FOR IMMEDIATE RELEASE – November 3, 2021

Athabasca Oil Corporation Announces 2021 Third Quarter Results

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to report its 2021 third quarter results. Record financial results during the quarter, including $57 million of Free Cash Flow, demonstrate the quality of Athabasca's asset base and unique positioning in the current oil price environment.

Q3 Highlights

- **Production:** ~34,250 boe/d including ~26,700 bbl/d in Thermal Oil and ~7,500 boe/d in Light Oil.
- **Record Operating Income**: $121 million ($36/boe) driven by strong oil prices and 90% Liquids weighting. Record Operating Netback of $36/bbl in Thermal Oil.
- **Capital Expenditures:** $16 million focused on high-value Leismer projects to sustain production.
- **Record Funds Flow:** Adjusted Funds Flow of $72 million ($0.14 per share) and Free Cash Flow of $57 million.

Recent Operational Highlights

- **Leismer:** Current production of ~19,000 bbl/d has been supported by the tie-in of the L6 infills and an additional well pair on Pad L7. Pad L8 commenced steaming in October, with first oil expected in early 2022. The five well pairs are anticipated to ramp-up to >5,000 bbl/d in mid-2022.
- **Hangingstone:** Expanded NCG co-injection has supported field pressure management with current production of ~9,000 bbl/d. Optimization projects have yielded a significantly lower cost structure driving a $33/bbl Operating Netback in Q3.
- **Light Oil:** Focused on free cash flow generation with continued strong Operating Netback of $37/boe.
- **Carbon Capture (CCUS):** Continuing to advance a scoping study with Entropy Inc. to determine feasibility of a carbon capture at Leismer with ongoing evaluation of local storage and carbon trunkline options.

2021 Guidance and Outlook (Strip Pricing October 4)[1]

- **Production:** increased annual guidance to ~34,250 boe/d (previously 32,000 – 34,000 boe/d).
- **Capital:** an unchanged ~$100 million annual capital program primarily directed towards Leismer.
- **Financial:** Adjusted EBITDA ~$255 million; ~$190 million Adjusted Funds Flow; ~$90 million Free Cash Flow.
- **Balance Sheet:** Resilient and refinanced balance sheet with no term debt maturities until Q4 2026 and strong liquidity of ~$265 million, including ~$195 million cash (2021e year-end).
- **Compelling Leverage Metrics:** Net Debt to Adjusted EBITDA of ~0.8x (2021e year-end). The Company anticipates being in a net cash position in 2023.
- **2022 Budget:** Anticipated to be released in December. Activity will be focused on sustaining base production and maximizing free cash flow generation.

"Athabasca has taken deliberate steps to reposition the portfolio over the past number of years," said Robert Broen, President and CEO. "The quarterly results and outlook validate the Company's enviable position in the current environment. The recent balance sheet refinancing provides us significant strategic flexibility. We remain steadfast in our capital allocation priorities and have a clear path to net zero leverage in 2023. Reduced cash flow volatility, consistent operational execution and a best-in-class balance sheet is expected to unlock significant shareholder value through this period and beyond."

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

[1] 2021 strip pricing at October 4, 2021: US$67.50 WTI, US$12.40 WCS differentials, C$3.64/mcf AECO, 0.80 US$/C$ FX

Strategic Outlook

- **Managing for Strong Free Cash Flow:** Athabasca intends to maximize free cash flow while maintaining its production base. The Company forecasts >$600 million in Free Cash Flow (US$70 WTI & US$12.50 WCS differentials) during the 3-year timeframe of 2022 – 2024.
- **Clear Debt Reduction Targets:** The Company will direct at least 75% of future free cash flow towards achieving a total outstanding term debt reduction of US$175 million (50% reduction) while maintaining a strong liquidity position. The Company is targeting to achieve this target and to be in a net cash position in 2023. Debt reduction utilizing free cash flow, permitted under the new term note, will commence semi-annually with the first repayment in May 2022 (for the period Q4 2021 – Q1 2022).
- **Maintain Annual Corporate Production:** The portfolio of long reserve life assets under-pins a low corporate decline rate of ~10%. Athabasca requires low sustaining capital of ~$125 million annually to maintain production. The Company retains a large portfolio of future investment opportunities.

Business Environment

Commodity prices continue to strengthen as the world has emerged from the COVID-19 pandemic and the recovery in oil demand continues to outpace the growth in supply. Global oil demand is set to exceed pre-pandemic levels in 2022 and inventories are below the 5-year average. The OPEC+ supply agreement is expected to keep the market in a deficit and guidance for higher capacity will be needed in coming years given growing under-investment (Goldman Sachs Commodity Research).

In Alberta, physical markets and regional benchmark prices (e.g. Western Canadian Select “WCS” heavy oil) have improved with higher WTI prices. Athabasca expects current WCS differentials to remain stable with muted industry growth and improving basin egress, including the recently completed Enbridge Line 3 replacement. There is strong demand for heavy oil from US Gulf Coast refineries as they face structural declines in global heavy oil supply (Venezuela and Mexico). Athabasca believes conditions have emerged for WCS heavy oil to be among the most valuable global crude benchmarks.

Balance Sheet and Risk Management Update

On October 22, 2021, Athabasca announced the closing of US$350 million of 5-year Senior Secured Notes (“New Notes”) and a $110 million reserve based credit facility. The refinanced 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.

The Company estimates 2021 year-end liquidity of ~$265 million (including ~$195 million of cash) with a 2021 Net Debt to Adjusted EBITDA of 0.8x (US$67.50 WTI & US$12.50 WCS differentials). The New Notes provide Athabasca the ability to further reduce debt in the near-term by utilizing at least 75% of free cash flow semi-annually to retire notes at 105% of face value. The Company is targeting to be in a net cash position in 2023.

Athabasca has commenced its 2022 hedging programing which includes 13,500 bbl/d of fixed WCS swaps at an average price of ~US$54 (implied WTI of ~US$66.50 assuming a US$12.50 WCS differential). These swaps fully protect the sustaining capital program down to ~US$50 WTI. Additional hedges are anticipated to include collars and puts to strategically balance downside protection while maintaining upside exposure to the current price environment.

Footnote: Refer to the “Reader Advisory” section within this news release for additional information on Non-GAAP Financial Measures (e.g. Operating Income, Adjusted Funds Flow, Free Cash Flow, Net Debt, Adjusted EBITDA) and production disclosure.
[1] 2021 strip pricing at October 4, 2021: US$67.50 WTI, US$12.40 WCS differentials, C$3.64/mcf AECO, 0.80 US$/C$ FX

Financial and Operational Highlights

($ Thousands, unless otherwise noted)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
CONSOLIDATED				
Petroleum and natural gas production (boe/d)[1]	34,255	32,061	34,439	31,896
Operating Income (Loss)[1]	$ 120,581	$ 50,171	$ 279,705	$ 11,574
Operating Income (Loss) Net of Realized Hedging[1][2]	$ 92,742	$ 42,812	$ 212,929	$ 50,076
Operating Netback ($/boe)[1]	$ 36.02	$ 17.19	$ 29.54	$ 1.29
Operating Netback Net of Realized Hedging ($/boe)[1][2]	$ 27.70	$ 14.67	$ 22.49	$ 5.61
Capital expenditures	$ 15,608	$ 12,381	$ 73,790	$ 94,438
Capital Expenditures Net of Capital-Carry[1]	$ 15,608	$ 12,381	$ 73,790	$ 71,698
Free Cash Flow[1]	$ 56,625	$ 2,236	$ 67,632	$ (101,178)
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	26,729	20,231	26,374	22,043
Operating Income (Loss)[1]	$ 94,796	$ 26,844	$ 204,532	$ (30,886)
Operating Netback ($/bbl)[1]	$ 35.71	$ 14.66	$ 28.16	$ (4.98)
Capital expenditures	$ 15,228	$ 10,454	$ 69,630	$ 32,872
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)[1]	7,526	11,830	8,065	9,853
Percentage Liquids (%)[1]	55%	62%	56%	61%
Operating Income (Loss)[1]	$ 25,785	$ 23,327	$ 75,173	$ 42,460
Operating Netback ($/boe)[1]	$ 37.25	$ 21.43	$ 34.15	$ 15.73
Capital expenditures	$ 128	$ 1,917	$ 1,640	$ 61,534
Capital Expenditures Net of Capital-Carry[1]	$ 128	$ 1,917	$ 1,640	$ 38,794
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 75,743	$ (4,782)	$ 113,064	$ (38,989)
per share - basic	$ 0.14	$ (0.01)	$ 0.21	$ (0.07)
Adjusted Funds Flow[1]	$ 72,233	$ 14,617	$ 141,422	$ (29,480)
per share - basic	$ 0.14	$ 0.03	$ 0.27	$ (0.06)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ 104,951	$ (18,818)	$ 73,535	$ (600,634)
per share - basic	$ 0.20	$ (0.04)	$ 0.14	$ (1.14)
per share - diluted	$ 0.19	$ (0.04)	$ 0.14	$ (1.14)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	530,675,391	530,675,391	530,675,391	528,220,593
Weighted average shares outstanding - diluted	547,618,860	530,675,391	544,597,372	528,220,593

As at ($ Thousands)	September 30, 2021	December 31, 2020
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 273,989	$ 165,201
Restricted cash	$ 46,107	$ 135,624
Available credit facilities[3]	$ 3,568	$ 348
Face value of long-term debt, including current portion[4]	$ 573,345	$ 572,940

(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 $27.8 million and $66.8 million for the three and nine months ended September 30, 2021 (three and nine months ended September 30, 2020 - $7.4 million loss and $38.5 million gain).
(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility (see page 13 of the Q3 MD&A).
(4) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the September 30, 2021 exchange rate of US$1.00 = C$1.2741 (December 31, 2020 – C$1.2732).

Operations Update

Thermal Oil

Bitumen production for Q3 2021 averaged 26,729 bbl/d. The Thermal Oil division generated Operating Income of $94.8 million and capital expenditures were $15.2 million. Operating Netbacks for Leismer and Hangingstone were a record $37.09/bbl and $32.92/bbl, respectively.

Leismer

Bitumen production for Q3 2021 averaged 18,023 bbl/d. Production has increased over Q2 volumes following the tie-in of two L6 infills and L7P6 in late June and Leismer is currently producing ~19,000 bbl/d.

The Company has significantly advanced the completion of Pad 8. Facility construction was completed in October and steam circulation has commenced ahead of schedule. First production is anticipated in early 2022. The initial five well pairs on Pad L8 are expected to ramp-up in excess of 5,000 bbl/d in mid-2022. The existing pipeline will support future development for a total of 14 well pairs on Pad L8. Preparations are underway for drilling operations to commence on the next sustaining pad in 2022.

Hangingstone

Bitumen production for Q3 2021 averaged 8,706 bbl/d. Reservoir performance through 2021 has been strong as a result of excellent facility run time and the implementation of NCG co-injection aiding in pressure build-up and reduced energy usage. Production is expected to be supported by an additional well pair (AA03) that is currently steaming and will be placed on production in November.

Light Oil

Q3 production averaged 7,526 boe/d (55% liquids) in Q3 2021. The division generated Operating Income of $25.8 million ($37.25/boe) and capital expenditures were $0.1 million. Athabasca's Light Oil netback continues to be top tier when compared to Alberta's other liquids-rich Montney and Duvernay resource producers and are supported by a high liquids weighting and low operating expenses.

At Greater Placid, production averaged 4,205 boe/d (44% liquids) with an Operating Netback of $30.02/boe. The asset is positioned for flexible future development with an inventory of ~150 gross drilling locations and no near-term land retention requirements.

At Greater Kaybob, production averaged 3,321 boe/d (69% liquids) with an Operating Netback of $46.38/boe. Production results have been consistently strong with wells screening as top liquids producers in the basin. Athabasca's latest 12 wells at Kaybob East and Two Creeks have average IP180s of ~725 boe/d (85% liquids) and IP365s of ~550 boe/d (83% liquids). Strong well results coupled with a large well inventory (~700 gross drilling locations) and flexible development timing indicate significant value to Athabasca. The Kaybob area is supported by a strong Joint Development Agreement, established infrastructure and no near-term land retention requirements. The Company remains encouraged by competitor activity and recent new entrants into the play.

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

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”, “forecast”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “target”, “should”, “believe”, “predict”, “pursue”, “potential”, “view” and “contemplate” 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 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 and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. In particular, this News Release contains forward-looking information pertaining to, but not limited to, the following: our strategic plans and Free Cash Flow potential; expected capital programs to maintain production; the Company’s 2021 Outlook, including expected unrestricted cash, EBITDA, funds flow, net debt, production outlook and capital budget; EBITDA sensitivity; future debt levels and composition; timing of Leismer well on stream dates and expected benefits therefrom; our drilling plans in Leismer and L8 project economics; timing for first oil from new well pair at Hangingstone; expectations for WCS heavy oil to be amongst the most valuable global crude benchmarks; target net debt to Adjusted EBITDA; and other matters.

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 and sustaining capital 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 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, 2020 (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 3, 2021 and Management’s Discussion and Analysis dated November 3, 2021, 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; continued impact of the COVID-19 pandemic; ability to finance capital requirements; climate change and carbon pricing risk; regulatory environment and changes in applicable law; gathering and processing facilities, pipeline systems and rail; statutes and regulations regarding the environment; political uncertainty; state of capital markets; anticipated benefits of acquisitions and dispositions; abandonment and reclamation costs; changing demand for oil and natural gas products; royalty regimes; foreign exchange rates and interest rates; reserves; hedging; operational dependence; operating costs; project risks; 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; 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.

Also included in this News Release are estimates of Athabasca's 2021 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 financial outlook 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 financial outlook, 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 News Release 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, 2020. 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. 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.

The 700 Duvernay (Greater Kaybob) 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 Montney drilling (Greater Placid) locations referenced include: 63 proved undeveloped locations and 35 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, 2020 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 Financial Measures and Production Disclosure

The "Adjusted Funds Flow", "Light Oil Operating Income", "Light Oil Operating Netback", "Placid Operating Netback", Kaybob Operating Netback", "Light Oil Capital Expenditures Net of Capital-Carry", "Thermal Oil Operating Income (Loss)", "Thermal Oil Operating Netback", "Consolidated Operating Income", "Consolidated Operating Netback", "Consolidated Operating Income Net of Realized Hedging", "Consolidated Operating Netback Net of Realized Hedging", "Consolidated Capital Expenditures Net of Capital-Carry", "Adjusted EBITDA", "Net Debt" and "Free Cash Flow" 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 measures. 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 "Advisories and Other Guidance" section within the Company's Q3 2021 MD&A includes reconciliations of these measures, where applicable, to the nearest IFRS measures.

Adjusted Funds Flow is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. Adjusted Funds Flow is calculated by adjusting for changes in non-cash working capital, restructuring expenses and settlement of provisions from cash flow from operating activities. The Adjusted Funds Flow measure allows 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 calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding.

The Operating Income (Loss) measures in this News Release are calculated by subtracting the cost of diluent, royalties, operating expenses and cash transportation & marketing expenses from petroleum, natural gas and midstream sales. The Operating Netback measures are calculated by dividing the respective projects Operating Income (Loss) by its respective sales volumes and is presented on a per boe basis. The Operating Income (Loss) and the Operating Netback measures allow management and others to evaluate the production results from the Company's assets.

The Consolidated Operating Income (Loss) Net of Realized Hedging measure in this News Release is calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, royalties, cost of diluent, operating expenses and cash transportation & marketing expenses from petroleum, natural gas and midstream sales. The Consolidated Operating Netback Net of Realized Hedging measure is calculated by dividing Consolidated Operating Income (Loss) Net of Realized Hedging by the total sales volumes and is presented on a per boe basis. The Consolidated Operating Income (Loss) 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 Consolidated Capital Expenditures Net of Capital-Carry and Light Oil Capital Expenditures Net of Capital-Carry measures in this News Release are outlined in the Company's Q3 2021 MD&A. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

Net Debt is defined as face value of term debt plus accounts payable and accrued liabilities plus current portion of provisions and other liabilities less current assets.

Adjusted EBITDA is defined as Net income (loss) and comprehensive income (loss) before financing and interest expense, depreciation, depletion, impairment and taxation (recovery) expense adjusted for unrealized foreign exchange gain (loss), unrealized gain (loss) on risk management contracts, gain (loss) on revaluation of provisions and other, gain (loss) on sale of assets and non-cash stock-based compensation.

The Free Cash Flow measure in this News Release is calculated by subtracting Capital Expenditures Net of Capital-Carry from Adjusted Funds Flow. This measure allows management and others to evaluate Athabasca's ability to generate funds to finance operations and capital expenditures.

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

Term Debt is defined as the face value of the New Notes.

Production volumes details

Production		Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Light Oil:					
Oil(1)	bbl/d	1,984	3,685	2,258	3,208
Condensate NGLs	bbl/d	1,312	2,612	1,430	2,005
Oil and condensate NGLs	bbl/d	3,296	6,297	3,688	5,213
Other NGLs	bbl/d	846	964	862	785
Natural gas(2)	mcf/d	20,304	27,414	21,087	23,129
Total Light Oil division	boe/d	7,526	11,830	8,065	9,853
Total Thermal Oil division bitumen	bbl/d	26,729	20,231	26,374	22,043
Total Company production	boe/d	34,255	32,061	34,439	31,896

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

This News Release also makes reference to Athabasca's forecasted total average daily production of 34,250 boe/d for 2021. Athabasca expects that approximately 78% of that production will be comprised of bitumen, 10% shale gas, 6% tight oil, 4% condensate natural gas liquids and 2% other natural gas liquids.

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

Additionally, this News Release makes reference to Athabasca's well results in Two Creeks and Kaybob East that have seen average productivity of ~725 boe/d IP180s (85% Liquids), which is comprised of ~80% tight oil, ~15% shale gas and ~5% NGLs, and ~550 boe/d (83% Liquids) IP365s, which is comprised of ~78% tight oil, ~17% shale gas and ~5% NGLs.