ATHABASCA
OIL CORPORATION

FOR IMMEDIATE RELEASE
November 2, 2017

Athabasca Oil Corporation Announces 2017 Third Quarter Results

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to provide its 2017 third quarter results and an operations update. The quarter marks continued execution of Athabasca's strategy with strong consecutive quarterly cash flow growth supported by corporate production now in excess of 40,000 boe/d.

Third Quarter and Recent Highlights

- **Q3 2017 Operating and Financial Results**
  - Production of 36,133 boe/d (90% liquids), representing 143% year over year per share growth
    - Current production of approximately 41,000 boe/d (October estimate)
  - Consecutive quarter of strong cash flow growth, earnings and ongoing cost discipline
    - Funds flow of $34.4 million ($0.07 per share)
    - Net income of $5.1 million ($0.01 per share)
    - G&A of $2/boe, a 64% reduction year over year
    - Capital expenditures of $67.7 million
  - Net debt of $365 million (2.7x D/CF annualized) and strong liquidity supported by $174 million of cash and equivalents, a $183 million Duvernay capital carry balance and a $120 million credit facility
- **Light Oil – High Margin Liquids-Rich Growth**
  - Production of 7,875 boe/d (54% liquids), representing 108% per share growth over Q3 2016
    - Current production of 10,500 boe/d (October estimate)
  - Realized netbacks of ~$19/boe

  Placid Montney (70% working interest)
  - Recent IP30s of 1,206 boe/d (66% liquids) exceed upsized type curve expectation
  - Currently drilling a 6 well pad that is intended to maintain 2018 Light Oil volumes in excess of 10,000 boe/d

  Kaybob Duvernay (30% working interest)
  - 3 well volatile oil pad exceeds type curve with restricted IP30s of 795 boe/d (72% liquids)
  - Murphy planning to operate two rigs until break-up for significant volatile oil delineation
- **Thermal Oil – Underpins Low Corporate Decline and Free Cash Flow Generation**
  - Production of 28,258 bbl/d, representing 155% per share growth over Q3 2016
    - Current production of 30,400 bbl/d (October estimate)
  - Operating income of $38.6 million and $18.2 million of free cash flow
  - Realized netbacks of ~$15/bbl (~$18/bbl Leismer & ~$3/bbl Hangingstone)

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's near term focus is maximizing profitability and shareholder returns through modest activity in Light Oil and ongoing Thermal Oil optimization. Both divisions are positioned for accelerated operations and growth with commodity price 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
  - Current production in excess of 10,000 boe/d with scalable growth to 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 and established low decline production base
  - Significant free cash flow generation in the current environment
  - Reserve life index of over 70 years (proved plus probable)
- **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
  - Five year term debt with no financial covenants and strong liquidity

Financial and Operating Highlights

($ Thousands, unless otherwise noted)		3 months ended Sept. 30 2017		2016		9 months ended Sept. 30 2017		2016
CONSOLIDATED PRODUCTION								
Petroleum and natural gas volumes (boe/d)		**36,133**		11,848		**33,183**		12,098
LIGHT OIL DIVISION								
Petroleum and natural gas sales volumes (boe/d)		**7,875**		3,018		**6,197**		5,019
Light Oil operating income[1]	$	**13,748**	$	5,511	$	**37,001**	$	17,632
Light Oil operating netback[1] ($/boe)	$	**18.98**	$	19.85	$	**21.87**	$	12.82
Capital expenditures	$	**53,406**	$	18,920	$	**162,113**	$	55,095
Recovery of capital-carry through capital expenditures	$	**(6,092)**	$	(4,286)	$	**(30,265)**	$	(5,760)
THERMAL OIL DIVISION								
Bitumen production (bbl/d)		**28,258**		8,830		**26,986**		7,079
Thermal Oil operating income (loss)[1]	$	**38,610**	$	(6,088)	$	**78,345**	$	(41,079)
Thermal Oil operating netback[1] ($/bbl)	$	**14.66**	$	(6.80)	$	**10.64**	$	(20.99)
Capital expenditures[2]	$	**20,382**	$	3,754	$	**45,376**	$	6,857
CASH FLOW AND FUNDS FLOW								
Cash flow from operating activities	$	**49,488**	$	(18,990)	$	**24,637**	$	(51,297)
per share (basic)	$	**0.10**	$	(0.05)	$	**0.05**	$	(0.13)
Funds flow from operations[1]	$	**34,400**	$	(15,778)	$	**60,315**	$	(84,622)
per share (basic)	$	**0.07**	$	(0.04)	$	**0.12**	$	(0.21)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)								
Net income (loss) and comprehensive income (loss)	$	**5,113**	$	(33,032)	$	**181**	$	(157,331)
per share (basic and diluted)	$	**0.01**	$	(0.08)	$	**-**	$	(0.39)
SHARES OUTSTANDING								
Weighted average shares outstanding (basic)		**509,335,251**		405,556,092		**496,845,215**		405,357,248
Weighted average shares outstanding (diluted)		**513,332,423**		405,556,092		**502,283,110**		405,357,248
ACQUISITIONS AND FINANCINGS								
Leismer Corner Acquisition[3]	$	**(881)**	$	-	$	**(626,645)**	$	-
Net proceeds from sale of assets	$	**-**	$	(1,944)	$	**90,205**	$	390,394
Net proceeds from issuance of 2022 Notes	$	**-**	$	-	$	**542,117**	$	-
Repayment of 2017 Notes and term loan	$	**-**	$	-	$	**(550,000)**	$	(285,441)

As at ($ Thousands)		Sept. 30, 2017		Dec. 31 2016
LIQUIDITY AND INDEBTEDNESS				
Cash and cash equivalents	$	**174,076**	$	650,301
Restricted cash	$	**113,372**	$	107,012
Capital-carry receivable (current & LT portion – undiscounted)	$	**183,204**	$	213,469
Face value of long-term debt (current & LT portion)[4]	$	**562,950**	$	550,000

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 $435.9 million, common shares of $166.0 million and contingent payment obligations of $24.7 million for the nine months ended September 30, 2017.
4) Face value of the US dollar denominated 2022 Notes as at September 30, 2017 is US$450 million. The 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00=C$1.2510.

Operations Update

Light Oil

Production averaged 7,875 boe/d (54% liquids) in Q3 2017. October production averaged approximately 10,500 boe/d with volumes driven by the tie-in of Montney wells from last winter's program and representing approximately 175% per share growth since Q3 2016. The Company remains on track to achieve the upper end of its annual Light Oil guidance of 6,500 – 7,500 boe/d.

Light Oil operating income was $13.7 million ($18.98/boe netback). Capital expenditures totaled $47.3 million net with activity focused on completing two Montney pads, commencing the second half drilling program at Placid and ongoing Duvernay joint development operations. Operating expenses were $10.90/boe in Q3 2017 and were impacted by a 19 day planned turnaround at the Keyera Simonette gas plant. Operating expenses are expected to drop in Q4 2017 and into 2018 supported by additional production growth and field optimization.

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

At Placid the Company has established scale of operations with a high netback production base, ownership in strategic regional infrastructure and a multi-year low risk development inventory. The Montney asset is positioned for flexible, scalable and economic growth in the current price environment.

During the quarter Athabasca completed the remaining two pads (eight wells) from last winter's five multi-well pad program. The first pad (surface location 03-04-61-23W5) was placed on production in September and the second pad (surface location 7-33-60-20W5) is expected to be on production through permanent facilities in early November. IP30s from the 3-4 pad averaged 1,206 boe/d (66% liquids) supporting the previously increased type curve (IP30s 1,000 boe/d 57% liquids & 675 mboe EUR). The Company attributes stronger well performance to the higher proppant completion design which appears to yield a more effective reservoir stimulation. Extended production is supporting stronger liquids rates at higher flowing pressures when compared to the prior design as well as offsetting regional industry wells. Long term liquids yields are a significant driver in well economics.

Placid 2016/17 Winter Program		**IP30[1]**		**IP90[1]**		**IP180[1]**	
Pad Surface Location		*boe/d*	*% liquids*	*boe/d*	*% liquids*	*boe/d*	*% liquids*
07-30-60-23W5	On-stream December	813	70%	690	67%	657	61%
12-19-60-23W5 (Pod 2)[2]	On-stream April	821	51%	670	61%	705	55%
16-30-60-23W5[2]	On-stream April	1,053	50%	798	58%	824	52%
03-04-61-23W5[3]	**On-stream September**	**1,206**	**66%**	-	-	-	-
07-33-60-20W5	On-stream November	-	-	-	-	-	-

1) IPs reflect sales gas, free condensate and estimated plant based NGL recovery.
2) Peak 30 day rates reported on Pad 2 & 3 as the initial rates in April were temporarily restricted by spring road bans and the 16-day Keyera unplanned outage.
3) Includes IP30s for 3 wells and an IP27 for the 1-28 well which was initially shut-in during completions operations of the adjacent 7-33 pad.

The Company spud a six well pad in August (surface location 7-30-60-23W5 – Pod 2) with completions anticipated in Q1 2018. The Company views the 7-30 Pod 2 pad as a low risk capital efficient development that should maintain base Light Oil production levels through 2018. Decisions regarding 2018 activity 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 Athabasca 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, 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 objectives of driving near-term production and cash flow growth, delineation across all phase windows, optimizing well design and maximizing land retention.

The 2017/18 winter program is underway and Murphy expects to run two rigs until spring break-up. Planned operations include significant volatile oil delineation at Simonette, Kaybob West, Kaybob North and Kaybob East as well as condensate rich gas drilling Saxon. Murphy is testing a number of completion techniques in the initial wells, leveraging off their experience in the Eagle Ford oil window.

During the quarter a three well volatile oil pad at Kaybob West (11-18-64-20W5 surface location) had average restricted IP30s of 795 boe/d (72% liquids), exceeding Athabasca type well expectations of 530 boe/d.

Kaybob Duvernay Activity	**Area**	**Date**	**Restricted IP30[1]**	
Pad Location / UWI			*boe/d*	*% liquids*
2 well pad (Surface 04-32-064-20W5)				
16-36-64-21W5	Kaybob West Volatile Oil	On-stream June	1,790	75%
3-28-64-20W5		On-stream June	830	74%
3 well pad (11-18-064-20W5)				
16-23-64-21W5		On-stream July	780	72%
10-23-64-21W5	Kaybob West Volatile Oil	On-stream July	850	71%
13-24-64-21W5		On-stream July	760	74%
1 well pad (16-18-065-20W5)				
05-09-065-20W5	Kaybob West Volatile Oil	On Soak / Q4 test	-	-
2 well pad (05-29-064-20W5)				
10-36-64-21W5	Kaybob West Volatile Oil	Completed / Q4 On-stream	-	-
9-36-64-21W5				
2 well pad (15-16-063-24W5)				
00/7-29-63-24W5	Simonette Volatile Oil	Q4 Completion / Q1 On-stream	-	-
02/7-29-63-24W5				
2 well pad (12-29-064-18W5)				
14-36-64-19W5	Kaybob East Volatile Oil	Q4 spud	-	-

15-36-64-19W5				
3 well pad (16-03-062-23W5)				
13-09-62-23W5				
14-09-62-23W5	Saxon Condensate Rich Gas	Q4 Spud	-	-
15-09-62-23W5				

1) IPs reflect sales gas, free condensate and estimated plant based NGL recovery.

The Company remains encouraged by strong offsetting industry well results and robust activity levels (Shell, Encana and Chevron). The Duvernay competes 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$55/bbl WTI are approximately C$45/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 an inventory of approximately 1,500 drilling locations.

Thermal Oil

Production averaged 28,258 bbl/d in Q3 2017. Thermal Oil operating income was $38.6 million ($14.66/bbl) with $20.4 million of capital expenditures during the quarter. Resulting free cash flow was $18.2 million. Current Thermal Oil production is approximately 30,400 bbl/d (October estimate).

Leismer

Leismer production averaged 19,498 bbl/d in Q3 2017 which incorporated facility maintenance in July and August. October production averaged approximately 20,900 bbl/d.

The Company is taking deliberate steps to prudently manage reservoir performance and maximize profitability. Near-term operations are focused on production and steam optimization across the field and the start-up of predrilled infills on Pad L5 in 2018. The Company expects to manage production between 20,000 – 22,000 bbl/d.

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 over 30 years proven and over 70 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 8,760 bbl/d in Q3 2017 with $2.3 million of operating income. October production averaged approximately 9,500 bbl/d. Production is expected to continue to increase with steam chamber growth. Hangingstone is expected to require minimal capital over the next several years.

Balance Sheet, Hedging and Sustainability

Financial sustainability remains a core part of Athabasca's strategy and throughout 2017 the Company has focused on activities that drive increased margins and improve financial resiliency. 2017 capital has been primarily directed to the high margin Montney and Duvernay with Light Oil volumes currently in excess of 10,000 boe/d.

The Company manages its exposure to commodity prices through an active hedging program and intends to hedge up to 50% of 2018 volumes. The Company currently has 20,000 bbl/d hedged for the remainder of 2017 at an average price of ~C$50.75/bbl Western Canadian Select (heavy blend), 18,000 bbl/d for Q1 2018 at ~C$48/bbl, 11,000 bbl/d for Q2 2018 at ~C$48/bbl and 5,000 bbl/d for Q3 2018 at ~C$48/bbl.

The Company maintains a strong balance sheet with net debt at the end of Q3 2017 of $365 million (2.7x net debt to quarterly funds flow annualized). Liquidity is supported by $174 million of cash and equivalents, a $183 million Duvernay carry balance and a $120 million credit facility. The Company also has significant asset value in its established and operated Thermal and Light Oil infrastructure.

2017 Guidance and 2018 Outlook

Reaffirming 2017 Guidance

Athabasca's 2017 capital budget is unchanged at $210 million with annual corporate production expected to average approximately 35,000 boe/d.

	2017 Full Year
CORPORATE (net)	
Production (boe/d)	33,500 – 36,500
Liquids Weighting (%)	~91%
Funds Flow from Operations ($MM)	~$80
LIGHT OIL (net)	
Production (boe/d)	6,500 – 7,500
Operating Income ($MM)	~$60
Capital Expenditures ($MM)	$150
THERMAL OIL	
Bitumen Production (bbl/d)	27,000 – 29,000
Operating Income ($MM)	~$105
Capital Expenditures ($MM)	$60
COMMODITY ASSUMPTIONS	
WTI (US$/bbl)	$50.00
Western Canadian Select (C$/bbl)	$49.25
AECO Gas (C$/mcf)	$2.15
FX (US$/C$)	0.77

2018 Outlook

Management expects to align 2018 capital spending with corporate cash flow. The Company's assets afford it significant capital flexibility in both the Light Oil and Thermal Oil divisions.

Placid Montney activity has no near-term land expiries and a program of six to eight wells annually is expected to hold production flat. Drilling operations are underway on a six well development pad with completions expected to follow in Q1 2018. This base level of activity is expected to support Light Oil volume in excess of 10,000 boe/d for 2018.

In the Duvernay, funded growth is driven through the joint venture and the Company is protected by a capital carry on the first $1 billion of investment (7.5% capital exposure for a 30% WI). 2018 activity is expected to be consistent with the joint development agreement which contemplates approximately $350 million of gross investment (approximately $26 million net), up from approximately $200 million gross in 2017.

In Thermal Oil, the Company will continue to optimize capital and operations in order to maximize profitability and long-term recoveries.

Athabasca is firmly positioned as an intermediate producer and in 2018 expects to maintain production in excess of 40,000 boe/d (~90% liquids), approximately 15% growth year over year, with a modest capital program. The Company retains readiness to accelerate activity in both divisions with commodity price support. The 2018 capital budget and guidance will be released on December 6th.

Board Additions and Management Update

Athabasca is pleased to announce the recent appointments of Anne Downey and Henry Sykes as directors to the Company's Board of Directors, which is now comprised of seven members.

Ms. Downey has 40 years of upstream oil and gas experience at Gulf Canada, Petro-Canada and Statoil Canada. Ms. Downey previously held the role of VP Operations at Statoil Canada responsible for oil sands asset development, operations and technology strategy and implementation. Ms. Downey was selected to be an Industry member of the Alberta Government's Oil Sands Advisory Group.

Mr. Sykes has more than 35 years of legal and upstream oil and gas experience. Mr. Sykes was previously President and a director of MGM Energy from 2007-2014 and President of ConocoPhillips Canada from 2001-2006. Prior to this Mr. Sykes was a partner at Bennett Jones, specializing in mergers and acquisitions, corporate and securities law in Calgary.

The Company is also pleased to announce a key addition to Athabasca's executive leadership team with the appointment of Angela Avery as General Counsel and Vice President of Business Development. Ms. Avery has over 20 years of diverse legal and business experience within the energy industry with a focus on major transactions. Prior to Athabasca, Ms. Avery held senior management roles at ConocoPhillips including Chief Compliance Officer of the global business based in Houston and Vice President, Law and Business Development of the Canadian business.

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”, “view”, ”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 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 November 2, 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 News Release includes 34 proved undeveloped and 12 probable undeveloped locations, for a total of 46 undeveloped booked 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", "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) is calculated as Funds Flow from Operations divided by the number of weighted average basic 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 Leismer Project measures also include gas revenues received. 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.