FOR IMMEDIATE RELEASE
November 2, 2022

Athabasca Oil Announces 2022 Third Quarter Results including Record $102 million of Adjusted Funds Flow along with $223 million in Debt Redemptions Year to Date

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to report its 2022 third quarter results with record Adjusted Funds Flow, strong Free Cash Flow and material deleveraging. Athabasca is uniquely positioned as a low leveraged company generating significant Free Cash Flow through its low-decline, oil weighted asset base.

Q3 Corporate Highlights

- **Production:** 37,240 boe/d (93% Liquids) consisting of 31,023 bbl/d in Thermal Oil and 6,217 boe/d (57% Liquids) in Light Oil. The Company is on track to exceed its increased annual production guidance of 34,000 – 35,000 boe/d, based on strong underlying asset performance.
- **Record Cash Flow:** Record Adjusted Funds Flow[1] of $102 million and Free Cash Flow of $50 million.
- **Netbacks:** $39.25/bbl in Thermal Oil ($41.73/bbl at Leismer and $33.70/bbl at Hangingstone) and $38.76/boe in Light Oil ($48.11/boe at Kaybob and $29.82/boe at Placid).
- **Capital Expenditures:** $52 million primarily focused on sustaining operations at the Leismer asset in Thermal Oil.
- **Significant Deleveraging:** Redeemed $223 million (US$172 million) in Term Debt year to date, including $65 million (US$48 million) in and subsequent to the third quarter. The Company has been steadfast on its balance sheet commitments and has achieved 98% of its US$175MM debt reduction target, demonstrating the significant Free Cash Flow generation of Athabasca's business. The Company has low Net Debt of ~$65 million and forecasts a Net Cash position in 2023 onwards.
- **Strong Liquidity:** $278 million of Liquidity, inclusive of $200 million of Cash at the end of Q3.

Operational Highlights

- **Leismer:** Q3 production averaged 22,309 bbl/d with a 2.8x SOR supported by strong rates from the new Pad 8 (5 well pairs). The Company recently placed two additional infill wells on production at Pad L6 and rig released an additional five well pairs at Pad L8 that are expected to be on production in H1 2023. Athabasca has estimated Profit-to-Investment Ratios (NPV/Investment) of ~10x on recent sustaining pads (long term $85 WTI and $12.50 Western Canadian Select "WCS" heavy differentials).
- **Hangingstone:** Q3 production averaged 8,714 bbl/d and non-condensable gas co-injection has resulted in reduced energy intensity with the steam oil ratio of 3.8x year to date.
- **Light Oil Duvernay and Montney:** Three Duvernay wells at Two Creeks completed in Q1 continue to outperform expectations with IP180s averaging ~500 boe/d per well (94% Liquids). The Company has a flexible development portfolio of ~850 gross de-risked Montney and Duvernay wells along with strategic ownership and operatorship of liquids and gas infrastructure.

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Operating Income/Netbacks, Adjusted Funds Flow, Free Cash Flow, Net Debt/Cash) and production disclosure.
[1] Cash Flow from Operating Activities of $118 million.
[2] Pricing Assumptions: realized prices year to date through September and flat pricing of US$85 WTI, US$25 Western Canadian Select "WCS" heavy differential, C$5 AECO, and $0.73 C$/US$ FX for the balance of 2022.

Strategic Update and Corporate Outlook

- **Low Decline, Long Life Asset Base:** Athabasca has a deep asset inventory with 1,230 mmbbl 2P Reserves in Thermal Oil and ~850 gross wells of short cycle-time, high returning Light Oil future locations. The asset portfolio is demonstrating its ability to generate significant Free Cash Flow and will provide tremendous optionality into the future. Production guidance of 34,000 – 35,000 boe/d (92% Liquids) in 2022 is expected to be attained through its modest capital program that is also indicative of long term sustaining capital requirements.
- **Managing for Free Cash Flow:** For 2022, Athabasca is updating its financial forecasts based on strong operational performance and current commodity price assumptions. Adjusted Funds Flow[1] is forecasted at ~$330 million including Free Cash Flow[1] of ~$180 million. The Company further expects to generate ~$900 million in Free Cash Flow during the 3-year timeframe of 2022-24 (inclusive of 2022 guidance and flat pricing of US$85 WTI and US$12.50 WCS differentials thereafter). Every $5/bbl WTI change impacts Free Cash Flow by ~$45 million annually (unhedged). Strong margins and Free Cash Flow is supported by ~$3 billion in tax pools and a Thermal Oil pre-payout Crown royalty structure.
- **Significant Deleveraging with Clear Targets:** 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).
- **Excellent Exposure to Commodity Price Upside:** Athabasca has excellent exposure to upside in commodity prices with minimal hedges in 2023. The Company has a constructive outlook on oil prices given years of industry underinvestment in energy. The Company believes the recent wider WCS differentials is transitory as the US administration tapers Strategic Petroleum Reserve releases and refinery maintenance season concludes.
- **Thermal Oil Differentiation:** Athabasca's Thermal assets operate in a pre-payout Crown royalty structure, with royalty rates between 5 - 9%, and is anticipated to last beyond 2028 (US$85 WTI & US$12.50 WCS differentials). This results in maximum cash flow at current commodity prices and creates a significant advantage over the majority of Industry oil sands projects. The Company's low decline, long reserve life Thermal Oil assets are forecasted to generate ~$450 million in Operating Income[1] in 2022. At current commodity prices, these assets compete exceptionally well on all cash flow metrics against top plays in North America.
- **Planning for the Future:** A ~$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.
- **Unlocking Shareholder Value:** Deleveraging in 2022 has transitioned a significant portion of enterprise value to shareholders. Athabasca is committed to further enhancing shareholder returns by utilizing Free Cash Flow and cash balances for share buy-backs once its debt target is achieved. The Company sees tremendous intrinsic value not reflected in the current share price. Guidance on shareholder returns and the corporate capital allocation framework will be provided in early December in conjunction with the 2023 budget.

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Operating Income/Netbacks, Adjusted Funds Flow, Free Cash Flow, Net Debt/Cash) and production disclosure.

[1] Pricing Assumptions: realized prices year to date through September and flat pricing of US$85 WTI, US$25 Western Canadian Select "WCS" heavy differential, C$5 AECO, and $0.73 C$/US$ FX for the balance of 2022.

Financial and Operational Highlights

($ 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 "Reader Advisory" section within this news release 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).

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Operating Income/Netbacks, Adjusted Funds Flow, Free Cash Flow, Net Debt/Cash) and production disclosure.

Operations Update

Thermal Oil

Bitumen production for Q3 2022 averaged 31,023 bbl/d. The Thermal Oil division generated Operating Income of $117.9 million. Q3 2022 Operating Netbacks for Leismer and Hangingstone were $41.73/bbl and $33.70/bbl, respectively. Capital expenditures were $35.4 million.

For 2022, Athabasca has fully hedged its Thermal Oil gas input costs through its Light Oil gas production with the balance financially hedged at ~C$4/mcf AECO. The Company has also commenced hedging its gas input costs for 2023 locking in 21 mmcf/d at ~C$5/mcf.

Leismer

Bitumen production at Leismer for the third quarter averaged 22,309 bbl/d.

In June, 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 for five additional well pairs. Steaming is expected to commence before year-end with first production in H1 2023. The pad encountered excellent reservoir and is expected to ramp-up to a plateau rate of ~6,000 bbl/d, similar to the first Pad 8 well pairs that came on production earlier this year.

Leismer's current production is ~22,000 bbl/d (October) with ~50% of volumes attributed to newer vintage production (Pad L7 and L8). Strong new well performance, combined with effective use of non-condensable gas co-injection on mature pads, is resulting in a current steam oil ratio of 2.9x (October). Athabasca has the ability to grow Leismer's production up to the facility's oil handling capacity of ~25,000 bbl/d by maintaining its current capital cadence of approximately one sustaining pad per year. Leismer has regulatory approval for expansion to 40,000 bbl/d which could provide capital efficient growth through debottlenecking of the facility and the drilling of incremental well pairs.

Leismer has a significant Unrecovered Capital Balance of $1.6 billion which ensures a low Crown royalty framework (between 5-9% royalty depending on commodity prices). The asset is forecasted to remain pre-payout until 2028 (US$85 WTI & US$12.50 WCS differential) and this is a unique competitive advantage compared to most peer oil sands projects.

Hangingstone

Bitumen production at Hangingstone for the third quarter averaged 8,714 bbl/d, inclusive of planned maintenance activity. Non-condensable gas co-injection has aided in pressure support and reduced energy usage. Hangingstone's steam oil ratio averaged 3.8x year to date. In 2022, Hangingstone will have no capital allocation other than routine pump replacements. The asset is expected to generate ~$125 million of Operating Income[1] in 2022.

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Operating Income/Netbacks, Adjusted Funds Flow, Free Cash Flow, Net Debt/Cash) and production disclosure.

[1] Pricing Assumptions: realized prices year to date through September and flat pricing of US$85 WTI, US$25 Western Canadian Select "WCS" heavy differential, C$5 AECO, and $0.73 C$/US$ FX for the balance of 2022.

Light Oil

Production averaged 6,217 boe/d (57% Liquids) for Q3 2022. The Light Oil division generated Operating Income of $22.2 million with an Operating Netback of $38.76/boe. Capital expenditures were $0.9 million.

Placid Montney

At Greater Placid, production averaged 3,181 boe/d (43% Liquids) during the third quarter with an Operating Netback of $29.82/boe. Placid is positioned for flexible future development with an inventory of ~150 gross drilling locations and minimal near-term land retention requirements.

Kaybob Duvernay

At Greater Kaybob, production averaged 3,036 boe/d (72% Liquids) during the third quarter with an Operating Netback of $48.11/boe.

Three Duvernay wells in the oil window at Two Creeks were completed early in the year with IP180's averaging 500 boe/d, 94% Liquids. The Company now has extended production data for 27 wells at Kaybob East and Two Creeks in the oil window, with the latest 12 wells at Two Creeks IP365's averaging ~550 boe/d per well, ~85% Liquids. The wells have consistently supported the Company's type curve expectations, demonstrating the significant potential of the asset.

Industry activity continues to accelerate in the play with significant Crown land sales, increased competitor drilling and new entrants. Minimal capital activity is planned for the remainder of 2022 with operations focused on facility maintenance and readiness for future optionality. Athabasca is positioned with an enviable position of ~700 gross de-risked drilling locations, along with ownership and control of strategic regional infrastructure. Athabasca's Duvernay position is supported by a strong Joint Development Agreement.

Executive Update

Athabasca is pleased to announce the appointment of Mr. Cam Danyluk as General Counsel and Vice President, Business Development. Mr. Danyluk has over twenty years of legal, business development, and investment banking experience in the Canadian energy sector.

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.

For more information, please contact:

Matthew Taylor	Robert Broen
Chief Financial Officer	President and CEO
1-403-817-9104	1-403-817-9190
mtaylor@atha.com	rbroen@atha.com

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Operating Income/Netbacks, Adjusted Funds Flow, Free Cash Flow, Net Debt/Cash) and production disclosure.

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”, “continue”, “estimate”, “expect”, “may”, “will”, “target”, “forecast”, “goal”, “aspiration”, “commit”, “believe”, “should”, “could”, “intend”, “may”, “potential”, “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 for shareholder returns including share buybacks and dividends; our drilling plans in Leismer; Leismer ramp-up to expected production rates; timing of Leismer’s pre-payout royalty status; applicability of tax pools; expected operating results at Hangingstone; Net Debt/Cash positions; Adjusted Funds Flow and Free Cash Flow in 2022 to 2024; the impact of lower future hedge levels; type well economic metrics; forecasted daily production and the composition of production; 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, 2021 (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 2, 2022 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; 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. 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 2022 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 in this presentation should be considered to be preliminary, except 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, 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 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, 2021 and based on average pricing of McDaniel, Sproule and GLJ as of January 1, 2022.

The 700 gross Duvernay drilling locations referenced 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 gross Montney drilling locations referenced 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.

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" and "Cash Transportation & Marketing Expenses" 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. Net Debt/Cash and Liquidity are supplementary financial measures. 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 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

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

($ Thousands)		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	$	22,165	$	25,785	$	90,156	$	75,173

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)		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		(56,027)		(41,518)		(152,965)		(113,791)
Cash transportation and marketing[1]		(23,146)		(22,405)		(64,375)		(62,120)
THERMAL OIL OPERATING INCOME	$	(117,916)	$	(94,796)	$	(369,820)	$	(204,532)

(1) *Cash 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).*

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)		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)
Cash transportation and marketing[2]		(25,367)		(25,094)		(71,337)		(69,660)
Operating Income		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 NET OF REALIZED HEDGING	$	110,021	$	92,742	$	316,564	$	212,929

(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) *Cash 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).*

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.

Net Debt/Cash

Net Debt/Cash is defined as the face value of term debt, plus accounts payable and accrued liabilities, plus current portion of provisions and other liabilities less current assets, and excluding risk management contracts.

Liquidity

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

Production volumes details

($ Thousands)		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 News Release also makes reference to Athabasca's forecasted total average daily production of 34,000 – 35,000 boe/d for 2022. Athabasca expects that ~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.

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.

Recycle ratio is calculated by dividing estimated project operating netbacks by finding and development costs per boe. Profit-to-Investment Ratio is a measure of a projects net value relative to its capital investment and is calculated by dividing a project's NPV10 value by its Capital. Reserve life is calculated by dividing year-end reserves with management’s forecasted production guidance.