FOR IMMEDIATE RELEASE
March 2, 2022

Athabasca Oil Announces 2021 Year-end Results, Annual Reserves and Strategic Update

CALGARY – Athabasca Oil Corporation (TSX: ATH) (“Athabasca” or the “Company”) is pleased to report its audited 2021 year-end results and annual reserves, along with a strategic update and corporate outlook. 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 2021 Corporate Highlights

- **Production:** 35,147 boe/d (91% Liquids) in Q4 and 34,618 boe/d (90% Liquids) in 2021. Exceeded original annual guidance of 31-33,000 boe/d and higher than 2020 production of 32,483 boe/d.
- **Capital Expenditures:** $92 million, with largest spend of $82 million in Thermal Oil, including five new well pairs at Leismer that are now in operation and will ramp-up to an expected 5,400 bbl/d in 2022.
- **Earnings:** Net Income of ~$458 million in 2021; Adjusted EBITDA ~$245 million.
- **Cash Flow:** Cash Flow from Operating Activities of ~$194 million in 2021; Adjusted Funds Flow ~$184 million; Free Cash Flow ~$92 million. Significant cash flow expansion is expected in 2022 and beyond as described below.
- **Q4 Netbacks:** Operating netbacks in Q4 of $42.95/boe in Light Oil and $33.43/boe in Thermal Oil. All assets are competitively generating strong cash flow for the Company.
- **Balance Sheet:** ~$300 million of Liquidity at year-end, including ~$223 million cash. Term on debt until Q4 2026. The Company announced a $32 million (US$25 million) term note repayment effective February 1, 2022 as part of its goal to be in a net cash position by the end of 2022.

2021 Reserves

- **2021 Reserves Increase:** 87 MMBoe Proved Developed Producing (PDP) reserves resulting in a ~15% increase over 2020, and 441 MMboe Total Proved (TP) reserves representing a ~10% increase over 2020. Total Proved plus Probable (2P) reserves are 1,301 MMBoe, a ~13% increase over 2020. These increases were attained with a very modest capital program of $92 million in 2021.
- **Long-Life Reserves:** Athabasca has a large resource base with Total Proved reserve life of ~34 years and a Total Proved plus Probable reserve life of ~100 years.
- **Reserve Value (NPV10 before tax):** The Company saw a substantial increase in value year over year due to the increase in technical reserves and a significant commodity price recovery. Athabasca holds $1.5 billion of PDP reserves ($2.83 per share), $2.7 billion of TP reserves ($5.17 per share) and $4.5 billion of 2P reserves ($8.49 per share).

Strategic Update and Corporate Outlook

- **Managing for Free Cash Flow.** For 2022, Athabasca forecasts Adjusted EBITDA of ~$350 million, Adjusted Funds Flow of ~$300 million and Free Cash Flow of ~$180 million (US$85 WTI, US$13.50 Western Canadian Select “WCS” heavy differential). The Company further expects to generate ~$900 million in Free Cash Flow during the three year timeframe of 2022-24 (US$85 WTI, US$12.50 WCS differential flat pricing). Every $5 WTI impacts free cash flow by ~$45 million annually (unhedged).

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, Adjusted EBITDA) and production disclosure.

- **Clear Debt Reduction Targets.** The Company is planning to utilize 100% of near-term free cash flow to reduce its term debt and is anticipating being in a net cash position by year end 2022 at current commodity prices. Athabasca expects to also achieve its target term debt of US$175 million (50% reduction) in H1 2023. The Company recently redeemed US$25 million of debt in the open market with scheduled future debt repayments in May and November.
- **Excellent Exposure to Commodity Upside.** Athabasca has retained excellent exposure to upside in commodity prices with 50% of forecasted 2022 sales volumes unhedged, 20% collars with upside to US$110 WTI and 30% fixed swaps at an implied US$67.50 WTI. The Company has minimal hedging in 2023 and expects lower future hedge levels to protect its capital program as debt targets are achieved.
- **Large Tax Pools:** The Company has ~$3.2 billion of tax pools, including ~$2.4 billion of immediately deductible non-capital losses and exploration pools.
- **Modest Capital Program to Hold Production Flat.** The Company is maintaining its previously announced $128 million capital program in 2022, including a turnaround at Leismer. Corporate production is expected to be maintained at 33-34,000 boe/d. The largest capital allocation of $115 million will be to Thermal Oil, including the drilling of two infill wells and another five well pairs at Leismer following a successful 2021 drilling program. Light Oil allocation is $13 million and includes the completion of three Duvernay wells in Q1.
- **Thermal Oil Differentiation.** The top tier Leismer/Corner project underpins the Company's free cash flow profile and long reserve life. Thermal Oil has strong operational netbacks ($34.97/bbl and $30.15/bbl at Leismer and Hangingstone in Q4 2021) and is forecasted to generate ~$390 million in Operating Income in 2022 (US$85 WTI, US$13.50 WCS heavy differential). At current commodity prices, these assets compete exceptionally well on cash flow metrics against top plays in North America with capital investments generating double-digit recycle ratios. *Volumes are forecasted to grow through 2022 as Leismer Pad L8 ramps-up to its expected plateau rate of 5,400 bbl/d (five well pairs). The existing L8 gathering pipeline will support future development for a total of 14 well pairs on Pad L8. The Company will drill two additional infill wells at Pad L6 and five additional well pairs at Pad L8 in H2 2022.*
- **Pre-payout Royalty Position on Thermal Assets.** Strong margins are supported by a pre-payout Crown royalty structure with Leismer forecasted to remain pre-payout until 2028 and Hangingstone well into the 2030s (US$85 WTI, US$12.50 WCS differential).
- **High Margin Light Oil.** The Company has a flexible development portfolio of ~850 de-risked Montney and Duvernay locations with existing infrastructure in place and minimal near-term land expiries. Athabasca's Light Oil assets generate top tier netbacks ($42.95/boe in Q4 2021) with a long inventory of short cycle-time, high returning investment options. These assets are also a natural hedge for Thermal Oil assets through their production of diluent and natural gas. *In Q1 2022, three Duvernay wells were completed and are expected to be on stream by the end of the quarter. These wells are in the Two Creeks area and the 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).*
- **Carbon Capture and Storage (CCS).** Athabasca has a partnership with Entropy Inc. to develop and implement a carbon capture and storage project at Leismer using Entropy's proprietary CCS technology. The partnership is currently progressing detailed design engineering plans and has developed a commercial model for investment with no expected capital costs for Athabasca. The

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partnership will share emissions credits and help achieve Athabasca's target of reducing carbon emissions by 30% by 2025 (from 2015) and its aspiration of producing a net-zero barrel long term.

- **Annual Environmental Social Governance "ESG" Disclosure.** The Company will release its comprehensive ESG update in the Spring of 2022, following the release of its inaugural 2021 ESG report.
- **Unlocking Shareholder Value.** Transitioning the enterprise value to equity holders is expected to unlock significant shareholder value. Upon achieving its debt target the Company will enhance shareholder returns through the distribution of free cash flow and cash balances, including the consideration of share buybacks and dividends. The Company sees tremendous intrinsic value not reflected in the current share price. Additional guidance on the Company's return of capital strategy will be provided in H2 2022.

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Financial and Operational Highlights

($ Thousands, unless otherwise noted)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
CONSOLIDATED				
Petroleum and natural gas production (boe/d)[1]	35,147	34,233	34,618	32,483
Petroleum, natural gas and midstream sales	$ 292,405	$ 155,109	$ 1,016,323	$ 464,648
Operating Income (Loss)[1]	$ 110,648	$ 40,288	$ 390,353	$ 51,862
Operating Income (Loss) Net of Realized Hedging[1][2]	$ 65,735	$ 30,935	$ 278,664	$ 81,011
Operating Netback ($/boe)[1]	$ 35.43	$ 12.88	$ 31.00	$ 4.31
Operating Netback Net of Realized Hedging ($/boe)[1][2]	$ 21.05	$ 9.89	$ 22.13	$ 6.73
Capital expenditures	$ 18,352	$ 17,202	$ 92,142	$ 111,640
Capital Expenditures Net of Capital-Carry[1]	$ 18,352	$ 17,202	$ 92,142	$ 88,900
Free Cash Flow[1]	$ 24,291	$ (6,449)	$ 91,923	$ (107,627)
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	28,084	24,839	26,805	22,745
Petroleum, natural gas and midstream sales	$ 265,076	$ 132,635	$ 914,058	$ 383,940
Operating Income (Loss)[1]	$ 82,729	$ 20,746	$ 287,261	$ (10,140)
Operating Netback ($/bbl)[1]	$ 33.43	$ 9.17	$ 29.49	$ (1.19
Capital expenditures	$ 12,355	$ 16,915	$ 81,985	$ 49,787
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)[1]	7,063	9,394	7,813	9,738
Percentage Liquids (%)[1]	56%	58%	56%	60%
Petroleum, natural gas and midstream sales	$ 40,237	$ 30,180	$ 147,705	$ 107,600
Operating Income (Loss)[1]	$ 27,919	$ 19,542	$ 103,092	$ 62,002
Operating Netback ($/boe)[1]	$ 42.95	$ 22.61	$ 36.15	$ 17.40
Capital expenditures	$ 5,291	$ 117	$ 6,931	$ 61,651
Capital Expenditures Net of Capital-Carry[1]	$ 5,291	$ 117	$ 6,931	$ 38,911
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 81,189	$ 16,079	$ 194,253	$ (22,910)
per share – basic	$ 0.15	$ 0.03	$ 0.37	$ (0.04)
Adjusted Funds Flow[1]	$ 42,643	$ 10,753	$ 184,065	$ (18,727)
per share – basic	$ 0.08	$ 0.02	$ 0.35	$ (0.04)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ 384,073	$ (56,891)	$ 457,608	$ (657,525)
per share – basic	$ 0.72	$ (0.11)	$ 0.86	$ (1.24)
per share – diluted	$ 0.70	$ (0.11)	$ 0.84	$ (1.24)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding – basic	530,744,156	530,675,391	530,692,724	528,837,646
Weighted average shares outstanding – diluted	551,124,848	533,453,490	546,717,181	528,837,646

(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 $44.9 million and $111.7 million for the three months and year ended December 31, 2021 (three months and year ended December 31, 2020 - $9.4 million loss and $29.1 million gain).

As at ($ Thousands)	Dec. 31, 2021	Dec. 31, 2020
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 223,056	$ 165,201
Restricted cash	$ —	$ 135,624
Available credit facilities[3]	$ 77,844	$ 348
Face value of long-term debt[4]	$ 443,730	$ 572,940

(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, 2021 was US$350 million (December 31, 2020 – US$450 million) translated into Canadian dollars at the December 31, 2021 exchange rate of US$1.00 =C$1.2678 (December 31, 2020 – C$1.2732).

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Operations Update

Thermal Oil

Bitumen production for Q4 2021 and 2021 averaged 28,084 bbl/d and 26,805 bbl/d, respectively. The Thermal Oil division generated Operating Income of $82.7 million and $287.3 million in Q4 2021 and 2021, respectively. Operating Netbacks for Q4 2021 were $33.43/bbl ($34.97/bbl at Leismer and $30.15/bbl at Hangingstone). Capital expenditures for Q4 2021 and 2021 were $12.4 million and $82.0 million, respectively.

The Company's Thermal Oil portfolio is expected to contribute significant cash flow in 2022 with an estimated Operating Income of ~$390 million (US$85 WTI, US$13.50 WCS differential).

Leismer

Bitumen production for Q4 2021 and 2021 averaged 18,794 bbl/d and 17,707 bbl/d, respectively. The asset generated $202.1 million Operating Income in 2021 with a Q4 Operating Netback of $34.97/bbl.

In 2021 the Company completed the drilling of two infill wells at Pad L6, an additional well pair at Pad L7 and five well pairs at Pad L8. At L8, the producer wells encountered the highest quality reservoir across all of Leismer's wells drilled to date. Facility construction was completed in October, steaming commenced last Fall and three wells were converted to full SAGD production in January, with the remaining wells to be placed on production in early Q2. Volumes are forecasted to grow through 2022 as Pad L8 ramps-up to its expected plateau rate of ~5,400 bbl/d (five well pairs). The existing L8 gathering pipeline will support future development for a total of 14 well pairs on Pad L8.

The Company will drill two additional infill wells at Pad L6 and five additional well pairs at Pad L8 in the second half of 2022. These wells will support production through 2023 and have unparalleled Profit to Investment Ratios (NPV/Investment) of ~10x and double-digit recycle rations at current commodity prices. Leismer production is expected to exit 2022 at ~21,000 bbl/d.

The Company has expanded non-condensable gas ("NCG") co-injection across the field on mature pads supporting lower energy intensity with a current project steam oil ratio ("SOR") of ~3.2x (February 2022).

Athabasca and Entropy Inc. are progressing their partnership under a letter of intent. Detailed engineering is underway and a commercial framework has been established that results in no capital commitments from Athabasca and a sharing of emissions credits. The plan is to implement a carbon capture module at the Leismer central processing unit along with evaluating local storage and future carbon trunkline options. It is expected that implementation will be done in stages with the aspiration of producing a net zero barrel longer-term.

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 2028 (US$85 WTI, US$12.50 WCS differential).

Hangingstone

Bitumen production for Q4 2021 and 2021 averaged 9,290 bbl/d and 9,098 bbl/d respectively. The asset generated $85.2 million Operating Income in 2021 with a Q4 Operating Netback of $30.15/bbl.

In early 2022, the Hangingstone asset continues to exceed internal expectations with current production of ~9,500 bbl/d. In March 2021, the Company executed a commercial arrangement with an industry leading marketing company to construct a truck-in terminal at no cost to Athabasca. Trucking operations

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commenced on schedule in July. The additional volumes are forecasted to generate in excess of $5 million in additional annual cash flow through a processing fee while leveraging existing volume commitments under Athabasca's transportation agreements. In May, Athabasca amended the Hangingstone Transportation and Storage Services Agreement that resulted in a $44 million prepayment from restricted cash, a ~$5 million reduction to annual tolls and a reduction in financial assurances by ~$44 million to ~$27 million.

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. The Company recently started up an additional well pair (AA03) and NCG co-injection is aiding in pressure support and reduced energy usage. The project achieved a record low SOR of ~3.7x (February 2022).

In 2022, Hangingstone will have no capital allocation other than routine pump replacements. Strong operational performance, cost enhancements and improved commodity prices are driving competitive margins.

Light Oil

Production averaged 7,063 boe/d (56% Liquids) and 7,813 boe/d (56% Liquids) in Q4 2021 and 2021, respectively. The business division generated Operating Income of $27.9 million ($42.95/boe) and $103.1 million ($36.15/boe) during these periods. Athabasca's Light Oil Netbacks continue to be top quartile 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. Capital expenditures were $5.3 million and $6.9 million in Q4 2021 and 2021, respectively.

The Company's Light Oil portfolio is expected to contribute significant cash flow in 2022 with an estimated Operating Income of ~$95 million (US$85 WTI, US$13.50 WCS differential).

Placid Montney

At Greater Placid, production averaged 3,902 boe/d (44% Liquids) in Q4 2021 with an Operating Netback of $36.13/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 3,161 boe/d (70% Liquids) in Q4 2021 with an Operating Netback of $51.40/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.

Three Duvernay wells in the oil window at Two Creeks were recently completed. The wells are expected to be placed on-stream by the end of Q1. The Kaybob area is supported by a strong Joint Development Agreement, established infrastructure and minimal near-term land retention requirements. The Company remains encouraged by competitor activity and recent new entrants into the play.

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2021 Year-End Reserves

Athabasca's independent reserves evaluator, McDaniel & Associates Consultants Ltd. ("McDaniel"), prepared the year-end reserves evaluation effective December 31, 2021. The Company achieved an increase in total reserves through its modest capital program and a substantial increase in NPV value due to the significant improvement in commodity prices.

The Company's 2P 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 $1.5 billion PDP ($2.83 per share), $2.7 billion TP ($5.17 per share) and $4.5 billion 2P ($8.49 per share).

For additional information regarding Athabasca's reserves and resources estimates, please see "Independent Reserve and Resource Evaluations" in the Company's 2021 Annual Information Form which is available on the Company's website or on SEDAR www.sedar.com.

	Light Oil		Thermal Oil		Corporate	
	2020	2021	2020	2021	2020	2021
Reserves (mmboe)						
Proved Developed Producing	14	**13**	61	**74**	76	**87**
Total Proved	37	**27**	365	**414**	403	**441**
Proved Plus Probable	73	**72**	1,083	**1,230**	1,156	**1,301**
NPV10 BT ($MM)[1]						
Proved Developed Producing	$165	**$191**	$343	**$1,313**	$508	**$1,504**
Total Proved	$234	**$278**	$1,321	**$2,466**	$1,555	**$2,744**
Proved Plus Probable	$414	**$568**	$2,307	**$3,940**	$2,721	**$4,507**

1) Net present value of future net revenue before tax and at a 10% discount rate (NPV 10 before tax) for 2021 is based on an average of McDaniel, Sproule and GLJ pricing as at January 1, 2022.
2) Numbers in the table may not add precisely due to rounding.

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", "continue", "estimate", "expect", "may", "will", "project", "target", "should", "believe", "predict", "pursue", "potential", "view", "forecast" 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. In particular, this News Release contains forward-looking information pertaining to, but not limited to, the following: our strategic plans; the Company's 2022 Outlook; future debt levels and composition; the allocation of future capital; timing of Leismer and Light Oil new well on stream dates and expected benefits therefrom; our drilling plans in Leismer; Leismer ramp-up to expected production rates; type well economic metrics; 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; 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.

Also included in this News Release are estimates of Athabasca's 2022 and 2022-2024 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 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 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 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", "Light Oil Capital Expenditures Net of Capital-Carry", "Thermal Oil Operating Income (Loss)", "Thermal Oil Operating Netback", "Consolidated Operating Income (Loss)", "Consolidated Operating Netback", "Consolidated Operating Income (Loss) Net of Realized Hedging", "Consolidated Operating Netback Net of Realized Hedging", "Consolidated Capital Expenditures Net of Capital-Carry", "Cash Transportation & Marketing Expenses" and "Adjusted EBITDA" 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 and the Leismer and Hangingstone operating results are a supplementary financial measure that when aggregated, combine to the Thermal Oil segment results.

<u>Consolidated Capital Expenditures Net of Capital-Carry and Light Oil Capital Expenditures Net of Capital-Carry</u>

The Consolidated Capital Expenditures Net of Capital-Carry and Light Oil Capital Expenditures Net of Capital-Carry are non-GAAP measures in this News Release and are outlined in the Company's Q4 2021 MD&A. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

($ Thousands)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Capital expenditures	$ 18,352	$ 17,202	$ 92,142	$ 111,640
Less: Recovery of capital-carry proceeds	—	—	—	(22,740)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY	$ 18,352	$ 17,202	$ 92,142	$ 88,900
Total Light Oil capital expenditures	$ 5,291	$ 117	$ 6,931	$ 61,651
Less: Recovery of capital-carry proceeds	—	—	—	(22,740)
TOTAL LIGHT OIL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY	$ 5,291	$ 117	$ 6,931	$ 38,911

<u>Adjusted Funds Flow, Adjusted Funds Flow Per Share and Free Cash Flow</u>

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, 2021	2020	Year ended December 31, 2021	2020
Cash flow from operating activities	$ 81,189	$ 16,079	$ 194,253	$ (22,910)
Restructuring expenses	—	—	—	5,703
Changes in non-cash working capital	(38,794)	(5,614)	(11,872)	(11,670)
Settlement of provisions	248	288	1,684	10,150
ADJUSTED FUNDS FLOW	$ 42,643	$ 10,753	$ 184,065	$ (18,727)
Total Capital Expenditures Net of Capital-Carry[(1)]	(18,352)	(17,202)	(92,142)	(88,900)
FREE CASH FLOW	$ 24,291	$ (6,449)	$ 91,923	$ (107,627)

(1) Non-GAAP financial measure. See table above.

<u>Light Oil Operating Income and Operating Netback</u>

The Light Oil Operating Income is a non-GAAP measure in this News Release 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, unless otherwise noted)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Petroleum and natural gas sales	$ 40,237	$ 30,180	$ 147,705	$ 107,600
Royalties	(3,883)	(1,286)	(10,160)	(3,940)
Operating expenses	(5,917)	(6,856)	(24,395)	(27,883)
Transportation and marketing	(2,518)	(2,496)	(10,058)	(13,775)
LIGHT OIL OPERATING INCOME	$ 27,919	$ 19,542	$ 103,092	$ 62,002

Thermal Oil Operating Income (Loss) and Operating Netback

The Thermal Oil Operating Income (Loss) is a non-GAAP measure in this News Release calculated by subtracting the Thermal Oil segments cost of diluent blending, royalties, operating expenses and cash transportation & marketing expenses from heavy oil (i.e. blended bitumen) 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 (Loss) by its respective bitumen sales volumes. The Thermal Oil Operating Income (Loss) 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 (Loss) is calculated using the Thermal Oil Segments GAAP results, as follows:

($ Thousands, unless otherwise noted)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Heavy oil (blended bitumen) and midstream sales	$ 265,076	$ 132,635	$ 914,058	$ 383,940
Cost of diluent	(105,753)	(57,806)	(360,824)	(212,400)
Total bitumen and midstream sales	159,323	74,829	553,234	171,540
Royalties	(14,089)	(557)	(27,557)	(2,150)
Operating expenses	(42,645)	(32,328)	(156,436)	(109,474)
Cash transportation and marketing[(1)]	(19,860)	(21,198)	(81,980)	(70,056)
THERMAL OIL OPERATING INCOME (LOSS)	$ 82,729	$ 20,746	$ 287,261	$ (10,140)

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

Consolidated Operating Income (Loss) and Consolidated Operating Income (Loss) Net of Realized Hedging and Operating Netbacks

The Consolidated Operating Income (Loss) is a non-GAAP measure in this News Release calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, royalties, the cost of diluent blending, operating expenses and cash transportation & marketing expenses from petroleum and natural gas sales which is the most directly comparable GAAP measure. The Consolidated Operating Netback per boe is a non-GAAP ratio calculated by dividing Consolidated Operating Income (Loss) by the total sales volumes and is presented on a per boe basis. The Consolidated Operating Income (Loss) and the Consolidated Operating Netback 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.

($ Thousands, unless otherwise noted)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Petroleum, natural gas and midstream sales[(1)]	$ 305,313	$ 162,815	$ 1,061,763	$ 491,540
Royalties	(17,972)	(1,843)	(37,717)	(6,090)
Cost of diluent[(1)]	(105,753)	(57,806)	(360,824)	(212,400)
Operating expenses	(48,562)	(39,184)	(180,831)	(137,357)
Cash transportation and marketing[(2)]	(22,378)	(23,694)	(92,038)	(83,831)
Operating Income (Loss)[(3)]	110,648	40,288	390,353	51,862
Realized gain (loss) on commodity risk management contracts	(44,913)	(9,353)	(111,689)	29,149
OPERATING INCOME (LOSS) NET OF REALIZED HEDGING	$ 65,735	$ 30,935	$ 278,664	$ 81,011

(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 $1.5 million for the three months and year ended December 31, 2021.

Cash Transportation & Marketing Expenses

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

Supplementary Financial Measure

The supplementary financial measure Liquidity is defined as cash and cash equivalents plus available credit capacity.

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, Adjusted EBITDA) and production disclosure.

Adjusted EBITDA

The Adjusted EBITDA non-GAAP financial measure is calculated as follows:

($ Thousands)	Year ended December 31, 2021	2020
Net income (loss) and comprehensive income (loss)	$ 457,608	$ (657,525)
Financing and interest	92,816	86,402
Realized foreign exchange gain on repayment of US dollar debt	(32,940)	—
Depletion and depreciation	98,640	113,165
Impairment (reversal) expense	(345,700)	471,839
Unrealized foreign exchange (gain) loss	25,637	(4,454)
Unrealized (gain) loss on commodity risk mgmt. contracts	34,083	(13,329)
Total (gain) loss on revaluation of provisions and other	(68,000)	61,072
(Gain) loss on sale of assets	(20,123)	(21,289)
Non-cash transportation and marketing	1,487	—
Non-cash stock-based compensation	917	3,281
ADJUSTED EBITDA	$ 244,425	$ 39,162

Production volumes details

Production		2021 Q4	2021 Q3	2021 Q2	2021 Q1	2021 Annual	2020 Q4	2020 Q3	2020 Q2	2020 Q1	2020 Annual
Greater Placid:											
Condensate NGLs	bbl/d	1,211	1,311	1,439	1,540	1,374	1,841	2,612	1,916	1,480	1,964
Other NGLs	bbl/d	494	522	570	460	512	523	632	389	351	474
Natural gas(1)	mcf/d	13,182	14,226	15,174	15,598	14,537	17,900	19,668	14,221	12,939	16,197
Total Greater Placid	**boe/d**	**3,902**	**4,204**	**4,538**	**4,600**	**4,309**	**5,347**	**6,522**	**4,675**	**3,988**	**5,138**
Greater Kaybob:											
Oil(2)	bbl/d	1,885	1,984	2,285	2,511	2,164	2,845	3,685	3,226	2,708	3,117
Other NGLs	bbl/d	342	324	384	327	344	264	332	291	359	311
Natural gas(1)	mcf/d	5,603	6,078	6,116	6,083	5,969	5,629	7,746	7,642	7,123	7,032
Total Greater Kaybob	**boe/d**	**3,161**	**3,321**	**3,688**	**3,852**	**3,503**	**4,047**	**5,308**	**4,791**	**4,254**	**4,600**
Light Oil:											
Oil(2)	bbl/d	1,885	1,984	2,285	2,511	2,164	2,845	3,685	3,226	2,708	3,117
Condensate NGLs	bbl/d	1,211	1,311	1,439	1,540	1,374	1,841	2,612	1,916	1,480	1,964
Oil and condensate NGLs	bbl/d	3,096	3,296	3,724	4,051	3,539	4,686	6,297	5,142	4,188	5,081
Other NGLs	bbl/d	836	846	953	787	856	787	964	680	710	785
Natural gas(1)	mcf/d	18,784	20,304	21,290	21,686	20,506	23,529	27,414	21,863	20,062	23,229
Total Light Oil division	**boe/d**	**7,063**	**7,526**	**8,226**	**8,452**	**7,812**	**9,394**	**11,830**	**9,466**	**8,242**	**9,738**
Total Thermal Oil division bitumen	**bbl/d**	**28,084**	**26,729**	**26,433**	**25,949**	**26,805**	**24,839**	**20,231**	**17,601**	**28,315**	**22,745**
Total Company production	**boe/d**	**35,147**	**34,255**	**34,660**	**34,401**	**34,618**	**34,233**	**32,061**	**27,067**	**36,557**	**32,483**

(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 33,000 - 34,000 boe/d for 2022. Athabasca expects that approximately 82% 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.

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.

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. P/I is a measure of a projects net value relative to its capital investment and is calculated by dividing a project's NVP10 value by its Capital. Reserve life is calculated by dividing year-end reserves with management’s forecasted production guidance.

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, Adjusted EBITDA) and production disclosure.