FOR IMMEDIATE RELEASE
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Athabasca Oil Corporation Announces 2018 First Quarter Results

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to provide its 2018 first quarter results and an operations update.

The quarter marks continued operational success across both business units. Athabasca is uniquely positioned as a low-decline, oil-weighted producer with assets in the best plays in Western Canada (Montney, Duvernay and oil sands). The Company's focus remains on margin growth and financial sustainability.

Recent Operations Highlights and Q1 Results

Light Oil – High Margin Liquids Rich Growth

- Q1 production of 10,495 boe/d (50% liquids), representing 207% growth year over year
- Top decile operating netbacks of $25.75/boe and $24.3 million operating income
- Placid Montney: multi-well pad on stream in March and additional 6 well pad rig released in May
- Kaybob Duvernay: strong well results with the latest five IP30s averaging ~1,000 boe/d (>70% liquids)

Thermal Oil – Low Decline Production

- Q1 production of 30,077 bbl/d, representing 29% growth year over year
- Operating income of ($6.7) million impacted by short term volatility of heavy oil differentials, product basis spreads and seasonality in blend ratios
- Norlite diluent line expected on-stream in Q2 with anticipated annual savings of $20 million at Leismer
- Four infill wells ready for production in Q3 at Leismer

Consolidated – Strength in Execution and Financial Sustainability

- Consolidated production of 40,572 boe/d (87% liquids), representing 52% growth year over year
- Capital spend of $57 million with funding capacity of approximately $330 million
- Operating income of $16.9 million with adjusted funds flow of ($6.4) million or ($0.01) per share

2018 Outlook

Athabasca's 2018 operational outlook is unchanged with a $140 million capital budget and production guidance of 38,500 – 41,000 boe/d (87% liquids). Annual funds flow guidance has been increased to $145 million (from $125 million) on stronger underlying commodity prices which are closely aligned to strip prices (US$65 WTI and US$20 Western Canadian Select "WCS" heavy differential).

Canadian producers were faced with unprecedented volatility in Canadian heavy oil differentials and basis spreads in early 2018 due to pipeline capacity constraints which impacted short term profitability and financial results. WCS differentials peaked in excess of US$30 in Q1 2018, averaging 67% (~US$10) higher than Q1 2017. Since Q1 2018, WCS pricing has improved considerably, with strip prices tightening to approximately US$20 for the balance of the year. The global outlook for crude oil also continues to strengthen, supporting Athabasca's oil-weighted portfolio. Adjusting for this macro volatility the Company estimates that it would have realized an incremental $38 million in Thermal Oil operating income in Q1 2018 assuming a US$5/bbl improvement in WCS differentials and normalized basis spreads.

Athabasca's outlook and financial sustainability are underpinned by high margin Light Oil growth, low break-even costs at Leismer, strong capital discipline, and an active commodity hedging program targeting up to 50% of near term production. Athabasca has secured long term egress to multiple end markets with capacity on the Kinder Morgan Trans Mountain Expansion Project and TransCanada Keystone XL.

Athabasca provides investors excellent exposure to improving oil prices with low total leverage with estimated unhedged funds flow sensitivity of ~$80 million for each incremental US$5/bbl increase in WTI. The Company is a net consumer of gas and is a beneficiary of the current low Alberta gas pricing environment.

Midstream Process

Athabasca is exploring monetization options of its extensive Thermal Oil infrastructure. The Company believes that current timing is favorable following the integration of Leismer and strong market precedent transactions. A process is underway to explore a wide range of alternatives for this infrastructure which could include a sale, partnership or joint venture. The infrastructure will remain a strategic asset for future growth initiatives at Leismer and Corner.

The Company maintains flexibility for use of potential proceeds which could include bolstering liquidity and/or debt reduction, investing in projects across its asset base that will generate attractive returns for shareholders, and initiating a share buyback program.

Athabasca's Strategy

Athabasca is an intermediate producer with strong and competitive investment opportunities across its portfolio in the current operating environment. The Company has tremendous leverage to oil prices and is focused on maximizing profitability through measured activity in Light Oil and ongoing Thermal Oil optimization. The strategy is guided by:

- **Light Oil (Montney and Duvernay):** Defined and Material Margin Growth
- **Thermal Oil:** Low Decline, Long-Life, Free Cash Flow Generating Assets
- **Financial Sustainability:** Increasing Margins, Flexible Capital, Strong Liquidity

The Company's strategy is intended to ensure both its Light Oil and Thermal Oil businesses are financially robust and competitive, with exceptional growth potential. The Company will continue its strategic emphasis on generating strong oil-weighted margins and significant free cash flow to maximize shareholder returns and provide strategic optionality into the future.

Financial and Operational Highlights

($ Thousands, unless otherwise noted)	3 Months ended March 31 2018	2017
CONSOLIDATED		
Petroleum and Natural Gas Volumes (boe/d)	**40,572**	26,737
Operating Income[1,2]	$ **16,876**	$ 19,204
Operating Netback[1,2] ($/boe)	$ **4.65**	$ 7.99
Capital Expenditures[3]	$ **82,261**	$ 90,124
Capital Expenditures Net of Capital-Carry[1,3]	$ **56,661**	$ 79,444
LIGHT OIL DIVISION		
Oil, Condensate and NGLs (bbl/d)	**5,243**	1,961
Gas (mcf/d)	**31,511**	8,760
Petroleum and Natural Gas Volumes (boe/d)	**10,495**	3,421
Operating Income[1]	$ **24,292**	$ 6,863
Operating Netback[1] ($/boe)	$ **25.72**	$ 22.28
Capital Expenditures[3]	$ **66,630**	$ 77,646
Capital Expenditures Net of Capital-Carry[1,3]	$ **41,030**	$ 66,966
THERMAL OIL DIVISION		
Bitumen Production (bbl/d)	**30,077**	23,316
Operating Income / (Loss)[1]	$ **(6,744)**	$ 10,050
Operating Netback[1] ($/bbl)	$ **(2.51)**	$ 4.80
Capital Expenditures[3]	$ **15,631**	$ 10,868
CASH FLOW AND FUNDS FLOW		
Cash Flow from Operating Activities	$ **(3,241)**	$ (52,896)
per share (basic)	$ **(0.01)**	$ (0.11)
Adjusted Funds Flow[1]	$ **(6,360)**	$ (1,649)
per share (basic)	$ **(0.01)**	$ -
NET LOSS AND COMPREHENSIVE LOSS		
Net Loss and Comprehensive Loss	$ **(93,330)**	$ (29,162)
per share (basic and diluted)	$ **(0.18)**	$ (0.06)
COMMON SHARES OUTSTANDING		
Weighted Average Shares Outstanding (basic and diluted)	**510,191,864**	472,157,006

As at ($ Thousands)	March 31, 2018	Dec. 31 2017
LIQUIDITY AND INDEBTEDNESS		
Cash and Cash Equivalents	$ **128,915**	$ 163,321
Restricted Cash	$ **111,778**	$ 113,406
Capital-Carry Receivable (current & LT portion undiscounted)	$ **138,423**	$ 164,023
Face Value of Long-term Debt[4]	$ **580,545**	$ 563,310

1) Refer to "Advisories and Other Guidance" in the MD&A for additional information on Non-GAAP Financial Measures.
2) Includes realized gain (loss) on commodity risk management contracts.
3) Capital expenditures include capitalized G&A.
4) The face value of the US dollar denominated 2022 Notes is US$450 million. As at March 31, 2018, the 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00=C$1.2901.

Operations Update

Light Oil

Q1 2018 production averaged 10,495 boe/d (50% liquids), representing 207% growth year over year. Light Oil operating income was $24.3 million with a netback of $25.72/boe, supported by a high liquids weighting and low operating costs of $8.88/boe. Athabasca's Light Oil business unit has top decile netbacks when compared to Alberta's other liquids-rich resource producers. The Company spent $41 million in Montney and Duvernay programs (net of capital carry) during the quarter.

The Company forecasts 2018 Light Oil operating income of $125 million and free cash flow of $55 million (US$65 WTI and C$1.50 AECO). The $70 million capital program includes $40 million for Placid Montney and $387 million ($30 million net) for Kaybob Duvernay. Second half activity levels in the Montney will be assessed mid-year.

Greater Placid Montney (Athabasca operated, 70% working interest)

Q1 2018 production from Placid averaged 8,213 boe/d (46% liquids). Volumes were impacted temporarily as a result of shut-in production for offsetting completion activities.

In March, the Company placed the 7-30 pad on production (surface location 07-30-60-23W5 Pod 2). Initial production from the pad has been temporarily restricted as facilities are at maximum liquids handing capacity. These restrictions are expected to be resolved in the second half of 2018. Restricted IP30 rates for the pad have averaged 822 boe/d (61% liquids). An additional Montney six well development pad (surface location 12-19-60-23W5 Pod 3) spud in December and was rig released in early May. The Company maintains operational readiness for completions following spring breakup.

Placid Program		IP30[1]		IP90[1]		IP180[1]	
Pad Surface Location	On-stream Date	*boe/d*	*% liquids*	*boe/d*	*% liquids*	*boe/d*	*% liquids*
07-30-60-23W5	December 2016	813	70%	690	67%	657	61%
12-19-60-23W5 (Pod 2)[2]	April 2017	821	51%	670	61%	705	55%
16-30-60-23W5[2]	April 2017	1,053	50%	798	58%	824	52%
03-04-61-23W5	September 2017	1,206	66%	1,067	57%	929	52%
07-33-60-20W5 (Pod 2)	November 2017	1,010	57%	1,023	49%	916	44%
07-30-60-23W5 (Pod 2)[3]	March 2018	822	61%	-	-	-	-

1) IPs reflect sales gas, free condensate and estimated plant based NGL recovery.
2) Peak 30 day rates reported on Pad 12-19 & 16-30 as the initial rates were temporarily restricted by spring road bans and the 16-day Keyera unplanned outage in April 2017.
3) Restricted 30 day rates reported due to facilities being temporarily at maximum liquids handling capacity.

Greater Kaybob Duvernay (Murphy operated, 30% working interest)

A robust drilling program is underway in the Duvernay with two to three rigs expected to remain active for the balance of 2018. Activity levels were accelerated during the quarter with a jointly approved annual budget of C$387 million (~$30 million net). Operations are focused on development drilling at Kaybob West and ongoing volatile oil delineation across the extensive acreage positon. The budget includes releasing 26 wells, completion operations on 29 wells and placing 28 wells on production. The Duvernay is expected to contribute strong production and cash flow growth into year-end.

Duvernay Program			IP30[1]	
Area	UWI or Pad Surface Location	On-stream Date / Status	*boe/d*	*% liquids*
Kaybob West Volatile Oil	100/05-09-065-20W5[2]	November 2017	IP30 468 IP150 450	100%
	4 well pad (06-33-64-20W5)	Rig Released	-	-
	3 well pad (16-18-065-20W5)	Rig Released	-	-
Simonette Volatile Oil	02/10-29-63-24W5	February 2018	745	72%
	02/06-29-63-24W5	February 2018	913	71%
Kaybob East Volatile Oil	14-36-64-19W5	March 2018	1,178	82%
	15-36-64-19W5	March 2018	979	81%
	2 well pad (16-06-65-18W5)	Rig Released	-	-
Saxon Wet Gas	02/14-09-62-23W5[3]	April 2018	IP25 1,525	53%
	00/14-09-62-23W5[3]	April 2018	-	-
	00/03-16-62-23W5[3]	April 2018	-	-
Kaybob West Gas	5 well pad (11-14-62-20W5)	Completions Underway	-	-

1) IPs reflect sales gas, free condensate and estimated plant based NGL recovery.
2) Facility constrained. 5-9 on production through temporary facilities with gas flared and oil trucked.
3) Restricted IP25 reported. 3 well pad currently being tied into permanent production facilities.

Thermal Oil

Q1 2018 production averaged 30,077 bbl/d, representing 29% growth year over year. Growth was driven by the Leismer acquisition effective January 31, 2017 and the continued ramp-up at Hangingstone. Q1 2018 capital expenditures were $15.6 million.

Thermal Oil generated a Q1 operating income of ($6.7) million ($4.9 million operating income for Leismer and ($11.6) million for Hangingstone).

Financial results were adversely impacted by significant volatility in the macro environment and business seasonality.

WCS differentials averaged at US$24.32 during Q1 2018 and peaked in excess of US$30. Product basis spreads which reflect quality differentials and apportionment were also volatile. Athabasca's dilbit sales received a C$6.62 discount to the WCS benchmark, compared to C$3.88 in the Q4 2017. Since Q1, Athabasca has seen marked improvement on both fronts with WCS pricing tightening to approximately US$20/bbl for the balance of the year.

Adjusting for the macro volatility the Company estimates that it would have realized an incremental $38 million in Thermal Oil operating income in Q1 for a US$5/bbl improvement in WCS differentials and normalized basis spreads.

Thermal operations have seasonality with respect to condensate blending. Blend ratios in winter months increase up to approximately 47% and in the summer months decline to approximately 40% (example: 1 barrel of bitumen + 0.40 barrel of condensate). Athabasca will complete the Norlite diluent tie-in at the end of May, which is expected to lower annual fixed costs by approximately $20 million, further enhancing Leismer's low cost operating structure.

With the strength in oil prices and improved differential outlook the Company now forecasts 2018 Thermal Oil operating income of $130 million (up from $100 million) with free cash flow of $60 million (US$65 WTI and US$20 WCS differential).

Leismer

Leismer production averaged 21,021 bbl/d in Q1 2018. Athabasca remains focused on reservoir management to maximize profitability while managing production between 20,000 – 22,000 bbl/d. The Company intends to tie-in four pre-drilled infill wells on Pad L5 in the second half of 2018 to maintain production. A scheduled turnaround commenced in late April and is expected to be completed in May. The Company estimates that the turnaround will impact annual average volumes by approximately 1,000 bbl/d. The Norlite diluent tie-in will be operational at the end of May.

Hangingstone

Hangingstone production averaged 9,056 bbl/d in Q1 2018 with facility maintenance impacting volumes for the quarter. 2018 operations are focused on cost optimization and the start-up of a standing pre-drilled well pair. Hangingstone production is expected to continue to increase with steam chamber growth and minimal capital is forecasted over the next several years.

2018 Guidance

Athabasca's 2018 operations outlook is unchanged with a $140 million capital budget and production guidance of 38,500 – 41,000 boe/d (87% liquids). Annual funds flow guidance has been increased to $145 million (from $125 million) on stronger underlying commodity prices which are aligned to strip prices.

The Company maintains a strong financial position with funding capacity of approximately $330 million, including cash, available credit facilities and the Duvernay capital carry balance.

2018 Guidance	Full Year
CORPORATE (net)	
Production (boe/d)	38,500 – 41,000
Liquids Weighting (%)	~87%
Adjusted Funds Flow ($MM)	$145
Operating Income ($MM)	$255
LIGHT OIL (net)	
Production (boe/d)	10,500 – 11,500
Operating Income ($MM)	$125
Capital Expenditures ($MM)	$70
THERMAL OIL	
Bitumen Production (bbl/d)	28,000 – 29,500
Operating Income ($MM)	$130
Capital Expenditures ($MM)	$70
COMMODITY ASSUMPTIONS	
WTI (US$/bbl)	$65.00
WCS Differential (US$/bbl)	$20.00
AECO Gas (C$/mcf)	$1.50
FX (US$/C$)	0.77

Board Renewal Update

Athabasca is pleased to announce the appointment of Mr. Tom Ebbern as an independent director to the Board. Tom has a diverse background in Canadian energy and capital markets.

Tom is currently the Chief Financial Officer of Northwest Refining, a private Alberta based Company that is a 50% partner with Canadian Natural Resources in the Sturgeon Refinery which is in the process of commissioning. Prior thereto Tom was Managing Director of Energy Investment Banking for Macquarie Capital Markets Canada and previously was a senior partner in Tristone Capital. Tom’s oil and gas experience also includes prior roles in upstream exploration, business development, gas marketing and energy infrastructure development.

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: the Company’s 2018 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 7, 2018 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 2018 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 on May 9, 2018, 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 in this news release include: 64 proved undeveloped or non-producing locations and 35 probable undeveloped locations for a total of 99 undeveloped booked locations with the balance being unbooked locations. The 200 Montney drilling locations referenced include: 84 proved undeveloped 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, 2017 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 and 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”, “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 and operating and transportation 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 and marketing expenses from blended bitumen sales. The Thermal Oil Operating Netback measure is presented on a per bbl 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 and Consolidated Operating Netback measures in this News Release are calculated by subtracting realized gains/losses on commodity risk management contracts, royalties, the cost of diluent blending, operating expenses and transportation and marketing expenses from petroleum and natural gas sales. The Consolidated Operating Netback measure is presented on a per boe basis. The Consolidated Operating Income 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 Q1 2018 MD&A. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.