FOR IMMEDIATE RELEASE
March 9, 2017

Athabasca Oil Corporation Announces 2016 Year-end Results and Reserves

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to provide its 2016 year-end financial and operating results.

2016 was a transformational year for Athabasca which established itself as an intermediate oil weighted producer with a funded five-year growth outlook and exposure to several of the largest resource plays in Western Canada including the Montney, Duvernay and oil sands.

2016 AND RECENT HIGHLIGHTS

- **2016 operational results**
  - Production of 11,981 boe/d (81% liquids), in line with guidance of 11,800 boe/d.
  - Capital expenditures of $122 million, with $111 million directed towards Light Oil growth.
- **Established a new core Montney growth area at Placid (70% working interest)**
  - Following a successful appraisal program, Athabasca commenced a winter drilling program with 10 wells rig released by year end 2016 and 20 gross wells expected to be drilled by April 2017.
  - Commenced construction of a new oil battery in Q3 2016 that will be connected to Athabasca operated regional infrastructure and is expected to be commissioned in April 2017.
- **$486 million light oil joint venture driving funded growth in the Duvernay (30% working interest)**
  - Athabasca completed a $486 million joint venture with Murphy Oil in May 2016 which secures $1 billion of gross investment in the Duvernay over the next four years while minimizing Athabasca's near term capital exposure ($75 million net).
- **Acquired top tier thermal assets from Statoil for $578 million (5.8x P/CF & $24,000/bbl/d)**
  - In December 2016, Athabasca announced the acquisition of Statoil's Thermal oil assets for $431 million cash, 100 million common shares and at prices above US$65/bbl WTI annual contingent value payments ending in 2020. The acquisition immediately drives a larger cash flow base and accelerates the Company's transition to sustainable free cash flow generation which is expected in 2018 at strip prices.
- **Strong reserve additions resulting in 210% Proved plus Probable per share growth**
  - Athabasca has increased its Proved plus Probable reserves to 1,120 mmboe through the acquisition of the Leismer and Corner properties and a successful light oil drilling program.
- **Monetized long dated thermal oil resources for $397 million**
  - Athabasca raised $397 million through a series of royalty transactions with Burgess Energy. The royalties are structured with a sliding scale and ensure the assets are not encumbered at lower prices with the first 2% royalty triggered at approximately US$75/bbl WTI. There are no commitments for future development.

- **Solidified the balance sheet and long-term funding position**
  - In early 2017, Athabasca completed a comprehensive refinancing transaction which included the issuance of US$450 million senior secured second lien notes due in 2022 and the establishment of a new $120 million reserve based credit facility.
  - Athabasca is well positioned with net debt of approximately $335 million and approximately $365 million of cash. The Company has multi-year funding certainty and a strong liquidity outlook that will allow the Company to continue to advance its strategic objectives.
  - The Company has hedged 12,000 bbl/d at C$52.70/bbl WCS and intends to hedge a minimum of 20,000 bbl/d for the balance of 2017.

GO-FORWARD STRATEGY

Athabasca has a fully funded five-year development outlook capable of delivering a 30% production per share CAGR over the next five years, guided by go-forward strategy that includes:

- **Light Oil: Defined and Material Growth**
  - A scalable operated Montney position and funded Duvernay development through the joint venture with Murphy Oil.
  - Light Oil is expected to grow to over 25,000 boe/d in the next five years at current strip pricing.
- **Thermal Oil: Free Cash Flow with Leverage to Oil prices**
  - A large low decline asset base accelerates free cash flow generation with future low risk expansion options.
  - The Company intends to hold its thermal production base flat and expects to generate approximately $250 million of free cash over a five year period at current strip pricing.
- **Financial Sustainability**
  - Maturing cash flow profile with strong sustainability metrics. A diverse asset base provides flexibility in future capital allocation decisions with a low overall corporate production decline of approximately 7.5% annually.
  - Under current strip pricing, net debt to cash flow is expected to be approximately 2.5x at year-end 2018 and trending lower in subsequent years.

2017 GUIDANCE (unchanged)

- **Corporate production of 36,000 – 40,000 boe/d (~90% liquids)**
  - Near term production growth will be driven by activity in the Montney and Duvernay with stable Thermal Oil production.
- **Capital program of $240 million**
  - The capital program includes $135 million directed towards H1 2017 Light Oil growth. The Company retains flexibility in future capital allocation decisions to react to operational results and market conditions.
- **Funds flow of $93 million at current strip pricing with free cash flow generation in 2018**
  - The Company anticipates sustainable free cash flow generation in 2018 at strip pricing.

FINANCIAL AND OPERATING HIGHLIGHTS

($ Thousands, except per share and boe amounts)	Three months ended December 31, 2016	2015	Year-ended December 31, 2016	2015
CONSOLIDATED PRODUCTION				
Petroleum and natural gas volumes (boe/d)	**11,630**	11,581	**11,981**	7,560
LIGHT OIL DIVISION				
Petroleum and natural gas sales volumes (boe/d)	**3,337**	5,873	**4,597**	5,587
Light Oil operating income[1]	$ **6,152**	$ 10,551	$ **23,784**	$ 33,928
Light Oil operating netback[1] ($/boe)	$ **20.04**	$ 19.50	$ **14.13**	$ 16.63
Capital expenditures	$ **62,003**	$ 50,921	$ **117,090**	$ 175,977
Recovery of capital-carry through capital expenditures	$ **(52)**	$ —	$ **(5,812)**	$ —
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	**8,293**	5,708	**7,384**	1,973
Bitumen sales volumes (bbl/d)	**8,015**	4,096	**7,358**	1,526
Thermal Oil operating income (loss)[1,2]	$ **(4,719)**	$ (18,166)	$ **(45,796)**	$ (30,200)
Thermal Oil operating netback[1,2]	$ **(6.41)**	$ (48.22)	$ **(17.01)**	$ (55.74)
Capital expenditures	$ **4,088**	$ 2,257	$ **10,945**	$ 114,150
CASH FLOWS AND FUNDS FLOW				
Cash flow from operating activities	$ **(19,656)**	$ (54,496)	$ **(70,968)**	$ (67,826)
Cash flow from operating activities per share (basic & diluted)	$ **(0.05)**	$ (0.13)	$ **(0.17)**	$ (0.17)
Funds flow from operations[1]	$ **(16,867)**	$ (32,986)	$ **(101,502)**	$ (47,003)
Funds flow from operations per share[1] (basic & diluted)	$ **(0.04)**	$ (0.08)	$ **(0.25)**	$ (0.12)
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss	$ **(779,405)**	$ (604,375)	$ **(936,734)**	$ (696,771)
Net loss and comprehensive loss per share (basic & diluted)	$ **(1.92)**	$ (1.50)	$ **(2.31)**	$ (1.73)
SHARES OUTSTANDING				
Weighted average shares outstanding (basic & diluted)	**406,406,458**	404,046,046	**405,621,706**	403,214,050
FINANCING AND DIVESTITURES				
Net proceeds from sale of assets	$ **178,450**	$ 301	$ **702,736**	$ 451,788
Issuance (repayment) of long-term debt	$ **-**	$ (769)	$ **(285,441)**	$ (2,921)
Derivative proceeds upon repayment of long-term debt	$ **-**	$ -	$ **40,956**	$ —

As at ($ Thousands)	December 31, 2016	December 31, 2015
BALANCE SHEET ITEMS		
Cash and cash equivalents	$ 650,301	$ 559,487
Promissory Note(s)	$ —	$ 133,892
Restricted Cash	$ 107,012	$ 3,044
Capital-carry receivable (current & long term portion – discounted)	$ 191,174	$ —
Total assets	$ 2,257,887	$ 3,462,442
Long-term debt (current & LT portion)[3]	$ 546,209	$ 841,273
Shareholders' equity	$ 1,557,097	$ 2,482,140

1) Refer to "Advisories and Other Guidance" in the MD&A for additional information on Non-GAAP Financial Measures.
2) Negative Operating Netbacks are customary during ramp-up of a SAGD project as revenues from lower initial production are more than offset by operating and transportation costs which are largely fixed in nature regardless of production volumes.
3) As at December 31, 2016, the face value of the Company's long-term debt was $550.0 million (December 31, 2015 - $856.8 million).

Operations Update and 2017 Guidance

Light Oil

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

At Placid, Athabasca currently has two rigs active in the field completing its winter drilling program. A total of 20 wells are expected to be rig released before breakup and drilling operations are underway on the final two pads. The infrastructure and battery buildout remains on track to be in-service early in the second quarter and is designed to handle near-term production growth.

The 7-30-60-23W5 ("7-30") pad was drilled and completed last fall. Average well costs were $7.3 million and completion operations were designed to test ball-drop versus plug and perf design. The wells were placed on production in December with average restricted IP30s of approximately 800 boe/d per well (278 bbl/mmcf free condensate). Regional volumes will remain restricted by facility capacity until the new Placid battery comes into service this spring.

The Company recently completed frac operations on the 12-19-60-23 and 16-30-60-23 pads. The Company utilized plug and perf completion design with 1,000 lbs/ft (1.6T/m) average proppant intensity. Drill and completion costs averaged $7.0 million ($3.2 million drilling & $3.8 million completion) with average lateral lengths of approximately 2,500 meters per well. The eight wells have been inline tested and are expected to be placed on production in early Q2 2017.

The Company is drilling its final two pads for the winter program at surface locations 3-4-61-23W5 (4 wells) and 7-33-60-23W5 (4 wells). The pads are expected to be rig released near the end of the first quarter with completions operations to commence in the summer.

Decisions regarding second half activity levels will be finalized in the summer and the Company retains flexibility to adapt the program to results and external market conditions.

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

Murphy and Athabasca have finalized 2017 capital plans which are consistent with the development plan contained in the joint development agreement. Core objectives of the program include near-term production and cash flow growth, delineation across all phase windows, optimizing well design and maximizing land retention.

The 2017 program will include the spudding of 16 gross wells. The wells include a mix of pad development locations and delineation wells throughout the volatile oil window. Murphy intends to optimize well design with average lateral lengths increasing to approximately 2,800 meters and frac intensity up to approximately 2,000 lbs/ft (~3T/m). The program will target total lateral meters drilled of approximately 45,000 meters and this compares to Athabasca's initial 20 well appraisal campaign of approximately 27,000 meters since 2012.

The Company's partner, Murphy, currently has two rigs active in the field. The first two-well pad spud in November of 2016 at Kaybob West (surface location 1-18-64-20W5). The pad was rig released in January with average drill times of 22 days (spud to rig release) and an average lateral length of ~1,400 meters. The wells have been completed with a high proppant intensity design and are expected to be placed on production before break-up.

A two well pad at surface location 4-32-64-20W5 (2,650 meter average lateral length) was recently rig released and drilling operations are underway on a three well pad at 11-18-64-20W5 (2,700 meter average lateral length). Completions operations on both pads are expected to commence this summer.

Light Oil Guidance

Athabasca's 2017 Light Oil capital budget is $135 million ($120 million for Placid Montney and $15 million net for Duvernay) with production guidance of 6,500 – 7,500 boe/d and an exit target in excess of 10,000 boe/d. H2 2017 Montney capital will be assessed mid-year.

Thermal Oil

Leismer

Athabasca assumed operatorship of Leismer following closing of the acquisition on January 31, 2017. Production in February averaged 22,600 bbl/d (field estimates) and the Company intends to maintain a stable production base between 22,000 – 24,000 bbl/d for the foreseeable future. Operations will be focused on production optimization and drilling additional sustaining and infill wells. The Company has a well-defined development plan for the mid-term which includes the start-up of four predrilled infills on Pad L5, infill opportunities on Pads L3 and L4 and regulatory approval and operational readiness to expand Pad L2.

Hangingstone

Hangingstone averaged 8,800 bbl/d in February (field estimates). The Company is anticipating facility maintenance in April which was previously incorporated in guidance. The project is expected to reach name plate capacity of approximately 12,000 bbl/d in 2018 with minimal maintenance capital expected within the first five years of operations.

Egress Update

Athabasca recently secured 20,000 bbl/d of blended bitumen capacity on the Kinder Morgan Trans Mountain pipeline expansion project. The expansion project is federally approved and is expected to be in-service in late 2019. The Company believes securing term take-away capacity to multiple end markets is essential to its long-term strategy. The Trans Mountain pipeline will provide Athabasca exposure to global oil demand growth.

Thermal Oil Guidance

Athabasca's 2017 Thermal Oil budget is approximately $105 million with production guidance of 29,000 – 32,500 bbl/d, reflecting the Leismer acquisition effective February 1, 2017. The capital program consists of $84 million at Leismer, $15 million at Hangingstone and an additional $6 million for maintaining Athabasca's long dated thermal leases.

2017 Budget & Guidance Details

	Full Year
CORPORATE (net)	
Production[1] (boe/d)	36,000 – 40,000
Liquids Weighting (%)	~90%
Funds Flow from Operations ($MM)	~$93
THERMAL OIL	
Bitumen Production[1] (bbl/d)	29,000 – 32,500
Operating Income ($MM)	~$104
Capital Expenditures ($MM)	$105
LIGHT OIL	
Production (boe/d)	6,500 – 7,500
Operating Income ($MM)	~$79
Capital Expenditures ($MM)	$135
COMMODITY ASSUMPTIONS *(strip pricing as at February 6)*	
WTI (US$/bbl)	$54.55
Edmonton Par (C$/bbl)	$67.41
Western Canadian Select (C$/bbl)	$51.97
AECO Gas (C$/mcf)	$2.66
FX (US$/C$)	0.763

Notes:
1) Production guidance reflects a January 31, 2017 closing date for the Statoil acquisition with Leismer volumes to be reported from February – December.

Balance Sheet and Risk Management Update

Subsequent to year-end, Athabasca completed a comprehensive balance sheet refinancing transaction. This included the issuance of US$450 million of second lien notes due 2022, the establishment of a $120 million reserve based credit facility and the repayment of its existing $550 million second lien notes which is expected to be completed by March 27, 2017.

Athabasca is positioned with multi-year funding certainty and a strong liquidity outlook that will allow the Company to continue to advance its strategic objectives and maintain business flexibility. The Company anticipates sustainable free cash flow generation in 2018 under current strip pricing with net debt to cash flow of approximately 2.5x at year-end 2018 and trending lower in subsequent years. Current net debt is estimated at approximately $335 million with $365 million of cash.

The Company has commenced a risk management program designed to protect a base level of cash flow and support its capital plans. The Company intends to hedge a minimum of 20,000 bbl/d for the balance of 2017 with 12,000 bbl/d of WCS hedges already in place at an average price of C$52.70/bbl. Going forward, a multi-year hedging program is expected to form a part of the Company's risk management strategy.

2016 Reserves and Contingent Resource Update (Pro Forma Statoil Acquisition)

Athabasca's independent qualified reserves evaluators, GLJ Petroleum Consultants and DeGolyer and MacNaughton Canada Limited, prepared year-end reserve evaluations effective December 31, 2016 for the Company's existing properties and the recently acquired Leismer and Corner properties.

Corporately, Athabasca has increased its Proved plus Probable reserves by approximately 210% per share year over year to 1,120 mmboe through the acquisition of the Leismer and Corner properties, and a successful light oil drilling program at Greater Kaybob and Greater Placid.

The Company has significant exposure to long dated resource in its Thermal Oil division with 6.5 billion barrels of best estimate contingent resource unrisked (4.0 billion barrels risked).

	Light Oil[2]		Thermal Oil				Corporate[4]	
	2015	**2016**	2015	2016	Statoil	**2016 Pro Forma**	2015	**2016 Pro Forma**
Reserves (mmboe)[1]								
PDP	6	**4**	51	48	30	**78**	57	**82**
Proved	27	**20**	95	92	290	**382**	122	**402**
2P	65	**42**	225	222	855	**1,077**	290	**1,120**
per basic share							0.72	**2.21**
NPV10 BT ($MM)[3]								
PDP	$63	**$49**	$551	$431	$413	**$844**	$614	**$892**
Proved	$157	**$176**	$763	$538	$1,540	**$2,078**	$920	**$2,255**
2P	$533	**$467**	$1,334	$801	$2,714	**$3,515**	$1,867	**$3,982**

1) 2016 year-end pro forma reserves reported on a gross basis. Proved Developed Producing "PDP", Total Proved "Proved", Proved plus Probable "2P".

2) 2016 Light Oil reserves reflect the disposition of a 70% and 30% working interest in the Greater Kaybob and Greater Placid areas respectively in conjunction with the Murphy Oil joint venture which closed in May 2016.

3) Net present value of future net revenue before tax and at a 10% discount rate (NPV 10 BT) for 2016 is based on GLJ pricing as at January 1, 2017 (which is available on its website at www.gljpc.com). NPV 10BT for 2015 is based on GLJ pricing at January 1, 2016.

4) For additional information regarding Athabasca's reserves and resources estimates, please see "Independent Reserve and Resource Evaluations" in the Company's most recent Annual Information Form dated March 9, 2017 that is available on SEDAR at 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.

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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”, “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 five-year growth outlook and that such growth outlook is fully funded; estimates of, and timing of, sustainable free cash flow generation, net debt to cash flow levels and cash and cash equivalents and liquidity, for certain future periods; the Company’s 2017 production guidance corporately and for its Light Oil and Thermal Oil projects; the expected contingent value payments pursuant to the Statoil transaction; the impact of, and the benefits expected to be realized from, the Statoil transaction; and future performance and characteristics of the Leismer and Corner assets including their quality and resilience to lower commodity prices; the Company’s expectation that the Statoil transaction will accelerate its free cash flow generation; the Company’s expectation that it will be able to maintain stable production from the Leismer assets for the foreseeable future; the Company’s expectation that its Thermal Oil assets provide future low risk expansion options; the timing for achievement of name plate capacity at Hangingstone and expectations regarding maintenance capital within the first five years of operations; the timing of facilities construction and commissioning and in-service dates and the capacity thereof; the number of wells expected to be drilled and timing of drilling, rig-releasing and completing such wells; the timing of when such wells will be placed on production; the total number of lateral meters expected to be drilled in 2017; expectations with respect to future production hedging levels; estimates of 2017 corporate, Thermal Oil and Light Oil production levels and decline rates; estimates of 2017 funds flow from operations, operating income and capital expenditures; the capability of the Company's five-year development outlook to deliver potential growth in per share production; the estimated impact of the Burgess royalties on the economics of future expansion phases and development projects; the Company’s forecasted price of oil before such royalties are payable; future drilling and completion plans including numbers of wells and the timing thereof; the benefits expected to be realized by the Company from its issuance of the $US450 million senior secured second lien notes and establishment of the $120 million credit facility; 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 prices for petroleum and natural gas; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct its business and the effects that such regulatory framework will have on the Company, including on the Company’s financial condition and results of operations; the Company’s financial and operational flexibility; the Company’s financial sustainability, the Company’s ability to accelerate development when prices recover; Athabasca’s cash-flow break-even commodity price; geological and engineering estimates in respect of Athabasca’s reserves and resources; the applicability of technologies for the recovery and production of the Company’s reserves and resources; the Company’s ability to demonstrate the quality of its asset base and to build large-scale projects; future capital expenditures to be made by the Company; future sources of funding for the Company’s capital programs; the Company’s future debt levels; the Company’s ability to obtain equipment in a timely and cost-efficient manner; the geography of the areas in which the Company is conducting exploration and development activities; that Athabasca and its security holders will obtain the anticipated benefits from the $US450 senior secured second lien note and the $120 million credit facility and the Company’s ability to obtain equipment in a timely and cost-efficient manner.

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 9, 2017 that is or will be available on SEDAR at www.sedar.com, including, but not limited to: fluctuations in market prices for crude oil, natural gas and bitumen blend; political and general economic, market and business conditions in Alberta, Canada, the United States and globally; changes to royalty regimes, environmental risks and hazards; alternatives to and changing demand for petroleum products; the potential for management estimates and assumptions to be inaccurate; dependence on Murphy as the Company’s joint venture participant in the Company’s Duvernay and Montney assets; the dependence on Murphy as the operator of the Company’s Duvernay assets; the substantial capital requirements of Athabasca’s projects and the ability to obtain financing for Athabasca’s capital requirements; operational and business interruption risks associated with the Company’s facilities; failure by counterparties to make payments or perform their operational or other obligations to Athabasca in compliance with the terms of contractual arrangements between Athabasca and such counterparties, and the possible consequences thereof; long term reliance on third parties; aboriginal claims; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; failure to meet development schedules and potential cost overruns; variations in foreign exchange and interest rates; factors affecting potential profitability; risks related to future acquisition and joint venture activities; reliance on, competition for, loss of, and failure to attract key personnel; uncertainties inherent in estimating quantities of reserves and resources; changes to Athabasca’s status given the current stage of development; litigation risk; risks and uncertainties inherent in SAGD and other bitumen recovery processes; risks related to hydraulic fracturing, including those related to induced seismicity; expiration of leases and permits; risks inherent in Athabasca’s operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources; risks related to gathering and processing facilities and pipeline systems; availability of drilling and related equipment and limitations on access to Athabasca’s assets; increases in costs could make Athabasca’s projects uneconomic; the effect of diluent and natural gas supply constraints and increases in the costs thereof; environmental risks and hazards; failure to accurately estimate abandonment and reclamation costs; reliance on third party infrastructure; seasonality; hedging risks; risks associated with maintaining systems of internal controls; insurance risks; claims made in respect of Athabasca’s operations, properties or assets; competition for, among other things, capital, export pipeline capacity and skilled personnel; the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits; 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 2017 capital expenditures, funds flow from operations 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 9, 2017, and is included to provide readers with an understanding of the funding of Athabasca's capital expenditure program in 2017 and an outlook for the Company's activities and results and readers are cautioned that the information may not be appropriate for other purposes. 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.

Reserves Data

For important additional information regarding Athabasca's reserves and resources estimates and the evaluations that were conducted by GLJ and D&M, please see "Independent Reserve and Resource Evaluations" in the Company's AIF that is or will be available on SEDAR at www.sedar.com.

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.

Non-GAAP Financial Measures

The "Funds Flow from Operations", "Light Oil Operating Income", "Thermal Oil Operating Income" and "Net Debt" financial measures contained in this News Release do not have standardized meanings which are prescribed by International Financial Reporting Standards ("IFRS") and they are considered to be non-GAAP measures. Investors should be cautioned that these measures should not be construed as an alternative to net income or other measures of financial performance as determined in accordance with IFRS. 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.

Funds Flow from Operations is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Funds Flow from Operations 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.

The Light Oil Operating Income measure in this News Release is calculated by subtracting royalties and operating and transportation expenses from petroleum and natural gas sales and midstream revenues received. The Light Oil Operating Income measure allows management and others to evaluate the production results from the Company's Light Oil assets.

The Thermal Oil Operating Income measure in this News Release is calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation expenses from blended bitumen sales received. The Thermal Oil Operating Income measure allows management and others to evaluate the production results from the Company's Thermal Oil assets.

The Net Debt measure in this News Release is calculated by subtracting the face value of the Company's long term debt less cash and equivalents. 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.