FOR IMMEDIATE RELEASE
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Athabasca Oil Corporation Announces Balance Sheet Refinancing and Strategic Update

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CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to announce a balance sheet refinancing transaction which marks the conclusion of a series of strategic steps undertaken over the past year to transform the Company. The comprehensive refinancing plan provides Athabasca multi-year funding certainty and a strong liquidity outlook that will allow the Company to continue to advance its strategic objectives and maintain business flexibility.

Athabasca has established itself as an intermediate oil weighted producer with a funded five-year growth outlook and exposure to several of the largest resource plays in Western Canada including the Montney, Duvernay and oil sands. A complementary asset base of high rate of return light oil opportunities and low decline thermal production positions the Company for strong financial sustainability and free cash flow generation in the current environment while maintaining significant exposure to improving oil prices.

Highlights of the refinancing plan include:

- **New term debt instrument –** entered into agreements to issue senior secured second lien notes due 2022 ("the "New Notes") in the amount of US$450 million. Proceeds will be directed towards the retirement of Athabasca's existing C$550 million second lien notes due November 2017 (the "Existing Notes") for which the Company has announced the commencement of a cash tender offer.
- **New reserve-based credit facility –** concurrently with the issuance of the New Notes, the establishment of a new $120 million credit facility supported by seven major financial institutions.
- **Contingent Bitumen Royalty ("Royalty") –** additional Royalty grant to Burgess Energy Holdings L.L.C. ("Burgess Energy") on the Leismer and Corner Leases for $90 million cash consideration under the same terms as its prior deals. Athabasca has now raised approximately $400 million cash proceeds in exchange for a sliding scale royalty on its thermal assets which is not triggered until oil prices are at least US$75/bbl WTI.
- **Hedging implementation –** hedged 12,000 bbl/d at an average price of approximately C$52.75/bbl Western Canadian Select ("WCS") for the remainder of 2017. The Company intends to hedge up to 50% of its corporate production this year to protect near term cash flow.
- **Strong reserve growth –** the refinancing transaction was supported by pro forma year-end 2016 proved plus probable reserves of 1,120 mmboe, representing approximately 210% per share year over year growth.

Athabasca maintains a strong financial position with pro forma net debt on closing of the refinancing transactions estimated at $290 million and $400 million of available liquidity. The Company anticipates sustainable free cash flow generation in 2018 under current strip pricing with net debt to cash flow of less than 2.5x at year-end 2018 and trending lower in subsequent years.

The balance sheet refinancing supports the Company's go-forward strategy:

- **Light Oil: Defined and Material Growth** – A scalable operated Montney position and funded Duvernay development through the joint venture with Murphy Oil Company Ltd.
- **Thermal Oil: Leverage to Oil Prices –** A large low decline asset base accelerates free cash flow generation with future low risk expansion options.
- **Financial Sustainability –** Maturing cash flow profile with strong sustainability metrics. A diverse asset base provides flexibility in future capital allocation decisions.

The Company is also pleased to provide its 2017 production and capital budget guidance which is adjusted for the Leismer acquisition effective February 1, 2017. Highlights include:

- **Corporate production of 36,000 – 40,000 boe/d (>90% liquids)**. Comprised of 29,000 – 32,500 bbl/d in Thermal Oil and 6,500 – 7,500 boe/d in Light Oil. The Company has an overall base decline of approximately 7.5%.
- **Capital program of $240 million.** Comprised of $105 million in Thermal Oil and $135 million in Light Oil.

Athabasca has a fully funded five-year development outlook capable of delivering a 30% per share production CAGR. The Company retains significant flexibility in future capital allocation decisions to react to operational results and market conditions.

Additional details on the refinancing transactions, 2017 guidance and an operational update are provided within this release.

Balance Sheet Refinancing

Athabasca has entered into agreements to issue the New Notes in the amount of US$450 million. The New Notes, due in 2022 will pay interest at a rate of 9.875% per year and are not subject to maintenance or financial covenants. The New Notes are secured by a second priority lien on substantially all of the assets of Athabasca.

The New Notes offering is expected to close on or about February 24, 2017, subject to customary closing conditions. Athabasca intends to use the net proceeds from the offering to repurchase for cash any and all of the Existing Notes pursuant to a cash tender offer. Details of the tender offer are outlined in a separate press release issued today.

In conjunction with the New Notes, the Company will establish a $120 million reserve-based credit facility supported by growth in its proved developed producing reserves. The new credit facility is syndicated with seven major financial institutions, with closing anticipated to occur concurrently with the New Notes.

RBC Capital Markets, LLC, Goldman, Sachs & Co., Credit Suisse and TD Securities acted as placement agents for Athabasca.

Athabasca maintains a strong financial position with current pro forma net debt of approximately $300 million and total liquidity of approximately $400 million. The Company anticipates sustainable free cash flow generation in 2018 with net debt to cash flow of less than 2.5x under current strip pricing and less than 1.5x under GLJ pricing at year-end 2018.

This press release shall not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of the New Notes in any state in which such offer, solicitation or sale would be unlawful. The New Notes have not been registered under the United States Securities Act of 1933, as amended, and may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirements thereof.

Hedging Update

The Company has commenced a risk management program designed to protect a base level of cash flow and support its capital plans. The Company intends to hedge a minimum of 20,000 bbl/d for the balance of 2017 with 12,000 bbl/d of WCS hedges already in place at an average price of approximately C$52.75/bbl. Going forward, a multi-year hedging program is expected to form a part of the Company's risk management strategy.

Contingent Bitumen Royalty

Athabasca has granted a Royalty to Burgess Energy on the recently acquired Leismer and Corner leases for $90 million of cash consideration. The Royalty follows the same structure as the existing thermal oil contingent bitumen royalties and ensures the assets are not encumbered at low commodity prices. The Royalty is based on a linear scale (0 – 12%) with a WCS benchmark. The minimum 2% trigger is US$60/bbl WCS at Leismer and Corner (US$75/bbl WTI assuming a US$15/bbl WCS differential). The Royalty is not expected to materially impact economics of future expansion phases or development projects and there are no associated commitments for development.

Over the past year Athabasca has raised approximately $400 million through the series of Royalty transactions with Burgess Energy. These transactions unlocked long dated resource value and facilitated the recent acquisition of top tier producing Leismer thermal assets.

Preliminary 2016 Results

Athabasca achieved its 2016 corporate guidance with annual production averaging approximately 12,000 boe/d (field estimates) compared to guidance of 11,800 boe/d. Capital spending for the full year was approximately $122 million, also in-line with prior guidance. Annual corporate volumes reflect the Murphy Oil Joint Venture which was completed in May 2016. Q4 2016 production averaged approximately 11,600 boe/d comprised of Light Oil at 3,300 boe/d (54% liquids) and Thermal Oil at 8,300 bbl/d.

Operations Update and 2017 Guidance

Thermal Oil

Leismer

Leismer averaged approximately 23,800 bbl/d (field estimates) for Q4 2016 with a 2.6x SOR. Athabasca intends to maintain a stable production base between 22,000 – 24,000 bbl/d for the foreseeable future. Operations will be focused on production optimization and drilling additional sustaining and infill wells. The Company has a well-defined development plan for the mid-term which includes the start-up of four predrilled infills on Pad L5, infill opportunities on Pads L3 and L4 and regulatory approval and operational readiness to expand Pad L2.

Hangingstone

Hangingstone averaged approximately 8,300 bbl/d (field estimates) for Q4 2016 with a 4.9x SOR. Volumes in recent months have been impacted by facility maintenance and ongoing pump conversions which have largely been completed by the end of January. The project is expected to reach name plate capacity of 12,000 bbl/d in 2018 with minimal maintenance capital expected within the first five years of operations.

Thermal Oil Guidance

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

Light Oil

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

At Placid, Athabasca currently has two rigs active in the field. 12 wells have been drilled to date and another eight wells are planned before breakup. Facilities construction is underway for a battery which will tie into Athabasca's owned and operated regional infrastructure network. The battery is expected to be in service at the beginning of the second quarter with capacity for growth up to 10,000 bbl/d and 36 mmcf/d.

The 7-30-60-23W5 ("7-30") pad was rig released in late September. The four wells were drilled with an average lateral length of approximately 2,350 meters and an average drilling cost of $3.1 million. Completion operations concluded in November and the pad was designed to test ball-drop versus plug and perf design. Of the three wells completed on the 7-30 pad, two were cased hole and one open hole for an average cost of $4.2 million per well. Completions operations on the fourth well have been delayed and the Company anticipates completing the well in conjunction with future drilling operations on this pad site.

The 7-30 pad came on production in December. Initial rates are meeting expectations with restricted IP30s of approximately 800 boe/d (278 bbl/mmcf free condensate). Regional volumes will remain restricted by facility capacity until the new Placid battery comes into service this spring.

Eight wells have been drilled on the 12-19-60-23 and 16-30-60-23 pads with an average lateral length of approximately 2,500 meters and an average cost of $3.2 million. These wells have been designed for plug and perf completions. Completion operations are underway and both pads are expected to be placed on production before breakup.

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

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

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

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

The 2017 program will include the spudding of 16 gross wells. The wells include a mix of pad development locations and delineation wells throughout the volatile oil window. Murphy intends to optimize well design with average lateral lengths increasing to approximately 2,800 meters and frac intensity up to approximately 2,000 lbs/ft (~3T/m). The program will target total lateral meters drilled of approximately

45,000 meters and this compares to Athabasca's initial 20 well appraisal campaign of approximately 27,000 meters since 2012.

The Company's partner, Murphy, currently has two rigs active in the field. The first two-well pad spud in November of 2016 at Kaybob West (surface location 1-18-64-20W5). The pad was rig released in January with average drill times of 22 days (spud to rig release) and an average lateral length of ~1,400 meters. Completion operations are underway with on-stream timing expected before breakup. Murphy intends to complete the well with proppant intensity of approximately 2,000 lbs/ft.

Drilling operations are underway on a two well pad at surface location 4-32-65-20W5 (2,650 meter average lateral length) and a three well pad at 11-18-64-20W5 (2,700 meter average lateral length). Both pads are expected to be rig released before breakup.

Light Oil Guidance

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

2017 Budget & Guidance Details

	Full Year
CORPORATE (net)	
Production[1] (boe/d)	36,000 – 40,000
Liquids Weighting (%)	~90%
Funds Flow from Operations[2] ($MM)	~$93
THERMAL OIL	
Bitumen Production[1] (bbl/d)	29,000 – 32,500
Operating Income[2] ($MM)	~$104
Capital Expenditures ($MM)	$105
LIGHT OIL	
Production (boe/d)	6,500 – 7,500
Operating Income[2] ($MM)	~$79
Capital Expenditures ($MM)	$135
COMMODITY ASSUMPTIONS *(strip pricing as at February 6)*	
WTI (US$/bbl)	$54.55
Edmonton Par (C$/bbl)	$67.41
Western Canadian Select (C$/bbl)	$51.97
AECO Gas (C$/mcf)	$2.66
FX (US$/C$)	0.763

Notes:
1) Production guidance reflects a January 31, 2017 closing date for the Statoil acquisition with Leismer volumes to be reported from February – December.
2) Corporate funds flow and operating income based on mid-points of guidance.

2016 Reserves Update (Pro Forma Statoil Acquisition)

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

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

Additional details on reserves will be provided in conjunction with Athabasca's year-end disclosure in March.

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

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

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

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

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.

For more information, please contact:
Media and Financial Community
Matthew Taylor
Vice President, Capital Markets and Communications
1-403-817-9104
mtaylor@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 five-year growth outlook and that such growth outlook is fully funded; the anticipated closing of the offering of New Notes and the $120 million credit facility and the use of proceeds therefrom; the benefits expected to be realized by the Company from offering of New Notes and the $120 million credit facility; estimates of sustainable free cash flow generation, net debt to cash flow levels and cash and cash equivalents and liquidity, for certain future periods; expectations with respect to future production hedging levels; estimates of 2017 corporate, Thermal Oil and Light Oil production levels and base decline rates; estimates of 2017 funds flow from operations, operating income and capital expenditures; the capability of the Company's five-year development outlook to deliver potential growth in per share production; the estimated impact of the Royalty on the economics of future expansion phases and development projects; future drilling and completion plans including numbers of wells and the timing thereof; the timing for achievement of name plate capacity at Hangingstone and expectations regarding maintenance capital within the first five years of operations; the timing of facilities construction and in service dates and the capacity thereof; the timing of completion operations; 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: closing of the offering of New Notes and the $120 million credit facility and that Athabasca and its security holders will obtain the anticipated benefits thereof; commodity prices for petroleum and natural gas; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct its business and the effects that such regulatory framework will have on the Company, including on the Company’s financial condition and results of operations; the Company’s financial and operational flexibility; the Company’s financial sustainability, the Company’s ability to accelerate development when prices recover; Athabasca’s cash-flow break-even commodity price; geological and engineering estimates in respect of Athabasca’s reserves and resources; the applicability of technologies for the recovery and production of the Company’s reserves and resources; the Company’s ability to demonstrate the quality of its asset base and to build large-scale projects; future capital expenditures to be made by the Company; future sources of funding for the Company’s capital programs; the Company’s future debt levels; the Company’s ability to obtain equipment in a timely and cost-efficient manner; the geography of the areas in which the Company is conducting exploration and development activities; 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: failure to complete the offering of New Notes and the $120 million credit facility on the terms or within the time frames anticipated or at all; fluctuations in market prices for crude oil, natural gas and bitumen blend; political and general economic, market and business conditions in Alberta, Canada, the United States and globally; changes to royalty regimes, environmental risks and hazards; alternatives to and changing demand for petroleum products; the potential for management estimates and assumptions to be inaccurate; dependence on Murphy as the Company’s joint venture participant in the Company’s Duvernay and Montney assets; the dependence on Murphy as the operator of the Company’s Duvernay assets; the substantial capital requirements of Athabasca’s projects and the ability to obtain financing for Athabasca’s capital requirements; operational and business interruption risks associated with the Company’s facilities; failure by counterparties to make payments or perform their operational or other obligations to Athabasca in compliance with the terms of contractual arrangements between Athabasca and such counterparties, and the possible consequences thereof; long term reliance on third parties; aboriginal claims; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; failure to meet development schedules and potential cost overruns; variations in foreign exchange and interest rates; factors affecting potential profitability; risks related to future acquisition and joint venture activities; reliance on, competition for, loss of, and failure to attract key personnel; uncertainties inherent in estimating quantities of reserves and resources; changes to Athabasca’s status given the current stage of development; litigation risk; risks and uncertainties inherent in SAGD and other bitumen recovery processes; risks related to hydraulic fracturing, including those related to induced seismicity; expiration of leases and permits; risks inherent in Athabasca’s operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources; risks related to gathering and processing facilities and pipeline systems; availability of drilling and related equipment and limitations on access to Athabasca’s assets; increases in costs could make Athabasca’s projects uneconomic; the effect of diluent and natural gas supply constraints and increases in the costs thereof; environmental risks and hazards; failure to accurately estimate abandonment and reclamation costs; reliance on third party infrastructure; seasonality; hedging risks; risks associated with maintaining systems of internal controls; insurance risks; claims made in respect of Athabasca’s operations, properties or assets; competition for, among other things, capital, export pipeline capacity and skilled personnel; the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits; risks related to Athabasca’s amended credit facilities and senior secured notes; and risks related to Athabasca’s common shares.

Also included in this press release are estimates of Athabasca's 2017 capital expenditures, funds flow from operations and operating income levels, which are based on the various assumptions as to production levels, commodity prices and currency exchange rates and other assumptions disclosed in this news release. To the extent any such estimate constitutes a financial outlook, it was approved by management and the Board of Directors of Athabasca on February 9, 2017, and is included to provide readers with an understanding of the funding of Athabasca's capital expenditure program in 2017 and an outlook for the Company's activities and results and readers are cautioned that the information may not be appropriate for other purposes. Management does not have firm commitments for all of the costs, expenditures, prices or other financial assumptions used to prepare the financial outlook or assurance that such operating results will be achieved and, accordingly, the complete financial effects of all of those costs, expenditures, prices and operating results are not objectively determinable. The actual results of operations of the Company and the resulting financial results may vary from the amounts set forth herein, and such variations may be material. The financial outlook contained in this New Release was made as of the date of this press release and the Company disclaims any intention or obligations to update or revise such financial outlook, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.

Reserves Data

The reserves data set forth above is based upon the reports of GLJ and D&M, each dated effective December 31, 2016 and December 31, 2015 and prepared in accordance with the Canadian Oil and Gas Evaluation Handbook. The price forecast used in the 2016 reserve evaluations is the January 1, 2017 GLJ price forecast, which is available on ITS website, www.gljpc.com, and will be contained in the Company's Annual Information Form for the year ended December 31, 2016, which will be filed on SEDAR (accessible at www.sedar.com) on or before March 31, 2017. The price forecast used in the 2015 reserve evaluations is the January 1, 2016 GLJ price forecast, which is available in the Company's Annual Information Form for the year ended December 31, 2015, which is accessible on SEDAR at www.sedar.com.

There are numerous uncertainties inherent in estimating quantities of bitumen, crude oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

All evaluations and reviews of future net revenue are stated prior to any provisions for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The after-tax net present value of the Company's properties reflects the tax burden on the properties on a stand-alone basis and utilizes the Company's tax pools. It does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the after-tax value of the Company, which may be significantly different. The Company's financial statements and the management's discussion and analysis should be consulted for information at the level of the Company.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to effects of aggregations. The estimated values of future net revenue disclosed in this press release do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

The reserve data provided in this news release presents only a portion of the disclosure required under National Instrument 51-101. All of the required information will be contained in the Company's Annual Information Form for the year ended December 31, 2016, which will be filed on SEDAR (accessible at www.sedar.com) on or before March 31, 2017.

Unaudited Financial Information

Certain financial and operating results included in this news release including, without limitation, capital spending and production information are based on unaudited estimated results. These estimated results are subject to change upon completion of the audited financial statements for the year ended December 31, 2016, and changes could be material.

Oil and Gas Information

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Initial Production Rates

The initial production rates provided in this News Release should be considered to be preliminary. Initial production rates disclosed herein may not necessarily be indicative of long term performance or of ultimate recovery.

Non-GAAP Financial Measures

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

Funds Flow from Operations is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Funds Flow from Operations measure allows management and others to evaluate the Company's ability to fund its capital programs and meet its ongoing financial obligations using cash flow internally generated from ongoing operating related activities.

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

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

The Net Debt measure in this News Release is calculated by subtracting the face value of the Company's long term debt less cash and equivalents. The Net Debt measure is not intended to represent other measures of financial position on the Company's balance sheet that are calculated in accordance with IFRS. The Net Debt financial measure allows management and others to evaluate the Company's funding position and utilization of debt within its capital structure.