FOR IMMEDIATE RELEASE
March 6, 2019

Athabasca Oil Corporation Announces 2018 Year-end Results

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to provide its 2018 year-end results and annual reserves.

Athabasca is a liquids-weighted intermediate producer with exposure to Canada's most active resource plays (Montney, Duvernay, Oil Sands). The Company's high quality, long life assets provide investors with unique exposure to free cash flow which, combined with focus on strong margin opportunities, drives shareholder returns. Despite unprecedented pricing volatility in 2018, Athabasca delivered strong operational results and bolstered its financial resiliency. With the improved differential environment, the Company is well positioned for 2019 and beyond.

2018 Corporate Highlights

Consolidated Annual Results

- Production of 39,203 boe/d (86% liquids), representing 11% growth year over year
- Capex of $194 million with a balanced investment profile between Light and Thermal Oil
- Operating income of $118 million (excl. hedging) and funds flow of $6 million; financial results impacted by extreme differentials in Q4 2018

Reserves – Significant Long Term Value

- 2P reserves of 1.3 Billion boe including 1 Billion bbl of top tier reserves at Leismer/Corner
- Net asset value of $1.28/share PDP, $4.50/share Proved and $8.94/share 2P

Financial Resiliency

- $265 million Leismer infrastructure transaction closed on January 15, 2019; funding capacity of $550 million and liquidity of $468 million (cash & available credit facilities) on closing
- Pro forma net debt of $292 million or 1.8x debt to 2019 funds flow (US$60 WTI & US$17.50 diff)
- 25% reduction in forecasted 2019 G&A to ~$22 million ($1.50/boe)

2018 Asset Highlights

Light Oil – High Margin Liquids Rich Growth

- Production of 11,280 boe/d (51% liquids), representing 50% growth year over year
- Operating income of $107 million; netbacks of $26/boe supported by low lifting costs ($8.22/boe)
- Active development with 11 Montney and 26 Duvernay wells placed on-stream

Thermal Oil – Low Decline Production

- Production of 27,923 bbl/d includes ~2,000 bbl/d impact of turnaround and strategic curtailments
- ~$40 million in run-rate annual savings from 2017 levels (non-energy costs optimization and Norlite diluent sourcing)
- Installed a fifth steam generator at Leismer and spud a sustaining pad to be on-stream in H2 2019

The Company offers investors excellent exposure to improving oil prices with low total financial leverage and funds flow sensitivity of approximately $80 million for each incremental US$5/bbl increase in WTI.

Financial and Operational Highlights

($ Thousands, unless otherwise noted)	3 months ended Dec 31 2018	3 months ended Dec 31 2017	Year ended Dec 31 2018	Year ended Dec 31 2017
CONSOLIDATED				
Petroleum and Natural Gas Production (boe/d)	**37,984**	42,064	**39,203**	35,421
Operating Income (Loss)[1,2]	$ **(53,180)**	$ 65,002	$ **94,118**	$ 180,348
Operating Netback[1,2] ($/boe)	$ **(14.80)**	$ 17.25	$ **6.52**	$ 14.06
Capital Expenditures[3]	$ **65,399**	$ 52,418	$ **276,328**	$ 262,048
Capital Expenditures Net of Capital-Carry[1,3]	$ **46,042**	$ 33,236	$ **193,980**	$ 212,601
LIGHT OIL DIVISION				
Oil, Condensate and NGLs Production (bbl/d)	**6,891**	5,856	**5,763**	4,054
Natural Gas Production (mcf/d)	**34,309**	33,905	**33,104**	20,890
Petroleum and Natural Gas Production (boe/d)	**12,609**	11,507	**11,280**	7,535
Operating Income[1]	$ **22,121**	$ 26,696	$ **107,144**	$ 63,697
Operating Netback[1] ($/boe)	$ **19.07**	$ 25.22	$ **26.02**	$ 23.16
Capital Expenditures	$ **39,569**	$ 40,988	$ **192,495**	$ 203,101
Capital Expenditures Net of Capital-Carry[1]	$ **20,212**	$ 21,806	$ **110,147**	$ 153,654
THERMAL OIL DIVISION				
Bitumen Production (bbl/d)	**25,375**	30,557	**27,923**	27,886
Operating Income (Loss)[1]	$ **(84,544)**	$ 45,385	$ **10,669**	$ 117,039
Operating Netback[1] ($/bbl)	$ **(34.72)**	$ 16.75	$ **1.03**	$ 11.62
Capital Expenditures[3]	$ **25,703**	$ 11,368	$ **83,696**	$ 56,744
CASH FLOW AND FUNDS FLOW				
Cash Flow from Operating Activities	$ **(2,253)**	$ 37,060	$ **83,844**	$ 61,697
per share (basic)	$ **-**	$ 0.07	$ **0.16**	$ 0.12
Adjusted Funds Flow[1]	$ **(75,296)**	$ 41,808	$ **6,175**	$ 102,123
per share (basic)	$ **(0.15)**	$ 0.08	$ **0.01**	$ 0.20
NET LOSS AND COMPREHENSIVE LOSS				
Net Loss and Comprehensive Loss	$ **(488,479)**	$ (209,588)	$ **(569,657)**	$ (209,407)
per share (basic and diluted)	$ **(0.95)**	$ (0.41)	$ **(1.11)**	$ (0.42)
COMMON SHARES OUTSTANDING				
Weighted Average Shares Outstanding (basic & diluted)	**515,862,850**	509,901,413	**514,151,731**	500,136,092

As at ($ Thousands)	Dec. 31 2018	Dec. 31 2017
LIQUIDITY AND BALANCE SHEET		
Cash and Cash Equivalents	$ **73,898**	$ 163,321
Restricted Cash	$ **111,056**	$ 113,406
Available Credit Facilities[4]	$ **126,491**	$ 61,899
Capital-Carry Receivable (current & LT portion – undiscounted)	$ **81,675**	$ 164,023
Face Value of Long-term Debt[5]	$ **614,070**	$ 563,310

1) Refer to the "Advisories and Other Guidance" section in the MD&A for additional information on Non-GAAP Financial Measures.
2) Includes realized gain (loss) on commodity risk management contracts of $9.2 million and $(23.7) million for the three months and year ended December 31, 2018, respectively; and $(7.1) million and $(0.4) million for the three months and year ended December 31, 2017, respectively.
3) 2017 capital expenditures excludes the cost of the Leismer Corner Acquisition.
4) Includes available credit under its Credit Facility and Unsecured Letter of Credit Facility.
5) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the December 31, 2018 exchange rate of US$1.00 = C$1.3646.

Business Environment

The Canadian energy industry was negatively impacted by unprecedented macro conditions in Q4 2018. Producers experienced extreme differential and basis spread volatility across both heavy and light product streams due to pipeline capacity constraints. This culminated in Western Canadian Select ("WCS") heavy and Edmonton Light differentials trading to record levels of ~US$55 and ~US$35 respectively in Q4 2018.

In December, the Alberta Government announced mandatory industry production curtailments ("the Industry Curtailments") starting in January 2019 to alleviate the high differential situation until additional egress is added. Athabasca is supportive of these actions and views them as a necessary step to rebalance inventories in the near term and provide a bridge to permanent market access initiatives.

Following the Alberta Government's announcement, the WCS outlook has markedly improved and differentials are expected to be supported by the ramp-up in crude by rail and tightness in the global heavy market.

Athabasca continues to optimize netbacks through financial hedges matched with direct refinery sales. The Company has ~40% of its blended Thermal Oil production hedged with apportionment protection for the balance of 2019 at an average differential of ~US$20.50. The Company has access to 130,000 bbl of storage at Edmonton to manage and optimize product sales. Athabasca has secured long term egress to multiple end markets with 25,000 bbl/d of capacity on TransCanada Keystone XL and 20,000 bbl/d of capacity on the Trans Mountain Expansion Project.

Athabasca has taken a number of steps to enhance liquidity to ensure financial resiliency including the closing of the $265 million Leismer infrastructure transaction on January 15, 2019. On closing the Company had funding capacity of $550 million (cash and cash equivalents, available credit facilities and Duvernay capital carry) and liquidity of $468 million (cash & available credit facilities). Athabasca's existing term debt is in place until 2022 with no maintenance covenants.

Reiterating a Disciplined 2019 Outlook

Athabasca is reiterating its minimal 2019 capital program with expenditures aligned to forecasted funds flow and aimed at maintaining base production. Future capital decisions will be evaluated in the context of financial resiliency, corporate funds flow and external market conditions. The Company has flexibility to direct free cash flow to high returning projects across its portfolio, debt reduction and share buy backs.

2019 Guidance	Full Year
CORPORATE (net)	
Production (boe/d)	37,500 – 40,000
Capital Expenditures ($MM)	$95 - $110
LIGHT OIL (net)	
Production (boe/d)	10,000 – 11,000
Capital Expenditures ($MM)	$15 – $30
THERMAL OIL (net)	
Production[1] (bbl/d)	27,500 – 29,000
Capital Expenditures ($MM)	$80
FUNDS FLOW SENSITIVITY[2] ($MM)	
US$55 WTI / US$17.50 WCS diff	$110
US$60 WTI / US$17.50 WCS diff	$165
US$65 WTI / US$17.50 WCS diff	$220

1) The Government mandated curtailments are estimated to have up to a 2,000 bbl/d impact on productive capacity through Q1 2019 which equates to ~500 bbl/d on an annualized basis. The Company's annual production guidance only incorporates the mandated cuts through Q1 2019.
2) Sensitivity incorporates current hedges, Q1 2019 strip prices and flat pricing assumptions thereafter (US$10 MSW diffs, US$5 C5 diffs, C$1.50 AECO, 0.75 C$/US$ FX).

Operations Update

Light Oil

2018 production averaged 11,280 boe/d (51% liquids), representing 50% growth year over year. Q4 2018 production averaged 12,609 boe/d (55% liquids), representing 10% growth year over year. The business division generated operating income of $107.1 million and $22.1 million for 2018 and Q4 2018 respectively, with netbacks of $26.02/boe and $19.07/boe during these time periods. Athabasca'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 ($8.22/boe and $7.18/boe for 2018 and Q4 2018 respectively). Capital expenditures were $110.1 million and $20.2 million (net of capital carry) for 2018 and Q4 2018 respectively.

Over the past two years Athabasca has transitioned Greater Placid (70% operated working interest) from early stage resource capture to efficient multi-well pad development. The Company has organically grown production to ~7,500 boe/d net (~12,000 boe/d gross) and maintains a regional competitive advantage with ownership and operatorship of significant infrastructure. The Company has high graded ~200 liquids rich Montney locations and is positioned for scalable and flexible development. The completion of a previously drilled multi-well pad (7 wells) has been deferred beyond H1 2019.

Activity in the Greater Kaybob Duvernay (30% non-operated working interest) remains robust with the joint venture partnership planning to execute a 2019 budget of ~C$280 million gross (~C$20 million net of capital carry). Activity is focused on continued resource delineation in the volatile oil window with an initial emphasis on the Two Creeks area. The Duvernay has contributed to strong production and cash flow growth. Q4 2018 Duvernay production was 5,060 boe/d net (59% liquids), up 160% year over year. IP30/90s on the latest four well pad at Kaybob West averaged 980 boe/d (80% liquids) and 825 boe/d (78% liquids) per well respectively. Results from the first appraisal well at Two Creeks are encouraging with liquids IP30/60s averaging 475 bbl/d and 400 bbl/d respectively. Athabasca drilled this shorter horizontal well in 2015 for land retention and a future resource appraisal test.

Thermal Oil

2018 production averaged 27,923 bbl/d. Q4 2018 production averaged 25,375 bbl/d. The Company strategically curtailed production during November and December in response to extreme pricing differentials with an estimated impact of ~1,000 bbl/d on the annual average. The business division generated operating income (loss) of $10.7 million and $(84.5) million in 2018 and Q4 2018, respectively. Financial results were impacted by extreme differentials in Q4 2018 and the Company is well positioned for an improved 2019 outlook. Capital expenditures were $83.7 million and $25.7 million for 2018 and Q4 2018 respectively.

At Leismer, the Company recently completed drilling the L7 sustaining pad which included five SAGD well pairs with four observation wells. The average producer lateral length was 1,250 meters or 50% longer than existing horizontals at Leismer with all well pairs drilled into high quality reservoir. The Company expects initial steaming to commence this summer with production in early Q4 2019. Sustaining operations are expected to support productive capacity of approximately 20,000 bbl/d over the next several years.

With the mandated Industry Curtailments the Company expects Q1 2019 Thermal Oil production to average approximately 27,500 bbl/d. The Company anticipates that the financial impact of its curtailed volumes will be more than offset by an expected improvement in realized WCS prices, resulting in a positive impact on its funds flow for 2019.

2018 Year-End Reserves

Athabasca's independent reserves evaluator, McDaniel & Associates Consultants Ltd. ("McDaniel"), prepared the year-end reserves evaluation effective December 31, 2018.

Proved Plus Probable reserves increased to 1,279 mmboe, representing 3% growth year-over-year. Proved Developed Producing reserves increased to 78 mmboe, representing 7% growth, with a reserve value of $951 million (McDaniel 2018 year-end NPV10 before tax).

The Company estimates its 2018 year end net asset value of $1.28/share Proved Developed Producing, $4.50/share Proved and $8.94/share Proved Plus Probable (McDaniel 2018 year-end NPV10 before tax less pro forma year-end net debt of $292 million).

	Light Oil		Thermal Oil		Corporate	
	2017	2018	2017	2018	2017	2018
Reserves (mmboe)						
Proved Developed Producing	9	**15**	64	**63**	73	**78**
Total Proved	53	**49**	395	**404**	448	**453**
Proved Plus Probable	77	**74**	1,169	**1,205**	1,246	**1,279**
NPV10 BT ($MM)[1]						
Proved Developed Producing	$115	**$205**	$742	**$746**	$857	**$951**
Total Proved	$431	**$410**	$1,692	**$2,203**	$2,123	**$2,613**
Proved Plus Probable	$739	**$628**	$3,003	**$4,279**	$3,742	**$4,907**

1) Net present value of future net revenue before tax and at a 10% discount rate (NPV 10 before tax) for 2018 is based on an average of McDaniel, Sproule and GLJ pricing as at January 1, 2019. NPV 10BT for 2017 is based on McDaniel pricing at January 1, 2018.
2) For additional information regarding Athabasca's reserves and resources estimates, please see "Independent Reserve and Resource Evaluations" in the Company's 2018 Annual Information Form which is available on Company's website or on SEDAR www.sedar.com.

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
Vice President, Capital Markets and Communications
1-403-817-9104
mtaylor@atha.com

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: the Company’s 2019 guidance and five year outlook; type well economic metrics; estimated recovery factors and reserve life index; 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.

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 6, 2019 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 2019 capital expenditures, adjusted funds flow, operating netbacks and operating income levels, which are based on the various assumptions as to production levels, commodity prices and 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

The initial production rates provided in this News Release should be considered to be preliminary. Initial production rates disclosed herein may not necessarily be indicative of long term performance or of ultimate recovery.

Drilling Locations

The 1,000 Duvernay drilling locations referenced include: 50 proved undeveloped or non-producing locations and 35 probable undeveloped locations for a total of 85 booked locations with the balance being unbooked locations. The 200 Montney drilling locations referenced include: 77 proved undeveloped locations and 12 probable undeveloped locations for a total of 89 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, 2018 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

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 (Loss)”, “Consolidated Operating Netback”, and “Consolidated Capital Expenditures Net of Capital-Carry” 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.

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 and Light Oil Operating Netback measures in this News Release are calculated by subtracting royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Light Oil Operating Netback measure is presented on a per boe basis. 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 Operating Income (Loss) and Operating Netback measures in this News Release with respect to the Leismer Project and Hangingstone Project are 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 presented on a per bbl basis of bitumen sales. 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) and Consolidated Operating Netback measures in this News Release are 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 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 2018 MD&A. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.