FOR IMMEDIATE RELEASE
March 10, 2016

Athabasca Oil Corporation Reports 2015 Year-end Results and Reserves

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or "the Company") is pleased to provide its fourth quarter and 2015 year-end financial and operating results in conjunction with its year-end reserves and resource information. Athabasca achieved several significant strategic and operational milestones in both its Light Oil and Thermal Oil divisions despite exceptionally challenging external market conditions.

- **Corporate Production –** 2015 production averaged 7,560 boe/d with fourth quarter averaging 11,581 boe/d. Fourth quarter volumes increased 60% over the third quarter reflecting a material ramp-up of production at Hangingstone and strong performance from four additional Duvernay wells tied-in during the quarter. December volumes averaged 15,200 boe/d exceeding the Company's upwardly revised guidance of 12,000 – 15,000 boe/d.
- **Capital and Cost Structure –** 2015 development capital totaled $225 million, approximately 25% lower than the original budget of $305 million despite increased scope in both the Duvernay and Montney. Corporate G&A has been reduced by greater than 50% with 2016 expensed G&A currently estimated at $30 million. Athabasca has significantly improved competitiveness and resiliency in the prevailing low commodity price environment.
- **Light Oil Joint Venture –** In January, Athabasca entered into a $475 million light oil joint venture with Murphy Oil Company Ltd. ("Murphy") in the Kaybob Area ("Murphy Transaction"). Murphy will pay approximately $250 million in cash to Athabasca at closing with an additional $225 million capital carry of 75% of the Company's share of expenditures in the Duvernay. The Company is progressing towards closing in Q2 2016.
- **Balance Sheet Strength –** On closing of the Murphy Transaction, Athabasca will have approximately $900 million of liquidity and a net cash position of approximately $80 million. The Company is now even better positioned to withstand a prolonged low pricing environment, meet its 2016 refinancing objectives and to accelerate development when prices recover. Athabasca expects to reduce its debt position by $300 – $400 million in 2016.
- **Montney –** At Placid, Athabasca recently completed a three well pad in Section 19-60-23W5 for an average drilling and completion cost ("D&C") of $6.9 million per well (D&C). The Placid inter-connect project connecting Placid to Athabasca's extensive Kaybob infrastructure is on track for commissioning in April. The Placid area has approximately 25,000 gross acres with prospective Montney in two separate intervals.
- **Duvernay –** The Company has significantly progressed its strategic objectives which include lowering well costs and delineation of the volatile oil window. Recent D&C costs have averaged less than $10 million per well with a step-change in drilling times and pad completion efficiencies. A two well pad was brought on-stream in Q1 2016. The proppant loading test at Kaybob East has

yielded encouraging preliminary results with restricted IP30s of 758 boe/d (86% liquids) for 02/16-6-65-18W (~2,000 lbs/ft proppant loading) and 541 boe/d (88% liquids) for 00/16-6-65-18W5 (~1,100 lbs/ft). The higher proppant completion resulted in a 40% improvement in its IP30 rate. The company has exposure to approximately 200,000 gross acres of prospective Duvernay land for future development.

- **Hangingstone –** The Company commissioned its first SAGD project in 2015. Bitumen production volumes are currently approximately 8,000 bbl/d. The Company remains on track to achieve 12,000 bbl/d design capacity in Q4 2016.
- **Year-end Reserves –** Light Oil proved plus probable ("2P") reserves increased by 31% on a per share basis to 65 MMboe with a 21% reduction in future development capital. With the start-up of Hangingstone, 42% or 95 MMbbl of project reserves are now classified as proved. Corporate 2P reserves stand at 290 MMboe (89% liquids, 58% proven).

FINANCIAL AND OPERATING HIGHLIGHTS

($ Thousands, except per share and boe amounts)	Three months ended December 31, 2015	Three months ended December 31, 2014	Year-ended December 31, 2015	Year-ended December 31, 2014
CONSOLIDATED PRODUCTION				
Petroleum and natural gas volumes (boe/d)[1]	**11,581**	6,035	**7,560**	6,120
LIGHT OIL DIVISION				
Petroleum and natural gas sales volumes (boe/d)	**5,873**	6,035	**5,587**	6,120
Light Oil operating income[2]	$ **10,551**	$ 12,431	$ **33,928**	$ 78,734
Light Oil operating netback[2] ($/boe)	$ **19.50**	$ 22.38	$ **16.63**	$ 35.24
Capital expenditures	$ **50,921**	$ 87,870	$ **175,977**	$ 199,938
THERMAL OIL DIVISION				
Bitumen production (bbl/d) (including capitalized volumes) [1]	**5,708**	—	**1,973**	—
Bitumen sales volumes (bbl/d)	**4,096**	—	**1,526**	—
Thermal Oil operating income (loss)[2, 3]	$ **(18,166)**	$ —	$ **(30,200)**	$ —
Thermal Oil operating netback[2, 3]	$ **(48.22)**	$ —	$ **(55.74)**	$ —
Capital expenditures	$ **2,257**	$ 78,876	$ **114,150**	$ 416,967
CASH FLOWS AND FUNDS FLOW				
Cash flow from operating activities	$ **(54,496)**	$ (8,883)	$ **(67,826)**	$ 18,177
Cash flow from operating activities per share (basic & diluted)	$ **(0.13)**	$ (0.02)	$ **(0.17)**	$ 0.05
Funds flow from operations[2]	$ **(30,141)**	$ (2,520)	$ **(47,003)**	$ 23,782
Funds flow from operations per share (basic & diluted)	$ **(0.07)**	$ (0.01)	$ **(0.12)**	$ 0.06
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss[4]	$ **(604,375)**	$ (129,507)	$ **(696,771)**	$ (227,558)
Net loss and comprehensive loss per share (basic & diluted)	$ **(1.50)**	$ (0.32)	$ **(1.73)**	$ (0.57)
SHARES OUTSTANDING				
Weighted average shares outstanding (basic & diluted)	**404,046,046**	402,031,471	**403,214,050**	401,512,412
FINANCING AND DIVESTITURES				
Net proceeds from sale of Dover Investment	$ —	$ —	$ **450,000**	$ 601,304
Net proceeds from sale of oil and gas assets	**301**	3,302	**1,788**	59,974
Net proceeds (repayment of) from long-term debt	**(769)**	(651)	**(2,921)**	235,394
	$ **(468)**	$ 2,651	$ **448,867**	$ 896,672

As at ($ Thousands)	December 31, 2015	December 31, 2014
BALANCE SHEET ITEMS		
Cash and cash equivalents	$ 559,487	$ 531,475
Short-term investments	$ —	$ 47,618
Promissory Notes – short-term portion	$ 133,892	$ 450,000
Promissory Notes – long-term portion	$ —	$ 133,892
Long-term debt	$ 838,205	$ 786,649
Net Debt[2]	$ 154,711	$ (123,625)
Shareholders' equity	$ 2,482,140	$ 3,164,186

1) For the year ended December 31, 2015, Thermal Oil bitumen production and sales volumes on a bbl/d basis represent all Hangingstone sales and production volumes (including capitalized volumes) for the period averaged over 365 days.
2) For additional information on Non-GAAP Financial Measures, refer to "Advisories and Other Guidance" beginning on page 27 of the Athabasca's Management Discussion & Analysis dated March 10, 2016 which is available on SEDAR at www.sedar.com.
3) Hangingstone Project 1 was ready for use in the manner intended by management on August 1, 2015. Operating results prior to August 1, 2015 have been capitalized and excluded from the calculation of the Thermal Oil Operating Loss and Netback. Negative Operating Netbacks are customary during ramp up of a SAGD project as revenues from lower initial production is more than offset by operating and transportation costs which are largely fixed in nature regardless of production volumes. Athabasca anticipates that operating costs per barrel from Project 1 will continue to materially improve as production increases.
4) For the year ended December 31, 2015 the Company recognized an impairment of $636.7 million.

Operations Update

Light Oil

In the Light Oil Division, Athabasca and industry continue to de-risk the Duvernay play at Kaybob with select areas transitioning to commercial operations. The Company has achieved material cost reductions with the transition to pad style operations and remains encouraged by early production results in the volatile oil window where the Company has significant exposure.

Athabasca's production averaged 5,873 boe/d (50% liquids) in the fourth quarter of 2015 with December volumes averaging 7,740 boe/d. Exit volumes were supported by the tie-in of four Duvernay wells (16-36-63-25W5, 12-28-62-23W5, 01-36-63-20W5 and 08-36-63-20W5). The Company anticipates maintaining a relatively flat production profile to its exit through 2016 with the completion of a limited winter program and the tie-in of behind pipe wells.

The Company deployed $51 million of capital in Light Oil during the fourth quarter of 2015. Field activity related to drilling operations on a three well Montney pad at Placid and a four well Duvernay pad at Kaybob West and commencing the build of the Placid inter-connect to the Company's owned and operated infrastructure at Saxon. Total Light Oil capital spend for 2015 came in approximately 25% lower than the original budget. Despite the increased scope of the program, material capital savings over the original budget were achieved primarily driven by improved cycle times and pad operating efficiencies in conjunction with continued service cost deflation.

Placid Montney

The Company recently completed a three well Montney pad at Placid in Section 19-60-23W5 to follow up on two successful wells drilled in the winter of 2014/15. Average drilling costs for the pad were approximately $4 million per well with spud to rig release times averaging 23 days for extended reach laterals (~2,500 meters). Completions operations concluded in early March with estimated frac costs averaging $2.9 million per well. All-in D&C costs are expected to average $6.9 million per well.

The pipeline inter-connect project to Saxon remains on track for commissioning in early April. At that time, five operated Montney wells are expected to be tied into the Company's regional infrastructure, of which four are new producers (9-26-60-24W5, 3-17-60-23W5, 6-17-60-23W5 and 11-17-60-23W5).

This limited Montney development is expected to be economic in the current commodity environment and provides shareholders a material growth platform longer term. With no near-term land expiries the Company has significant flexibility to control the pace of development going forward. Athabasca has operated exposure to approximately 25,000 gross acres of prospective Montney land with two separately defined Montney intervals.

Duvernay Update

The Company's core objectives for the winter program included demonstrating pad drilling cost efficiencies and ongoing appraisal and delineation of the volatile oil window. These strategic objectives are expected to establish the strong economic potential and significant running room that Athabasca believes it has in this play.

At Kaybob East, the Company recently tied-in a two well pad at Section 5-65-18W5. The completion design was intended to test proppant loading in the volatile oil window. Industry has seen a positive trend in productivity and ultimate recoveries by increasing proppant loading in both the Duvernay and other leading North American shale plays. The 00/16-6-65-18W5 well was completed at ~1,100 lbs/ft with a D&C cost of $8.8 million. The well had an IP30 of 541 boe/d (88% liquids). The 02/16-6-65-18W5 well was completed at ~2,000 lbs/ft with a D&C cost of $9.4 million. The well had an IP30 of 758 boe/d (86% liquids). The higher proppant completion resulted in a 40% improvement in its IP30 rate. The Company remains encouraged by the initial production and high quality product (44^{o} API field condensate) of these wells.

At Kaybob West, in the condensate rich gas window, the Company completed drilling operations on a four well cost demonstration pad at Section 36-63-20W5 in early January. Average drilling costs for the pad were $4 million per well with spud to rig release times averaging less than 18 days (~1,400 meter average laterals). The Company has seen a significant improvement in drilling efficiencies with average spud to rig release days down 50% from the prior winter’s program. The Company intends to complete the four wells after break-up, with a planned on-stream date in Q3 2016. D&C costs are expected to be within $8 - $10 million per well depending on completion intensity.

Light Oil Joint Venture

In January 2016, Athabasca entered into an agreement to form a strategic joint venture with Murphy to develop the Duvernay and Montney Formations in the Greater Kaybob and Greater Placid areas. As part of the transaction, Athabasca is selling 70% of its interest in its Greater Kaybob area assets and 30% of its interest in Greater Placid area assets for gross proceeds of $475 million. Murphy will assume operatorship of the Greater Kaybob area assets and Athabasca will retain operatorship of the Greater Placid area assets under separate joint development agreements. Athabasca will also retain operatorship of the regional midstream infrastructure in the near term.

Murphy will pay approximately $250 million in cash to Athabasca on closing. Additional consideration of $225 million will be in the form of a capital carry whereby Murphy will fund 75% of Athabasca's share of Duvernay development capital up to a maximum five year period. Expected gross capital investment over this time period is planned to be approximately $1 billion with flexibility on spending as commodity prices recover. The effective date of the transaction is January 1, 2016. The Company is progressing towards closing in Q2 2016 subject to meeting certain conditions and regulatory approvals.

The joint venture with Murphy will leverage both partners’ extensive shale play expertise and ensure capital is directed towards de-risking the volatile oil window in the Duvernay. Athabasca is positioned with a capital risk profile appropriate to its size while retaining tremendous upside in the Duvernay shale play. Athabasca’s operated Montney position at Placid provides a material platform for future economic growth with over 100 high quality locations.

Thermal Oil - Hangingstone

In the Thermal Division, Hangingstone Project 1 was completed in 2015 with first steam achieved late Q1 2015. The Company is now eight months into its production ramp-up with 21 well pairs converted to SAGD production and two additional well pairs currently on circulation steaming. The dilbit sales pipeline to the Cheecham terminal was successfully commissioned in December. Athabasca's production averaged 5,708 bbl/d in the fourth quarter of 2015 with December volumes averaging approximately 7,460 boe/d, exceeding the Company's guidance of 5,000 – 7,000 bbl/d. Reservoir response and operations performance continue to meet management expectations.

Athabasca conducted water treating system maintenance and subsurface performance improvements in late January and early February which affected volumes for those months. Current production is now approximately 8,000 bbl/d and the Company remains on track to achieve design capacity of 12,000 bbl/d by Q4 2016. No additional development capital is required to reach design capacity and only minimal maintenance capital will be needed in the initial years. Through management of the existing SAGD producers and the additional available well pairs, Athabasca forecasts that the facility will have a relatively flat production profile for the first five to seven years of operation once it reaches design capacity later this year.

2015 Year-end Reserves and Resources

Athabasca's independent qualified reserves evaluators, GLJ Petroleum Consultants ("GLJ") and DeGolyer and MacNaughton Canada Limited ("D&M"), completed their respective independent reserve and resource evaluations effective December 31, 2015.

The Light Oil Division realized 31% per share growth in gross proved plus probable reserves, increasing to 65 MMboe (50% liquids), which was primarily driven by Duvernay appraisal drilling. Total proved plus probable future development capital decreased by approximately 21% to $596 million (down from $755 million); a function of recent drilling and completion performance as well as external market conditions.

In the Thermal Oil Division, Hangingstone reserves underwent a significant reclassification to proved developed producing as the project commenced production and progressed ramp-up through 2015. Hangingstone proved plus probable reserves stand at 225 MMbbl of which 51 MMbbl (23%) are classified as proved developed producing and 95 MMbbl as total proved (42%). D&M assessed Hangingstone's contingent resources at 587 MMbbl (best estimate, risked) and 790 MMbbl (best estimate, unrisked).

	Light Oil[1] (MMboe)		Thermal[2] (MMbbl)		Total (MMboe)	
	Proved	Proved + Probable	Proved	Proved + Probable	Proved	Proved + Probable
December 31, 2014	11.6	49.6	**51.4**	**312.7**	**63.0**	**362.3**
Discoveries	0.0	0.0	0.0	0.0	0.0	**0.0**
Extensions and Improved Recovery	18.0	18.6	0.0	0.0	18.0	**18.6**
Technical Revisions	-0.7	0.4	44.4	-87.1	43.7	**-86.6**
Acquisitions	0.0	0.0	0.0	0.0	0.0	**0.0**
Dispositions	0.0	0.0	0.0	0.0	0.0	**0.0**
Economic Factors	0.0	-1.2	0.0	0.0	0.0	**-1.2**
Production	-2.1	-2.1	-0.7	-0.7	-2.8	**-2.8**
December 31, 2015	**26.8**	**65.4**	**95.1**	**224.9**	**121.9**	**290.3**
NPV10 (Before Tax - $ millions)	156.6	533.2	763.4	1,334.0	919.5	1,867.3

1) In the first quarter of 2016, Athabasca entered into the Murphy Transaction which is anticipated to result in the sale of approximately 38MMboe of Proved plus Probable Reserves from the Light Oil Division to Murphy. The transaction progressing towards closing in the second quarter.
2) In light of the commodity outlook Athabasca has elected to defer development of a 12,000 bbl/d Dover West Sands thermal oil project beyond its previous five-year development plan and as such has reclassified 87.1 MMbbl of proved plus probable reserves to contingent resources.

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 most recent Annual Information Form ("AIF") dated March 10, 2016 that is available on SEDAR at www.sedar.com.

Corporate Update and 2016 Outlook

Preserving a strong balance sheet and continued financial discipline remain top priorities for Athabasca. The Company will limit capital expenditures in 2016 with plans for continuing cost optimization. Athabasca is well positioned to advance its strategic operating priorities in a lower for longer pricing environment and remains nimble to increase activity when the external environment recovers.

In December, Athabasca released its 2016 capital budget of $91 million (gross) and average corporate production of 16,000 – 18,000 boe/d (gross).

The preliminary 2016 capital outlook incorporating the Murphy Transaction assumes a $60 - $65 million net program ($40 - $45 million Light Oil and $11 million Thermal Oil and $8 million capitalized G&A). Corporate production is expected to average between 13,000 – 14,500 boe/d net of which Light Oil accounts for 4,000 – 4,500 boe/d and Thermal Oil 9,000 – 10,000 bbl/d. The aforementioned numbers reflect the Company's initial 2016 budget released in December adjusted for joint working interests, an estimated Q2 2016 closing date for the Murphy Transaction and excludes purchase price adjustments from the January 1, 2016 effective date.

On closing of the Murphy Transaction, Athabasca will have approximately $900 million of liquidity and a net cash position of approximately $80 million. Liquidity is further bolstered by the $225 million Duvernay capital carry commitment. The Company is continuing to evaluate alternatives to enhance its capital structure and remains committed to reducing total leverage by $300 to $400 million during 2016. Core refinancing objectives include the extension of the Company's 2017 debt maturities, a reduction in corporate carrying costs to increase sustainability and the preservation of a multi-year funding outlook that will allow the Company to strategically advance its assets. Athabasca continues to believe that its demonstrated strong operational performance within both Light Oil and Thermal Oil are key drivers in the success of its refinancing initiatives.

Based on current strip commodity pricing the Company forecasts 2016 year-end liquidity of approximately $750 million with net debt of approximately $40 million based on the current capital structure.

Athabasca will provide an updated 2016 budget and guidance on close of the Murphy Transaction.

Board Renewal Update

The Company is pleased to announce the appointment of Mr. Bryan Begley to its Board as an independent director. Mr. Begley is currently a Managing Director and Partner at 1901 Partners, a private equity firm formed in 2014 to make private investments in the energy sector. From 2007 to 2014, Mr. Begley served as a Managing Director of ZBI Ventures, LLC, a private equity firm focused on the energy sector. Prior to joining ZBI Ventures, Mr. Begley was a Partner at MckInsey & Co. in the Houston and Dallas offices where he advised clients across the global energy sector.

In conjunction with Mr. Begley's appointment and as part of Athabasca's commitment to Board Renewal, Mr. Tom Buchanan, current Chair, and Mr. Gary Dundas have retired from the Board effective March 10, 2016. Mr. Ron Eckhardt, current Lead Director, has been appointed to the Chair position. Both Mr. Buchanan and Mr. Dundas have been with the Board of Athabasca since inception and this transition is part of a natural evolution for the Company as it moves from early stage resource capture towards development of large scale assets. Athabasca would like to thank both directors for their valuable contributions to the Company and wishes them well on future endeavors.

Conference Call

A conference call to discuss the results will be held for the investment community on Friday, March 11, 2016 at 7:00 a.m. MT (9:00 a.m. ET).

Conference Call Details:

Date: Friday, March 11, 2016

Time: 7:00am MT (9:00am ET)

Dial In: 877-648-7976 (toll-free in North America) or 617-826-1698

Replay: 855-859-2056 (toll-free in North America) or 404-537-3406

Replay code: 38955152

Webcast Details:

http://www.gowebcasting.com/7271

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", "should", "believe", "predict", "pursue", "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 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 may contain forward-looking information pertaining to the following: the expected timing of the closing of the Murphy Transaction; the benefits expected to be realized by the Company from the Murphy Transaction, including the impact on the Company's financial position and balance sheet strength; the Company's forecasted liquidity and net cash position upon closing of the Murphy Transaction; the timing of receipt of regulatory approvals; Athabasca's plans to retire a portion of its debt in 2016; the expected potential of the Duvernay volatile oil window; the growth potential of and the economic returns expected to be realized from, the Company's Montney lands in the Placid area; the improvements in Duvernay well drilling and completion costs expected to be realized by the Company, including from employing pad drilling; the timing of completion and commissioning operations in the Company's Light Oil division; the timing of the on-stream date the Company's Kaybob West area wells; the benefits expected to be realized from the use of recovery technologies in the Company's Light Oil division, including multi-stage, energized hybrid completion technology and the utilization of a high proppant loading completion design; the Company's expected flexibility in its pace of development; the Company's drilling plans, in particular, with respect to the Duvernay and Montney formations and the costs of such drilling operations; the timing of the ramp-up of production and of achieving plateau production from Hangingstone Project 1; the Company's expectation that Hangingstone Project 1 will have a flat production profile for its initial 5 to 7 years of production after achieving nameplate production (12,000 bbl/d); the Company's estimated future commitments; the Company's business and financing strategies and plans; expectations regarding the Company's 2016 capital budget; and the future allocation of capital.

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 impact that the Murphy Transaction will have on the Company, including on the Company's financial condition and results of operations; the Company's ability to meet its re-financing objectives; 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; 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 10, 2016 that is 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; compliance with greenhouse gas regulations; changes to royalty regimes, environmental risks and hazards; alternatives to and changing demand for petroleum products; failure to meet the conditions precedent to closing of the Murphy Transaction; dependence on Murphy as the Company's joint venture participant in the Company's Duvernay and Montney assets; 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, including in respect of the Murphy Transaction, and the possible consequences thereof; the potential for adverse consequences in the event that the Company defaults under certain of the agreements in respect of the Murphy Transaction; 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; the potential for management estimates and assumptions to be inaccurate; 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; senior secured notes and term loans; and risks related to Athabasca's common shares.

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 available on SEDAR at www.sedar.com. The forward-looking statements included in this News Release are expressly qualified by this cautionary statement. Athabasca does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

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.

Test Results and Initial Production Rates:
The well test results and initial production rates provided in this News Release should be considered to be preliminary. Test results and initial production rates disclosed herein may not necessarily be indicative of long term performance or of ultimate recovery.