ATHABASCA OIL CORPORATION

FOR IMMEDIATE RELEASE - May 4, 2021

Athabasca Oil Corporation Announces 2021 First Quarter Results, Hangingstone Cost Reductions, Inaugural ESG Report

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to report its 2021 first quarter results that demonstrate the resilience and quality of its asset base. The Company is also pleased to provide an update on initiatives to further improve its positioning in a post COVID recovery. Athabasca plans to refinance its debt in the coming months that will allow shareholders to capture the unparalleled cashflow generation potential from its long reserve life, oil weighted asset base.

Q1 Highlights

- **Production:** ~34,400 boe/d including ~25,950 bbl/d in Thermal Oil and ~8,450 boe/d in Light Oil.
- **Operating Income**: $66 million driven by stronger oil prices and high liquids weighting (89%).
- **Adjusted Funds Flow:** $19 million ($0.04 per share).
- **Capital Expenditures:** $36 million focused on high-value Leismer projects to sustain production.
- **Netbacks:** Industry leading $31.24/boe in Light Oil, and $17.85/bbl in Thermal Oil.

Recent Operational Highlights

- **Leismer:** Drilled one sustaining well pair and two infill wells with first oil expected in July; drilled five producer wells at Pad L8 with steaming to commence in Q4 2021. The L8 pad will ramp up to >5,000 bbl/d in 2022 and has project economics of ~$270 million NPV10 (US$55 WTI flat pricing).
- **Hangingstone:** Production at pre-2020 shut-in levels with April averaging ~9,500 bbl/d. Forecasting $5 million in annual savings through the addition of a truck terminal at no capital cost to the Company and contracted third-party volumes up to 5,000 bbl/d (starting July).
- **Light Oil:** Focused on free cash flow generation; Kaybob East & Two Creeks Duvernay wells screen as top producers with IP180s and IP365s averaging 725 boe/d (85% oil) and ~550 boe/d (83% oil).

Financial Update and 2021 Outlook (US$60 WTI & US$11 WCS heavy differentials)

- **Unrestricted Cash:** $141 million forecasted to grow to ~$210 million by year-end.
- **Cash Flow:** Forecasted Adjusted EBITDA of >$210 million (~$155 million of Adjusted Funds Flow); unhedged annual EBITDA sensitivity of ~$70 million for every US$5/bbl move in oil prices.
- **Net Debt:** $419 million (excl. $135 million of restricted cash), 2x 2021 forecasted Adjusted EBITDA.
- **Increased Production Outlook:** Revised guidance of 32,000 – 34,000 boe/d (~90% liquids).
- **Low Sustaining Capital:** Unchanged $100 million capital budget funded within forecasted funds flow and generating free cash flow of ~$55 million.
- **Reserve Based Lending Facility:** Normal course extension completed to November 30, 2021.
- **Balance Sheet:** Planning to refinance US$450 million Second Lien Notes in the coming months as energy credit markets continue to improve. The refinancing will be supported by strong asset performance, continued execution on cost initiatives, and compelling cash generating outlook.

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

Inaugural ESG Report

- **Inaugural Report:** Proud to publish an Inaugural ESG report following Global Reporting Initiative ("GRI") and Sustainability Accounting Standards Board ("SASB") guidelines. The report is available on the Company's website (https://www.atha.com/responsibility.html) and SEDAR (https://www.sedar.com).
- **Environment:** Achieved a 20% reduction in GHG emissions intensity since 2015 with a goal of a 30% reduction by 2025 by developing high quality resources and the deployment of new technology.
- **Social:** In 2020 best in class safety excellence with a 0.1 Total Recordable Frequency and no reportable spills; partnered with the Mikisew Cree First Nation and the Government of Alberta to create the world's largest contiguous protected boreal forest area (Kitaskino Nuwenëné Wildland Provincial Park).
- **Governance:** Independent Board with established and robust corporate policies.

Business Environment and the Recovery from COVID-19

The COVID-19 pandemic that began in March 2020 had a significant negative impact on global commodity prices due to a reduction in oil demand as countries around the world enacted emergency measures to combat the spread of the virus. The Company took swift action in response to the pandemic and the economic crisis. Major initiatives included a reduction to the 2020 capital program, temporary production curtailments, partnering with service companies to reduce operating costs and reducing future financial commitments on the Keystone XL pipeline ("KXL").

In the second half of 2020, commodity prices began to improve with both OPEC+ and North American producers reducing production allowing for global inventories to fall. Economies have started to reopen with positive developments on the vaccine front and world oil demand has almost recovered to pre-pandemic levels. Supply and demand fundamentals are now supporting a much stronger oil futures market.

In Alberta, physical markets and regional benchmark prices (e.g. WCS heavy oil) have also strengthened with higher WTI prices and tighter differentials as a result of curtailed volumes and falling inventories. Athabasca expects current WCS differentials to remain supported by muted industry growth, significant Q2 turnaround programs in the oil sands, and improving basin egress (including Enbridge Line 3 replacement H2 2021). 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 are emerging for WCS heavy oil to be among the most valuable global crude benchmarks.

Balance Sheet Update & Capital Guidance

Athabasca plans to refinance its US$450 million Senior Secured Second Lien Notes ("2022 Notes") in the coming months as energy credit markets continue to improve. The Company's goals include providing multi-year funding certainty and lowering the overall quantum and cost of debt.

The $100 million unchanged 2021 capital program is fully funded within forecasted Adjusted Funds Flow of ~$155 million (US$60 WTI & US$11 WCS differential) and the Company is expected to generate ~$55

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million of Free Cash Flow through the balance of the year. Capital activity is focused on sustaining production at the Company's cornerstone Leismer asset. The first quarter results support the strong start to the year and the Company is increasing its production guidance to 32,000 – 34,000 boe/d (90% liquids).

Net debt at March 31, 2021 was $419 million and represents 2x 2021 forecasted adjusted EBITDA (>$210 million). Liquidity is expected to grow from $141 million (unrestricted cash) at March 31, 2021 to ~$210 million at year-end (US$60 WTI & US$11 WCS differentials). The Company is committed to allocating free cash flow in order to achieve its long term debt targets of <1.5x Net Debt to EBITDA at US$55 WTI.

In April, the Company's banking syndicate renewed the reserve-based lending facility until November 30, 2021. The credit facility remains unchanged at $37.6 million which reflects current outstanding letters of credit for long term transportation commitments. The banking syndicate has been streamlined to four long-term partners (ATB Financial, RBC Capital Markets, BMO Capital Markets and Goldman Sachs). In the current environment the Company's low risk reserves have the potential to support a first lien credit facility which could provide access to additional liquidity concurrent with the 2022 Notes refinancing. At year-end 2020, McDaniel & Associates assigned reserve value (NPV10 before tax) of $508 million Proved Developed Producing and $1.6 billion Total Proved reserves under conservative price forecasts relative to the current strip commodity prices.

Athabasca's risk management program targets hedging up to 50% of corporate production with an emphasis on securing funds flow to protect a base sustaining capital program. For the balance of 2021 (Q2 – Q4) the Company has hedged ~5,000 bbl/d of WTI swaps at ~US$60, ~11,700 bbl/d of WCS differentials at ~US$12, and ~13,600 bbl/d of WTI sold calls at ~US$55.75. The Company intends to add additional WTI hedging for 2021 with the recent strength in spot prices.

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Financial and Operational Highlights

($ Thousands, unless otherwise noted)	Three months ended March 31, 2021	2020
CONSOLIDATED		
Petroleum and natural gas production (boe/d)	34,401	36,557
Operating Income (Loss)[1]	$ 65,928	$ (20,328)
Operating Income Net of Realized Hedging[1][2]	$ 44,815	$ 1,098
Operating Netback[1] ($/boe)	$ 21.12	$ (5.98)
Operating Netback Net of Realized Hedging[1][2] ($/boe)	$ 14.36	$ 0.33
Capital expenditures	$ 35,554	$ 76,246
Capital Expenditures Net of Capital-Carry[1]	$ 35,554	$ 53,506
LIGHT OIL DIVISION		
Petroleum and natural gas production[1] (boe/d)	8,542	8,242
Percentage Liquids[1] (%)	57%	59%
Operating Income (Loss)[1]	$ 23,760	$ 12,783
Operating Netback[1] ($/boe)	$ 31.24	$ 17.04
Capital expenditures	$ 968	$ 58,527
Capital Expenditures Net of Capital-Carry[1]	$ 968	$ 35,787
THERMAL OIL DIVISION		
Bitumen production (bbl/d)	25,949	28,315
Operating Income (Loss)[1]	$ 42,168	$ (33,111)
Operating Netback[1] ($/bbl)	$ 17.85	$ (12.50)
Capital expenditures	$ 33,014	$ 17,696
CASH FLOW AND FUNDS FLOW		
Cash flow from operating activities	$ 1,138	$ (3,021)
per share – basic	$ -	$ (0.01)
Adjusted Funds Flow[1]	$ 18,961	$ (27,883)
per share – basic	$ 0.04	$ (0.05)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)		
Net income (loss) and comprehensive income (loss)	$ (17,472)	$ (516,481)
per share – basic and diluted	$ (0.03)	$ (0.99)
COMMON SHARES OUTSTANDING		
Weighted average shares outstanding – basic and diluted	530,675,391	523,595,977

As at ($ Thousands)	March 31, 2021	Dec. 31, 2020
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 141,130	$ 165,201
Restricted cash	$ 135,120	$ 135,624
Available credit facilities[3]	$ 98	$ 348
Face value of long-term debt, including current portion[4]	$ 565,875	$ 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 $21.1 million for the three months ended March 31, 2021 (three months ended March 31, 2020 - $21.4 million gain).
(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility (see page 14 of the Company’s Q1 2021 MD&A).
(4) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the March 31, 2021 exchange rate of US$1.00 = C$1.2575 (2020 – C$1.2732).

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Operations Update

Thermal Oil

Bitumen production for Q1 2021 averaged 25,949 bbl/d. The Thermal Oil division generated Operating Income of $42.2 million. The Western Canadian Select heavy oil benchmark averaged C$57.40/bbl for Q1 2021, up 61% from an average price of C$35.58/bbl in 2020. Q1 2021 Operating Netbacks for Leismer and Hangingstone were $20.67/bbl and $12.58/bbl, respectively. Thermal Oil margins have continued to improve year to date with March Operating Netbacks of ~$28/bbl and ~$20/bbl for each asset respectively. Capital expenditures for the quarter were $33.0 million.

Leismer

Bitumen production for Q1 2021 averaged 17,002 bbl/d.

Current activity is focused on sustaining production at Leismer. In Q1 2021 the Company completed the drilling of two infill wells at Pad L6 and an additional well pair at Pad L7 with first production expected in July. Drilling operations are underway on a five well-pair sustaining pad (Pad L8). The five producer wells encountered the highest quality reservoir across all of Leismer's wells drilled to date. The Company anticipates completing the drilling of the five injector wells and facility construction through Q2 and Q3 2021. Initial steam circulation is expected before year-end with first production in early 2022. The initial five well pairs on Pad L8 are expected to ramp-up to in excess of 5,000 bbl/d in 2022. The existing pipeline will support future development for up to 14 well pairs on Pad L8.

The Company is expanding its non-condensable gas co-injection ("NCG") program across the field following successful implementation in 2020 (Pad L1 – L4) which has lowered mature pad SORs by ~16% from 4.2x to 3.5x (2019 vs. Q1 2021). NCG is expected to be operational on Pad L5 and L6 in Q2 2021.

Leismer has an estimated US$27/bbl WCS 2021 operating break-even. The asset is forecasted to generate ~$155 million of Operating Income in 2021 (US$60 WTI & US$11 WCS differentials).

Hangingstone

Bitumen production for Q1 2021 averaged 8,947 bbl/d. The field restart has exceeded expectations with volumes recovering to pre shut-in levels. Current production is ~9,500 bbl/d (April). The standing well pair (AA03) started steaming in April with first oil expected in September. The Company is implementing NCG field-wide in 2021 that will support more efficient steam and pressure management.

During 2020, the Company implemented several cost saving measures reducing non-energy operating costs to a record low of $5.70/bbl in Q1 2021.

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. Operations are expected to commence in July with up to 5,000 bbl/d of third party truck-in capacity. The additional volumes are expected to generate up to $5 million in annual savings through a processing fee and by leveraging existing volume commitments under Athabasca's transportation agreements.

In 2021, Hangingstone will have no capital allocation other than routine pump replacements and has no sustaining capital requirements for the next several years.

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Management's execution to date on streamlining Hangingstone's cost structure has materially improved the assets resiliency and profitability. Hangingstone now has an estimated US$33/bbl WCS operating break-even. The asset is forecasted to generate ~$55 million of Operating Income in 2021 (US$60 WTI & US$11 WCS differentials).

Light Oil

Production averaged 8,452 boe/d (57% Liquids) in Q1 2021. The division generated Operating Income of $23.8 million ($31.24/boe). Athabasca's Light Oil Netbacks continue 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. Capital expenditures were $1.0 million during the quarter.

At Placid, the asset is positioned for flexible future development with an inventory of ~150 gross drilling locations and no near-term land retention requirements. Activity will be revisited following a successful refinancing.

At Kaybob, production results have been consistently strong with wells screening as top liquids producers in the basin. Well results in Two Creeks and Kaybob East have seen average productivity of ~725 boe/d IP180s (85% liquids) and ~550 boe/d IP365s (83% liquids). Under full development, well costs are expected to be less than $7.5 million in the volatile oil window. These 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.

Minimal capital activity ($5 million) is planned for 2021 with operations focused on facility maintenance and readiness for Duvernay completions in 2022. Light Oil is forecasted to generate ~$75 million of Operating Income in 2021 (US$60 WTI).

Annual General Meeting

Athabasca will hold its Annual General Meeting on Wednesday, May 5, 2021 at 9:00am (MDT). Due to restrictions on gatherings implemented by the Government of Alberta in response COVID-19 the Company is hosting a virtual meeting. Shareholders can listen to the Meeting via live webcast at:

https://web.lumiagm.com/456712114

with additional details available at:

https://www.atha.com/investors/presentation-events.html.

An archived recording of the webcast will be available on the Company's website for those unable to listen live.

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
Chief Financial Officer
1-403-817-9104
mtaylor@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; the Company’s 2021 Outlook; including expected unrestricted cash, EBITDA, funds flow, net debt, production outlook, capital budget and operating income for Thermal Oil and Light Oil; EBITDA sensitivity; refinancing of its US$450 million Senior Secured Second Lien Notes and potential support for a first lien credit facility; future debt levels and composition; Trans Mountain and Keystone in-service dates; timing of Leismer well on stream dates and expected benefits therefrom; our drilling plans in Leismer and L8 project economics; timing for NCG to be operational; expected operating cost savings at Hangingstone and timing for first oil from new well pair; expected costs savings resulting from the Hangingstone truck-in terminal; type well economic metrics; expectations for WCS heavy oil to be amongst the most valuable global crude benchmarks; emissions reductions target; target net debt to EBITDA; and other matters.

In addition, information and statements in this News Release relating to "Reserves" are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves 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 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 May 4, 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.

Operating break-even reflects the estimated WCS oil price per barrel required to generate an asset level operating income of Cdn $0. Break-even is used to assess the impact of changes in WCS oil prices on operating income of an asset and could impact future investment decisions. Steam oil ratio, or SOR, measures the average volume of steam required to produce a barrel of oil. Operating break-even and SOR do not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

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. 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, 2020 and based on average pricing of McDaniel, Sproule and GLJ as of January 1, 2021.

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: 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", "Light Oil Capital Expenditures Net of Capital-Carry", "Thermal Oil Operating Income (Loss)", "Thermal Oil Operating Netback", "Consolidated Operating Income", "Consolidated Operating Netback", "Consolidated Capital Expenditures Net of Capital-Carry", "Adjusted EBITDA", 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 Q1 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 royalties, diluent expenses, operating expenses and transportation & marketing expenses from petroleum and natural gas sales and adjusting for the impacts of inventory write-downs in the first quarter of 2020 within the Thermal Oil division. The Operating Netback measures are calculated by dividing the Operating Income (Loss) by the production 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, the cost of diluent blending, operating expenses and transportation & marketing expenses from petroleum and natural gas sales and adjusting for the impacts of inventory write-downs in the first quarter of 2020. 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 Q1 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 settled stock-based compensation.

Free cash flow is defined as Adjusted Funds Flow less Consolidated Capital Expenditures.

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

Production volumes details

Production		2021 Q1	2020 Q4	2020 Q3	2020 Q2	2020 Q1	2020 Annual
Greater Placid:							
Condensate NGLs	bbl/d	1,540	1,841	2,612	1,916	1,480	1,964
Other NGLs	bbl/d	460	523	632	389	351	474
Natural gas(1)	mcf/d	15,599	17,900	19,668	14,221	12,939	16,197
Total Greater Placid	**boe/d**	**4,600**	**5,347**	**6,522**	**4,675**	**3,988**	**5,138**
Greater Kaybob:							
Oil(2)	bbl/d	2,511	2,845	3,685	3,226	2,708	3,117
Other NGLs	bbl/d	327	264	332	291	359	311
Natural gas(1)	mcf/d	6,083	5,629	7,746	7,642	7,123	7,032
Total Greater Kaybob	**boe/d**	**3,852**	**4,047**	**5,308**	**4,791**	**4,254**	**4,600**
Light Oil:							
Oil(2)	bbl/d	2,511	2,845	3,685	3,226	2,708	3,117
Condensate NGLs	bbl/d	1,540	1,841	2,612	1,916	1,480	1,964
Oil and condensate NGLs	bbl/d	4,051	4,686	6,297	5,142	4,188	5,081
Other NGLs	bbl/d	787	787	964	680	710	785
Natural gas(1)	mcf/d	21,682	23,529	27,414	21,863	20,062	23,229
Total Light Oil division	**boe/d**	**8,452**	**9,394**	**11,830**	**9,466**	**8,242**	**9,738**
Total Thermal Oil division bitumen	**bbl/d**	**25,949**	**24,839**	**20,231**	**17,601**	**28,315**	**22,745**
Total Company production	**boe/d**	**34,401**	**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 32,000 - 34,000 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, 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% oil), which is comprised of ~80% tight oil, ~15% shale gas and ~5% NGLs, and ~550 boe/d (83% oil) IP365s, which is comprised of ~78% tight oil, ~17% shale gas and ~5% NGLs.