CALGARY, ALBERTA--(Marketwired - Jul 26, 2017) - Athabasca Oil Corp. (TSX:ATH) ("Athabasca" or the "Company") is pleased to provide its 2017 second quarter results and an operations update. The quarter marks continued operational momentum, positive cash flow driven by strong liquids-rich Montney growth at Placid and the full integration of Athabasca's new thermal oil asset at Leismer.

Second Quarter and Recent Highlights

- Q2 2017 Operating and Financial Results
  - Production of 36,574 boe/d (91% liquids), representing 27% per share growth over Q1 2017 and 162% year over year
  - Funds flow of $27.6 million ($0.05 per share) and capital expenditures of $31.7 million
  - Continued cost discipline with a 61% year over year reduction in G&A to $2.15/boe
  - Net debt of $351 million with approximately $180 million of cash and equivalents
- Light Oil - High Margin Liquids-Rich Growth
  - Production of 7,246 boe/d (56% liquids), representing 97% per share growth over Q1 2017
  - Positioned to exit 2017 at approximately 10,000 boe/d and hold production flat in the near-term with a one rig Montney program at Placid

Placid Montney (70% working interest)

- 30 day restricted rates from the eight most recent wells averaged 950 boe/d, approximately 20% ahead of type curve expectations
- Increased type curve due to strong performance, with the plug and perf completion design supporting higher extended production rates (restricted IP90s averaged 725 boe/d, 62% liquids)
- Strategic land acquisitions have increased Athabasca's gross operated acres by 22,000 acres to approximately 80,000 acres (55,000 net)

Kaybob Duvernay (30% working interest)

- A new well at Kaybob West North had an IP30 and IP60 of 1,790 boe/d (75% liquids) and 1,450 boe/d (74% liquids), respectively. This well is one of the top industry producers in the volatile oil window
- The 2017 program is approximately $200 million gross ($15 million net) and includes a total of 16 spuds and 13 completions

- Thermal Oil - Underpins Low Corporate Decline and Free Cash Flow Generation
  - Production of 29,328 bbl/d, representing 17% per share growth over Q1 2017
  - $13.3 million of Thermal Oil of free cash flow in Q2 2017
  - With a focus on maximizing profitability and long-term recoveries, the Company has reduced Thermal Oil capital by a total of $45 million, from the original $105 million annual budget

Athabasca's Strategy

Athabasca is an intermediate oil weighted producer with exposure to several of the largest resource plays in Western Canada, including the Montney, Duvernay and oil sands. The Company has a funded and flexible development outlook capable of delivering strong economic growth.

The Company is focused on maintaining scale of operations within Light Oil and continued optimization of Thermal Oil to maximize profitability and long-term recoveries. Athabasca retains optionality to accelerate operations across both divisions with pricing support. The Company is guided by a strategy that includes:

- Light Oil: Defined and Material Margin Growth
  - A scalable operated Montney position at Placid
  - Funded Duvernay development through the joint venture with Murphy Oil
  - Production growth to approximately 10,000 boe/d by year-end 2017 and potential to over 20,000 boe/d by 2020 with a 1-rig program in the Montney and current Duvernay development plans

- Thermal Oil: Free Cash Flow with Leverage to Oil Prices
    - A large low decline asset base accelerates free cash flow
    - Free cash flow of approximately $350 million over a five year period at US$55/bbl WTI
    - Future low risk expansion options
- Financial Sustainability
    - Maturing cash flow profile with strong sustainability metrics and a low overall corporate production decline of approximately 10% annually
    - Diverse asset base provides flexibility in future capital allocation decisions
    - Strong liquidity supported by $180 million of cash and equivalents, $189 million Duvernay carry balance, $15 million market to market hedge gains and a $120 million credit facility at the end of Q2 2017

Financial and Operating Highlights

	3 months ended June 30		6 months ended June 30	
($ Thousands, except per share and boe amounts)	2017	2016		2016
CONSOLIDATED PRODUCTION				
Petroleum and natural gas volumes (boe/d)	36,574	11,101	31,683	12,224
LIGHT OIL DIVISION				
Petroleum and natural gas sales volumes (boe/d)	7,246	5,743	5,344	6,031
Light Oil operating income[1]	$ 16,391	$ 7,215	$ 23,253	$ 12,123
Light Oil operating netback[1] ($/boe)	$ 24.85	$ 13.80	$ 24.04	$ 11.03
Capital expenditures	$ 31,061	$ 5,518	$ 108,707	$ 36,176
Recovery of capital‐carry through capital expenditures	$ (13,493)	$ (1,474)	$ (24,173)	$ (1,474
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	29,328	5,358	26,339	6,193
Thermal Oil operating income (loss)[1]	$ 27,396	$ (11,915)	$ 39,735	$ (34,990
Thermal Oil operating netback[1] ($/bbl)	$ 10.39	$ (29.33)	$ 8.40	$ (33.03
Capital expenditures[2]	$ 14,127	$ 2,187	$ 24,994	$ 3,094
CASH FLOWS AND FUNDS FLOW				
Cash flow from operating activities	$ 28,049	$ 5,759	$ (24,851)	$ (32,268
Cash flow from operating activities per share (basic & diluted)	$ 0.06	$ 0.01	$ (0.05)	$ (0.08
Funds flow from operations[1]	$ 27,567	$ (27,304)	$ 25,915	$ (67,420
Funds flow from operations per share (basic & diluted)	$ 0.05	$ (0.07)	$ 0.05	$ (0.17
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss	$ 24,233	$ (59,169)	$ (4,932)	$ (124,298
Net loss and comprehensive loss per share (basic & diluted)	$ 0.05	$ (0.15)	$ (0.01)	$ (0.31
SHARES OUTSTANDING				
Weighted average shares outstanding (basic)	508,655,464	405,222,515	490,492,488	404,964,70
ACQUISITIONS AND FINANCINGS				
Leismer Corner Acquisition[3]	$ (3,687)	$ ‐	$ (625,764)	$ ‐
Net proceeds from sale of assets	$ 35	$ 392,175	$ 90,205	$ 392,338
Net proceeds from issuance of 2022 Notes	$ (437)	$ ‐	$ 542,117	$ ‐
Repayment of 2017 Notes	$ ‐	$ (284,722)	$ (550,000)	$ (285,441

As at ($ Thousands)	June 30, 2017	December 31, 2016
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 179,611	$ 650,301
Restricted cash	$ 113,853	$ 107,012
Capital‐carry receivable (current & LT portion - discounted)	$ 189,296	$ 213,469
Face value of long‐term debt	$ 584,212	$ 550,000
Total assets	$ 2,488,995	$ 2,257,887
Total Liabilities	$ 765,260	$ 700,790
Shareholders' equity	$ 1,723,735	$ 1,557,097

(1) Refer to "Advisories and Other Guidance" in the MD&A for additional information on Non-GAAP Financial Measures.

(2) Thermal Oil capital expenditures excludes the cost of the Leismer Corner Acquisition.

(3) Consists of cash of $435.0 million, common shares of $166.0 million and contingent payment obligations of $24.7 million.

Operations Update

Light Oil

Production averaged 7,246 boe/d (56% liquids) in Q2 2017, representing 97% per share growth over Q1 2017. The step change in production was driven by the tie-in of Montney wells from the winter program. Volumes were impacted by a 16 day unplanned outage at Keyera's Simonette Gas Plant in April which the Company was able to partially mitigate by redirecting a portion of production to the SemCAMS KA plant.

Light Oil operating income was $16.4 million ($24.85/boe netback). Capital expenditures totaled $17.6 million net with activity focused on completing the Montney and Duvernay winter programs. Light Oil lease operating expenses decreased to $9.96/boe in Q2 2017, down 35% from Q1 2017, and are expected to drop an additional 20% to approximately $8/boe by year-end 2017, supported by additional production growth and field optimization.

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

At Placid, Athabasca completed an active winter program that included rig releasing 20 Montney wells, commissioning a new battery and the tie-in of three multi-well pads. Placid is positioned for flexible and scalable economic growth over the next five years.

A total of three pads, 11 wells, were completed and placed on production this winter. The Company modified its completion design to a plug and perf system (from previous ball drop design) with the goal to improve fracture intensity and ultimately long-term rates and recoveries.

Following initial clean-up, the wells are exhibiting strong extended production at higher flowing pressures with results coming in ahead of the type curve expectations. Peak 30 day rates from the 11 wells averaged 900 boe/d (56% liquids) and IP90s averaged 725 boe/d (62% liquids). The Company is increasing its Placid Montney type curve to reflect the strong results with IP30s and EURs moving up approximately 20% to 1,000 boe/d (57% liquids) and 675mboe (45% liquids), respectively. Placid boasts strong economics with single well type curve metrics of 21 month payback, 46% IRR and $13,000/boe/d 1 year capital efficiencies (US$50/bbl WTI flat pricing).

Placid 2016/17 Winter Program[1]		Peak 30 Day[2]	IP60	IP90
Pad 1 - 07-30-60-23W5[3]	On-stream December	813 boe/d (70%)	742 boe/d (66%)	690 boe/d (67%)
Pad 2 - 12-19-60-23W5 (Pod 2)	On-stream April	821 boe/d (51%)	632 boe/d (65%)	670 boe/d (61%)
Pad 3 - 16-30-60-23W5	On-stream April	1,053 boe/d (50%)	673 boe/d (64%)	798 boe/d (58%)
Pad 4 - 03-04-61-23W5	Completions underway	-	-	-
Pad 5 - 07-33-60-20W5	Completions Aug/Sept	-	-	-

(1) Liquids% includes free condensate and estimated plant based NGL recovery.
(2) Peak 30 day rates reported as the initial rates in April were temporarily restricted by spring road bans and the 16-day Keyera unplanned outage.
(3) 7-30 wells were restricted through Q1 2017 due to elevated regional line pressure prior to the commissioning of the Placid infrastructure in April.

Completions operations are underway on Pad 4 and will follow on Pad 5 in Q3 2017. Drill and completion costs are estimated at approximately $7.9 million per well, with drilling totaling $2.8 million per well and completions estimated at $5.1 million per well (2,900 meter average laterals and 1,300 lb/ft proppant intensity). Both pads are expected to be placed on-stream in H2 2017 and will support further production growth.

The Company will spud a six well pad in late Q3 2017 (surface location 7-30-60-23W5 - Pod 2) with completions anticipated in early 2018. The 7-30 Pod 2 pad is low risk capital efficient development that will maintain base production levels. Decisions regarding 2018 activity levels will be finalized later this year and the Company retains flexibility to adapt activity levels to results and external market conditions.

Over the past year the Company has completed a number of strategic land acquisitions through industry swaps and crown land sales. The Company's operated Montney position now stands at approximately 80,000 gross acres (up from 58,000 acres), of which 48,000 gross acres (36,000 net) are high-graded Placid development. An inventory of over 200 locations positions the Company for multi-year growth.

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

Joint venture operations commenced in the fall of 2016 with the objective of driving near-term production and cash flow growth, delineation across all phase windows, optimizing well design and maximizing land retention.

Murphy operated two drilling rigs through the winter season and rig released eight wells from four pads. Initial activity has been focused in the condensate rich gas window at Kaybob West and in the volatile oil window at Kaybob West North. Activity through the second half will step out through the volatile oil window at Kaybob East, Two Creeks and Simonette. Murphy is experimenting with a number of completion techniques in the initial wells, leveraging off their experience in the Eagle Ford oil window.

A two well pad at surface location 4-32-64-20W5 was completed in Q2 and placed on-stream in early June. The 16-36-64-21W5 well is a 2,300 meter lateral and was completed with 3,000 lb/ft proppant intensity (38 stages, 4.5 T/M). The well had an IP30 of 1,790 boe/d (75% liquids) and an IP60 of 1,450 boe/d (74% liquids). The 3-28-64-20W5 well is a 2,450 meter lateral and was completed with 2,000 lb/ft proppant intensity (41 stages, 3.0 T/M). The well had a restricted rate IP30 of 830 boe/d (74% liquids). The early stage production and pressure data from these wells remain very encouraging and compares favorably to prior regional wells and type curve expectations.

A three well pad at surface location 11-18-64-20W5 was rig released in April and subsequently completed. Initial flow back is underway on the pad. A single well at surface location 16-18-65-20W5 was rig released in late March with a 2,900 meter lateral.

The 2017 budget includes spudding 16 gross wells which are a mix of pad development locations and delineation wells throughout the volatile oil window. Total lateral drilling for the program is approximately 45,000 meters and this compares to Athabasca's initial 20 well appraisal campaign of approximately 27,000 meters since 2012. Results from the Duvernay program are expected through H2 2017 with 10 spuds planned for the balance of the year.

Athabasca is encouraged by continued positive industry well results, robust activity levels by offsetting majors (Shell, Encana and Chevron) and initial results from the Murphy operated wells. The Duvernay is competitive 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%). Resulting operating netbacks for an 80% liquids well at US$50/bbl WTI are approximately C$44/boe. The joint venture positions Athabasca shareholders with a funded Duvernay development profile over the next four years and long-term upside with a 30% working interest in over 200,000 prospective Duvernay acres and a 1,500+ well inventory.

Thermal Oil

Production averaged 29,328 bbl/d in Q2 2017, representing 17% per share growth over Q1 2017. Volumes were supported by the full integration of Leismer for the quarter and the continued ramp-up at Hangingstone. Thermal Oil operating income was $27.4 million ($10.39/boe netbacks) with $14.1 million of capital expenditures during the quarter. Resulting free cash flow was $13.3 million.

Leismer

Leismer production averaged 20,463 bbl/d in Q2 2017. The Company is taking deliberate steps to prudently manage reservoir performance and maximize profitability. The 2017 capital budget at Leismer has been reduced to $40 million, representing a 54% or $45 million reduction from the original $85 million budget. The Company expects to manage production between 20,000 - 22,000 bbl/d. Near-term operations will focus on production and steam optimization across the field and the start-up of predrilled infills on Pad L5 into 2018.

The Company estimates a low average 32% recovery factor on existing wells to date with recoveries expected to reach approximately 65% long-term, in line with comparable industry projects. The asset's reserve life index is 35 years proven and 75 years proved plus probable. Management remains pleased with the quality of the asset and inherent flexibility to reduce capital while maintaining production in this environment.

Hangingstone

Hangingstone averaged 8,865 bbl/d in Q2 2017, up from 8,552 bbl/d in Q1 2017. June production averaged over 9,200 bbl/d with positive operating netback. Facility performance has been stable and production is expected to continue to increase with steam chamber growth. Hangingstone will require minimal capital over the next several years to maintain production levels.

Balance Sheet and Sustainability

Financial sustainability remains a core part of Athabasca's strategy and throughout 2017 the Company has focused on activities that will drive increased margins and improve financial resiliency. 2017 capital has been primarily directed to the high margin Montney and Duvernay with Light Oil volumes expected to grow to approximately 10,000 boe/d (and contribute approximately 50% of operating income) by year-end. Material production growth in Light Oil along with the strategic Leismer acquisition and an ongoing focus on cost optimization has resulted in lower year over year operating and G&A expenses per boe of 35% and 61%, respectively. The Company has also taken steps to manage its exposure to commodity prices with 20,000 bbl/d hedged for the balance of 2017 at an average WCS price of approximately C$50.75/bbl. Going forward, a multi-year hedging program will form a key part of the Company's risk management strategy.

The Company maintains a solid balance sheet position with net debt at the end of Q2 2017 of $351 million and a strong liquidity position. Liquidity is supported by $180 million of cash and equivalents, a $189 million Duvernay carry balance, $15 million market to market hedge gains and a $120 million credit facility, which was reaffirmed by the Company's lenders on May 31, 2017. The Company also has significant asset value in its established and operated Thermal and Light Oil infrastructure.

2017 Guidance and 2018 Capital Outlook

Corporate Guidance

Athabasca's 2017 capital budget is unchanged at $210 million and includes running a single rig in the Placid Montney area during H2 2017. Annual corporate production is expected to average between 33,500 - 36,500 boe/d.

Light Oil Guidance

Athabasca's 2017 Light Oil capital budget has been increased by $15 million to $150 million ($135 million for Placid Montney and $15 million net for Duvernay). The increased activity reflects spudding a 6-well Montney pad in Q3 2017 with completions and tie-in anticipated in early 2018. The increase in capital has been funded through an optimized Thermal Oil budget which is outlined below. Light Oil annual production guidance is unchanged at 6,500 - 7,500 boe/d and production is expected to reach 10,000 boe/d before year-end. Guidance incorporates a 19 day planned turnaround at Keyera's Simonette plant through August.

Thermal Oil Guidance

Athabasca's 2017 Thermal Oil capital budget has been reduced by an additional $15 million to $60 million. Inclusive of the prior reduction at Q1, the Company has reduced its Thermal Oil budget by a total of $45 million from the original $105 million budget. Annual production guidance is between 27,000 - 29,000 bbl/d. The capital program consists of $40 million at Leismer, $15 million at Hangingstone and $5 million for maintaining Athabasca's long dated thermal leases.

2017 Budget & Guidance Details

	Full Year
CORPORATE (net)	
Production (boe/d)	33,500 - 36,500
Liquids Weighting (%)	~91%
Funds Flow from Operations ($MM)	~$55
LIGHT OIL	
Production (boe/d)	6,500 - 7,500
Operating Income ($MM)	~$61
Capital Expenditures ($MM)	$150
THERMAL OIL	
Bitumen Production (bbl/d)	27,000 - 29,000
Operating Income ($MM)	~$83
Capital Expenditures ($MM)	$60
COMMODITY ASSUMPTIONS	
WTI (US$/bbl)	$48.00
Western Canadian Select (C$/bbl)	$47.25
AECO Gas (C$/mcf)	$2.50
FX (US$/C$)	0.76

2018 Capital Outlook

Management's expectations are to align 2018 capital spending with corporate cash flow. The Company's assets afford it significant capital flexibility in both the Light and Thermal Oil divisions. Placid Montney activity has no near-term land expiries, with a single rig capable of holding production flat. In the Duvernay, the Company is protected by a capital carry on the first $1 billion of investment (7.5% capital exposure for a 30% WI). In the event the partners agree to reduce the pace or change scope from the original joint development agreement, Athabasca is entitled to a cash payment for carry capital not spent in that year (2018 JDA $356 million gross, $27 million net, $80 million capital carry). In Thermal Oil, capital and operations will continue to be optimized to maximize profitability and long-term recoveries. Athabasca retains readiness to accelerate activity in both divisions with commodity support.

Conference Call

A conference call to discuss the results and provide a mid-year update will be held for the investment community on July 27, 2017 at 7:00 a.m. MT (9:00 a.m. ET). To participate, please dial (877) 291-4570 (toll-free in North America) or (647) 788-4919 approximately 15 minutes prior to the conference call and enter passcode 61002546. Alternatively, to listen to this event online, please enter http://www.gowebcasting.com/8579 in your web browser. For those unable to participate in the conference call at the scheduled time, it will be archived for replay on the Company's website at www.atha.com.

About Athabasca Oil Corporation

Athabasca Oil Corp. 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.

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 2017 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 9, 2017 that 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 2017 capital expenditures, funds flow from operations, 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 July 26, 2017, 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 200 (gross) Montney inventory referenced in this presentation includes 8 probable 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 GLJ Petroleum Consultants Ltd. as of December 31, 2016 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. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Non-GAAP Financial Measures

The "Funds Flow from Operations", "Light Oil Operating Income", "Light Oil Operating Netback", "Thermal Oil Operating Income" and "Thermal Oil Operating Netback", 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.

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. Funds Flow from Operations per share (basic and diluted) is calculated as Funds Flow from Operations divided by the number of weighted average basic and diluted 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 and midstream revenues received. 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 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 expenses from blended bitumen sales. The consolidated Thermal Oil Operating Income and Operating Netback measures also include realized gains on commodity risk management contracts. The Thermal Oil Operating Netback measure is presented on a per bbl basis. The Thermal Oil Operating Income and the Thermal Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Thermal Oil assets.

The Net Debt measure is calculated by summing the face value of outstanding term debt with current liabilities and subtracting current assets adjusted for the capital carry receivable and risk management contracts. 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.

Contact

Athabasca Oil Corp.
Media and Financial Community
Matthew Taylor
Vice President, Capital Markets and Communications
1-403-817-9104
mtaylor@atha.com