ATHABASCA OIL CORPORATION

FOR IMMEDIATE RELEASE
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Athabasca Oil Corporation Announces Fourth Quarter and Year End 2017 Results

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

Over the last three years, Athabasca has transitioned from an early-stage exploration company into a sustainable intermediate producer with a strong cash flow outlook. During 2017, the Company successfully integrated a cornerstone Thermal Oil asset, achieved scale in its Light Oil Division and recapitalized its balance sheet. Corporate margins have improved significantly through liquids-rich Montney growth, funded Duvernay development and low-decline Thermal Oil assets that generate free cash flow. Athabasca achieved record production and cash flow in 2017 which has led to an internally funded capital program in 2018 and supports significant future free cash flow generation. The Company is uniquely positioned as a low-decline, oil-weighted producer with assets in the best plays in Western Canada.

Corporate Q4 2017 and Year End Highlights

Record Production

- Q4 volumes of 42,064 boe/d (87% liquids)
- 2017 volumes of 35,421 boe/d (90% liquids), representing ~200% growth year over year

Material Cash Flow Growth

- Q4 adjusted funds flow of $41.8 million ($0.08/share)
- 2017 adj. funds flow of $102.1 million ($0.20/share), an increase of ~$200 million year over year

Corporate Reserves Underpin Significant Value

- 2P reserves increased to 1,246 mmboe, representing ~370% growth year over year
- Light Oil 2P reserves increased by ~85% to 77 mmboe and now exceed pre-joint venture levels
- Net asset value of $1.14/share PDP, $3.62/share Proved and $6.80/share 2P

Financial Sustainability

- Capital – Q4 capital of $33.2 million and 2017 capital of $212.6 million
- Balance sheet – ~$275 million net debt with ~$390 million of funding capacity
- G&A – 2017 G&A reduced to $2.26/boe, a decrease of ~60% year over year

Asset Highlights

Light Oil – High Margin Liquids-Rich Growth

- Q4 volumes of 11,507 boe/d (51% liquids), with 9,556 boe/d from the operated Placid Montney
- Top quartile Q4 netbacks of ~$25.25/boe
- Placid Montney wells continue to beat management's type curve (IP30 1,000 boe/d & 57% liquids)
- Six well Montney pad on-stream in March with an additional six well pad drilled
- Accelerated Duvernay activity with a gross 2018 budget of ~C$387 million (~$30 million net)

Thermal Oil – Low Decline and Free Cash Flow Generation

- Q4 volumes of 30,557 bbl/d with netbacks of $16.75/bbl
- Leismer volumes of 20,991 bbl/d with a $20.60/bbl operating netback in Q4
- Hangingstone volumes of 9,566 bbl/d with a $8.08/bbl operating netback in Q4
- ~$60 million of free cash flow in 2017

2018 Outlook

Athabasca's 2018 budget remains unchanged with $140 million in capital expenditures and corporate production guidance between 38,500 – 41,000 boe/d (87% liquids). The budget will be internally funded with estimated 2018 adjusted funds flow of ~$125 million (US$60 WTI & US$20 WCS differential). The Company maintains a strong balance sheet with funding capacity at year end 2017 of ~$390 million.

The Company's has an active risk management program designed to provide near term balance sheet stability while preserving the Company's upside to improving commodity prices in the medium term. The Company has hedged ~45% of H1/2018 dilbit production at ~C$48.50/bbl WCS with targets to hedge up to 50% of 12 month forward production. Athabasca expects heavy oil differentials to tighten through H2 2018 as industry rail activity increases. The Company has secured long-term egress for its production to tidewater through Trans Mountain (20,000 bbl/d) and to the Gulf Coast through Keystone XL (10,000 bbl/d). The Company is a net consumer of gas and is a beneficiary of the low Alberta pricing environment.

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.

Midstream Process

Consistent with the execution of its existing strategy, 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. The Company owns and operates a 300,000 barrel tank farm at Cheecham and dilbit and diluent pipelines between Leismer and Cheecham.

The Company intends 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 maintaining a healthy balance sheet, opportunities across its asset base that will generate attractive returns for shareholders, and initiating a share buyback program.

Financial and Operational Highlights

($ Thousands, unless otherwise noted)	3 months ended Dec. 31 2017	2016	Year ended Dec. 31 2017	2016
CONSOLIDATED				
Petroleum and Natural Gas Volumes (boe/d)	**42,064**	11,630	**35,421**	11,981
Operating Income[1,2] (Loss)	$ **65,002**	$ 1,433	$ **180,348**	$ (22,012)
Operating Netback[1,2] ($/boe)	$ **17.25**	$ 1.37	$ **14.06**	$ (5.04)
Capital Expenditures[3]	$ **52,418**	$ 66,139	$ **262,048**	$ 128,079
Capital Expenditures Net of Capital-Carry[1,3]	$ **33,236**	$ 66,087	$ **212,601**	$ 122,267
LIGHT OIL DIVISION				
Petroleum and Natural Gas Volumes (boe/d)	**11,507**	3,337	**7,535**	4,597
Operating Income[1]	$ **26,696**	$ 6,152	$ **63,697**	$ 23,784
Operating Netback[1] ($/boe)	$ **25.22**	$ 20.04	$ **23.16**	$ 14.13
Capital Expenditures[3]	$ **40,988**	$ 62,003	$ **203,101**	$ 117,090
Capital Expenditures Net of Capital-Carry[1,3]	$ **21,806**	$ 61,951	$ **153,654**	$ 111,278
THERMAL OIL DIVISION				
Bitumen Production (bbl/d)	**30,557**	8,293	**27,886**	7,384
Operating Income[1] (Loss)	$ **45,385**	$ (4,719)	$ **117,039**	$ (45,796)
Operating Netback[1] ($/bbl)	$ **16.75**	$ (6.41)	$ **11.62**	$ (17.01)
Capital Expenditures[3]	$ **11,368**	$ 4,088	$ **56,744**	$ 10,945
CASH FLOW AND FUNDS FLOW				
Cash Flow from Operating Activities	$ **37,060**	$ (19,656)	$ **61,697**	$ (70,968)
per share (basic)	$ **0.07**	$ (0.05)	$ **0.12**	$ (0.17)
Adjusted Funds Flow[1]	$ **41,808**	$ (16,867)	$ **102,123**	$ (101,502)
per share (basic)	$ **0.08**	$ (0.04)	$ **0.20**	$ (0.25)
NET LOSS AND COMPREHENSIVE LOSS				
Net Loss and Comprehensive Loss	$ **(209,588)**	$ (779,405)	$ **(209,407)**	$ (936,734)
per share (basic and diluted)	$ **(0.41)**	$ (1.92)	$ **(0.42)**	$ (2.31)
COMMON SHARES OUTSTANDING				
Weighted Average Shares Outstanding (basic and diluted)	**509,901,413**	406,406,458	**500,136,092**	405,621,706

As at ($ Thousands)	Dec. 31 2017	Dec. 31 2016
LIQUIDITY AND INDEBTEDNESS		
Cash and Cash Equivalents	$ **163,321**	$ 650,301
Restricted Cash	$ **113,406**	$ 107,012
Capital-Carry Receivable (current & LT portion undiscounted)	$ **164,023**	$ 213,469
Face Value of Long-term Debt (current & LT portion)[4]	$ **563,310**	$ 550,000

1) Refer to "Advisories and Other Guidance" in the MD&A for additional information on Non-GAAP Financial Measures.
2) Includes realized loss on commodity risk management contracts.
3) Capital expenditures include capitalized G&A.
4) The face value of the US dollar denominated 2022 Notes as at December 31, 2017 is US$450 million. The 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00=C$1.2518.

Operations Update

Light Oil

2017 production averaged 7,535 boe/d, representing 64% growth year over year, and achieved the high-end of annual guidance of 6,500 – 7,500 boe/d. High netback liquids weighted growth was driven by active Montney and Duvernay programs.

The Company achieved record Q4 2017 production of 11,507 boe/d (51% liquids), representing 46% growth over Q3 2017 and 245% growth year over year. Q4 2017 operating income was $26.7 million ($25.22/boe netback) and net capital expenditures totaled $21.8 million. Operating expenses fell to ~$7.50/boe in Q4 2017, down ~50% year over year, supported by production growth and ongoing field optimization. The Company is positioned with top quartile netbacks amongst Alberta liquids-rich resource producers.

During 2017, Athabasca grew its 2P Light Oil reserves to 77 mmboe (69% proved), representing 83% growth year over year. Successful drilling results in both the Montney and Duvernay over the past two years has resulted in record reserve bookings in Light Oil which now exceed pre-Murphy joint venture levels.

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

In November, Athabasca tied-in the final pad from last winter's five multi-well pad program (surface location 07-33-60-23W5). Restricted IP30s from the 7-33 pad averaged 1,010 boe/d (57% liquids) per well supporting the previously increased management type curve (IP30s 1,000 boe/d 57% liquids & 675 mboe EUR).

Athabasca spud a six well infill development pad in August (surface location 07-30-60-23W5 Pod 2). The pad was recently completed and is expected to be tied into facilities in March.

An additional six well development pad (surface location 12-19-60-23W5 Pod 3) was spud in late December and is expected to be rig released in April. Drilling performance remains competitive with other top industry players with spud to total depth averaging ~15 days for a total measured depth of ~5,800m. The Company maintains operational readiness for completions operations on the six well 12-19 pad 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%	-	-
07-33-60-20W5 (Pod 2)	**November 2017**	**1,010**	**57%**	**1,023**	**49%**	-	-
07-30-60-23W5 (Pod 2)	March 2018	-	-	-	-	-	-

1) IPs reflect sales gas, free condensate and estimated plant based NGL recovery.
2) Peak 30 day rates reported on Pad 2 & 3 as the initial rates in April were temporarily restricted by spring road bans and the 16-day Keyera unplanned outage.

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. Operations are transitioning to development at Kaybob West with continued delineation drilling at Saxon, Simonette, Kaybob North and Kaybob East.

2018 activity levels have been accelerated with a jointly approved budget of C$387 million (~$30 million net). Operations will now include rig releasing 26 wells, completion operations on 29 wells and placing 28 wells on production.

At Kaybob West, drilling and completion (D&C) performance continues to improve with the latest two well pad averaging C$11.6 million per well. Additional completion efficiencies are expected on the next four well pad (surface location 06-33-64-20W5) with D&C costs budgeted at C$10 million per well.

At Kaybob North, the Company remains encouraged by production results from a significant step-out in the volatile oil window. 100/05-09-065-20W5 had a facility constrained IP90 of ~516 boe/d (86% liquids) with a relatively flat production profile over this period. An extension of the field gathering system is underway with up to three additional wells planned off the pad in 2018.

At Simonette, a two well pad at surface location 15-16-063-24W5 was recently placed on production with IP23s averaging ~970 boe/d per well (73% liquids).

Kaybob Duvernay Recent Wells	**Area**	**Timing**	**IPs[1]**	
Pad Surface Location & UWI			*boe/d*	*% liquids*
1 well pad (16-18-065-20W5)				
100/05-09-065-20W5	Kaybob West Volatile Oil	On-stream Nov	516	86
2 well pad (15-16-063-24W5)				
02/10-29-63-24W5 02/06-29-63-24W5	Simonette Volatile Oil	On-stream Feb	970	73
2 well pad (12-29-064-18W5)				
14-36-64-19W5 15-36-64-19W5	Kaybob East Volatile Oil	On-stream March	-	-
3 well pad (16-03-062-23W5)	Saxon Wet Gas	On-stream April	-	-
5 well pad (11-14-62-20W5)	Kaybob South Gas Condensate	Drilling ongoing	-	-
4 well pad (06-33-64-20W5)	Kaybob West Volatile Oil	Drilling ongoing	-	-
2 well pad (16-06-65-18W5)	Kaybob East Volatile Oil	Drilling ongoing	-	-

1) IPs reflect sales gas, free condensate and estimated plant based NGL recovery. IP90s for 16-18 and IP23s for 15-16.

The Company remains encouraged by strong offsetting industry well results and robust activity levels. The Duvernay competes with other top North American shale plays and boasts high free liquids (200 – 1,000 bbl/mmcf), premium value condensate production and a low 5% royalty over the first three years (compared to average Permian rates of ~25%). The joint venture positions Athabasca shareholders with a funded Duvernay development profile and long-term upside with a 30% working interest in over 200,000 prospective Duvernay acres and an inventory of approximately 1,000 drilling locations (management estimate, extended reach horizontals).

Thermal Oil

2017 production averaged 27,886 bbl/d, representing 278% growth year over year. Growth was driven by the Leismer acquisition effective January 31, 2017 and the continued ramp-up at Hangingstone. During Q4 2017, the Company achieved record quarterly production of 30,557 bbl/d.

2017 capital expenditures totaled $56.7 million, a ~50% reduction from the original $105 million guidance. 2017 operating income was $117.0 million ($11.62/bbl) with free cash flow of $60.3 million.

Q4 2017 operating income was $45.4 million ($16.75/bbl) with free cash flow of $34.0 million. Non-energy operating expenses fell to $9.34/bbl in Q4 2017, down ~50% year over year. The Company saw significant netback expansion through 2017 driven by production, optimized costs and stronger realized pricing.

During 2017, Athabasca grew its Thermal Oil 2P reserves to 1,169 mmbbl (35% Proved), representing 427% growth year over year. Reserve additions are primarily attributed to the acquisition of the Leismer and Corner assets.

Leismer

Leismer production averaged 20,991 bbl/d in Q4 2017. Athabasca remains focused on reservoir management to maximize profitability while managing production between 20,000 – 22,000 bbl/d. The facility will undergo a five year scheduled turnaround in May. The Company intends to tie-in four pre-drilled infill wells on Pad L5 in H2 2018.

Near term initiatives have been aimed at lowering break-evens and low risk capital efficient projects. During 2017, the Company installed flow control devices (FCD) in three well pairs. FCDs are a proven technology that improves steam chamber conformance across the wellbore resulting in increased production and reduced SOR. Recent FCDs at Leismer have each yielded greater than a 250 bbl/d production uplift with an estimated four to five month payout.

As of Q4 2017, Athabasca has implemented NCG co-injection (non-condensable gas) on three additional well pairs on Pad 4. NCG co-injection provides pressure maintenance in the reservoir, reduces the SOR, and allows steam to be redistributed to newer pads to increase production.

Non-energy operating expenses fell to $8.11/bbl in Q4 2017, down ~20% from Q1 2017. The Company estimates an additional ~$20MM in annualized savings commencing in H2 2018 related to Norlite diluent sourcing and revised transportation contracts.

Athabasca estimates a current recovery factor of 35% on existing wells with recoveries expected to reach approximately 65% long-term, in line with comparable industry projects. The asset's reserve life index is 40 years proven and 85 years proved plus probable.

Hangingstone

Hangingstone averaged 9,566 bbl/d in Q4 2017 with $6.7 million of operating income ($8.08/bbl netback). Non-energy operating expenses fell to $12.12/bbl in Q4 2017, down 33% year over year contributing to positive operating income. 2018 operations remain focused on further 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.

2017 Corporate Reserves Update

Athabasca's independent qualified reserves evaluators, McDaniel & Associates Consultants Ltd. ("McDaniel"), prepared year-end reserve evaluations effective December 31, 2017.

Corporately, Athabasca has increased its 2P reserves to 1,246 mmboe, representing 372% growth year over year. The Company estimates its 2017 year end net asset value of $1.14/share Proved Developed Producing, $3.62/share Proved and $6.80/share 2P (McDaniel's January 2018 price forecast, NPV10 before tax less year-end net debt).

Light Oil 2P reserves have increased to 77 mmboe (70% proved), representing 83% growth year over year.

Thermal Oil 2P reserves have increased to 1,169 mmbbl (35% proved), representing 427% growth year over year.

	Light Oil		Thermal Oil		Corporate	
	2016	2017	2016	2017	2016	**2017**
Reserves (mmboe)						
PDP	4	**9**	48	**64**	52	**73**
Proved	20	**53**	92	**395**	112	**448**
2P	42	**77**	222	**1,169**	264	**1,246**
NPV10 BT ($MM)[1]						
PDP	$49	**$115**	$431	**$742**	$480	**$857**
Proved	$176	**$431**	$538	**$1,692**	$714	**$2,123**
2P	$467	**$739**	$801	**$3,003**	$1,268	**$3,742**

1) Net present value of future net revenue before tax and at a 10% discount rate (NPV 10 BT) for 2017 is based on McDaniel pricing as at January 1, 2018 (which is available on its website at http://www.mcdan.com/priceforecast). NPV 10BT for 2016 is based on GLJ pricing at January 1, 2017.
2) For additional information regarding Athabasca's reserves and resources estimates, please see "Independent Reserve and Resource Evaluations" in the Company's 2017 Annual Information Form which is available on SEDAR at www.sedar.com.

2018 Capital Budget & Guidance Summary

2018 Guidance	Full Year
CORPORATE (net)	
Production (boe/d)	38,500 – 41,000
Liquids Weighting (%)	~87%
Adjusted Funds Flow ($MM)	~$125
LIGHT OIL (net)	
Production (boe/d)	10,500 – 11,500
Operating Income ($MM)	~$120
Capital Expenditures ($MM)	$70
THERMAL OIL	
Bitumen Production (bbl/d)	28,000 – 29,500
Operating Income ($MM)	~$100
Capital Expenditures ($MM)	$70
COMMODITY ASSUMPTIONS	
WTI (US$/bbl)	$60.00
WCS Differential (US$/bbl)	$20.00
AECO Gas (C$/mcf)	$1.50
FX (US$/C$)	0.77

Midstream Process

Athabasca has completed a comprehensive review of its competitive positioning, asset portfolio and strategy with the assistance of a global investment bank. Following this review the Company has decided to explore monetization options of its extensive Thermal Oil infrastructure. The Company believes that current timing is favorable following the successful integration of the Statoil asset acquisition and strong market precedent transactions.

The Company owns and operates a 300,000 barrel tank farm at Cheecham and 75km dilbit and diluent pipelines between Leismer and Cheecham. The infrastructure is located to the southwest of Fort McMurray and within industry's main corridor for oil sands market access. The tank farm is dually connected to Enbridge's Cheecham Terminal providing access to the Waupisoo Dilbit Pipeline and the Norlite Diluent pipeline as well as Keyera's South Cheecham Rail and Truck Terminal. The Cheecham terminal is the 6th largest storage hub in Alberta and accounts for ~25% of constructed storage capacity in the province outside of Edmonton and Hardisty.

The Company intends to explore a wide range of alternatives for these infrastructure assets which could include a sale, partnership or joint venture structure. The infrastructure will remain a strategic asset for potential future growth initiatives at Leismer and Corner. The Company maintains flexibility for use of potential proceeds which could include reducing corporate leverage maintaining a healthy balance sheet (e.g. bolster liquidity and/or debt reduction), growth initiatives opportunities across its asset base that will generate attractive returns for shareholders, and initiating a share buyback program.

Athabasca has retained RBC Capital Markets as financial advisor for the midstream process.

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 in respect of the Leismer assets; 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 March 7, 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”, “Consolidated Capital Expenditures Net of Capital-Carry” and “Net Debt” 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 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 calculated as highlighted in the tables on pages 7 and 9 in the Company's Year-end MD&A. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

The Net Debt measure is calculated by summing the face value of outstanding term debt with current liabilities and subtracting current assets. The Net Debt measure is not intended to represent other measures of financial position on the Company's balance sheet that are calculated in accordance with IFRS. The Net Debt financial measure allows management and others to evaluate the Company's funding position and utilization of debt within its capital structure.