FOR IMMEDIATE RELEASE
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Athabasca Oil Corporation Reports 2016 Second Quarter Results and an Increased Capital Budget for the Placid Montney

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or "the Company") is pleased to provide its 2016 second quarter results and an operations update. During the quarter the Company continued to progress its operational targets in both business divisions and bolstered its financial position through the closing of two strategic transactions.

Athabasca's strategy positions the Company for strong growth and sustainability into the future:

- **Defined and Material Growth in Light Oil –** a scalable operated Montney position and funded Duvernay development through the joint venture with Murphy Oil Company Ltd. ("Murphy").
- **Thermal Oil Leverage to Commodity Prices –** successful ramp-up of Hangingstone Project 1, a low decline asset with significant cash flow torque and minimal capital requirements in the initial years of operations.
- **Financial Sustainability –** Significant financial flexibility with current liquidity of $607 million and a $91 million net cash position.

Notable highlights include:

- **Q2 2016 Operating Highlights –** Corporate production, adjusted for the Murphy joint venture, averaged 11,101 boe/d (74% liquids), an increase of 103% year over year. Capital expenditures were approximately $6 million in the quarter.
- **Contingent Bitumen Royalty –** On June 17, the Company granted a Contingent Bitumen Royalty (the "Royalty") on its Thermal Oil assets to Burgess Energy Holdings L.L.C. for cash proceeds of $129 million. The Royalty is structured with a 0 – 6% sliding scale based on a realized bitumen price (C$), which is determined net of diluent, transportation and storage costs. The Royalty is not triggered until the realized bitumen price reaches a minimum of C$50/bbl at Hangingstone ($60/bbl for each of the Company's other thermal assets) so that the assets will not be encumbered at lower pricing levels. At Hangingstone, the Company estimates a US$75/bbl WTI price at 12,000 bbl/d would be required before the realized bitumen price reaches C$50/bbl and the first 1% Royalty is triggered. At this pricing level, Hangingstone Project 1 is estimated to have an annual operating netback of approximately $120 million (net of a $2 million Royalty). The Royalty is not expected to materially impact economics of future expansion phases or future development projects and there are no associated commitments to develop the assets.

- **Corporate Debt Reduction and Balance Sheet Strength –** In June 2016, Athabasca reduced its outstanding corporate debt by approximately $250 million through repaying its US$221 million Term Loan and unwinding its US dollar foreign exchange hedge. The recent Royalty grant along with the debt repayment are further steps towards aligning the Company's capital structure with its go forward operating plans. As of the end of June 30, 2016, the Company had a net cash position of $91 million, $607 million in liquidity and maintains an undrawn $45 million revolving credit facility. Liquidity through the mid-term is further supported by the remaining $218 million Duvernay capital carry balance with Murphy.

- **Capital Budget Increase for Placid Montney –** In the Light Oil division, Athabasca has increased its capital budget to $102 million net (from $47 million net). All additional capital is being directed towards its Montney program at Placid, which will include the drilling of 12 development wells, the completion and tie-in of a four well pad and long lead commitments on an oil battery to accommodate mid-term growth plans. A single rig is currently operating and Athabasca retains significant flexibility to control the pace of development. The Company is positioned with a multi-year development inventory that has robust economics in the current commodity price environment.

- **Light Oil Duvernay Joint Venture –** In May 2016, Athabasca closed its light oil joint venture with Murphy in the Kaybob Area for consideration of $486 million ($267 million cash and a $219 million carry). Athabasca recently completed fracturing operations on a previously drilled four well pad at Kaybob West in the condensate rich gas window with expected on-stream timing in Q4 2016. The transition of operatorship of the Duvernay to Murphy will be substantially completed by the end of July. The joint development plan contemplates approximately $1 billion of Duvernay gross investment over the next four to five years with gross production potential up to 30,000 boe/d (60% liquids, 30% working interest), of which Athabasca's net capital exposure is approximately $75 million.

- **Hangingstone –** Following a three week shut-down in May in response to the regional Fort McMurray wildfires, operations have resumed with bitumen production averaging 7,831 bbl/d in June and forecasted to average approximately 8,600 bbl/d in July. The project is expected to approach design capacity of 12,000 bbl/d by the end of 2016 with no additional development capital required. The wildfire impact and other unplanned downtime year to date is expected to impact annual volumes with revised 2016 production guidance between 7,500 – 8,500 bbl/d on an unchanged capital budget.

FINANCIAL AND OPERATING HIGHLIGHTS

($ Thousands, except per share and boe amounts)		3 months ended June 30 2016		2015		6 months ended June 30 2016		2015
CONSOLIDATED PRODUCTION								
Petroleum and natural gas volumes (boe/d)		11,101		5,459		12,224		5,667
LIGHT OIL DIVISION								
Petroleum and natural gas sales volumes (boe/d)		5,743		5,459		6,031		5,667
Light Oil operating income[1]	$	7,215	$	10,689	$	12,123	$	17,281
Light Oil operating netback[1] ($/boe)	$	13.80	$	21.51	$	11.03	$	16.84
Capital expenditures	$	5,518	$	14,959	$	36,176	$	94,200
Recovery of capital-carry through capital expenditures	$	(1,474)	$	—	$	(1,474)	$	—
THERMAL OIL DIVISION								
Bitumen production (bbl/d)		5,358		—		6,193		—
Bitumen sales volumes (bbl/d)		4,463		—		5,820		—
Thermal Oil operating income (loss)[1, 2]	$	(11,915)	$	—	$	(34,990)	$	—
Thermal Oil operating netback[1, 2] ($/bbl)	$	(29.33)	$	—	$	(33.03)	$	—
Capital expenditures	$	2,187	$	33,118	$	3,094	$	101,685
CASH FLOWS AND FUNDS FLOW								
Cash flow from operating activities	$	5,759	$	8,576	$	(32,268)	$	5,922
Cash flow from operating activities per share (basic & diluted)	$	0.01	$	0.02	$	(0.08)	$	0.01
Funds flow from operations[1]	$	(27,304)	$	5,085	$	(67,420)	$	8,201
Funds flow from operations per share (basic & diluted)	$	(0.07)	$	0.01	$	(0.17)	$	0.02
NET LOSS AND COMPREHENSIVE LOSS								
Net loss and comprehensive loss	$	(59,169)	$	(29,044)	$	(124,298)	$	(54,156)
Net loss and comprehensive loss per share (basic & diluted)	$	(0.15)	$	(0.07)	$	(0.31)	$	(0.13)
SHARES OUTSTANDING								
Weighted average shares outstanding (basic & diluted)		405,222,515		402,981,471		404,964,704		402,698,520
FINANCING AND DIVESTITURES								
Cash proceeds from sales of assets	$	392,175	$	—	$	392,338	$	—
Promissory note proceeds	$	—	$	—	$	—	$	300,000
Repayment of long-term debt	$	(284,722)	$	(626)	$	(285,441)	$	(1,336)
Derivative proceeds upon repayment of long-term debt	$	40,956	$	—	$	40,956	$	—

As at ($ Thousands)		June 30, 2016		December 31, 2015
BALANCE SHEET ITEMS				
Cash and cash equivalents	$	447,282	$	559,487
Short-term investments	$	25,533	$	—
Promissory note	$	133,892	$	133,892
Restricted cash	$	101,652	$	—
Long-term receivables and other[3]	$	181,443	$	3,044
Total assets	$	3,028,938	$	3,462,442
Long-term debt	$	544,042	$	838,205
Net Debt[1]	$	(90,834)	$	154,711
Shareholders' equity	$	2,363,396	$	2,482,140

1) For additional information on Non-GAAP Financial Measures, refer to "Advisories and Other Guidance" beginning on page 19 of the Athabasca's Management Discussion & Analysis dated July 27, 2016 which is available on SEDAR at www.sedar.com.
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. Athabasca anticipates that operating and transportation costs per barrel from Hangingstone Project 1 will continue to materially improve as production increases.
3) Long-term receivables and other primarily consists of the long-term portion of the discounted capital-carry receivable of $181.4 million ($216.7 million undiscounted).

Operations Update

Light Oil

Production averaged 5,743 boe/d (49% liquids) in the second quarter of 2016. Capital expenditures totaled $4 million (net of capital carry) with activity focused on operational readiness for the second half 2016 Duvernay and Montney programs.

Greater Placid Montney – (70% working interest; Q2 2,960 boe/d net)

In the Montney at Placid, the Company has established a scalable and operated position which it believes has competitive returns relative to other North American plays.

During the winter 2015/16 program the Company placed four new Montney wells on-stream in early April. Three of the wells were drilled into the Montney C interval and 6-17-60-23W5 was drilled into the Montney D interval. Production and core data confirm that both Montney intervals are independent and demonstrates a liquids rich trend in the Placid area. IP30s on the Placid program over the past two years have averaged 805 boe/d (64% liquids) with IP90s averaging 686 boe/d (56% liquids). Extended production data supports management's type curve expectations and the wells are exhibiting modest declines as initial rates were restricted during the clean-up period.

Following a successful 2015/16 winter program, Athabasca has commenced its second half 2016 program with the recent spudding of a four well pad at surface location 7-30-60-23W5 ("7-30"). The pad is expected to be rig-released and completed in Q4 2016 with an on-stream date near year-end. Targeted drill and completion costs ("D&C") are $6.8 million per well with an average lateral length of approximately 2,400 meters and approximately 1,000 lb/ft completion intensity. The Company's second half program includes drilling 12 development wells, the completion and tie-in of the 7-30 four well pad and long lead commitments on an oil battery to accommodate mid-term growth plans.

As Placid operations transition to pad development the play is expected to drive top tier competitive capital efficiencies. Athabasca will remain focused on economically growing production while delineating both Montney intervals and growing the aerial extent of the play.

With no near-term land expiries and operated egress, Placid is set up with significant flexibility to control the pace of development going forward. Athabasca has high-graded exposure to approximately 25,000 gross acres of prospective Montney land. The development inventory is estimated at over 150 gross locations which could drive organic growth in excess of five years under an accelerated two rig development scenario.

Greater Kaybob Duvernay – (30% working interest; Q2 2,783 boe/d net)

Athabasca and Murphy closed the $486 million light oil joint venture on May 13, 2016. Integration of operations continues to progress with the transition of operatorship to Murphy on track to be substantially completed by the end of July.

At Kaybob West, in the condensate rich gas window, the Company recently completed fracturing operations on a previously drilled four well pad at Section 36-63-20W5. Completion intensity design on this pad was increased to approximately 2,000 lbs/ft from the prior design of approximately 1,100 lbs/ft.

Average completion costs on this pad are estimated at $5.5 million per well with all-in D&C costs estimated at less than $9.5 million per well. On-stream timing is expected near year-end 2016.

Joint venture drilling operations are expected to commence this fall. By the end of 2017, the joint development plans include drilling approximately 20 Duvernay wells. Operations will include a mix of continued resource delineation in the volatile oil window and pad operations in lower risk more defined areas of the play.

The joint development plan is designed to maximize land retention, delineate the volatile oil window and progress the entire asset to the self-funding stage post the initial carry period. The $219 million capital carry amount ($218 million currently remaining) will minimize Athabasca's financial exposure in the mid-term, with Murphy funding 75% of the Company's 30% working interest on the first $1 billion of investment ($75 million net exposure) in this play.

The Company believes that the recently announced Alberta Government Emerging Resource Program which overlays the Modernized Royalty Framework will support continued industry investment and activity in the emerging Duvernay play, in particular the volatile oil window.

Thermal Oil - Hangingstone

In the Thermal Oil Division, Hangingstone Project 1 is approximately one year into its production ramp-up with 23 well pairs converted to SAGD production.

Bitumen production for the second quarter averaged 5,358 bbl/d with volumes impacted by planned regulatory mandated maintenance of the steam boilers in April and the temporary shut-down of operations for approximately three weeks in May in response to the regional Fort McMurray wildfires. Operations resumed on May 22, 2016 with no damage to field equipment or long lasting effects expected on the reservoir from the shut in period. The field is currently ramping back up and bitumen production averaged 7,831 bbl/d in June and is forecasted to average approximately 8,600 bbl/d in July.

The project is expected to approach design capacity of 12,000 bbl/d by the end of 2016. No additional development capital is required to reach design capacity and only minimal maintenance capital will be needed in the initial years of operation.

2016 Budget and Outlook

Athabasca's updated guidance incorporates the closing of the recent Murphy joint venture and Royalty transactions, current operations, the planned expansion to the Light Oil Montney program at Placid and strip pricing as of July 5th, 2016.

In the Light Oil division, Athabasca has increased its capital budget to $102 million net (from $47 million net) to reflect the accelerated Montney development program at Placid. Annual Light Oil production guidance remains unchanged between 4,500 – 5,000 boe/d and the increased Montney activity will drive production growth in early 2017.

In the Thermal Oil division, the wildfire impact and other unplanned maintenance downtime year to date has impacted annual production volumes with revised guidance now expected between 7,500 – 8,500 bbl/d on an unchanged capital budget of $11 million.

The Company remains in a strong financial positon with net cash of $91 million and $607 million in liquidity (excluding an undrawn $45 million credit facility) as of June 30, 2016. Liquidity through the mid-term is further supported by the remaining $218 million Duvernay capital carry balance with Murphy.

2016 Capital Budget[1] ($ million)	**Full Year**
LIGHT OIL	Net
Greater Kaybob[2] (Duvernay)	$8
Greater Placid[3] (Montney)	94
Total Light Oil	**$102**
THERMAL OIL	
Hangingstone Maintenance	$7
Other Thermal	4
Total Thermal	**$11**
Capitalized G&A	$8
TOTAL CAPITAL SPENDING	**$121**

1) Figures may not add up due to rounding.
2) Greater Kaybob net capital reflects Athabasca's 30% interest following the application of the $219 million capital carry (Murphy funds 75% of Athabasca's 30% working interest).
3) Greater Placid net capital reflects Athabasca's 70% working interest.

2016 Operational & Financial Guidance	**Full Year**
LIGHT OIL (net)	
Production (boe/d)	4,500 – 5,000
Liquids Weighting (%)	50%
Operating Income[1] ($MM)	~$25
Operating Netback ($/boe)	~$14
THERMAL OIL	
Bitumen Production (bbl/d)	7,500 – 8,500
Operating Income[1] ($MM)	~($50)
CORPORATE	
Production (boe/d)	12,000 – 13,500 (~82% liquids)
Funds Flow from Operations[1] ($MM)	~($99)
Net Debt ($MM)	~$35
Cash & Equivalents ($MM)	~$510
COMMODITY ASSUMPTIONS *(strip pricing as at July 5, 2016)*	
WTI (US$/bbl)	$42.61
Edmonton Par (C$/bbl)	$51.14
Western Canadian Select (C$/bbl)	$36.96
AECO Gas (C$/mcf)	$1.97
FX (US$/C$)	0.762

1) Operating Income and Funds Flow from Operations estimates reflect the mid-point of production guidance.

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 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 benefits expected to be realized by the Company from its light oil joint venture with Murphy (the “Murphy Transaction”), including the impact on the Company’s financial position and balance sheet strength; 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 Montney well drilling and completion costs expected to be realized by the Company, including from employing pad drilling; the Company’s expectation that its Duvernay interests will be self-funding after Murphy’s payment of the Capital Carry; the timing of drilling completion and commissioning operations in the Company’s Light Oil division; the timing of rig release of the 7-30 well; the number of drilling rigs expected to be used to drill the Company’s Montney and Duvernay 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 and completion plans, in particular, with respect to the Duvernay and Montney formations and the costs of such drilling and completion operations; the Company’s production guidance from its Light Oil and Thermal Oil projects; the impact that the Company’s grant of the Royalty will have on Athabasca; the Company’s forecasted annual operating netbacks of Hangingstone Project 1, the Company’s forecasted price of oil before the Royalty is payable; the timing of the ramp-up of production and of achieving plateau production from Hangingstone Project 1; the Company’s expectation that the shut-down of Hangingstone Project 1 operations as a result of the regional Fort McMurray fires will have no long lasting effects on the reservoir; that only minimal maintenance capital will be needed in respect of Hangingstone Project 1 in the initial years of operations; 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 Company’s financial and operational flexibility; 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; changes to royalty regimes, environmental risks and hazards; alternatives to and changing demand for petroleum products; 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 or in respect of the Royalty; 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 and senior secured notes; 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 most recent Annual Information Form (“AIF”) dated March10, 2016 that is 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.

Drilling Locations: the ~150 Montney inventory referenced in this News Release 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, 2015 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.