FOR IMMEDIATE RELEASE
March 4, 2020

Athabasca Oil Corporation Announces 2019 Year-end Results

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to provide its 2019 year-end results and annual reserves.

2019 Corporate Highlights

- **Production:** Annual production of ~36,200 boe/d (87% liquids) which included ~10,100 boe/d (54% liquids) in Light Oil and ~26,100 bbl/d in Thermal Oil.
- **Funds Flow, Capital Expenditures & Free Cash Flow:** Annual Adjusted Funds Flow of ~$155 million ($0.30/share) and ~$140 million of capital expenditures resulting in approximately $15 million of Free Cash Flow.
- **Netbacks:** Maintained top decile annual Light Oil Operating Netback of $25.68/boe; annual Thermal Oil Operating Netback of $19.59/bbl ($23.35/bbl Leismer & $11.50/bbl Hangingstone).
- **Balance Sheet & Sustainability:** Year-end Net Debt of $308 million representing 2.0x Net Debt to Adjusted Funds Flow and 1.4x Adjusted EBITDA

2019 Reserves

- **Reserves:** 1.3 billion boe Proved plus Probable (2P) Reserves, including 1 billion barrels at Leismer/Corner. Proved Developed Producing (PDP) Reserves increased 3 mmboe to 81 mmboe.
- **Value Optimization:** 19% increase in PDP value to $1.1 billion through drilling additions and cost optimization, offsetting lower commodity prices.
- **Net Asset Value:** $1.58/share PDP, $4.92/share Proved and $8.90/share 2P.

2020 Resiliency and Disciplined Operations

- **Balance Sheet:** Strong liquidity of $340 million (cash equivalents & available credit facilities) provides business flexibility during commodity price volatility and market egress constraints.
- **Low Sustaining Capital:** $125 million 2020 capital budget aimed at sustaining production between 36,000 – 37,500 boe/d (88% liquids).
- **Risk Management**. Protection in place to mitigate near term pricing volatility including 18,000 bbl/d of Western Canadian Select hedged for H1 2020 at ~C$49.25 vs. strip at ~C$42.75 (Mar. 2).
- **Strong Business Momentum**: A recent 5-well pad at Leismer is supporting project volumes at ~20,000 bbl/d and the majority of 26 Light Oil wells (11.8 net) are planned to be on stream in H1.

In 2020, Athabasca remains focused on its drive for free cash flow while maintaining its production base with prudent capital expenditures. The Company plans to optimize its capital structure, including reducing debt levels over the next year. Athabasca maintains long term optionality across a deep inventory of high-quality Thermal Oil projects and flexible Light Oil development opportunities. This balanced portfolio provides shareholders with differentiated exposure to liquids weighted production and significant long reserve life assets.

Business Environment

In 2019 and 2020 the Alberta government has continued mandated industry production curtailments at modest levels to manage unprecedented differentials due to a lack of egress. Athabasca is supportive of this government tool to manage extreme pricing dislocations and to provide a bridge to pipeline projects. WCS heavy differentials averaged US$12.76 for 2019 and US$15.83 for Q4 2019. In the first quarter of 2020, differentials increased modestly to settle at US$20.53. The outlook for the balance of 2020 has improved to ~US$15.75 (March 2 strip) driven by seasonality impacts over the summer, pipeline optimization and industry crude by rail ramp-up.

The global heavy oil market continues to see structural supply declines in Venezuela and Mexico, extended OPEC production cuts and growing petrochemical demand. These shifting dynamics are expected to support heavy oil pricing benchmarks with US refineries in PADD II and III requiring a heavier feedstock. Athabasca is well positioned for this changing dynamic with its Thermal Oil assets.

With continued market access constraints, Athabasca has been prudent in securing long term transportation agreements and protecting realized pricing through its hedging program. For the balance of 2020 Athabasca has hedged ~12,500 bbl/d of WTI at ~US$55 and ~14,500 bbl/d of WCS differential at US$18.25 (March – December). 8,000 bbl/d is protected from apportionment through direct sales to refineries. The Company has secured long term capacity on the TC Energy Keystone XL pipeline and the Trans Mountain Expansion Project.

Recent concerns surrounding COVID19 has resulted in markets reacting to potential demand disruptions. Athabasca has protection against low commodity prices through its hedging strategy. The Company is also fortunate to have a minimal capital program that can maintain production at current levels. For 2020, the Company will have completed the majority of its capital program in H1 2020 with no requirement to increase capital for the remainder of the year. Despite strong well results, capital spending is flexible in the Placid Montney and protected through a strong Joint Development Agreement in the Duvernay that ensures minimal spending for the foreseeable future. In Thermal Oil, our production base at Leismer has been sustained through its most recent 5-well pad that is now on production. Hangingstone does not require sustaining capital this year. In addition to these measures, the Company has maintained strong liquidity of $340 million to protect against significant market volatility. Although the Company intends to optimize its capital structure, including reducing debt levels, the end of term on its existing high yield instrument is February 2022. Athabasca has been acutely aware of market volatility and intends on protecting the Company in the short term while ensuring its long term assets retain their upside potential.

The Company has been disappointed with the lack of Regulatory and Fiscal certainty resulting from poor Federal policy in Canada. Although there have been recent positive developments on market egress, this uncertainty has delayed returns that our investors expect. Canada is fortunate to have an abundance of resources and the technical strength for responsible development. With strong political leadership, we can balance Environmental, Social and Governance factors while also maintaining a thriving economy. Our Company is firm in its belief that we develop Energy responsibly to make lives better. The world needs more Canadian Energy, not less.

Financial and Operational Highlights

($ Thousands, unless otherwise noted)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
CONSOLIDATED				
Petroleum and natural gas production (boe/d)	36,403	37,984	36,196	39,203
Operating Income (Loss)[(1)(2)]	$ 42,881	$ (53,180)	$ 233,219	$ 94,118
Operating Netback[(1)(2)] ($/boe)	$ 13.84	$ (14.80)	$ 17.95	$ 6.52
Capital expenditures	$ 69,796	$ 65,399	$ 199,141	$ 276,328
Capital Expenditures Net of Capital-Carry[(1)]	$ 46,259	$ 46,042	$ 140,207	$ 193,980
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)	8,642	12,609	10,138	11,280
Percentage liquids (%)	54%	55%	54%	51%
Operating Income (Loss)[(1)]	$ 16,287	$ 22,121	$ 95,004	$ 107,144
Operating Netback[(1)] ($/boe)	$ 20.49	$ 19.07	$ 25.68	$ 26.02
Capital expenditures	$ 46,473	$ 39,569	$ 109,687	$ 192,495
Capital Expenditures Net of Capital-Carry[(1)]	$ 22,936	$ 20,212	$ 50,753	$ 110,147
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	27,761	25,375	26,058	27,923
Operating Income (Loss)[(1)]	$ 28,658	$ (84,544)	$ 182,196	$ 10,669
Operating Netback[(1)] ($/bbl)	$ 12.44	$ (34.72)	$ 19.59	$ 1.03
Capital expenditures	$ 23,229	$ 25,703	$ 89,343	$ 83,696
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 32,975	$ (2,253)	$ 92,632	$ 83,844
per share – basic	$ 0.06	$ —	$ 0.18	$ 0.16
Adjusted Funds Flow[(1)]	$ 21,478	$ (75,296)	$ 154,760	$ 6,175
per share – basic	$ 0.04	$ (0.15)	$ 0.30	$ 0.01
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ (8,757)	$ (488,479)	$ 246,865	$ (569,657)
per share – basic	$ (0.02)	$ (0.95)	$ 0.47	$ (1.11)
per share – diluted	$ (0.02)	$ (0.95)	$ 0.47	$ (1.11)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding – basic	523,428,276	515,862,850	521,316,320	514,151,731
Weighted average shares outstanding – diluted	523,428,276	515,862,850	526,290,689	514,151,731

As at ($ Thousands)	Dec. 31, 2019	Dec. 31, 2018
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 254,389	$ 73,898
Available credit facilities[(3)]	$ 85,815	$ 126,491
Capital-carry receivable (current and long-term portion - undiscounted)	$ 22,740	$ 81,675
Face value of long-term debt[(4)]	$ 583,425	$ 614,070

(1) Refer to “Reader Advisory” in this News Release and the “Advisories and Other Guidance” section in the MD&A for additional information on Non-GAAP Financial Measures.

(2) Includes realized commodity risk management losses of $2.1 million and $44.0 million for the three months and year ended December 31, 2019, respectively (December 31, 2018 - $9.2 million gain and $(23.7) million loss).

(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility.

(4) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the December 31, 2019 exchange rate of US$1.00 = C$1.2965.

Operations Update

Thermal Oil

Production for 2019 and Q4 2019 averaged 26,058 bbl/d and 27,761 bbl/d, respectively. 2019 production was impacted by government curtailments early in the year and facility maintenance during Q2 2019. The Thermal Oil division generated Operating Income of $182.2 million and $28.7 million in 2019 and Q4 2019, respectively, with Operating Netbacks of $19.59/bbl ($23.35/bbl at Leismer and $11.50/bbl at Hangingstone) and $12.44/bbl ($16.34/bbl at Leismer and $1.46/bbl at Hangingstone) for those respective periods. Capital expenditures for 2019 and Q4 2019 were $89.3 million and $23.2 million, respectively.

Production at Leismer averaged ~20,100 bbl/d in December supported by the five-well pair sustaining pad (Pad L7) that was brought on production in Q4 2019. The pad utilized technology to increase well lengths by 50% to ~1,250 meters per well. L7 project capital totaled $34 million (drilling, completions and facilities) and benefited from Emission Reduction Grants from the Government of Alberta and long-lead pre-investment by the previous operator. The project boasts strong capital efficiencies of ~$7,000/bbl/d with an expected stable production profile for multiple years.

Athabasca has commenced long lead initiatives for Pad L8 and has the flexibility to drill these wells when market conditions improve and the Leismer plant currently has steam capacity available for these wells. A water disposal project will be commissioned in Q2 2020 and is expected to reduce non-energy operating costs by $10 million on an annual basis. Through the addition of Pad L7 and cost structure improvements, Athabasca increased the PDP value of the reserves at Leismer in 2019 by 35% despite a lower price deck and increased transportation costs as a result of the non-core infrastructure sale (based on McDaniel 2019 NPV10 before tax).

At Hangingstone, the Company will complete its first facility turnaround during the second quarter. The facility is expected to be offline for approximately two weeks with production recovery expected over the following few months. Athabasca has accounted for the planned downtime and recovery within its 2020 guidance.

Light Oil

Production averaged 10,138 boe/d (54% liquids) and 8,642 boe/d (54% liquids) for 2019 and Q4 2019, respectively. The business division generated Operating Income of $95.0 million ($25.68/boe) and $16.3 million ($20.49/boe) during these periods. The Company's Light Oil Netbacks are 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 $50.8 million and $22.9 million (net of capital carry) for 2019 and Q4 2019 respectively.

The liquids rich Montney at Greater Placid is positioned for flexible and efficient development. The Company recently completed 2 multi-well pads (10 wells) which are expected to be on stream in Q2 2020. Drilling and completion costs ("D&C") averaged $5.9 million per well on the recent pads. The liquids rich Montney play at Greater Placid has a track record of consistently strong liquids yields, low lifting costs with a ~200 well inventory.

In the Greater Kaybob Duvernay, an active winter campaign includes the drilling of 7 wells, 13 completions and 16 tie-ins weighted to H1 2020. Athabasca's financial exposure remains protected by the capital-carry through the winter program ($22.7 million remaining balance). In the volatile oil window, production results have been consistently strong. D&C costs per well have been reduced to ~C$7.5 million on recent wells (2-well pad) with line of sight to further improvements with multi-well pad development. These results compare favorably to the East Shale Basin Duvernay due to lower capital costs and higher sustained liquids rates.

Recent Kaybob Duvernay Production Rates			
Area	**Pad / UWI**	**Estimated Rate (IP30)[1]**	
		boe/d	% liquids
Kaybob East	100/06-06-065-17W5/00 (2 wells)	900	90%
Kaybob East	100/09-03-065-18W5/00 (2 wells)	750	86%
Kaybob North	100/14-23-065-20W5/00 (single well)[2]	550	89%
Kaybob North	100/09-12-066-20W5/00 (single well)[2]	525	89%

1. IPs rounded to the nearest 25 boe/d with volumes adjusted for shrinkage.
2. Tied into temporary facilities and production is currently constrained

In Q1 2020, a $C1 billion investment at Kaybob (over four winter drilling seasons) will be completed that has seen the vast land position retained and the play commercially de-risked. The Duvernay play is now positioned for compelling future development. Athabasca has entered into an updated five-year plan under the Joint Development Agreement ("JDA") with its joint venture partner. The plan has C$50 – 60 million gross ($15 – 18 million net) annual capital spend levels between 2021-2024. The updated development plan will protect the Company's interests and was designed to be self-funding in the current environment. Future changes to the JDA requires approval from both parties and preserves optionality to increase spending in a more robust macro environment.

Reiterating 2020 Budget and Outlook

Athabasca is reiterating its front-end weighted 2020 capital program with expenditures aimed at sustaining base production.

2020 Guidance	Full Year
CORPORATE	
Production (boe/d)	36,000 – 37,500
% Liquids	~88%
Capital Expenditures ($MM)	$125
LIGHT OIL	
Production (boe/d)	10,000 – 10,500
Capital Expenditures (net of capital-carry) ($MM)	$60
THERMAL OIL	
Production (bbl/d)	26,000 – 27,000
Capital Expenditures ($MM)	$65

2019 Year-End Reserves

Athabasca's independent reserves evaluator, McDaniel & Associates Consultants Ltd. ("McDaniel"), prepared the year-end reserves evaluation effective December 31, 2019.

Proved Plus Probable reserves increased to 1,297 mmboe. This highlights Athabasca's low relative sustaining capital advantage to maintain a significant liquids weighted reserve base.

Proved Developed Producing reserves increased to 81 mmboe, representing 4% growth year-over-year. The Company was able to increase the value of its Proved Developed Producing reserves by 19% to $1.1 billion with cost structure optimization at all assets, high liquids well conversions at Kaybob Duvernay and Leismer Pad L7 reclassification to PDP from Proved Undeveloped, offsetting a lower price deck and the inclusion of Leismer infrastructure tolls (based on McDaniel 2019 NPV10 before tax).

The Company estimates its 2019 Net Asset Value of $1.58/share Proved Developed Producing, $4.92/share Proved and $8.90/share Proved Plus Probable (McDaniel 2019 NPV10 before tax less year-end net debt of $308 million).

	Light Oil		Thermal Oil		Corporate	
	2018	2019	2018	2019	2018	2019
Reserves (mmboe)						
Proved Developed Producing	15	**13**	63	**68**	78	**81**
Total Proved	49	**46**	404	**410**	453	**456**
Proved Plus Probable	74	**72**	1,205	**1,225**	1,279	**1,297**
NPV10 BT ($MM)[1]						
Proved Developed Producing	$205	**$170**	$746	**$963**	$951	**$1,133**
Total Proved	$410	**$375**	$2,203	**$2,507**	$2,613	**$2,882**
Proved Plus Probable	$628	**$604**	$4,279	**$4,364**	$4,907	**$4,968**

1) Net present value of future net revenue before tax and at a 10% discount rate (NPV 10 before tax) for 2019 is based on an average of McDaniel, Sproule and GLJ pricing as at January 1, 2020. NPV 10BT for 2018 is based on an average of McDaniel, Sproule and GLJ pricing as at January 1, 2019.
2) For additional information regarding Athabasca's reserves and resources estimates, please see "Independent Reserve and Resource Evaluations" in the Company's 2019 Annual Information Form which is available on Company's website or on SEDAR www.sedar.com.
3) 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”, “believe”, “view”, ”contemplate”, “target”, “potential” 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 and growth strategies; the Company’s 2020 guidance; future debt levels; 2020 non-energy operating costs; timing and related recovery from the Hangingstone facility turnaround; timing to commission a water disposal project at Leismer and the expected benefits therefrom; timing of Greater Placid Montney on stream dates and expected benefits therefrom; our drilling plans in the Greater Kaybob Duvernay; type well economic metrics; and other matters.

Information relating to "reserves" is also deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves 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 outlook; the regulatory framework in the jurisdictions in which the Company conducts business; the Company’s financial and operational flexibility; the Company’s, capital expenditure outlook, financial sustainability and ability to access sources of funding; geological and engineering estimates in respect of Athabasca’s reserves and resources; and other matters. Certain other assumptions related to the Company’s Reserves are contained in the report of McDaniel evaluating Athabasca’s Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2019 (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 4, 2020 available on SEDAR at www.sedar.com, including, but not limited to: fluctuations in commodity prices, foreign exchange and interest rates; political and general economic, market and business conditions in Alberta, Canada, the United States and globally; changes to royalty regimes, environmental risks and hazards; the potential for management estimates and assumptions to be inaccurate; the dependence on Murphy as the operator of the Company’s Duvernay assets; the capital requirements of Athabasca’s projects and the ability to obtain financing; operational and business interruption risks; failure by counterparties to make payments or perform their operational or other obligations to Athabasca in compliance with the terms of contractual arrangements; aboriginal claims; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; uncertainties inherent in estimating quantities of reserves and resources; litigation risk; environmental risks and hazards; reliance on third party infrastructure; hedging risks; insurance risks; claims made in respect of Athabasca’s operations, properties or assets; risks related to Athabasca’s amended credit facilities and senior secured notes; and risks related to Athabasca’s common shares.

Also included in this press release are estimates of Athabasca's 2020 guidance 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 press 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, 2019. There are numerous uncertainties inherent in estimating quantities of bitumen, crude oil, 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.

Net Asset Value per share 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, 2019 and based on average pricing of McDaniel, Sproule and GLJ as of January 1, 2020, minus our Net Debt and divided by the number of common shares outstanding.

The 200 Montney drilling locations referenced include: 77 proved undeveloped locations and 24 probable undeveloped locations for a total of 101 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, 2019 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, oil and natural gas prices, provincial fiscal and royalty policies, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Non-GAAP Financial 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. 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 Light Oil Operating Income (Loss) measure in this News Release is calculated by subtracting royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Light Oil Operating Netback measure is calculated by dividing the Light Oil Operating Income (Loss) by the Light Oil production and is presented on a per boe basis. The Light Oil Operating Income (Loss) and the Light Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil assets.

The Operating Income (Loss) measure in this News Release with respect to the Leismer Project and Hangingstone Project is calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation & marketing expenses from blended bitumen sales. The Thermal Oil Operating Netback measure is calculated by dividing the respective projects Operating Income (Loss) by its respective bitumen sales volumes and is presented on a per barrel basis. 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 Consolidated Operating Income (Loss) 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. The Consolidated Operating Netback measure is 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.

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 Q4 2019 MD&A. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

The Consolidated Free Cash Flow measure in this News Release is calculated by subtracting the 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 our operations and capital expenditures.

Net Debt is defined as face value of term debt plus current liabilities (adjusted for risk management contracts) less current assets (adjusted for risk management contracts and capital-carry receivable).

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 stock-based compensation.