FOR IMMEDIATE RELEASE
March 1, 2023

Athabasca Oil Announces 2022 Year-end Results & Reserves, Record Cash Flow and Plans to Execute a Share Buyback Program

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to report its audited 2022 year-end results. Athabasca is uniquely positioned as a low leveraged company generating significant Free Cash Flow through its low-decline, oil weighted asset base.

Q4 and Year-end 2022 Corporate Highlights

- **Sustainable Production:** 35,850 boe/d (93% Liquids) in Q4 and 35,262 boe/d (92% Liquids) in 2022, exceeding its annual upwardly revised guidance of 34-35,000 boe/d. The portfolio of long reserve life assets underpins a low corporate decline rate of ~5% annually.
- **Record Cash Flow:** Adjusted Funds Flow of $308 million and Cash Flow from Operating Activities of $316 million in 2022, underpinned by strong annual operating Netbacks of $47.95/boe in Light Oil and $40.26/bbl in Thermal Oil.
- **Capital Program:** $147 million in 2022, in-line with previous guidance, with $103 million invested at its cornerstone Leismer asset, including a planned turnaround.
- **Record Free Cash Flow:** $161 million with 100% allocated to debt repayment, achieving the Term Debt target of US$175 million significantly ahead of schedule.
- **Balance Sheet:** Achieved the lowest level of absolute debt in corporate history supporting resiliency and free cash flow generation. The Company also has Liquidity of $285 million, including cash of $198 million.

2022 Year End Reserves and Operational Highlights

- **Differentiated Long-life Reserves:** Athabasca holds 1.3 Billion barrels of Proved Plus Probable reserves. This includes $1.4 billion (NPV10 before tax) of Proved Developed Producing reserves ($2.38 per share), $2.7 billion of Total Proved reserves ($4.61 per share) and $4.6 billion of Proved Plus Probable reserves ($7.89 per share). Reserve value is supported by a deep inventory of future development projects including ~850 gross Montney and Duvernay locations (79% unbooked) and phased future expansions at its Thermal Oil properties.
- **Leismer:** The Company drilled seven wells during 2022 and steaming commenced on a new five well pad in Q1 2023. Production from this pad is expected to ramp up to ~6,000 bbl/d by year-end. The Company also sanctioned an expansion project with production expected to reach 28,000 bbl/d by mid-2024 at a competitive capital efficiency of ~$14,000/bbl/d. The expansion program is consistent with previous budget guidance, will not impact the return of capital strategy and bolsters future Free Cash Flow generation through enhanced margins.
- **Light Oil Duvernay:** In the oil window at Kaybob East and Two Creeks the Company has extended production history from 27 wells de-risking an inventory of 290 gross future locations. The wells have consistently supported the Company's type curve expectations with IP365's averaging ~550 boe/d per well, ~85% Liquids (latest 12 wells since 2020).

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Adjusted Funds Flow, Free Cash Flow, Excess Cash Flow, Sustaining Capital, Liquidity) and production disclosure.
[1] Pricing Assumptions: 2023 US$85 WTI, US$17.50 Western Canadian Select "WCS" heavy differential, C$5 AECO, and $0.75 C$/US$ FX. 2024-25 US$85 WTI, US$12.50 WCS heavy differential, C$5 AECO, and $0.75 C$/US$ FX.

Return of Capital Strategy

- **Excess Cash Flow Strategy**: In 2023, Athabasca plans to allocate a minimum of 75% of Excess Cash Flow (Adjusted Funds Flow less Sustaining Capital) to shareholders. The Company anticipates generating ~$415 million of Adjusted Funds Flow[1] and ~$270 million of Free Cash Flow[1] in 2023. Athabasca forecasts ~$1.1 billion in Free Cash Flow[1] during the three year timeframe of 2023-25.
- **Normal Course Issuer Bid ("NCIB"):** The Board of Directors has approved the filing of an application with the Toronto Stock Exchange ("TSX") for a NCIB. Athabasca plans to commence a share buyback program in April, the earliest date permitted under the Company's term debt agreement.

2023 Outlook and Guidance

- **Reiterating 2023 Guidance.** The Company is executing a ~$145 million capital program ($120 million Thermal and $25 million Light Oil) with activity primarily focused on advancing the expansion project at Leismer. Corporate annual production guidance is 34,500 – 36,000 boe/d (93% Liquids).
- **Managing for Free Cash Flow.** The Company expects to generate ~$1.1 billion in Free Cash Flow[1], or ~65% of the Company's current equity market capitalization, during the three-year timeframe of 2023-25. As a result of its $3 billion in corporate tax pools, Athabasca is not forecasted to pay cash taxes for approximately seven years.
- **Excellent Exposure to Commodity Upside.** Athabasca has excellent exposure to upside in commodity prices with 25% of forecasted 2023 production volumes hedged through collars providing upside to ~US$110 WTI.
- **Thermal Oil Differentiation.** Strong margins and Free Cash Flow is supported by a Thermal Oil pre-payout Crown royalty structure, with royalty rates between 5 – 9%. Leismer is forecasted to remain pre-payout until 2027[1] and Hangingstone well into the 2030s (US$85 WTI, US$12.50 WCS differential).
- **Environmental, Social and Governance "ESG" Disclosure.** The Company will release its annual ESG update in the Spring of 2023. In 2022, the Company maintained a strong safety record with a 0.08 Total Recordable Injury Frequency with zero reportable hydrocarbon spills.
- **Carbon Capture.** The Company is on track to achieve its stated target of a 30% reduction in emissions intensity by 2025. Athabasca has also partnered with Entropy Inc. to implement carbon capture and storage ("CCS") at Leismer, using Entropy's proprietary CCS technology. This project is expected to be sanctioned in 2023 once government fiscal and regulatory policy for CCS projects are fully in place.

Business Environment & Outlook

Global oil price benchmarks have been supported by improving demand and structural supply deficits. The war in Ukraine has amplified the emphasis on energy security and sanctions have altered energy flows across the globe. Athabasca maintains a constructive outlook on oil prices supported by years of industry underinvestment and demand trends moving higher led by China emerging from COVID restrictions.

Western Canadian Select ("WCS") differentials temporarily widened through the second half of 2022 as a result of unprecedented US Strategic Petroleum Reserve heavy barrel releases, TC Energy's Keystone pipeline leak in December 2022, the war in Ukraine impacting global heavy crude oil flows and significant unplanned US refinery outages. Looking to 2023, Athabasca anticipates a strengthening supply-demand picture for heavy barrels as these transient factors pass. The planned start-up of the Trans Mountain

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pipeline expansion (590,000 bbl/d) in late 2023 and new global heavy oil refining capacity are expected to strengthen WCS prices significantly and reduce overall volatility.

Athabasca maintains tremendous exposure to oil prices and its shareholders are well positioned for the constructive outlook. The Company's 2023 annual budget assumptions are US$85 WTI and US$17.50 WCS differential. Every $5/bbl WTI change impacts annual cash flow by ~$50 million (unhedged) and every US$5/bbl WCS differential change impacts annual cash flow by ~$80 million (unhedged).

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Financial and Operational Highlights

($ Thousands, unless otherwise noted)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
CONSOLIDATED				
Petroleum and natural gas production (boe/d)(1)	35,850	35,147	35,262	34,618
Petroleum, natural gas and midstream sales	$ 282,524	$ 292,405	$ 1,504,685	$ 1,016,323
Operating Income (Loss)(1)	$ 70,319	$ 110,648	$ 530,295	$ 390,353
Operating Income (Loss) Net of Realized Hedging(1)(2)	$ 62,131	$ 65,735	$ 378,695	$ 278,664
Operating Netback ($/boe)(1)	$ 23.17	$ 35.43	$ 41.65	$ 31.00
Operating Netback Net of Realized Hedging ($/boe)(1)(2)	$ 20.47	$ 21.05	$ 29.74	$ 22.13
Capital expenditures	$ 13,029	$ 18,352	$ 147,449	$ 92,142
Free Cash Flow(1)	$ 33,045	$ 24,291	$ 160,555	$ 91,923
THERMAL OIL DIVISION				
Bitumen production (bbl/d)(1)	30,210	28,084	28,989	26,805
Petroleum, natural gas and midstream sales	$ 255,749	$ 265,076	$ 1,382,627	$ 914,058
Operating Income (Loss)(1)	$ 50,691	$ 82,729	$ 420,511	$ 287,261
Operating Netback ($/bbl)(1)	$ 20.15	$ 33.43	$ 40.26	$ 29.49
Capital expenditures	$ 10,895	$ 12,355	$ 110,582	$ 81,985
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)(1)	5,640	7,063	6,273	7,813
Percentage Liquids (%)(1)	56%	56%	57%	56%
Petroleum, natural gas and midstream sales	$ 36,356	$ 40,237	$ 175,279	$ 147,705
Operating Income (Loss)(1)	$ 19,628	$ 27,919	$ 109,784	$ 103,092
Operating Netback ($/boe)(1)	$ 37.83	$ 42.95	$ 47.95	$ 36.15
Capital expenditures	$ 1,594	$ 5,291	$ 11,662	$ 6,931
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 69,368	$ 81,189	$ 315,618	$ 194,253
per share - basic	$ 0.12	$ 0.15	$ 0.56	$ 0.37
Adjusted Funds Flow(1)	$ 46,074	$ 42,643	$ 308,004	$ 184,065
per share - basic	$ 0.08	$ 0.08	$ 0.54	$ 0.35
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ 489,654	$ 384,073	$ 572,271	$ 457,608
per share - basic	$ 0.83	$ 0.72	$ 1.01	$ 0.86
per share - diluted	$ 0.81	$ 0.70	$ 0.98	$ 0.84
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	586,468,394	530,744,156	568,035,589	530,692,724
Weighted average shares outstanding - diluted	604,911,603	551,124,848	586,913,328	546,717,181

As at ($ Thousands)	Dec. 31, 2022	Dec. 31, 2021
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 197,525	$ 223,056
Available credit facilities(3)	$ 87,838	$ 77,844
Face value of term debt(4)	$ 237,231	$ 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 $8.2 million and $151.6 million for the three months and year ended December 31, 2022 (three months and year ended December 31, 2021 – loss of $44.9 million and $111.7 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 December 31, 2022 was US$175 million (December 31, 2021 – US$350 million) translated into Canadian dollars at the December 31, 2022 exchange rate of US$1.00 =C$1.3544 (December 31, 2021 – C$1.2678).

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Operations Update

Thermal Oil

Bitumen production for Q4 2022 and 2022 averaged 30,210 bbl/d and 28,989 bbl/d, respectively. The Thermal Oil division generated Operating Income of $50.7 million ($20.15/bbl) and $420.5 million ($40.26/bbl) during these periods. Capital expenditures for Q4 2022 and 2022 were $10.9 million and $110.6 million, respectively.

Leismer

Bitumen production for Q4 2022 and 2022 averaged 21,774 bbl/d and 20,135 bbl/d, respectively. The asset realized continued improvement in the steam oil ratio ("SOR") from expansion of the non-condensable gas co-injection and production additions from new wells resulting in an annual average SOR of 2.9 for 2022.

In 2022, the Company drilled two infill wells at Pad L6 and the wells were placed on production in September. At Pad L8, drilling and completion operations were completed in October on five additional well pairs. The Company recently commenced steam circulation on the pad with first production expected mid-year. The pad is projected to ramp-up ~6,000 bbl/d with a stable production profile for approximately five years. Leismer is expected to exit 2023 with production of ~24,000 bbl/d.

A facility expansion project has been sanctioned and will support sustainable growth up to ~28,000 bbl/d in mid-2024. This production level can be held with modest sustaining capital (~$6/bbl) for many years into the future. Capital scope in 2023 includes the expansion project along with drilling four additional sustaining well pairs at Pad L8 and four infill wells at Pad L7. The Company is able to leverage existing excess steam capacity and has been proactive in acquiring long lead equipment. The project is budgeted at a competitive capital efficiency of ~$14,000/bbl/d and is expected to enhance margins through increased operating scale.

The Company continues to progress engineering for the Leismer CCS project. This project is expected to be sanctioned in 2023 once government fiscal and regulatory policy for CCS projects are fully in place.

Leismer has a significant unrecovered capital balance of $1.6 billion which ensures a low Crown royalty framework as the asset is forecasted to remain pre-payout until 2027[1] (US$85 WTI, US$12.50 WCS differential).

Hangingstone

Bitumen production for Q4 2022 and 2022 averaged 8,436 bbl/d and 8,854 bbl/d respectively. Non-condensable gas co-injection has aided in pressure support and reduced energy usage. Hangingstone's steam oil ratio averaged 3.8 for 2022. The Company is preparing for operational readiness to drill sustaining well pairs in 2024 and beyond to maintain production levels.

Light Oil

Production averaged 5,640 boe/d (56% Liquids) and 6,273 boe/d (57% Liquids) in Q4 2022 and 2022, respectively. The Light Oil Division generated Operating Income of $19.6 million ($37.83/boe) and $109.8 million ($47.95/boe) during these periods. Capital expenditures were $1.6 million and $11.7 million in Q4 2022 and 2022, respectively.

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Three Duvernay wells at Two Creeks were completed early in 2022 with IP180's averaging ~500 boe/d (94% Liquids). In the oil window at Kaybob East and Two Creeks the Company has extended production history from 27 wells de-risking an inventory of 290 gross future locations. The wells have consistently supported the Company's type curve expectations with IP365's averaging ~550 boe/d per well, ~85% Liquids (latest 12 wells since 2020), demonstrating the significant potential of the asset.

The Light Oil land position has no near-term expiries and is ready for future development with ~850 gross Montney and Duvernay locations.

Differentiated Long-life Reserves

Athabasca's independent reserves evaluator, McDaniel & Associates Consultants Ltd. ("McDaniel"), prepared the year-end reserves evaluation effective December 31, 2022.

The Company's Proved plus Probable reserves base is 1.3 billion boe, with Leismer/Corner underpinning over 1 billion barrels of low risk, top tier, long reserve life resource. McDaniel's estimated reserve values (NPV10 before tax) are $1.4 billion Proved Developed Producing ($2.38 per basic share), $2.7 billion Total Proved ($4.61 per share) and $4.6 billion Proved plus Probable ($7.89 per share).

In 2023, Athabasca's management anticipates a reclassification of ~15 mmbbl of reserves from Proved Undeveloped to Proved Developed Producing following the ramp-up of the five new well pairs at Pad L8. The capital cost of this project was $48 million and management estimates finding costs of ~$3/bbl with an implied recycle ratio of 11.5x ($37/bbl 2023 forecasted Leismer Operating Netback).

For additional information regarding Athabasca's reserves and resources estimates, please see "Independent Reserve and Resource Evaluations" in the Company's 2022 Annual Information Form which is available on the Company's website or on SEDAR www.sedar.com.

	Light Oil		Thermal Oil		Corporate	
	2021	2022	2021	2022	2021	2022
Reserves (mmboe)						
Proved Developed Producing	13	**12**	74	**66**	87	**78**
Total Proved	27	**29**	414	**403**	441	**433**
Proved Plus Probable	72	**70**	1,230	**1,220**	1,301	**1,290**
NPV10 BT ($MM)[1]						
Proved Developed Producing	$191	**$191**	$1,313	**$1,201**	$1,504	**$1,393**
Total Proved	$278	**$317**	$2,466	**$2,384**	$2,744	**$2,702**
Proved Plus Probable	$568	**$642**	$3,940	**$3,985**	$4,507	**$4,627**

1) Net present value of future net revenue before tax and at a 10% discount rate (NPV 10 before tax) for 2022 is based on an average of McDaniel, Sproule and GLJ pricing as at January 1, 2023.
2) Numbers in the table may not add precisely due to rounding.

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Return of Capital to Shareholders and Normal Course Issuer Bid

Athabasca transitioned a significant portion of its enterprise value to shareholders through its debt reduction priority in 2022, by retiring $227 million (US$174.8 million) in outstanding principal, achieving its debt target representing a ~50% reduction.

The Company's capital allocation framework will balance material near-term return of capital initiatives for shareholders, with a strong multi-year growth trajectory of cash flow per share. Athabasca sees tremendous intrinsic value not reflected in the current share price and in 2023 is planning to allocate a minimum of 75% of Excess Cash Flow (Adjusted Funds Flow less Sustaining Capital) to shareholders. Additional Excess Cash Flow allocation will be commodity price dependent and could include additional share buybacks dependent on valuation, further debt reduction or high growth projects.

Athabasca's Board of Directors has approved the filing of an application with the TSX for a NCIB which, subject to review and approval by the TSX, will provide the Company with the ability to purchase up to 10% of the Company's float per annum. The Company intends to commence the buyback program in April, the earliest date permitted under the Company's term debt agreement.

About Athabasca Oil Corporation

Athabasca Oil Corporation is a Canadian energy company with a focused strategy on the development of thermal and light oil assets. Situated in Alberta's Western Canadian Sedimentary Basin, the Company has amassed a significant land base of extensive, high-quality resources. Athabasca's common shares trade on the TSX under the symbol "ATH". For more information, visit www.atha.com.

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Reader Advisory:

This News Release 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", "project", "continue", "maintain", "estimate", "expect", "will", "target", "forecast", "could", "intend", "potential", "guidance", "outlook" and similar expressions suggesting future outcome 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 operating and 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 News Release should not be unduly relied upon. This information speaks only as of the date of this News Release. In particular, this News Release contains forward-looking information pertaining to, but not limited to, the following: our strategic plans; future debt levels and repayment plans; the allocation of future capital; timing and quantum for shareholder returns including share buybacks; the terms of our NCIB program; our drilling plans in Leismer; Leismer ramp-up to expected production rates; timing of Leismer's pre-payout royalty status; applicability of tax pools and the timing of tax payments; expected operating results at Hangingstone; Adjusted Funds Flow and Free Cash Flow in 2023 to 2025; type well economic metrics; forecasted daily production and the composition of production; the reclassification of reserves from Proved Undeveloped to Proved Developed Producing; our plans to release an ESG update; the achievement of a 30% reduction in emissions intensity by 2025; the timing and implementation of our CCS project; our outlook in respect of the Corporation's business environment, including in respect of the Trans Mountain pipeline expansion and new global heavy oil refining capacity; and other matters.

In addition, information and statements in this News Release 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. With respect to forward-looking information contained in this News Release, 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; Athabasca's cash flow break-even commodity price; 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. Certain other 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, 2022 (which is respectively referred to herein as the "McDaniel Report").

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 Annual Information Form ("AIF") dated March 1, 2023 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; state of capital markets; ability to finance capital requirements; access to capital and insurance; abandonment and reclamation costs; continued impact of the COVID-19 pandemic; 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; labour supply, 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; and risks related to our debt and securities, including level of indebtedness, restrictions in our debt instruments, additional indebtedness and issuance of additional securities. Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this News Release could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking information are reasonable based on information available to it on the date such forward-looking information are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking information, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements.

Also included in this News Release are estimates of Athabasca's 2023 outlook which are based on the various assumptions as to production levels, commodity prices, currency exchange rates and other assumptions disclosed in this News Release. To the extent any such estimate constitutes a financial outlook, it was approved by management and the Board of Directors of Athabasca and is included to provide readers with an understanding of the Company's outlook. Management does not have firm commitments for all of the costs, expenditures, prices or other financial assumptions used to prepare the financial outlook or assurance that such operating results will be achieved and, accordingly, the complete financial effects of all of those costs, expenditures, prices and operating results are not objectively determinable. The actual results of operations of the Company and the resulting financial results may vary from the amounts set forth herein, and such variations may be material. The outlook and forward-looking information contained in this New Release was made as of the date of this News release and the Company disclaims any intention or obligations to update or revise such outlook and/or forward-looking information, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.

Oil and Gas Information

"BOEs" 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.

Initial Production Rates

Test Results and Initial Production Rates: The well test results and initial production rates provided herein should be considered to be preliminary, except

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as otherwise indicated. Test results and initial production rates disclosed herein may not necessarily be indicative of long-term performance or of ultimate recovery.

Reserves 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, 2022. 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 natural gas liquids 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. Reserves figures described herein have been rounded to the nearest MMbbl or MMboe. For additional information regarding the consolidated reserves and information concerning the resources of the Company as evaluated by McDaniel in the McDaniel Report, please refer to the Company's AIF.

Reserve Values (i.e. Net Asset Value) is calculated using the estimated net present value of all future net revenue from our reserves, before income taxes discounted at 10%, as estimated by McDaniel effective December 31, 2022 and based on average pricing of McDaniel, Sproule and GLJ as of January 1, 2023.

The 700 gross Duvernay drilling locations referenced include: 5 proved undeveloped locations and 77 probable undeveloped locations for a total of 82 booked locations with the balance being unbooked locations. The 150 gross Montney drilling locations referenced include: 48 proved undeveloped locations and 50 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, 2022 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.

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", "Cash Transportation & Marketing Expenses", "Excess Cash Flow" and "Sustaining Capital" financial measures contained in this News Release 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. Liquidity is a supplementary financial measure. The Leismer and Hangingstone operating results are a supplementary financial measure that when aggregated, combine to the Thermal Oil segment results and the Greater Placid and Greater Kaybob operating results are a supplementary financial measure 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:

($ Thousands)	Three months ended December 31, 2022	Three months ended December 31, 2021	Year ended December 31, 2022	Year ended December 31, 2021
Cash flow from operating activities	$ 69,368	$ 81,189	$ 315,618	$ 194,253
Changes in non-cash working capital	(23,356)	(38,794)	(8,970)	(11,872)
Settlement of provisions	62	248	1,356	1,684
ADJUSTED FUNDS FLOW	46,074	42,643	308,004	184,065
Capital expenditures	(13,029)	(18,352)	(147,449)	(92,142)
FREE CASH FLOW	$ 33,045	$ 24,291	$ 160,555	$ 91,923

Light Oil Operating Income and Operating Netback

The non-GAAP measure Light Oil Operating Income in this News Release is calculated by subtracting the Light Oil Segments royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales which is the most directly comparable GAAP measure. The Light Oil Operating Netback per boe is a non-GAAP financial ratio calculated by dividing the Light Oil Operating Income by the Light Oil production. The Light Oil Operating Income and the Light Oil Operating Netback measures allow management and others to evaluate the production results from the Company's

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Adjusted Funds Flow, Free Cash Flow, Excess Cash Flow, Sustaining Capital, Liquidity) and production disclosure.
[1] Pricing Assumptions: 2023 US$85 WTI, US$17.50 Western Canadian Select "WCS" heavy differential, C$5 AECO, and $0.75 C$/US$ FX. 2024-25 US$85 WTI, US$12.50 WCS heavy differential, C$5 AECO, and $0.75 C$/US$ FX.

Light Oil assets. The Light Oil Operating Income is calculated using the Light Oil Segments GAAP results, as follows:

($ Thousands)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Petroleum and natural gas sales	$ 36,356	$ 40,237	$ 175,279	$ 147,705
Royalties	(6,701)	(3,883)	(25,608)	(10,160)
Operating expenses	(7,791)	(5,917)	(30,689)	(24,395)
Transportation and marketing	(2,236)	(2,518)	(9,198)	(10,058)
LIGHT OIL OPERATING INCOME	$ 19,628	$ 27,919	$ 109,784	$ 103,092

Thermal Oil Operating Income and Operating Netback

The non-GAAP measure Thermal Oil Operating Income in this News Release is calculated by subtracting the Thermal Oil segments cost of diluent blending, royalties, operating expenses and cash transportation & marketing expenses from heavy oil (blended bitumen) and midstream sales which is the most directly comparable GAAP measure. The Thermal Oil Operating Netback per boe is a non-GAAP financial ratio calculated by dividing the respective projects Operating Income by its respective bitumen sales volumes. The Thermal Oil Operating Income and the Thermal Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Thermal Oil assets. The Thermal Oil Operating Income is calculated using the Thermal Oil Segments GAAP results, as follows:

($ Thousands, unless otherwise noted)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Heavy oil (blended bitumen) and midstream sales	$ 255,749	$ 265,076	$ 1,382,627	$ 914,058
Cost of diluent	(128,713)	(105,753)	(548,553)	(360,824)
Total bitumen and midstream sales	127,036	159,323	834,074	553,234
Royalties	(13,256)	(14,089)	(133,134)	(27,557)
Operating expenses - non-energy	(17,062)	(18,356)	(81,319)	(68,517)
Operating expenses - energy	(25,914)	(24,289)	(114,622)	(87,919)
Transportation and marketing[(1)]	(20,113)	(19,860)	(84,488)	(81,980)
THERMAL OIL OPERATING INCOME (LOSS)	$ 50,691	$ 82,729	$ 420,511	$ 287,261

(1) Cash transportation and marketing excludes non-cash costs of $0.6 million and $2.2 million for the three months and year ended December 31, 2022 (three months and year ended December 31, 2021 - $0.6 million and $1.5 million).

Consolidated Operating Income and Consolidated Operating Income Net of Realized Hedging and Operating Netbacks

The non-GAAP measures of Consolidated Operating Income including or excluding realized hedging in this News Release are calculated by adding or subtracting realized gains (losses) on commodity risk management contracts (as applicable), royalties, the cost of diluent blending, 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 Netbacks including or excluding realized hedging per boe are non-GAAP ratios calculated by dividing Consolidated Operating Income including or excluding hedging by the total sales volumes and are presented on a per boe basis. The Consolidated Operating Income and Consolidated Operating Netbacks including or excluding 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 (as applicable).

($ Thousands, unless otherwise noted)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Petroleum, natural gas and midstream sales[(1)]	$ 292,105	$ 305,313	$ 1,557,906	$ 1,061,763
Royalties	(19,957)	(17,972)	(158,742)	(37,717)
Cost of diluent[(1)]	(128,713)	(105,753)	(548,553)	(360,824)
Operating expenses	(50,767)	(48,562)	(226,630)	(180,831)
Transportation and marketing[(2)]	(22,349)	(22,378)	(93,686)	(92,038)
Operating Income (Loss)	70,319	110,648	530,295	390,353
Realized gain (loss) on commodity risk management contracts	(8,188)	(44,913)	(151,600)	(111,689)
OPERATING INCOME (LOSS) NET OF REALIZED HEDGING	$ 62,131	$ 65,735	$ 378,695	$ 278,664

(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, 2022 (three months and year ended December 31, 2021 - $0.6 million and $1.5 million).

Cash Transportation & Marketing Expenses

The Cash Transportation & Marketing Expense financial measure contained in this News Release is 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 is considered to be a non-GAAP financial measure.

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Adjusted Funds Flow, Free Cash Flow, Excess Cash Flow, Sustaining Capital, Liquidity) and production disclosure.

[1] Pricing Assumptions: 2023 US$85 WTI, US$17.50 Western Canadian Select "WCS" heavy differential, C$5 AECO, and $0.75 C$/US$ FX. 2024-25 US$85 WTI, US$12.50 WCS heavy differential, C$5 AECO, and $0.75 C$/US$ FX.

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.

Liquidity

Liquidity is defined as cash and cash equivalents plus available credit capacity.

Production volumes details

Production		Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Greater Placid:					
Condensate NGLs	bbl/d	843	1,211	962	1,375
Other NGLs	bbl/d	360	494	411	512
Natural gas(1)	mcf/d	10,259	13,181	11,149	14,537
Total Greater Placid	boe/d	2,913	3,902	3,232	4,310
Greater Kaybob:					
Oil(2)	bbl/d	1,707	1,885	1,886	2,164
Other NGLs	bbl/d	266	342	319	344
Natural gas(1)	mcf/d	4,526	5,603	5,020	5,969
Total Greater Kaybob	boe/d	2,727	3,161	3,041	3,503
Light Oil:					
Oil(2)	bbl/d	1,707	1,885	1,886	2,164
Condensate NGLs	bbl/d	843	1,211	962	1,375
Oil and condensate NGLs	bbl/d	2,550	3,096	2,848	3,539
Other NGLs	bbl/d	626	836	730	856
Natural gas(1)	mcf/d	14,785	18,784	16,169	20,506
Total Light Oil division	boe/d	5,640	7,063	6,273	7,813
Total Thermal Oil division bitumen	bbl/d	30,210	28,084	28,989	26,805
Total Company production	boe/d	35,850	35,147	35,262	34,618

(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 News Release also makes reference to Athabasca's forecasted total average daily production of 34,500 – 36,000 boe/d for 2023. Athabasca expects that ~84% of that production will be comprised of bitumen, 7% shale gas, 4% tight oil, 3% condensate natural gas liquids and 2% other natural gas liquids.

This News Release makes reference to Athabasca's three well results in Two Creeks that have seen average productivity of ~500 boe/d IP180s (94% Liquids), which is comprised of ~92% tight oil, ~6% shale gas and ~2% NGLs. Additionally, the latest 12 wells at Two Creeks have seen average productivity of ~550 boe/d IP365s (85% Liquids), which is comprised of ~80% tight oil, ~15% shale gas and ~5% NGLs.

Liquids is defined as bitumen, light crude oil, medium crude oil and natural gas liquids.

Finding cost is calculated as project total capital costs divided by project reserves.

Recycle ratio is calculated by dividing estimated project operating netbacks by finding and development costs per boe.

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Adjusted Funds Flow, Free Cash Flow, Excess Cash Flow, Sustaining Capital, Liquidity) and production disclosure.

[1] Pricing Assumptions: 2023 US$85 WTI, US$17.50 Western Canadian Select "WCS" heavy differential, C$5 AECO, and $0.75 C$/US$ FX. 2024-25 US$85 WTI, US$12.50 WCS heavy differential, C$5 AECO, and $0.75 C$/US$ FX.