,531	$ 138,923	$ 107,468
Operating Income (Loss)(1)	$ 22,165	$ 25,785	$ 90,156	$ 75,173
Operating Netback ($/boe)(1)	$ 38.76	$ 37.25	$ 50.92	$ 34.15
Capital expenditures	$ 860	$ 128	$ 10,068	$ 1,640
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 117,853	$ 75,743	$ 246,250	$ 113,064
per share - basic	$ 0.20	$ 0.14	$ 0.44	$ 0.21
Adjusted Funds Flow(1)	$ 102,370	$ 72,233	$ 261,930	$ 141,422
per share - basic	$ 0.17	$ 0.14	$ 0.47	$ 0.27
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ 155,097	$ 104,951	$ 82,617	$ 73,535
per share - basic	$ 0.27	$ 0.20	$ 0.15	$ 0.14
per share - diluted	$ 0.22	$ 0.19	$ 0.14	$ 0.14
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	585,058,807	530,675,391	561,823,801	530,675,391
Weighted average shares outstanding - diluted	620,563,273	547,618,860	580,580,442	544,597,372

As at ($ Thousands)	September 30, 2022	December 31, 2021
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 200,100	$ 223,056
Available credit facilities(3)	$ 77,838	$ 77,844
Face value of term debt(4)	$ 280,377	$ 443,730

(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 $30.1 million and $143.4 million for the three and nine months ended September 30, 2022 (three and nine months ended September 30, 2021 – loss of $27.8 million and $66.8 million).

(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility.

(4) The face value of the term debt at September 30, 2022 was US$205 million (December 31, 2021 – US$350 million) translated into Canadian dollars at the September 30, 2022 exchange rate of US$1.00 =C$1.3707 (December 31, 2021 – C$1.2678).

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended September 30, 2022	2021	Change	Nine months ended September 30, 2022	2021	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)(1)	$ 91.55	$ 70.56	30 %	$ 98.09	$ 64.82	51 %
West Texas Intermediate (WTI) (C$/bbl)(1)	$ 119.54	$ 88.91	34 %	$ 125.80	$ 81.10	55 %
Western Canadian Select (WCS) (C$/bbl)(2)	$ 93.48	$ 71.77	30 %	$ 105.49	$ 65.37	61 %
Edmonton Par (C$/bbl)(3)	$ 116.79	$ 83.70	40 %	$ 123.42	$ 75.74	63 %
Edmonton Condensate (C5+) (C$/bbl)(4)	$ 112.87	$ 86.78	30 %	$ 123.80	$ 80.23	54 %
WCS Differential:						
to WTI (US$/bbl)	$ (19.86)	$ (13.58)	46 %	$ (15.73)	$ (12.51)	26 %
to WTI (C$/bbl)	$ (26.06)	$ (17.14)	52 %	$ (20.31)	$ (15.73)	29 %
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (2.05)	$ (4.08)	(50) %	$ (1.84)	$ (4.14)	(56) %
to WTI (C$/bbl)	$ (2.75)	$ (5.21)	(47) %	$ (2.38)	$ (5.36)	(56) %
Natural gas:						
AECO (C$/GJ)(5)(6)	$ 3.95	$ 3.41	16 %	$ 5.10	$ 3.11	64 %
Foreign exchange:						
USD : CAD	1.3057	1.2601	4 %	1.2825	1.2511	3 %

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

2022 Operational & Financial Guidance ($ millions, unless otherwise noted)	Annual[2]
Production (boe/d)[1]	34,000-35,000
% Liquids[1]	92%
Adjusted Funds Flow[1]	$330
Free Cash Flow[1]	$180
Capital Expenditures	~$150

(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: realized prices year to date through September and flat pricing of US$85 WTI, US$25 WCS heavy differential, C$5 AECO, and $0.73 C$/US$ FX for the balance of 2022.

Athabasca's production guidance of 34,000 – 35,000 boe/d in 2022 is expected to be attained through its modest capital program that is indicative of long term sustaining capital that benefits from a low decline, large resource asset base. The Company has a deep asset inventory with 1,230 MMbbl of proved plus probable reserves in Thermal Oil and approximately 850 gross wells of short cycle-time, high returning Light Oil Assets. The asset portfolio is demonstrating its ability to generate significant Free Cash Flow and will provide tremendous optionality into the future.

For 2022, Athabasca is updating its financial forecasts based on strong operational performance and current commodity price assumptions. Adjusted Funds Flow is forecasted to be approximately $330 million including Free Cash Flow of approximately $180 million. The Company has utilized 100% of near term Free Cash Flow to reduce its Term Debt, with a clear target of US$175 million Term Debt (50% reduction). The Company has achieved 98% of this target with $223 million (US$172 million) redeemed in 2022 through open market purchases, equity redemptions through warrant proceeds and the Free Cash Flow payment feature within the indenture. This is significantly ahead of schedule while also maintaining a strong Liquidity position of $278 million (inclusive of $200 million cash).

An approximate $150 million capital program in 2022 now incorporates strategic readiness capital to maintain business momentum in its core assets in 2023 and beyond. The 2022 capital program has largely been insulated from inflation through prior advanced planning.

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 September 30, 2022	2021	Nine months ended September 30, 2022	2021
PRODUCTION				
Bitumen (bbl/d)	31,023	26,729	28,578	26,374
Oil and condensate (bbl/d)(1)	2,757	3,296	2,949	3,688
Natural gas (Mcf/d)(1)	15,966	20,304	16,635	21,087
Other natural gas liquids (bbl/d)(1)	799	846	765	862
Total (boe/d)(1)	37,240	34,255	35,064	34,439

(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 September 30, 2022	2021	Nine months ended September 30, 2022	2021
Petroleum, natural gas and midstream sales(1)	$ 406,794	$ 291,300	$ 1,265,801	$ 756,450
Royalties	(38,899)	(9,120)	(138,785)	(19,745)
Cost of diluent(1)	(138,244)	(89,149)	(419,840)	(255,071)
Operating expenses	(64,203)	(47,356)	(175,863)	(132,269)
Transportation and marketing(2)	(25,367)	(25,094)	(71,337)	(69,660)
Operating Income (Loss)(3)	140,081	120,581	459,976	279,705
Realized gain (loss) on commodity risk management contracts	(30,060)	(27,839)	(143,412)	(66,776)
OPERATING INCOME (LOSS) NET OF REALIZED HEDGING(3)	$ 110,021	$ 92,742	$ 316,564	$ 212,929
REALIZED PRICES(3)				
Heavy oil (Blended bitumen) ($/bbl)(3)	$ 89.89	$ 70.13	$ 101.12	$ 63.12
Oil and condensate ($/bbl)(3)	113.19	83.21	121.17	75.08
Natural gas ($/Mcf)(3)	4.29	3.84	5.80	3.65
Other natural gas liquids ($/bbl)(3)	67.61	53.08	72.05	46.24
Realized price (net of cost of diluent) ($/boe)(3)	75.10	60.40	87.24	52.96
Royalties ($/boe)(3)	(10.88)	(2.73)	(14.31)	(2.09)
Operating expenses ($/boe)(3)	(17.96)	(14.15)	(18.14)	(13.97)
Transportation and marketing ($/boe)(3)	(7.09)	(7.50)	(7.36)	(7.36)
Operating Netback ($/boe)(3)	39.17	36.02	47.43	29.54
Realized gain (loss) on commodity risk mgmt. contracts ($/boe)(3)	(8.41)	(8.32)	(14.79)	(7.05)
OPERATING NETBACK NET OF REALIZED HEDGING ($/boe)(3)	$ 30.76	$ 27.70	$ 32.64	$ 22.49

(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 $1.7 million for the three and nine months ended September 30, 2022 (three and nine months ended September 30, 2021 - $0.6 million and $0.9 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 (Loss)

($ Thousands)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Operating Income (Loss) Net of Realized Hedging(1)	$ 110,021	$ 92,742	$ 316,564	$ 212,929
Non-cash transportation and marketing	(557)	(557)	(1,672)	(929)
Unrealized gain (loss) on commodity risk management contracts	83,635	(6,076)	31,436	(62,598)
Depletion and depreciation	(30,353)	(23,579)	(87,129)	(71,377)
Gain (loss) on sale of assets	14	19,743	403	20,100
Exploration expenses	(2,003)	(1,311)	(2,487)	(2,394)
CONSOLIDATED SEGMENTS INCOME (LOSS)	$ 160,757	$ 80,962	$ 257,115	$ 95,731

(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 September 30, 2022	2021	Nine months ended September 30, 2022	2021
Thermal Oil Division	$ 35,412	$ 15,228	$ 99,687	$ 69,630
Light Oil Division	860	128	10,068	1,640
Corporate assets	16,028	252	24,665	2,520
CAPITAL EXPENDITURES(1)(2)(3)	$ 52,300	$ 15,608	$ 134,420	$ 73,790

(1) For the three and nine months ended September 30, 2022, expenditures include capitalized cash based stock-based compensation costs of $nil and $2.5 million (three and nine months ended September 30, 2021 - $0.3 million and $2.6 million).

(2) For the three and nine months ended September 30, 2022, expenditures include capitalized staff costs of $1.7 million and $5.4 million (three and nine months ended September 30, 2021 - $1.5 million and $4.8 million).

(3) Excludes non-cash capitalized stock-based compensation and non-cash capitalized decommissioning obligation asset costs.

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 50 years and a reserve life index of approximately 100 years (proved plus probable). The Leismer Project has Proved plus Probable Reserves of approximately 705 MMbbl[(1)] and Best Estimate Development Pending Contingent Resources of 314 MMbbl (risked)[(1)] (348 MMbbl unrisked)[(1)]. The Corner lease has Proved plus Probable Reserves of approximately 353 MMbbl[(1)] and Best Estimate Development Pending Contingent Resources of 416 MMbbl (risked)[(1)] (520 MMbbl unrisked)[(1)]. The Leismer and Corner development application have 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 July 2015 and has proven reserves in place to support a flat production profile for approximately 25 years and a reserve life index of approximately 50 years (proved plus probable). Hangingstone has Proved plus Probable Reserves of approximately 172 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, 2021. 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 September 30, 2022	2021	Nine months ended September 30, 2022	2021
VOLUMES				
Bitumen production (bbl/d)	22,309	18,023	19,583	17,341
Bitumen sales (bbl/d)	22,591	19,349	19,687	17,379
Heavy oil (blended bitumen) sales (bbl/d)	30,574	26,245	27,536	24,276

($ Thousands, unless otherwise noted)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Heavy oil (blended bitumen) sales	$ 250,927	$ 168,545	$ 755,917	$ 418,148
Cost of diluent	(95,387)	(58,623)	(280,762)	(160,481)
Total bitumen sales	155,540	109,922	475,155	257,667
Royalties	(22,876)	(4,742)	(82,309)	(9,135)
Operating expenses - non-energy	(15,422)	(13,133)	(43,934)	(34,528)
Operating expenses - energy	(17,437)	(12,920)	(50,749)	(34,974)
Transportation and marketing	(13,082)	(13,110)	(38,050)	(35,971)
LEISMER OPERATING INCOME (LOSS)(1)	$ 86,723	$ 66,017	$ 260,113	$ 143,059
REALIZED PRICE(1)				
Heavy oil (blended bitumen) sales ($/bbl)(1)	$ 89.21	$ 69.80	$ 100.56	$ 63.09
Bitumen sales ($/bbl)(1)	$ 74.84	$ 61.75	$ 88.41	$ 54.31
Royalties ($/bbl)(1)	(11.01)	(2.66)	(15.31)	(1.93)
Operating expenses - non-energy ($/bbl)(1)	(7.42)	(7.38)	(8.17)	(7.28)
Operating expenses - energy ($/bbl)(1)	(8.39)	(7.26)	(9.44)	(7.37)
Transportation and marketing ($/bbl)(1)	(6.29)	(7.36)	(7.08)	(7.58)
LEISMER OPERATING NETBACK ($/bbl)(1)	$ 41.73	$ 37.09	$ 48.41	$ 30.15

(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 and nine months ended September 30, 2022, was 22,309 bbl/d and 19,583 bbl/d, an increase of 24% and 13%, respectively, compared to the corresponding periods in 2021. Production increases are primarily attributed to the ramp-up of Pad 8 (five sustaining well pairs) through 2022.

Leismer's Operating Netback was $41.73/bbl and $48.41/bbl for the three and nine months ended September 30, 2022, respectively, representing increases of $4.64/bbl and $18.26/bbl, compared with the same periods in 2021. The increase is primarily due to higher WCS benchmark oil prices, partially offset by higher royalties and operating costs.

Government and contingent bitumen royalties increased in the third quarter and first nine months of 2022 due to higher oil prices.

Total operating expenses were $15.81/bbl in the third quarter of 2022 and $17.61/bbl in the first nine months of 2022, compared to $14.64/bbl and $14.65/bbl, respectively, in the comparable periods of 2021.

Total non-energy operating costs rose mainly due to higher production volumes along with higher labor, maintenance and regulatory costs. Energy operating costs increased as a result of higher natural gas and electricity prices, partially offsetting this increase are the corporate AECO fixed price swap purchase contracts that resulted in a total Thermal Oil realized gain of $0.3 million during the third quarter of 2022 and $8.0 million in the first nine months of 2022 (three and nine months ended September 30, 2021 - $0.6 million and $1.0 million).

Hangingstone Operating Results

	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
VOLUMES				
Bitumen production (bbl/d)	8,714	8,706	8,995	9,033
Bitumen sales (bbl/d)	10,059	9,503	9,347	9,231
Heavy oil (blended bitumen) sales (bbl/d)	13,779	13,244	13,286	13,387

($ Thousands, unless otherwise noted)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Heavy oil (blended bitumen) and midstream sales	$ 115,877	$ 86,224	$ 370,961	$ 230,834
Cost of diluent	(42,857)	(30,526)	(139,078)	(94,590)
Total bitumen and midstream sales	73,020	55,698	231,883	136,244
Royalties	(8,595)	(2,159)	(37,569)	(4,333)
Operating expenses - non-energy	(8,075)	(5,655)	(20,323)	(15,633)
Operating expenses - energy	(15,093)	(9,810)	(37,959)	(28,656)
Transportation and marketing[1]	(10,064)	(9,295)	(26,325)	(26,149)
HANGINGSTONE OPERATING INCOME (LOSS)[2]	$ 31,193	$ 28,779	$ 109,707	$ 61,473
REALIZED PRICE[2]				
Heavy oil (blended bitumen) and midstream sales ($/bbl)[2]	$ 91.41	$ 70.77	$ 102.28	$ 63.16
Bitumen and midstream sales ($/bbl)[2]	$ 78.90	$ 63.71	$ 90.87	$ 54.06
Royalties ($/bbl)[2]	(9.29)	(2.47)	(14.72)	(1.72)
Operating expenses - non-energy ($/bbl)[2]	(8.73)	(6.47)	(7.96)	(6.20)
Operating expenses - energy ($/bbl)[2]	(16.31)	(11.22)	(14.88)	(11.37)
Transportation and marketing ($/bbl)[2]	(10.87)	(10.63)	(10.32)	(10.38)
HANGINGSTONE OPERATING NETBACK ($/bbl)[2]	$ 33.70	$ 32.92	$ 42.99	$ 24.39

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $1.7 million for the three and nine months ended September 30, 2022 (three and nine months ended September 30, 2021 - $0.6 million and $0.9 million).

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

Hangingstone bitumen production was consistent year over year.

The Hangingstone Operating Netback was $33.70/bbl and $42.99/bbl for the three and nine months ended September 30, 2022, respectively, representing increases of $0.78/bbl and $18.60/bbl, compared with the same periods in 2021. The increase is primarily due to higher WCS benchmark oil prices, partially offset by higher royalties and operating costs.

Government and contingent bitumen royalties increased in the third quarter and first nine months of 2022 due to higher oil prices.

Total operating expenses were $25.04/bbl in the third quarter of 2022 and $22.84/bbl in the first nine months of 2022, compared to $17.69/bbl and $17.57/bbl, respectively, in the comparable periods of 2021.

Total non-energy operating costs rose mainly due to higher labor, maintenance and regulatory costs. Energy operating costs increased as a result of higher natural gas and electricity prices, partially offsetting this increase are the corporate AECO fixed price swap purchase contracts that resulted in a total Thermal Oil realized gain of $0.3 million during the third quarter of 2022 and $8.0 million in the first nine months of 2022 (three and nine months ended September 30, 2021 - $0.6 million and $1.0 million). The increase in the Hangingstone energy operating costs were partially offset by a 14% reduction in the steam to oil ratio year over year.

Consolidated Thermal Oil Operating Results

	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
VOLUMES				
Bitumen production (bbl/d)	31,023	26,729	28,578	26,374
Bitumen sales (bbl/d)	32,650	28,852	29,034	26,610
Heavy oil (blended bitumen) sales (bbl/d)	44,353	39,489	40,822	37,663

($ Thousands, unless otherwise noted)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Heavy oil (blended bitumen) and midstream sales	$ 366,804	$ 254,769	$ 1,126,878	$ 648,982
Cost of diluent	(138,244)	(89,149)	(419,840)	(255,071)
Total bitumen and midstream sales	228,560	165,620	707,038	393,911
Royalties	(31,471)	(6,901)	(119,878)	(13,468)
Operating expenses - non-energy	(23,497)	(18,788)	(64,257)	(50,161)
Operating expenses - energy	(32,530)	(22,730)	(88,708)	(63,630)
Transportation and marketing(1)	(23,146)	(22,405)	(64,375)	(62,120)
THERMAL OIL OPERATING INCOME (LOSS)(2)	$ 117,916	$ 94,796	$ 369,820	$ 204,532
REALIZED PRICE(2)				
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 89.89	$ 70.13	$ 101.12	$ 63.12
Bitumen and midstream sales ($/bbl)(2)	$ 76.09	$ 62.39	$ 89.20	$ 54.22
Royalties ($/bbl)(2)	(10.48)	(2.60)	(15.12)	(1.85)
Operating expenses - non-energy ($/bbl)(2)	(7.82)	(7.08)	(8.11)	(6.90)
Operating expenses - energy ($/bbl)(2)	(10.83)	(8.56)	(11.19)	(8.76)
Transportation and marketing ($/bbl)(2)	(7.71)	(8.44)	(8.12)	(8.55)
THERMAL OIL OPERATING NETBACK ($/BBL)(2)	$ 39.25	$ 35.71	$ 46.66	$ 28.16

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $1.7 million for the three and nine months ended September 30, 2022 (three and nine months ended September 30, 2021 - $0.6 million and $0.9 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 (Loss)

($ Thousands)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Thermal Oil Operating Income (Loss)(1)	$ 117,916	$ 94,796	$ 369,820	$ 204,532
Non-cash transportation and marketing	(557)	(557)	(1,672)	(929)
Depletion and depreciation	(20,234)	(12,122)	(55,835)	(34,871)
Gain (loss) on sale of assets	14	19,743	403	20,000
Exploration expenses	(2,003)	(1,311)	(2,487)	(2,394)
THERMAL OIL SEGMENT INCOME (LOSS)	$ 95,136	$ 100,549	$ 310,229	$ 186,338

(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 $8.1 million and $21.0 million during the three and nine months ended September 30, 2022, compared to the same periods in the prior year primarily due to the higher depletable cost base at Hangingstone as a result of the December 31, 2021 impairment reversal and higher production volumes at Leismer.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Leismer Project	$ 33,612	$ 12,920	$ 93,648	$ 64,332
Hangingstone Project	1,614	2,238	5,717	5,099
Other Thermal Oil exploration	186	70	322	199
THERMAL OIL CAPITAL EXPENDITURES(1)	$ 35,412	$ 15,228	$ 99,687	$ 69,630

(1) For the three and nine months ended September 30, 2022, capital expenditures include $1.2 million and $4.1 million of capitalized staff costs (three and nine months ended September 30, 2021 - $1.0 million and $3.1 million).

Thermal Oil capital expenditures for the first nine months of 2022 of $99.7 million were primarily related to sustaining operations and a planned facility turnaround at Leismer, along with routine pump replacements across both assets. The Company converted five Pad 8 wells to production, two Pad 6 infill wells were placed on production in September and rig released the Pad 8 expansion (five additional well pairs). Athabasca also executed and completed a turnaround at Leismer during the second quarter.

LIGHT OIL DIVISION

Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs. Development has been focused on the Montney in the Greater Placid area and the Duvernay in the Greater Kaybob area near the town of Fox Creek, Alberta. As at December 31, 2021, the Light Oil Division had approximately 72 MMboe of Proved plus Probable Reserves(1). Athabasca's Light Oil Division assets are supported by operated regional infrastructure consisting of four batteries and a network of gas pipelines which connect the facilities to two regional third party gas processing plants.

In Greater Placid, Athabasca has a 70% operated working interest in approximately 85,000 gross Montney acres. An inventory of approximately 150(2) gross development drilling locations positions the Company for multi-year development.

In Greater Kaybob, Athabasca has a 30% non-operated interest in approximately 195,000 gross acres of commercially prospective Duvernay lands with exposure to both Liquids-rich gas and volatile oil opportunities and an inventory of approximately 700(2) gross drilling locations.

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2021. 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.

Light Oil Operating Results

	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
PRODUCTION[1]				
Oil and condensate (bbl/d)	2,757	3,296	2,949	3,688
Natural gas (Mcf/d)	15,966	20,304	16,635	21,087
Other natural gas liquids (bbl/d)	799	846	765	862
Total (boe/d)	6,217	7,526	6,486	8,065
Consisting of:				
Greater Placid area (boe/d)	3,181	4,205	3,339	4,446
% Liquids	43%	44%	43%	44%
Greater Kaybob area (boe/d)	3,036	3,321	3,147	3,619
% Liquids	72%	69%	73%	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 September 30, 2022	2021	Nine months ended September 30, 2022	2021
Petroleum and natural gas sales	$ 39,990	$ 36,531	$ 138,923	$ 107,468
Royalties	(7,428)	(2,219)	(18,907)	(6,277)
Operating expenses	(8,176)	(5,838)	(22,898)	(18,478)
Transportation and marketing	(2,221)	(2,689)	(6,962)	(7,540)
LIGHT OIL OPERATING INCOME (LOSS)[1]	$ 22,165	$ 25,785	$ 90,156	$ 75,173
REALIZED PRICES[1]				
Oil and condensate ($/bbl)[1]	$ 113.19	$ 83.21	$ 121.17	$ 75.08
Natural gas ($/Mcf)[1]	4.29	3.84	5.80	3.65
Other natural gas liquids ($/bbl)[1]	67.61	53.08	72.05	46.24
Realized price ($/boe)[1]	69.92	52.76	78.46	48.81
Royalties ($/boe)[1]	(12.99)	(3.20)	(10.68)	(2.85)
Operating expenses ($/boe)[1]	(14.29)	(8.43)	(12.93)	(8.39)
Transportation and marketing ($/boe)[1]	(3.88)	(3.88)	(3.93)	(3.42)
LIGHT OIL OPERATING NETBACK ($/boe)[1]	$ 38.76	$ 37.25	$ 50.92	$ 34.15

(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 and nine months ended September 30, 2022 decreased as a result of natural declines, partially offset by three gross Greater Kaybob wells that were placed on production during the first quarter of 2022.

The Operating Netbacks were $38.76/boe and $50.92/boe for the three and nine months ended September 30, 2022, respectively, representing increases of $1.51/boe and $16.77/boe, compared with the same periods in 2021. The increases are primarily due to stronger commodity prices, partially offset by higher royalties and operating expenses.

The rise in royalties for both the third quarter and the first nine months of 2022 is due to stronger commodity prices and wells coming off government royalty incentive programs.

Operating expenses on a per boe basis increased as a result of lower production volumes and higher maintenance and power costs.

Light Oil Segment Income (Loss)

($ Thousands)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Light Oil Operating Income (Loss)[1]	$ 22,165	$ 25,785	$ 90,156	$ 75,173
Depletion and depreciation	(10,119)	(11,457)	(31,294)	(36,506)
Gain (loss) on sale of assets	—	—	—	100
LIGHT OIL SEGMENT INCOME (LOSS)	$ 12,046	$ 14,328	$ 58,862	$ 38,767

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

Depletion and depreciation decreased $1.3 million and $5.2 million during the three and nine months ended September 30, 2022, compared to the same periods in the prior year primarily due to lower production volumes.

Light Oil Capital Expenditures

($ Thousands)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Greater Placid	$ 656	$ 717	$ 2,057	$ 2,406
Greater Kaybob	204	(589)	8,011	(766)
LIGHT OIL CAPITAL EXPENDITURES[1]	$ 860	$ 128	$ 10,068	$ 1,640

(1) For the three and nine months ended September 30, 2022, capital expenditures include $0.5 million and $1.3 million of capitalized staff costs (three and nine months ended September 30, 2021 - $0.5 million and $1.7 million).

In the first nine months of 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 in the second quarter of 2022 the Company successfully completed two facility turnarounds at Kaybob West and Kaybob East.

The following table summarizes Athabasca's well activity for the three and nine months ended September 30, 2022 and 2021:

	Three months ended September 30,				Nine months ended September 30,			
	2022		2021		2022		2021	
Well activity[1]	Gross	Net	Gross	Net	Gross	Net	Gross	Net
GREATER PLACID								
Wells drilled	—	—	—	—	—	—	—	—
Wells completed	—	—	—	—	—	—	—	—
Wells brought on production	—	—	—	—	—	—	—	—
GREATER KAYBOB								
Wells drilled	—	—	—	—	—	—	—	—
Wells completed	—	—	—	—	3	0.9	—	—
Wells brought on production	—	—	—	—	3	0.9	—	—

(1) Drilling counts are based on rig release date and brought on production counts are based on first production date of in-line test or tie-in to permanent facilities.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

Athabasca is a low leveraged company that generates significant Free Cash Flow through its low-decline, oil weighted asset base at current commodity prices. The capital structure provides certainty to shareholders of the Company's ability to utilize Free Cash Flow to further reduce debt and enhance long-term resiliency. An active commodity risk management program and maintaining sufficient liquidity will allow the Company to manage periods of volatility. For the balance of 2022, it is anticipated that Athabasca's Light Oil and Thermal Oil capital and operating activities will be funded through cash flow from operating activities and existing cash and cash equivalents.

As at September 30, 2022, Athabasca had Liquidity of $277.9 million which included $200.1 million of cash and cash equivalents and $77.8 million of available capacity on its credit facilities.

Indebtedness

Athabasca had the following debt instruments and credit facilities in place as at September 30, 2022:

Term Debt

On October 22, 2021, Athabasca closed a private placement offering (the "Offering") of 350,000 units for gross cash proceeds of US$339.5 million. Each unit consisted of US$1,000 principal amount of senior secured second lien notes (US$350 million original principal) due November 1, 2026 (each "2026 Note") which bear interest at 9.75% per annum, and one five-year warrant (each "Warrant") to purchase 227 common shares at an exercise price of $0.9441 per common share issuable.

Up until an aggregate amount of US$175 million principal has been redeemed, the Company must direct at least 75% of Free Cash Flow ("FCF") towards the redemption of the 2026 Notes at a cash price equal to 105% of the principal, plus accrued and unpaid interest. The redemption dates are semiannual with the October to March (Q4 – Q1) FCF redemption payable in May and the April to September (Q2 – Q3) FCF redemption payable in November. Athabasca may also 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 Note 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.

As at September 30, 2022, the principal balance was $280.4 million (US$204.6 million). In October 2022, the Company redeemed an additional $35.9 million (US$26.2 million), resulting in the current principal balance of $244.5 million (US$178.4 million). In 2022, the Company has redeemed a total of $222.9 million (US$171.6 million) of principal through open market purchases, equity redemptions through warrant proceeds and the FCF payment feature within the indenture.

Credit Facility

In the third quarter of 2022, Athabasca renewed its $110.0 million reserve-based credit facility (the "Credit Facility"). The Credit Facility is a 364 day committed facility available on a revolving basis until October 21, 2023, at which point in time it may be extended at the lender's option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and any amounts outstanding would be repayable at the end of the non-revolving term, being October 21, 2024. The Credit Facility is subject to a semi-annual borrowing base review, occurring approximately in April and September of each year. The borrowing base is determined based on the lender's evaluation of the Company's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal. As at September 30, 2022 and December 31, 2021, 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 $50.0 million unsecured letter of credit facility (the "Unsecured Letter of Credit Facility") with a Canadian bank and is supported by a performance security guarantee from Export Development Canada (December 31, 2021 - $50 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 3.3%. As at September 30, 2022, the Company had $47.8 million of letters of credit outstanding under the Unsecured Letter of Credit Facility (December 31, 2021 - $47.8 million).

Financing and Interest

($ Thousands)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Financing and interest expense on indebtedness	$ 9,719	$ 14,583	$ 39,732	$ 43,581
Accretion of 2022 Notes	—	2,958	—	8,525
Accretion of 2026 Notes	826	—	19,133	—
Accretion of warrants	275	—	2,520	—
Accretion of provisions	2,606	3,556	7,875	10,351
Interest expense on lease liability	218	294	712	934
TOTAL FINANCING AND INTEREST	$ 13,644	$ 21,391	$ 69,972	$ 63,391

During the three and nine months ended September 30, 2022 and 2021, total financing and interest expenses were primarily attributable to the financing, interest and accretion expenses related to the Company's Notes.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Unrealized foreign exchange gain (loss)	$ (6,156)	$ (9,211)	$ (4,423)	$ 7,408
Realized foreign exchange gain (loss)	2,742	(375)	(375)	(1,650)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ (3,414)	$ (9,586)	$ (4,798)	$ 5,758

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. The unrealized foreign exchange gains (losses) recognized were primarily due to unrealized gains (losses) on the note principal as the value of the Canadian dollar fluctuates relative to the US dollar.

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 September 30, 2022, 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	October - December 2022	11,300 bbl/d	$ 68.54 - 157.63	$ 50.00 - 115.00
WTI collar	January - March 2023	13,750 bbl/d	$ 71.77 - 157.63	$ 52.36 - 115.00
WCS fixed price swap	October - December 2022	12,000 bbl/d	$ 73.42	$ 53.57
Purchase contracts			*C$/GJ/bbl*	*US$/GJ/bbl*
AECO fixed price swaps	October - December 2022	26,000 GJ/d	$ 4.05	$ 2.95
AECO fixed price swaps	January - December 2023	10,000 GJ/d	$ 5.48	$ 4.00
WTI/C5+ differential swap	October - December 2022	3,000 bbl/d	$ (7.42)	$ (5.42)

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the September 30, 2022 exchange rate of US$1.00 = C$1.3707.

In 2021, Athabasca entered into a seven-year marketing agreement for 15,000 bbl/d with an industry counterparty that will diversify 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 September 30, 2022, the pricing derivative had an asset value of $0.1 million (December 31, 2021 - $nil).

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three and nine months ended September 30, 2022 and 2021:

($ Thousands)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Unrealized gain (loss) on commodity risk mgmt. contracts	$ 83,635	$ (6,076)	$ 31,436	$ (62,598)
Realized gain (loss) on commodity risk mgmt. contracts	(30,060)	(27,839)	(143,412)	(66,776)
GAIN (LOSS) ON COMMODITY RISK MGMT. CONTRACTS, NET	$ 53,575	$ (33,915)	$ (111,976)	$ (129,374)

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

As at September 30, 2022	Change in WTI Increase of US$5.00/bbl	Change in WTI Decrease of US$5.00/bbl	Change in WCS differential Increase of US$1.00/bbl	Change in WCS differential Decrease of US$1.00/bbl
Increase (decrease) to fair value of commodity risk management contracts	$ (7,503)	$ 7,503	$ 1,500	$ (1,500)

Additional financial commodity risk management has taken place subsequent to September 30, 2022 as noted in the table below:

Instrument	Period	Volume	C$ Average Price[(1)]	US$ Average Price[(1)]
Purchase contracts			*C$/GJ*	*US$/GJ*
AECO fixed price swaps	January - December 2023	10,000 GJ/d	$ 4.33	$ 3.16

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the September 30, 2022 exchange rate of US$1.00 = C$1.3707.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future unrecognized minimum commitments as at September 30, 2022 for the following five years and thereafter:

($ Thousands)	Remaining 2022	2023	2024	2025	2026	Thereafter	Total
Transportation and processing[(1)]	$ 30,199	$ 118,497	$ 113,426	$ 109,539	$ 108,971	$ 1,147,766	$ 1,628,398
Interest expense on term debt[(1)]	6,834	27,337	27,337	27,337	22,781	—	111,626
Purchase commitments[(1)]	20,532	9,379	—	—	—	—	29,911
TOTAL COMMITMENTS	$ 57,565	$ 155,213	$ 140,763	$ 136,876	$ 131,752	$ 1,147,766	$ 1,769,935

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the September 30, 2022 exchange rate of US$1.00 = C$1.3707.

The Company is, from time to time, involved in claims arising in the normal course of business. The Company is currently undergoing income tax and partner related audits in the normal course of business. The final outcome of such audits cannot be predicted with certainty, however, management concluded that it has appropriately assessed any impact to the consolidated financial statements.

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 and 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 September 30, 2022. 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 September 30, 2022 of $200.1 million (December 31, 2021 - $223.1 million), from a 1.0% change in interest rates, would have an annualized impact of approximately $2.0 million (year ended December 31, 2021 - $2.2 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 September 30, 2022	2021	Nine months ended September 30, 2022	2021
TOTAL GENERAL AND ADMINISTRATIVE	$ 5,382	$ 3,866	$ 14,744	$ 11,447
G&A per boe[(1)]	$ 1.57	$ 1.23	$ 1.54	$ 1.22

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

During the three and nine months ended September 30, 2022, Athabasca's G&A expenses and G&A per boe increased compared to the same periods in the prior year primarily due to increased staffing levels and higher salaries and benefits.

Stock Based Compensation

During the three and nine months ended September 30, 2022, Athabasca's stock-based compensation (recovery) expense was ($0.6) million and $21.2 million, respectively, compared to $1.1 million and $12.2 million in the respective prior year periods. The increase year to date is primarily due to the increase in the fair value of the cash settled stock-based compensation plans as a result of the share price increasing in 2022.

Gain (Loss) on Revaluation of Provisions and Other

($ Thousands)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Change in fair value of warrant liability	$ 15,136	$ —	$ (61,233)	$ —
Change in estimated decommissioning obligations related to fully impaired E&E assets	—	—	(3,073)	—
Provision for pipeline project	—	60,564	—	60,564
Other	860	—	1,227	—
TOTAL GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER	$ 15,996	$ 60,564	$ (63,079)	$ 60,564

The warrants are classified as a financial liability due to the cashless exercise provision therefore they have to be revalued quarterly. The changes in the fair value of the warrant liability in 2022 primarily relate to changes in the share price.

Income Taxes

From time to time, Athabasca undergoes income tax audits in the normal course of business. The Company has received a notice of reassessment from the Canada Revenue Agency ("CRA") and Alberta Finance. While the final outcome of the reassessment cannot be predicted with certainty, Athabasca has received legal advice that confirms its position as filed and believes it is likely to be successful in appealing the reassessment. As such, the Company has not recognized any provision in its Consolidated Financial Statements with respect to the reassessment and previously posted a $12.6 million deposit with the CRA while objecting the reassessment.

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.

Uncertainty around timing of future pipeline infrastructure due to regulatory, judicial and legislative delays is a significant risk to Athabasca and could have a material impact on future financial results. Additional information is available in Athabasca's AIF that is filed on the Company's SEDAR profile at www.sedar.com.

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 September 30, 2022, there were 586.4 million common shares outstanding, an aggregate of 20.5 million restricted share units and performance share units outstanding, 7.2 million stock options outstanding and 31.8 million potential shares issuable under warrants agreements. During the nine months ended September 30, 2022, Athabasca issued 11.4 million common shares in respect of the Company's equity-settled share-based compensation plans and 44.1 million common shares from warrant exercises.

SUMMARY OF QUARTERLY RESULTS

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

	2022			2021				2020
($ Thousands, unless otherwise noted)	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	91.55	108.41	94.29	77.19	70.56	66.07	57.84	42.66
WTI (C$/bbl)	119.54	138.39	119.38	97.25	88.91	81.11	73.24	55.58
Western Canadian Select (C$/bbl)	93.48	122.04	100.96	78.67	71.77	66.96	57.40	43.40
Edmonton Par (C$/bbl)	116.79	137.83	115.62	93.14	83.70	77.07	66.44	49.98
Edmonton Condensate (C5+) (C$/bbl)	112.87	137.70	120.84	99.24	86.78	81.00	72.92	55.05
AECO (C$/GJ)	3.95	6.86	4.49	4.41	3.41	2.93	2.98	2.50
Foreign exchange (USD : CAD)	1.31	1.28	1.27	1.26	1.26	1.23	1.27	1.30
CONSOLIDATED								
Petroleum and natural gas production (boe/d)[1]	37,240	33,247	34,679	35,147	34,255	34,659	34,401	34,233
Realized price (net of cost of diluent) ($/boe)[1]	75.10	105.99	83.53	63.89	60.40	53.76	44.23	33.56
Petroleum, natural gas and midstream sales ($)[2]	406,794	453,618	405,389	305,313	291,300	243,868	221,282	162,815
Operating Income (Loss) ($)[1]	140,081	169,255	150,640	110,648	120,581	93,196	65,928	40,288
Operating Income (Loss) Net of Realized Hedging ($)[1]	110,021	103,549	102,994	65,735	92,742	75,372	44,815	30,935
Operating Netback ($/boe)[1]	39.17	57.51	47.40	35.43	36.02	31.09	21.12	12.88
Operating Netback Net of Realized Hedging ($/boe)[1]	30.76	35.18	32.41	21.05	27.70	25.14	14.36	9.89
Capital expenditures ($)	52,300	51,191	30,929	18,352	15,608	22,628	35,554	17,202
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	31,023	26,768	27,909	28,084	26,729	26,433	25,949	24,839
Bitumen sales volumes (bbl/d)	32,650	25,863	28,545	26,889	28,852	24,710	26,240	24,613
Realized bitumen price ($/bbl)[1]	76.09	109.67	85.78	64.40	62.39	55.49	43.83	33.05
Heavy Oil (blended bitumen) and midstream sales ($)	366,804	399,793	360,281	265,076	254,769	207,503	186,710	132,635
Operating Income (Loss) ($)[1]	117,916	131,067	120,837	82,729	94,796	67,568	42,168	20,746
Operating Netback ($/bbl)[1]	39.25	55.68	47.04	33.43	35.71	30.05	17.85	9.17
Capital expenditures ($)	35,412	43,093	21,182	12,355	15,228	21,388	33,014	16,915
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)[1]	6,217	6,479	6,770	7,063	7,526	8,226	8,452	9,394
Realized price ($/boe)[1]	69.92	91.29	74.03	61.92	52.76	48.58	45.45	34.92
Petroleum and natural gas sales ($)[2]	39,990	53,825	45,108	40,237	36,531	36,365	34,572	30,180
Operating Income (Loss) ($)[1]	22,165	38,188	29,803	27,919	25,785	25,628	23,760	19,542
Operating Netback ($/boe)[1]	38.76	64.77	48.92	42.95	37.25	34.23	31.24	22.61
Capital expenditures ($)	860	1,221	7,987	5,291	128	544	968	117
OPERATING RESULTS								
Cash flow from operating activities ($)	117,853	68,535	59,862	81,189	75,743	36,183	1,138	16,079
Adjusted Funds Flow ($)[1]	102,370	84,799	74,761	42,643	72,233	50,228	18,961	10,753
Net income (loss) ($)	155,097	47,121	(119,601)	384,073	104,951	(13,944)	(17,472)	(56,891)
Net income (loss) per share - basic ($)	0.27	0.08	(0.23)	0.72	0.20	(0.03)	(0.03)	(0.11)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	200,100	154,172	213,534	223,056	273,989	152,639	141,130	165,201
Restricted cash ($)	—	—	—	—	46,107	90,232	135,120	135,624
Total assets ($)	1,803,624	1,815,390	1,814,662	1,742,131	1,510,924	1,466,102	1,443,246	1,425,984
Term debt ($)[3]	240,078	250,756	355,328	384,298	568,428	549,855	555,160	559,498
Shareholders' equity ($)	1,218,174	1,057,355	909,852	1,025,959	640,542	534,330	547,035	567,025

(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.

ACCOUNTING POLICIES AND ESTIMATES

During the nine months ended September 30, 2022, there were no changes to Athabasca's accounting policies or use of estimates and judgments in the preparation of the Consolidated Financial Statements and the notes thereto. A summary of the significant accounting policies, including the use of estimates and judgments, used by Athabasca can be found in Note 3 of the December 31, 2021 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).

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” and “Cash Transportation & Marketing Expenses” 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.

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

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

($ Thousands)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Cash flow from operating activities	$ 117,853	$ 75,743	$ 246,250	$ 113,064
Changes in non-cash working capital	(16,320)	(3,580)	14,386	26,922
Settlement of provisions	837	70	1,294	1,436
ADJUSTED FUNDS FLOW	102,370	72,233	261,930	141,422
Capital expenditures	(52,300)	(15,608)	(134,420)	(73,790)
FREE CASH FLOW	$ 50,070	$ 56,625	$ 127,510	$ 67,632

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 12 reconciles Light Oil Operating Income to its segmented income in *Note 13 - Segmented Information* of the Consolidated Financial Statements for the three and nine months ended September 30, 2022. The table on page 9 reconciles Thermal Oil Operating Income to its segmented income in *Note 13 - Segmented Information* of the Consolidated Financial Statements for the three and nine months ended September 30, 2022.

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 5 reconciles Consolidated Operating Income Net of Realized Hedging to Consolidated segment income in *Note 13 - Segmented Information* of the Consolidated Financial Statements for the three and nine months ended September 30, 2022.

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.

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 September 30, 2022	2021	Nine months ended September 30, 2022	2021
Greater Placid:					
Condensate NGLs	bbl/d	908	1,312	1,003	1,430
Other NGLs	bbl/d	464	522	428	517
Natural gas(1)	mcf/d	10,855	14,226	11,449	14,994
Total Greater Placid	boe/d	3,181	4,205	3,339	4,446
Greater Kaybob:					
Oil(2)	bbl/d	1,849	1,984	1,946	2,258
Other NGLs	bbl/d	335	324	337	345
Natural gas(1)	mcf/d	5,111	6,078	5,186	6,093
Total Greater Kaybob	boe/d	3,036	3,321	3,147	3,619
Light Oil:					
Oil(2)	bbl/d	1,849	1,984	1,946	2,258
Condensate NGLs	bbl/d	908	1,312	1,003	1,430
Oil and condensate NGLs	bbl/d	2,757	3,296	2,949	3,688
Other NGLs	bbl/d	799	846	765	862
Natural gas(1)	mcf/d	15,966	20,304	16,635	21,087
Total Light Oil division	boe/d	6,217	7,526	6,486	8,065
Total Thermal Oil division bitumen	bbl/d	31,023	26,729	28,578	26,374
Total Company production	boe/d	37,240	34,255	35,064	34,439

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

This MD&A also makes reference to Athabasca's forecasted total average daily production of 34,000 – 35,000 boe/d for 2022. Athabasca expects that approximately 82% of that production will be comprised of bitumen, 8% shale gas, 5% tight oil, 3% condensate natural gas liquids and 2% other natural gas liquids.

Liquids:		Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Greater Placid:					
Condensate NGLs	bbl/d	908	1,312	1,003	1,430
Other NGLs	bbl/d	464	522	428	517
Total Greater Placid Liquids	bbl/d	1,372	1,834	1,431	1,947
as % of Greater Placid production		43%	44%	43%	44%
Greater Kaybob:					
Oil	bbl/d	1,849	1,984	1,946	2,258
Other NGLs	bbl/d	335	324	337	345
Total Greater Kaybob Liquids	bbl/d	2,184	2,308	2,283	2,603
as % of Greater Kaybob production		72%	69%	73%	72%
Total Light Oil:					
Oil and condensate NGLs	bbl/d	2,757	3,296	2,949	3,688
Other NGLs	bbl/d	799	846	765	862
Total Light Oil division Liquids	bbl/d	3,556	4,142	3,714	4,550
as % of Light Oil production		57%	55%	57%	56%
Total Company:					
Total Light Oil division Liquids	bbl/d	3,556	4,142	3,714	4,550
Total Thermal Oil division bitumen	bbl/d	31,023	26,729	28,578	26,374
Total Company Liquids	bbl/d	34,579	30,871	32,292	30,924
as % of Company production		93%	90%	92%	90%

Comparative Figures

Certain comparative figures have been restated to conform to the current period presentation.

Disclosure Control and Procedures

Athabasca is required to comply with National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). NI 52-109 requires that Athabasca disclose in its interim MD&A any material weaknesses in Athabasca's internal control over financial reporting and/or any changes in Athabasca's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect, Athabasca's internal controls over financial reporting. Athabasca confirms that no material weaknesses or such changes were identified in Athabasca's internal controls over financial reporting during the third quarter of 2022.

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;
- operational impacts related to COVID-19 (coronavirus);
- 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;
- 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; and
- negative economic impacts as a result of the spread of COVID-19 (coronavirus).

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.sedar.com.

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," "plan," "continue", "estimate", "expect", "may", "will", "project", "target", "should", "believe", "predict", "pursue" and "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; expectation of results of CRA audits and reassessments; the Company's anticipated sources of funding for 2022 and beyond; the Company's estimated future minimum commitments; the future allocation of capital; 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, 2021 (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.sedar.com, 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; continued impact of the COVID-19 pandemic; 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 and 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; 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.sedar.com. 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, 2021. 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.sedar.com.

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 700 Duvernay drilling locations referenced in this MD&A include: 7 proved undeveloped locations and 78 probable undeveloped locations for a total of 85 booked locations with the balance being unbooked locations. The 150 Montney drilling locations referenced in this MD&A include: 39 proved undeveloped locations and 59 probable undeveloped locations for a total of 98 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, 2021 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, 2021, 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
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