Management's Discussion and Analysis

Q3 2016

ATHABASCA
OIL CORPORATION

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Management's Discussion and Analysis

This Management's Discussion and Analysis of the financial condition and results of operations ("MD&A") of Athabasca Oil Corporation ("Athabasca" or the "Company") is dated November 10, 2016 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2015 and 2014 and the unaudited condensed interim consolidated financial statements of the Company for the three and nine months ended September 30, 2016. These financial statements, including the comparative figures, were prepared in accordance with International Financial Reporting Standards ("IFRS"). This MD&A contains forward looking information based on the Company's current expectations and projections. For information on the material factors and assumptions underlying such forward looking information, refer to the "Forward Looking Information" advisory on page 20 of this MD&A. See "Reserves and Resource information" on page 23 for important information regarding the Company's reserves and resource information included in this MD&A. For a listing of abbreviations, refer to "Abbreviations" on page 24 of this MD&A. Additional information relating to Athabasca is available on SEDAR at www.sedar.com, including the Company's most recent Annual Information Form dated March 10, 2016 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "ATH".

BUSINESS OVERVIEW

The Company is focused on the exploration and development of unconventional oil resource plays in Alberta, Canada. Athabasca is organized into two divisions:

Light Oil

Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs utilizing horizontal drilling and multi-stage hydraulic fracturing technology. Development has been focused in Saxon/Placid ("Greater Placid area") and Kaybob ("Greater Kaybob area") near the town of Fox Creek, Alberta. Athabasca has a 70% operated working interest in 60,000 gross acres of Montney lands within the Greater Placid area, of which 25,000 acres are considered commercially prospective, with a potential inventory estimated between 150 - 200(1) gross drilling locations. Athabasca also has a 30% non-operated interest in over 200,000 gross acres of commercially prospective Duvernay lands in the Greater Kaybob area at various stages of delineation and development with a potential inventory of approximately 1,500(1) gross drilling locations. Development to date in the Light Oil Division has resulted in the booking of approximately 65 MMboe of Proved plus Probable Reserves (100%) as of December 31, 2015(2). During the nine months ended September 30, 2016, the Light Oil Division produced 5,019 boe/d (net).

Thermal Oil

Athabasca's Thermal Oil Division consists of four major project areas in the Athabasca region of northeastern Alberta. The primary development focus is in the Hangingstone area where the Company is currently ramping up its first project, a 12,000 bbl/d SAGD project ("Project 1"). Development to date has resulted in the booking of approximately 225 MMbbl(2) of Proved plus Probable Reserves and 0.6 billion barrels (risked)(2) (0.8 billion barrels unrisked)(2) of Best Estimate Contingent Resources in the Hangingstone area. During the nine months ended September 30, 2016, the Thermal Oil Division produced 7,079 boe/d.

Athabasca's Thermal Oil exploration areas consist of Dover West Leduc Carbonates, Dover West Sands and Birch. Development targets include oil sands in the McMurray and Wabiskaw formations as well as carbonates in the Leduc formation. The Company expects to produce its recoverable bitumen from the exploration areas using in-situ recovery methods such as SAGD or other suitable experimental technologies such as TAGD. Development to date has resulted in the booking of approximately 3.0 billion barrels (risked)(2) (5.1 billion barrels unrisked)(2) of best estimate Contingent Resources in the Company's Thermal Oil exploration areas.

(1) Refer to "Advisories and Other Guidance" beginning on page 20 for additional information regarding the Company's drilling locations.
(2) Based on the reports of Athabasca's independent reserve evaluators effective December 31, 2015. The Murphy Transaction (discussed below) was completed on May 13, 2016 and resulted in the sale of approximately 38 MMboe of Proved plus Probable Reserves from the Light Oil Division based on Management's best estimate. Refer to page 20 and the AIF for additional important information about the Company's Reserves and Contingent Resources.

SELECTED FINANCIAL INFORMATION

The following tables summarize selected financial information of the Company for the periods indicated:

($ Thousands, except volume, boe and share amounts)	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
CONSOLIDATED PRODUCTION				
Petroleum and natural gas volumes (boe/d)	11,848	7,250	12,098	6,207
LIGHT OIL DIVISION				
Petroleum and natural gas sales volumes (boe/d)	3,018	5,145	5,019	5,491
Light Oil Operating Income[(1)]	$ 5,511	$ 6,096	$ 17,632	$ 23,376
Light Oil Operating Netback[(1)] ($/boe)	$ 19.85	$ 12.88	$ 12.82	$ 15.60
Capital expenditures	$ 18,920	$ 31,465	$ 55,095	$ 125,667
Recovery of capital-carry through capital expenditures	$ (4,286)	$ —	$ (5,760)	$ —
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	8,830	2,105	7,079	716
Bitumen sales volumes (bbl/d)	9,744	1,956	7,138	660
Thermal Oil Operating Loss[(1)(2)]	$ (6,088)	$ (12,146)	$ (41,079)	$ (12,146)
Thermal Oil Operating Netback ($/bbl)[(1)(2)]	$ (6.80)	$ (73.67)	$ (20.99)	$ (73.67)
Capital expenditures	$ 3,754	$ 9,366	$ 6,857	$ 111,073
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ (18,990)	$ (17,933)	$ (51,297)	$ (12,031)
Cash flow from operating activities per share (basic and diluted)	$ (0.05)	$ (0.04)	$ (0.13)	$ (0.03)
Funds Flow from Operations[(1)]	$ (15,778)	$ (24,223)	$ (84,622)	$ (17,035)
Funds Flow from Operations per share (basic and diluted)[(1)]	$ (0.04)	$ (0.06)	$ (0.21)	$ (0.04)
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss	$ (33,032)	$ (38,241)	$ (157,331)	$ (92,398)
Net loss and comprehensive loss per share (basic and diluted)	$ (0.08)	$ (0.09)	$ (0.39)	$ (0.23)
SHARES OUTSTANDING				
Weighted average shares outstanding (basic and diluted)	405,556,092	403,396,304	405,357,248	402,933,671
FINANCING AND DIVESTITURES				
Promissory note proceeds	$ 133,892	$ 150,000	$ 133,892	$ 450,000
Cash proceeds from sale of assets	$ (1,944)	$ 610	$ 390,394	$ 646
Repayment of long-term debt	$ —	$ (746)	$ (285,441)	$ (2,082)
Derivative proceeds upon repayment of long-term debt	$ —	$ —	$ 40,956	$ —

(1) Refer to "Advisories and Other Guidance" beginning on page 20 for additional information on Non-GAAP Financial Measures.

(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 Project 1 will continue to improve as production increases.

As at ($ Thousands)	September 30, 2016	December 31, 2015
BALANCE SHEET ITEMS		
Cash and cash equivalents	$ 535,477	$ 559,487
Short-term investments	$ 35,000	$ —
Promissory note	$ —	$ 133,892
Restricted cash	$ 103,827	$ —
Capital-carry receivable (current and long-term portion - discounted)	$ 188,448	$ —
Total assets	$ 3,017,285	$ 3,462,442
Long-term debt[(1)]	$ 545,126	$ 838,205
Shareholders' equity	$ 2,333,523	$ 2,482,140

(1) As at September 30, 2016, the face value of the Company's long-term debt was $550.0 million (December 31, 2015 - $856.8 million).

HIGHLIGHTS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2016

Light Oil Division

- On May 13, 2016, Athabasca closed a strategic joint venture with Murphy Oil Company Ltd. ("Murphy") to develop the Montney and Duvernay formations in the Greater Kaybob and Greater Placid areas. As part of the transaction, Athabasca sold an operated 70% interest in its Greater Kaybob area assets and a non-operated 30% interest in its Greater Placid area assets for gross proceeds of $486.5 million.
- For the three and nine months ended September 30, 2016, Athabasca produced 3,018 boe/d (46% liquids) and 5,019 boe/d (49% liquids), respectively, in the Light Oil Division, compared to 5,145 boe/d (48% liquids) and 5,491 boe/d (48% liquids) during the same periods in the prior year. The lower production was primarily due to the sale of the Light Oil joint venture assets to Murphy, partially offset by production from new wells coming on stream in 2015 and 2016.
- During the three months ended September 30, 2016, Athabasca's Light Oil Operating Netback(1) was $19.85/boe, compared to $12.88/boe during the same period in the prior year, primarily due to lower operating costs. During the nine months ended September 30, 2016, the Company's Light Oil Operating Netback(1) was $12.82/boe, compared to $15.60/boe during the same period in the prior year, primarily due to lower underlying commodity prices, partially offset by lower operating costs.
- Athabasca spent $44.0 million on capital projects in the Greater Placid area during the nine months ended September 30, 2016. The Company completed and brought on stream four Montney wells that had been drilled in the prior two years. Athabasca also commenced a 12-well (gross) winter drilling program consisting of three four-well pads with three of the 12 wells being rig-released at the end of the third quarter.
- Athabasca spent $11.1 million ($5.4 million net of the capital-carry) on capital projects in the Greater Kaybob area during the nine months ended September 30, 2016 primarily to complete and bring on stream a four-well (gross) Duvernay pad.

Thermal Oil Division

- On June 17, 2016, Athabasca sold a Contingent Bitumen Royalty ("Royalty") on its Thermal Oil assets to Burgess Energy Holdings L.L.C. ("Burgess") for gross cash proceeds of $128.5 million whereby Athabasca will pay Burgess a sliding-scale royalty of 0% - 6% based on Athabasca's realized bitumen price (C$), which is determined net of diluent, transportation and storage costs. On November 10, 2016, Athabasca closed an upsizing of the Royalty for additional gross cash proceeds of $128.5 million, bringing the total proceeds received to $257.0 million. Athabasca will now pay Burgess a sliding-scale royalty of 0% - 12% based on Athabasca's realized bitumen price (C$).
- During the three and nine months ended September 30, 2016, Athabasca's bitumen production averaged 8,830 bbl/d and 7,079 bbl/d in the Thermal Oil Division, respectively, compared to 2,105 bbl/d and 716 bbl/d during the same periods in the prior year. Athabasca achieved first oil at Project 1 during the third quarter of 2015 and continues to ramp-up the project toward its facility nameplate of 12,000 bbl/d which is currently anticipated in 2018.
- The ramp-up of Project 1 operations was impacted by a 19-day shutdown of the central processing facility in May as a result of the regional Fort McMurray wildfires. Athabasca resumed operations at Project 1 near the end of May with no damage to the facility, field pipelines or well sites.
- The Thermal Oil Operating Netback(1) for the three and nine months ended September 30, 2016 was $(6.80)/bbl and $(20.99)/bbl, respectively, compared to $(73.67)/bbl during the same periods in the prior year, primarily due to higher production volumes and improved commodity prices for bitumen during 2016.

Corporate

- During the three and nine months ended September 30, 2016, the Company's corporate production averaged 11,848 boe/d and 12,098 boe/d, compared to 7,250 boe/d and 6,207 boe/d during the same periods in the prior year. The net increases in production were primarily due to the ramp up of production at Hangingstone Project 1 in the Thermal Oil Division, partially offset by lower production due to the sale of Light Oil assets to Murphy in the second quarter of 2016.
- On June 17, 2016, Athabasca repaid its US$225.0 million senior secured term loan (the "Term Loan") at par for C$285.4 million. Athabasca also unwound its US dollar forward contract associated with the Term Loan for net proceeds of C$41.0 million.
- On August 29, 2016, the final promissory note issued to Athabasca on the sale of the Company's 40% interest in the Dover oil sands project matured and Athabasca received a cash payment of $138.5 million.
- Following completion of the sale of the upsized Royalty on November 10, 2016, Athabasca had Liquidity(1) of approximately $700 million consisting of cash, cash equivalents and short-term investments. As at September 30, 2016, the Company also had $213.5 million in capital-carry receivable (undiscounted) remaining from Murphy that will be used to fund Light Oil development.

(1) Refer to "Advisories and Other Guidance" beginning on page 20 for additional information on Non-GAAP Financial Measures.

SALE OF ASSETS

Sale of Light Oil assets

On January 27, 2016, Athabasca entered into a purchase and sale agreement to form a strategic joint venture with Murphy to develop the Montney and Duvernay formations in the Greater Kaybob and Greater Placid areas. As part of the transaction, Athabasca sold an operated 70% interest in its Greater Kaybob area assets and a non-operated 30% interest in its Greater Placid area assets for gross proceeds of $486.5 million.

The Murphy Transaction was completed on May 13, 2016. At the date of closing, Athabasca received $267.5 million in cash, including purchase price adjustments from the January 1, 2016 effective date. Additional consideration of $219.0 million (undiscounted) in the form of a capital-carry in the Greater Kaybob area, whereby Murphy will fund 75% of Athabasca's share of development capital up to a maximum five year period, was recognized by Athabasca. The carry supports approximately $1 billion of Duvernay investment over the next four to five years of which Athabasca’s financial exposure is limited to $75 million to retain its 30% working interest. The following table summarizes the net proceeds from the sale of assets to Murphy:

($ Thousands)		
Cash proceeds	$	267,479
Greater Kaybob capital-carry receivable (undiscounted)		219,038
Gross proceeds from sale of assets		486,517
Discount applied to Greater Kaybob capital-carry receivable[1]		(30,390)
Transaction costs and purchase price adjustments		(5,664)
Net proceeds from sale of assets to Murphy (discounted)	$	450,463

(1) The discount applied to the capital-carry reflects the time value of money of the receivable which is anticipated to be collected within five years.

Sale of Contingent Bitumen Royalty

On June 17, 2016, Athabasca sold a Royalty on each of its Thermal Oil assets to Burgess for aggregate gross cash proceeds of $128.5 million whereby Athabasca will pay Burgess a sliding-scale royalty ranging from 0% - 6% based on Athabasca’s realized bitumen price for each Thermal Oil asset. The realized bitumen price for each asset is calculated as the blended bitumen sales price received less diluent, transportation, storage and marketing costs. Burgess has the option of either receiving the Royalty in cash or in kind. The Royalty has no associated commitments to develop future expansions or projects.

On November 10, 2016, Athabasca closed an upsizing of the Royalty sold to Burgess for additional gross cash proceeds of $128.5 million, bringing the total proceeds to $257.0 million. The upsized Royalty will be calculated on a sliding scale ranging from 0% - 12% (previously 0% - 6%) of Athabasca’s realized bitumen price for each Thermal Oil asset. All remaining terms of the Royalty are unchanged.

The following table summarizes the expanded Royalty rates applicable at different realized bitumen price ranges:

Hangingstone		Other Thermal Oil exploration areas [1]	
Realized Bitumen Price ($/bbl)	Royalty rate	Realized Bitumen Price ($/bbl)	Royalty rate
Below $50/bbl	--	Below $60/bbl	--
$50/bbl to $69.99/bbl	2%	$60/bbl to $79.99/bbl	2%
$70/bbl to $89.99/bbl	4%	$80/bbl to $99.99/bbl	4%
$90/bbl to $109.99/bbl	6%	$100/bbl to $119.99/bbl	6%
$110/bbl to $129.99/bbl	8%	$120/bbl to $139.99/bbl	8%
$130/bbl to $149.99/bbl	10%	$140/bbl to $159.99/bbl	10%
$150/bbl and above	12%	$160/bbl and above	12%

(1) Other Thermal Oil exploration areas consists of Birch, Dover West, and Grosmont.

Consistent with the original agreement, the upsized Royalty has been structured so that the assets will not be encumbered at lower pricing levels nor is it expected to materially impact the economics of future Hangingstone Expansion phases or other future Thermal Oil exploration projects. Oil prices would have to reach approximately US$75/bbl WTI (at nameplate capacity of 12,000 bbl/d) before the first 1% Royalty is triggered[1]. At this pricing level, Project 1 is estimated to have an annual operating netback of approximately $120 million (net of $4 million royalty). There are no associated commitments to develop future expansions or projects.

(1) WTI based on a 0.8 US$/C$ foreign exchange assumption and US$15/bbl differential between WCS and WTI. Royalties are calculated and payable on a monthly basis.

RESULTS OF OPERATIONS

Business Environment

The following table summarizes the key commodity price benchmarks for the three and nine months ended September 30, 2016 and 2015:

	Three months ended September 30,			Nine months ended September 30,		
Monthly average	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)	$ 44.94	$ 46.43	(3)%	$ 41.33	$ 51.00	(19)%
West Texas Intermediate (WTI) (C$/bbl)	$ 58.87	$ 60.82	(3)%	$ 54.56	$ 64.26	(15)%
Western Canadian Select (WCS) (C$/bbl)	$ 41.01	$ 43.29	(5)%	$ 36.30	$ 47.47	(24)%
Edmonton Par (C$/bbl)	$ 54.66	$ 56.17	(3)%	$ 50.00	$ 58.53	(15)%
Edmonton Condensate (C5+) (C$/bbl)	$ 55.31	$ 56.94	(3)%	$ 52.48	$ 60.72	(14)%
Differential:						
WTI vs. WCS (US$/bbl)	$ (13.63)	$ (13.38)	(2)%	$ (13.83)	$ (13.33)	(4)%
WTI vs. WCS (C$/bbl)	$ (17.86)	$ (17.53)	(2)%	$ (18.26)	$ (16.79)	(9)%
Natural gas:						
NYMEX Henry Hub (US$/MMBtu)	$ 2.81	$ 2.80	— %	$ 2.29	$ 2.77	(17)%
AECO (C$/GJ)	$ 2.20	$ 2.75	(20)%	$ 1.76	$ 2.63	(33)%
Foreign exchange:						
USD : CAD	1.31	1.31	— %	1.32	1.26	5 %

The price of WTI for crude oil sales at Cushing, Oklahoma is the primary benchmark for crude oil pricing in North America. The price Athabasca receives for its oil production in both its Light Oil and Thermal Oil Divisions is primarily driven by the price of WTI, the foreign exchange rate, transportation costs and quality differentials. During the three and nine months ended September 30, 2016, the WTI price declined by 3% and 19%, respectively, compared to the same periods in the prior year primarily due to continuing global over-supply of petroleum production. The majority of the WTI price decline occurred during the first quarter of 2016, with the second and third quarters of 2016 averaging approximately US$45/bbl.

As North American crude oil prices are primarily set by U.S. benchmark prices, declines in the value of the Canadian dollar relative to the US dollar partially offset the negative impact of declining oil prices. During the nine months ended September 30, 2016, the value of the Canadian dollar declined relative to the US dollar by 5% compared to the same period in the prior year. During the three months ended September 30, 2016, the value of the Canadian dollar relative to the US dollar remained unchanged compared to the same period in the prior year.

The WCS price at Hardisty, Alberta is the primary benchmark for Athabasca's blended bitumen sales. The WCS price trades at a wider differential to the WTI price compared to lighter crude oil products. Compared to the same periods in the prior year, the WCS price declined by 5% and 24%, respectively, during the three and nine months ended September 30, 2016.

The Edmonton Par price is the primary benchmark for crude oil sales in the Company's Light Oil Division. For the three and nine months ended September 30, 2016, the average Edmonton Par price declined by 3% and 15%, respectively, compared to the same periods in the prior year.

The Edmonton Condensate (C5+) price is the primary benchmark for condensate and natural gas liquids sales in the Company's Light Oil Division. In the Thermal Oil Division, the Edmonton Condensate (C5+) price is the primary benchmark for diluent purchases which Athabasca utilizes in the blending process at Project 1 in order to deliver produced bitumen to the market. For the three and nine months ended September 30, 2016, the average Edmonton Condensate (C5+) price declined by 3% and 14%, respectively, compared to the same periods in the prior year.

During the three and nine months ended September 30, 2016, the AECO price declined by 20% and 33%, respectively, compared to the same periods in the prior year. In the Thermal Oil Division, the AECO price is the primary benchmark for natural gas purchases consumed by Athabasca in order to generate steam which is used for the SAGD recovery process. The AECO gas price was also the primary benchmark for Athabasca's natural gas sales in the Light Oil Division during the first three quarters of 2015 as Athabasca primarily delivered its sales product on the Alliance pipeline. In the fourth quarter of 2015, Athabasca began delivering sales product on the Fort Chicago pipeline and the average NYMEX gas price became the primary benchmark for natural gas sales in the Light Oil Division. For the nine months ended September 30, 2016, the average NYMEX price declined by 17% compared to the same period in the prior year.

Athabasca typically realizes lower prices for its oil and gas sales compared to benchmark prices as a result of transportation costs, discounts applied due to limited North American pipeline capacity and quality differentials.

Light Oil Division

Operating Results

The following tables summarize the Light Oil operating results for the three and nine months ended September 30, 2016 and 2015:

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
SALES VOLUMES				
Oil (bbl/d)	1,126	1,682	2,026	1,993
Natural gas (Mcf/d)	9,841	15,902	15,401	17,014
Natural gas liquids (bbl/d)	252	812	427	662
Total (boe/d)	3,018	5,145	5,019	5,491
Consisting of:				
Greater Placid area (boe/d)	1,818	939	1,823	987
% liquids	42%	42%	48%	47%
Greater Kaybob area (boe/d)	1,200	4,206	3,196	4,504
% liquids	51%	50%	49%	49%
REALIZED PRICES				
Oil ($/bbl)	$ 53.01	$ 59.25	$ 44.51	$ 54.63
Natural gas ($/Mcf)	2.69	2.78	1.86	2.81
Natural gas liquids ($/bbl)	15.34	21.29	19.76	25.94
Realized price ($/boe)	29.84	31.34	25.34	31.66
Royalties ($/boe)	(0.72)	(2.10)	(0.89)	(1.75)
Operating and transportation expenses[1] ($/boe)	(9.27)	(16.36)	(11.63)	(14.31)
LIGHT OIL OPERATING NETBACK[2] ($/boe)	$ 19.85	$ 12.88	$ 12.82	$ 15.60

(1) For the three and nine months ended September 30, 2016, operating and transportation expenses include midstream revenues of nil/boe and $0.15/boe, respectively (September 30, 2015 - $0.43, $0.58).
(2) Refer to "Advisories and Other Guidance" beginning on page 20 for additional information on Non-GAAP Financial Measures.

($ Thousands)	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Petroleum and natural gas sales	$ 8,285	$ 14,832	$ 34,850	$ 47,462
Midstream revenue	5	203	842	871
Royalties	(199)	(992)	(1,227)	(2,629)
Operating and transportation expenses	(2,580)	(7,947)	(16,833)	(22,328)
LIGHT OIL OPERATING INCOME[1]	$ 5,511	$ 6,096	$ 17,632	$ 23,376

(1) Refer to "Advisories and Other Guidance" beginning on page 20 for additional information on Non-GAAP Financial Measures.

During the three and nine months ended September 30, 2016, Athabasca's Light Oil production was lower by 41% and 9% compared to the same periods in the prior year averaging 3,018 boe/d and 5,019 boe/d, respectively. The lower production was primarily due to the sale of the Light Oil joint venture assets to Murphy on May 13, 2016, partially offset by production from four Duvernay wells brought on stream in the fourth quarter of 2015 and 10 wells (four Montney, six Duvernay) coming on stream during 2016.

Realized prices decreased by 5% and 20% during the three and nine months ended September 30, 2016 to $29.84/boe and $25.34/boe, respectively, compared to the same periods in the prior year. The declines were primarily due to lower underlying commodity prices for oil, natural gas and natural gas liquids. Consistent with the change in the WTI benchmark price, the majority of the declines in Athabasca's realized prices occurred during the first quarter of 2016.

Compared to the same periods in the prior year, operating and transportation expenses decreased by 43% to $9.27/boe during the three months ended September 30, 2016, and by 19% to $11.63/boe during the nine months ended September 30, 2016. The declines in operating and transportation expenses per boe were primarily due to cost saving initiatives and equalizations.

Segment Loss

The following table summarizes the Light Oil Segment loss for the three and nine months ended September 30, 2016 and 2015:

($ Thousands)	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Light Oil Operating Income[1]	$ 5,511	$ 6,096	$ 17,632	$ 23,376
Depletion of oil and gas assets	(5,050)	(14,509)	(25,016)	(45,853)
Depreciation of infrastructure assets	(243)	(684)	(1,040)	(2,464)
Loss on sale of assets	(2,084)	—	(7,668)	—
Exploration expense and other	(24)	(142)	(23)	(753)
LIGHT OIL SEGMENT LOSS	$ (1,890)	$ (9,239)	$ (16,115)	$ (25,694)

(1) Refer to "Advisories and Other Guidance" beginning on page 20 for additional information on Non-GAAP Financial Measures.

Depletion of oil and gas assets declined by $9.5 million and $20.8 million during the three and nine months ended September 30, 2016 compared to the same periods in the prior year. The declines were primarily due to lower production from the sale of the Light Oil joint venture assets to Murphy on May 13, 2016, lower depletion rates resulting from reserve additions in the Light Oil Division and lower average carrying values of property, plant and equipment in the Light Oil Division as a result of impairment losses incurred during the fourth quarter of 2015. The producing Light Oil properties, including estimated future development costs, are depleted using a unit-of-production method based on estimated Proved plus Probable Reserves. Major infrastructure, including the Division's oil batteries, gas processing facilities and delivery infrastructure, are depreciated on a straight-line basis over the estimated useful life of the components.

During the three and nine months ended September 30, 2016, Athabasca recognized a loss on sale of assets of $2.1 million and $7.7 million, respectively, primarily relating to closing adjustments and transaction costs associated with the Murphy Transaction.

Thermal Oil Division

Operating results

The following tables summarize the Thermal Oil operating results for the three and nine months ended September 30, 2016 and 2015:

	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
VOLUMES				
Bitumen production (bbl/d)	8,830	2,105	7,079	716
Bitumen sales (bbl/d)	9,744	1,956	7,138	660
Blended bitumen sales (bbl/d)	13,286	2,514	9,952	848
Bitumen sales consists of:				
Bitumen sales capitalized (bbl/d)	—	164	—	56
Bitumen sales recognized in income (bbl/d)	9,744	1,792	7,138	604
	9,744	1,956	7,138	660
REALIZED PRICES				
Blended bitumen sales ($/bbl)	$ 37.04	$ 29.39	$ 31.49	$ 29.39
Bitumen sales ($/bbl)	$ 28.56	$ 17.54	$ 20.61	$ 17.54
Royalties ($/bbl)	(0.17)	(0.11)	(0.15)	(0.11)
Operating expenses - non-energy ($/bbl)	(18.02)	(57.58)	(22.42)	(57.58)
Operating expenses - energy ($/bbl)	(5.20)	(20.16)	(5.69)	(20.16)
Transportation and marketing ($/bbl)	(11.97)	(13.36)	(13.34)	(13.36)
THERMAL OIL OPERATING NETBACK[1] ($/bbl)	$ (6.80)	$ (73.67)	$ (20.99)	$ (73.67)

(1) Refer to "Advisories and Other Guidance" beginning on page 20 for additional information on Non-GAAP Financial Measures.

($ Thousands)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Blended bitumen sales	$ 45,276	$ 6,163	$ 85,878	$ 6,163
Cost of diluent	(19,674)	(3,272)	(45,575)	(3,272)
Total bitumen sales	25,602	2,891	40,303	2,891
Royalties	(152)	(18)	(291)	(18)
Operating expenses - non-energy	(16,152)	(9,493)	(43,846)	(9,493)
Operating expenses - energy	(4,658)	(3,323)	(11,126)	(3,323)
Transportation and marketing	(10,728)	(2,203)	(26,119)	(2,203)
THERMAL OIL OPERATING LOSS[1]	$ (6,088)	$ (12,146)	$ (41,079)	$ (12,146)

(1) Refer to "Advisories and Other Guidance" beginning on page 20 for additional information on Non-GAAP Financial Measures.

During the three and nine months ended September 30, 2016, the Company averaged 8,830 bbl/d and 7,079 bbl/d of bitumen production, respectively, compared to 2,105 bbl/d and 716 bbl/d during the same periods in the prior year. Athabasca achieved first oil at Project 1 during the third quarter of 2015.

On May 5, 2016, Athabasca shut-down Project 1 for 19 days due to the regional Fort McMurray wildfires. The decision to shut down the well sites and central processing facility was due to elevated safety risks from the fire's proximity to Project 1. Athabasca resumed operations at Project 1 near the end of May with production reaching pre-fire levels by mid-June. The fires caused no damage to the facility, field pipelines or well sites.

Athabasca has completed an update to the Company's internal reservoir simulation that is based on a detailed geological interpretation of the reservoir from extensive delineation drilling prior to sanctioning the project, continuous temperature and pressure monitoring across the field and an annual 4D seismic monitoring program. Gathered data supports that the reservoir is bounded, pressure has stabilized and steam conditions are continuing to grow vertically which will drive higher oil volumes and lower SORs with time. The revised model reflects continued but slower vertical steam chamber growth than previously expected with the facility projected to achieve design capacity of 12,000 bbl/d in 2018. This revised outlook is not anticipated to impact long-term oil recoveries.

The Thermal Oil Operating Netback for the three and nine months ended September 30, 2016 was $(6.80)/bbl and $(20.99)/bbl, compared to $(73.67)/bbl during the same periods in the prior year. The improvements in the Thermal Oil Operating Netback were primarily due to higher production volumes and higher realized prices for bitumen as a result of lower quality differentials.

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. Excluding the impact of the regional Fort McMurray wildfires in May of 2016, operating and transportation costs per barrel from Project 1 have continued to improve each quarter as production increases.

Operating costs consist of energy and non-energy related costs. Energy operating costs include natural gas which is used to create steam for the SAGD recovery process and electricity to power the facility. Non-energy operating costs consist of all other operational expenditures relating to lifting costs. Transportation and marketing expenditures primarily consist of take or pay commitments to deliver blended bitumen from the central processing facility to the Cheecham terminal and then to Edmonton. First sales from the blended bitumen pipeline were completed in January 2016.

During the nine months ended September 30, 2016, no royalties were payable in respect of the Royalty.

Segment Loss

The following table summarizes the Thermal Oil Segment loss for the three and nine months ended September 30, 2016 and 2015:

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands)	2016	2015	2016	2015
Thermal Oil Operating Income[1]	$ (6,088)	$ (12,146)	$ (41,079)	$ (12,146)
Depletion of oil and gas assets	(4,057)	(889)	(9,694)	(889)
Depreciation of infrastructure assets	(4,026)	(1,635)	(10,386)	(1,635)
Exploration expense	(14)	(471)	(236)	(611)
Gain on sale of assets	—	—	—	—
THERMAL OIL SEGMENT LOSS	$ (14,185)	$ (15,141)	$ (61,395)	$ (15,281)

(1) Refer to "Advisories and Other Guidance" beginning on page 20 for additional information on Non-GAAP Financial Measures.

During the three and nine months ended September 30, 2016, depletion and depreciation expense increased to $8.1 million and $20.1 million, respectively, compared to $2.5 million during the same periods in the prior year. The increases in depletion and depreciation expense were primarily due to higher production from the ramp-up of Project 1 in 2016. Athabasca also recognized a full period of depletion and depreciation during the first nine months of 2016 compared to two months in the prior year as Project 1 did not become ready for use in the manner intended by management until the third quarter of 2015.

The central processing facility is depreciated on a unit-of-production basis over the total productive capacity of the facility. The supporting infrastructure is depreciated on a straight-line basis over the estimated useful life of the components. The producing oil sands properties, including estimated future development costs, are depleted using the unit-of-production method based on estimated Proved Reserves.

Corporate Review

General and Administrative ("G&A")

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands)	2016	2015	2016	2015
Salaries and benefits	$ 4,827	$ 8,070	$ 15,223	$ 27,049
Office costs	1,985	2,518	5,446	9,834
Legal, accounting and consulting	616	877	2,714	3,123
Stakeholder relations	35	243	626	686
Capitalized staff and environment costs	(1,471)	(3,039)	(5,577)	(15,326)
TOTAL GENERAL AND ADMINISTRATIVE	$ 5,992	$ 8,669	$ 18,432	$ 25,366
Capitalization rate	20%	26%	23%	38%

During the three and nine months ended September 30, 2016, salaries and benefits declined by $3.2 million and $11.8 million, respectively, compared to the same periods in the prior year. The declines were primarily due to restructuring activities undertaken by the Company in 2015 to streamline costs and better align the organization's cost structure to the current operating environment, its capital plans and growth objectives.

Compared to the same periods in the prior year, office costs declined by $0.5 million and $4.4 million during the three and nine months ended September 30, 2016, respectively, primarily due to office lease provisions on under-utilized space taken in the second quarter of 2015, ongoing cost saving initiatives and sub-lease recoveries.

Capitalized staff and environment costs decreased during the three and nine months ended September 30, 2016, compared to the same periods in the prior year, primarily due to staff reductions, the completion of Project 1 and a reduction in Thermal Oil and Light Oil capital activities.

Restructuring and Other Charges

There were no restructuring charges recognized during the nine months ended September 30, 2016. For the nine months ended September 30, 2015, Athabasca incurred $18.6 million in restructuring and other charges consisting of staff restructuring charges of $8.1 million, $7.0 million relating to lease commitments on vacated office space primarily as a result of the staff reductions, and net cancellation charges of $3.5 million primarily relating to Thermal Oil rig commitments.

Stock-based Compensation

For the three and nine months ended September 30, 2016, stock-based compensation expense declined from $2.7 million to $2.3 million and from $8.6 million to $7.0 million, respectively, compared to the same periods in the prior year. The declines were primarily due to lower balances of units outstanding under the 2010 RSU compensation plan which had carried higher fair values per award. The 2010 RSU compensation plan was discontinued during the second quarter of 2015. The declines were partially offset by equity awards granted to employees and directors during 2015 and 2016 under Athabasca's other equity compensation plans as well as lower capitalization rates from lower Thermal Oil and Light Oil capital activity.

Financing and Interest

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands)	2016	2015	2016	2015
Financing and interest expense on indebtedness	$ 10,551	$ 16,952	$ 45,651	$ 48,580
Accretion of provisions	1,841	1,584	5,702	5,002
Amortization of debt issuance costs	1,345	1,857	11,784	5,480
Capitalized financing and interest	—	(5,773)	—	(39,686)
TOTAL FINANCING AND INTEREST	$ 13,737	$ 14,620	$ 63,137	$ 19,376

During the three and nine months ended September 30, 2016 and 2015, financing and interest expenses were primarily attributable to three debt instruments held by the Company. Interest expense and amortization of debt issuance costs were incurred on the Company's $550.0 million senior secured second lien notes (the "Notes") which were issued during the fourth quarter of 2012. The Notes bear interest at a rate of 7.5% per annum. The Company also incurred interest and amortization of debt issuance costs on the US$225.0 million Term Loan issued in the second quarter of 2014. The Term Loan bore interest at a rate of LIBOR plus 7.25%, subject to a 1% LIBOR floor. Athabasca also incurred standby fees and fees on issued letters of credit on its $125.0 million Credit Facility and its US$50.0 million delayed-draw Term Loan.

During the second quarter of 2016, Athabasca repaid the Term Loan and canceled its undrawn US$50.0 million delayed-draw Term Loan. The Company also amended its undrawn Credit Facility which included a reduction of the facility from $125.0 million to $44.5 million (undrawn). In conjunction with the Credit Facility amendment, all letters of credit issued and outstanding under the Credit Facility were transferred to the Company's new $110.0 million Letter of Credit Facility. As at September 30, 2016, no amounts were drawn under the Credit Facility and $102.8 million of letters of credit were issued under the Letter of Credit facility.

During the three and nine months ended September 30, 2016, Athabasca incurred lower financing and interest expense on indebtedness of $6.4 million and $2.9 million, respectively, compared to the same periods in the prior year. The decreases were primarily due to lower interest expense as a result of the repayment of the Term Loan and the cancellation of the delayed-draw Term Loan during the second quarter of 2016. The declines were partially offset by an increase in letters of credit issued and outstanding under the Credit Facility during 2016 as well as financing costs relating to the Company's 2016 debt restructuring activities.

During the nine months ended September 30, 2016, amortization of debt issuance costs increased by $6.3 million compared to the same period in the prior year, primarily due to the acceleration of debt issuance costs to net income due to the Term Loan repayment and Credit Facility amendments completed during the second quarter of 2016. Amortization of debt issuance costs declined by $0.5 million during the third quarter of 2016 compared to the same period in the prior year, primarily due to Term Loan debt issuance costs and Credit Facility amendment fees no longer being amortized as a result of the second quarter acceleration.

In August of 2015, Athabasca discontinued the capitalization of interest and financing costs associated with Project 1 when the project became ready for use.

Interest Income and Other

($ Thousands)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Interest on cash, cash equivalents and short-term investments	$ 1,601	$ 1,561	$ 4,389	$ 5,573
Interest on promissory notes	373	1,009	1,555	4,300
Accretion of capital-carry receivable	3,292	—	4,905	—
Other	(56)	—	69	479
TOTAL INTEREST INCOME AND OTHER	$ 5,210	$ 2,570	$ 10,918	$ 10,352

During the three and nine months ended September 30, 2016, interest income on cash, cash equivalents, short-term investments and promissory notes decreased by $0.6 million and $3.9 million, respectively, compared to the same periods in the prior year. The decreases were primarily due to lower average balances of cash, cash equivalents, short-term investments and promissory notes during 2016. Athabasca also earned higher interest income in the prior year periods due to higher interest rates during 2015.

During the three and nine months ended September 30, 2016, Athabasca recognized $3.3 million and $4.9 million in non-cash interest income from the time value of money accretion on the Company's capital-carry receivable from Murphy.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Unrealized foreign exchange gain (loss)	$ —	$ (20,067)	$ —	$ (39,313)
Realized foreign exchange gain (loss)	—	(176)	19,880	(31)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ —	$ (20,243)	$ 19,880	$ (39,344)

Athabasca incurred foreign exchange gains and losses on the Company’s US$225.0 million Term Loan, which was issued on May 7, 2014, and fully repaid on June 17, 2016.

During the nine months ended September 30, 2016, Athabasca recognized a realized foreign exchange gain primarily due to a realized gain on the loan principal as the average value of the Canadian dollar increased relative to the US dollar by 7% from 1.38:1 to 1.29:1 from the beginning of the year until the date of the repayment of the Term Loan. Athabasca recognized a net foreign exchange loss during the three and nine months ended September 30, 2015 primarily due to an unrealized loss on the loan principal as the value of the Canadian dollar declined relative to the US dollar from 1.16:1 to 1.24:1 and from 1.16:1 to 1.34:1, respectively.

Derivative Gain (Loss), Net

($ Thousands)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Unrealized derivative gain (loss)	$ —	$ 22,271	$ —	$ 41,577
Realized derivative gain (loss)	—	1,147	(21,628)	2,568
DERIVATIVE GAIN (LOSS), NET	$ —	$ 23,418	$ (21,628)	$ 44,145

Concurrent with the issuance of the US$225.0 million Term Loan in May 2014, Athabasca entered into a three year foreign exchange par forward contract expiring on March 31, 2017 to reduce the Company’s exposure to fluctuations in foreign exchange rates on the US dollar denominated long-term debt. In anticipation of its repayment of the Term Loan, on June 15, 2016, Athabasca unwound its foreign exchange par forward contract and received net cash proceeds of $41.0 million.

During the nine months ended September 30, 2016, Athabasca recognized a realized derivative loss as the value of the Canadian dollar increased relative to the US dollar by 7% from 1.38:1 to 1.28:1 from the beginning of the year until the date that the foreign exchange par forward contract was settled. Athabasca recognized a net unrealized derivative gain during the three and nine months ended September 30, 2015 as the value of the Canadian dollar declined relative to the US dollar.

CAPITAL EXPENDITURES

Light Oil Division

The following table summarizes the Light Oil capital expenditures for the three and nine months ended September 30, 2016 and 2015:

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands)	2016	2015	2016	2015
Greater Placid area				
Drilling, completion and equipping	$ 13,035	$ 2,506	$ 36,087	$ 18,471
Land acquisitions	295	14	1,052	176
Facilities and project support	1,175	2,023	6,813	5,971
	14,505	4,543	43,952	24,618
Greater Kaybob area				
Drilling, completion and equipping	4,397	22,136	10,444	84,531
Land acquisitions	18	1,701	192	11,893
Facilities and project support	—	3,085	507	4,625
	4,415	26,922	11,143	101,049
TOTAL LIGHT OIL CAPITAL EXPENDITURES(1)(2)	$ 18,920	$ 31,465	$ 55,095	$ 125,667
Less: Greater Kaybob capital carry	(4,286)	—	(5,760)	—
Net cash outflow from Light Oil capital expenditures	$ 14,634	$ 31,465	$ 49,335	$ 125,667

(1) For the three and nine months ended September 30, 2016, capital expenditures include $1.0 million and $4.4 million in capitalized staff costs, respectively (September 30, 2015 - $1.5 million and $5.5 million, respectively).

(2) During the nine months ended September 30, 2016, $10.2 million of Light Oil PP&E expenditures related to assets sold as part of the Murphy Transaction

Greater Placid area

Following the completion of the Murphy Transaction, Athabasca holds an operated 70% interest in the Greater Placid area primarily targeting the development of the Montney formation. During the three and nine months ended September 30, 2016, Athabasca spent $14.5 million and $44.0 million (net), respectively, in the Greater Placid area primarily to complete three, and bring on stream four, Montney wells (gross) that had been drilled in the prior year. During the third quarter of 2016, Athabasca also commenced a 12-well (gross) winter drilling program. By the end of the quarter, three of the wells were rig-released and the remaining nine are anticipated to be rig-released by the end of the year. Athabasca anticipates that the 12 wells will be completed and brought on stream through the first quarter of 2017.

In the first quarter of 2016, Athabasca completed construction and commissioning of a pipeline network that connects the Company's Montney wells in the Greater Placid area to its regional infrastructure at Saxon. Building on this infrastructure development, Athabasca has commenced construction of a battery in the Placid area to accommodate future production growth. The Placid battery will utilize the previously constructed pipeline for sales egress and is expected to be in operation near the end of the first quarter of 2017.

Greater Kaybob area

Following the completion of the Murphy Transaction, Athabasca holds a non-operated 30% interest in the Greater Kaybob area primarily targeting the development of the Duvernay formation. During the three and nine months ended September 30, 2016, Athabasca spent $4.4 million and $11.1 million (net), respectively, in the Greater Kaybob area primarily to complete and bring on stream a four-well (gross) Duvernay pad. The Company also brought two Duvernay wells (gross) on stream that had been drilled and completed in the prior year. Including the recovery of the capital-carry, Athabasca's net cash outflow from capital expenditures in the Greater Kaybob Area was $0.1 million and $5.4 million during the three and nine months ended September 30, 2016, respectively.

Athabasca substantially completed the transition of operatorship of the Greater Kaybob area assets to Murphy during the third quarter of 2016 with field operations handed over to Murphy on August 1, 2016. Athabasca will continue to operate the Greater Kaybob area regional infrastructure in the near-term.

Thermal Oil Division

The following table summarizes the Thermal Oil capital expenditures for the three and nine months ended September 30, 2016 and 2015:

($ Thousands)	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Hangingstone Project 1	$ 1,482	$ 6,751	$ 3,212	$ 100,375
Hangingstone Expansion	478	582	1,225	2,659
Other Thermal Oil exploration	1,794	2,033	2,420	8,039
TOTAL THERMAL OIL CAPITAL EXPENDITURES[1]	$ 3,754	$ 9,366	$ 6,857	$ 111,073

(1) For the three and nine months ended September 30, 2016, Thermal Oil capital expenditures include $0.5 million and $1.2 million, respectively, in capitalized staff costs (September 30 30, 2015 - $1.5 million and $9.8 million, respectively).

There were minimal capital expenditures in the Thermal Oil Division during the first nine months of 2016. During 2015, capital expenditures on Project 1 primarily related to completing the project and commencing operations.

The Company's application for the expansion of Hangingstone by an incremental 70,000 bbl/d has been confirmed as technically complete by the AER and Athabasca anticipates receiving regulatory approval in 2017. Prior to the sanctioning of any expansion projects at Hangingstone, successful production ramp-up of Project 1 will need to be demonstrated, along with a recovered and stable commodity price environment and suitable project funding.

OUTLOOK

The following tables reflect Athabasca's 2016 updated capital budget and corporate production guidance as at September 30, 2016:

2016 Capital Budget ($ millions)	Full year
Light Oil Division	
Greater Kaybob area (Duvernay)[1]	$ 8
Greater Placid area (Placid)[2]	94
	102
Thermal Oil Division	
Hangingstone maintenance	7
Other thermal	4
	11
Capitalized general and administrative	8
Total capital expenditures	$ 121

(1) The Greater Kaybob area capital expenditures reflects Athabasca's 30% working interest, net of anticipated recovery from the capital-carry receivable.
(2) The Greater Placid area capital expenditures reflects Athabasca's 70% working interest.

2016 Operational & Financial Guidance ($ millions, unless otherwise noted)		Full year
Light Oil (net)		
Production (boe/d)		4,500
Liquids weighting (%)		~49%
Light Oil Operating Income(1)		~$23
Light Oil Operating Netback ($/boe)		~$14
Thermal Oil		
Bitumen production (bbl/d)		7,300
Thermal Oil Operating Income(1)		~($49)
Corporate		
Production (boe/d)		11,800
Liquids weighting (%)		~81%
Funds Flow from Operations(1)		~($103)
Cash and cash equivalents		~$620
Commodity assumptions(2)		
WTI (US$/bbl)	$	42.30
Edmonton Par (C$/bbl)	$	51.43
Western Canadian Select (C$/bbl)	$	37.29
AECO Gas (C$/mcf)	$	2.03
FX (US$/C$)		0.76

(1) Refer to "Advisories and Other Guidance" beginning on page 20 for additional information on Non-GAAP Financial Measures.
(2) Commodity assumptions reflects strip pricing as at October 5, 2016.

In the Light Oil Division, Athabasca maintains its $102 million net capital budget which reflects the previously announced expanded Montney program at Placid. Annual Light Oil production is estimated at approximately 4,500 boe/d and the Company anticipates strong Montney growth through the first half of 2017 as the wells are placed on production.

In the Thermal Oil Division, the wildfire impact and other unplanned maintenance downtime year to date has impacted annual production volumes with annual volumes estimated at approximately 7,300 bbl/d on an unchanged capital budget of $11 million.

Financial Outlook

Throughout 2016, Athabasca has successfully undertaken a series of transactions, including the Murphy joint venture and the thermal oil Royalty, which have secured a funding model for its assets and position the Company to further de-leverage and optimize its capital structure in the coming months. Consideration for these transactions has totaled $743 million, including $524 million of cash proceeds. The Company now has a cash balance of approximately $700 million (excluding $104 million of restricted cash) with a net cash position of approximately $150 million (adjusted for outstanding debt). The Company also has approximately $213.5 million of further funding available through the capital carry balance with Murphy on its Duvernay joint venture lands.

Since the beginning of 2016, Athabasca has reduced its term debt outstanding by approximately $250 million, and plans to direct the proceeds from the upsizing of the Royalty towards additional debt repayment, further de-leveraging the Company and reducing borrowing costs. Athabasca's final refinancing plans are underway and are expected to be completed prior to the end of 2016. The Company is targeting a capital structure that is well aligned with its future strategic plans and provides a multi-year funding outlook with significant flexibility for the future.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity risk

The Company's objective in managing liquidity risk is to maintain sufficient available reserves to meet its liquidity requirements at any point. The Company achieves this by managing its capital spending and maintaining sufficient funds for anticipated short-term spending in cash, cash equivalent and short-term investment accounts. Until required, excess cash will be invested in short-term deposits and investments.

Funding

On August 29, 2016, the final promissory note issued to Athabasca on the sale of the Company's 40% interest in the Dover oil sands project matured and Athabasca received a cash payment of $138.5 million, consisting of $133.9 million in principal and accrued interest of $4.6 million.

Including cash proceeds from the Murphy Transaction, the Royalty, the final promissory note and the Company's recently completed debt and credit facility refinancing activities, as at September 30, 2016, Athabasca had Liquidity of $570.5 million including cash and cash equivalents of $535.5 million and short term investments of $35.0 million. Following completion of the Royalty upsizing on November 10, 2016, Athabasca's Liquidity increased to approximately $700 million. As at September 30, 2016, the Company also has an additional $213.5 million (undiscounted) of funding available through the capital-carry receivable from Murphy that will be used to fund Light Oil development in the Greater Kaybob area over the next five years. Balance sheet strength and flexibility continues to remain a key priority for Athabasca going forward.

It is anticipated that Athabasca's 2016 and 2017 capital and operating budgets, including continued development activities in the Montney and Duvernay, the ramp-up of Project 1 and any additional debt repayments will be funded with existing cash and cash equivalents, short-term investments, proceeds from the upsized Royalty, operating income from the Light Oil and Thermal Oil Divisions, the capital-carry receivable, issuance of new debt or equity and available credit. Beyond 2017, the Company may require additional capital to develop its assets and Athabasca believes it will fund its capital programs through some combination of cash and cash equivalents, short-term investments, the capital-carry receivable, and a reasonable level of debt, equity or other external financing. The Company cannot guarantee the availability of these sources of additional funding and the availability of future funding will depend on, among other things, the current commodity price environment, operating performance, the Company's credit rating at the time and the current state of the equity and debt capital markets.

Indebtedness

The following table summarizes Athabasca's indebtedness as at September 30, 2016 and December 31, 2015:

As at ($ Thousands)		September 30, 2016		December 31, 2015
Senior Secured Second Lien Notes (a)	$	550,000	$	550,000
Senior Secured Term Loan (b)[(1)]		—		306,759
Debt issuance costs		(21,664)		(31,644)
Amortization of debt issuance costs		16,790		16,158
TOTAL LONG-TERM DEBT	$	545,126	$	841,273
Presented as:				
Current portion of long-term debt	$	—	$	3,068
Long-term debt	$	545,126	$	838,205

(1) The Term Loan was repaid on June 17, 2016. As at December 31, 2015, the US dollar denominated Senior Secured Term Loan of US$221.6 million and associated deferred borrowing costs were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.3840.

Senior Secured Second Lien Notes

On November 19, 2012, Athabasca issued Senior Secured Second Lien Notes (the "Notes") in an aggregate principal amount of $550 million. The Notes bear interest at a rate of 7.50% per annum and have a term of five years maturing on November 19, 2017. Interest payments are required semi-annually on May 19 and November 19 of each year.

Senior Secured Term Loans

On May 7, 2014, Athabasca entered into a US$225.0 million Term Loan which was fully drawn and a US$50 million committed delayed draw term loan which remained undrawn. The Term Loan amortized in equal quarterly installments in an aggregate annual amount equal to 1.00% of the original principal amount. Borrowings on drawn amounts under the Term Loan bore interest at a floating rate based on LIBOR plus 7.25%, subject to a LIBOR floor of 1.00%. During the second quarter of 2016, Athabasca repaid the Term Loan at par for $285.4 million (US$221.1 million) and the undrawn delayed draw term loan was also cancelled.

Revolving Senior Secured Credit Facility

During the second quarter of 2016, Athabasca amended its $125.0 million Credit Facility which included a reduction of the amount of available credit to $44.5 million. The Credit Facility is held with a syndicate of financial institutions and is available on a revolving basis until April 30, 2017. As at September 30, 2016, the Credit Facility was undrawn.

Amounts borrowed under the Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, LIBOR or bankers' acceptance rate, plus a margin of between 2.50% and 5.00% depending on the type of borrowing and the Company's indebtedness to consolidated cash flow ratio. The Company incurs a standby fee on the undrawn portion of the Credit Facility of between 0.875% and 1.25% based on the Company's indebtedness to consolidated cash flow ratio. As part of the Credit

Facility restructuring, all letters of credit issued and outstanding under the Credit Facility were transferred to a new Letter of Credit Facility (discussed below) and no letters of credit remain outstanding under the Credit Facility.

Bilateral Cash-Collateralized Letter of Credit Facility

Concurrent with the amendments to the Credit Facility, during the second quarter of 2016, Athabasca entered into a $110.0 million Letter of Credit Facility with a Canadian bank for issuing letters of credit to counterparties. The facility is available on a demand basis and letters of credit issued under the Letter of Credit Facility bear an issuance fee of 0.25%. Letters of credit issued under the Letter of Credit Facility are used to satisfy certain financial assurance requirements under Athabasca's long-term transportation agreements. Under the terms of the Letter of Credit Facility, Athabasca is required to contribute cash to a restricted cash-collateral account equivalent to 101% of the value of letters of credit issued under the facility. As at September 30, 2016, Athabasca had $102.8 million in letters of credit issued under the Letter of Credit Facility.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at September 30, 2016 for the following five years and thereafter:

($ Thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Transportation	$ 11,849	$ 50,832	$ 53,263	$ 54,524	$ 53,656	$ 841,098	$ 1,065,222
Repayment of long-term debt[(1)]	—	550,000	—	—	—	—	550,000
Interest expense on long-term debt	10,313	36,094	—	—	—	—	46,407
Office leases	613	2,452	2,452	2,452	2,452	11,808	22,229
Purchase commitments and other	5,884	2,850	2,976	—	—	—	11,710
Drilling rigs	719	2,915	—	—	—	—	3,634
TOTAL COMMITMENTS	$ 29,378	$ 645,143	$ 58,691	$ 56,976	$ 56,108	$ 852,906	$ 1,699,202

(1) The Term Loan was repaid on June 17, 2016.

Excluded from the table above is a commitment for $122.7 million of office leases which were assigned to an investment-grade third party in December 2013.

During the third quarter of 2016, Athabasca reassigned $26.4 million in transportation commitments in the Light Oil Division to Murphy.

Athabasca is responsible for the retirement of its resource assets at the end of their useful lives. The total future costs to reclaim the Company's oil and gas assets are estimated by management and recognized as a provision in the consolidated financial statements.

The Company is currently undergoing income tax related audits in the normal course of business. The final outcome of such audits cannot be predicted with certainty and management believes that it has appropriately reflected the Company's anticipated current and deferred income taxes in the consolidated financial statements.

The Company is, from time to time, involved in claims arising in the normal course of business.

Athabasca has entered into indemnity agreements with its directors and officers whereby the Company indemnifies the directors and officers to the fullest extent permitted by law against all personal liability and loss that may arise in service to the Company.

Credit Risk

The maximum exposure to credit risk is currently represented by the carrying amounts of cash, cash equivalents, short-term investments, restricted cash, accounts receivable, the capital-carry receivable, and other long-term assets on the consolidated balance sheets.

Cash, cash equivalents, short-term investments and restricted cash held by the Company are invested with counterparties meeting credit quality requirements and concentration limits pursuant to an investment policy that is periodically reviewed by the Audit Committee. The policy emphasizes security of assets over investment yield. As at September 30, 2016 and December 31, 2015, Athabasca's cash, cash equivalents, short-term investments and restricted cash were held with five counterparties and four counterparties, respectively, with all counterparties being large reputable financial institutions. The Company's management believes that credit risk associated with these investments is low. At September 30, 2016, no institution held more than 36% of the balances (December 31, 2015 - 32%).

The following table summarizes the concentration of accounts receivable held by Athabasca as at September 30, 2016 and December 31, 2015:

Concentration of accounts receivable (as at)	September 30, 2016	December 31, 2015
Joint interest billings	56%	18%
Petroleum and natural gas sales receivable (collected within 30 days)	36%	40%
Government receivables and other	8%	30%
Accrued interest on the Promissory Note	—%	12%

Management believes collection risk on the outstanding accounts receivable as at September 30, 2016 is low given the high credit quality of the Company's material counterparties. No material amounts were past due at September 30, 2016.

The discounted capital-carry receivable of $188.4 million, recognized in respect of the Murphy Transaction is considered to have low credit risk given the high credit quality of the Murphy subsidiary that has guaranteed the obligation. Timing of the recovery of the capital-carry is dependent on the extent of capital expenditures in the Greater Kaybob area, subject to a minimum annual recovery to be realized by Athabasca from Murphy, as set out in Greater Kaybob joint development agreement.

Foreign exchange risk

Athabasca was previously exposed to foreign currency risk on its US dollar denominated Term Loan. In May 2014, Athabasca entered into a US dollar forward contract for US$270.8 million relating to the interest payments and principal repayments on the Term Loan at a rate of US$1.00 = C$1.1211 expiring on March 31, 2017. This contract was accounted for as a derivative instrument and changes in the valuation were recognized in net income (loss) and the associated liability or asset was recognized on the balance sheet. During the second quarter of 2016, Athabasca unwound its derivative contract and received net cash proceeds of $41.0 million concurrent with the repayment of the Term Loan. The following tables summarizes the change in the derivative asset during the nine months ended September 30, 2016 and the year ended December 31, 2015:

As at ($ Thousands)	September 30, 2016	December 31, 2015
OPENING DERIVATIVE ASSET	$ 62,584	$ 12,638
Unrealized derivative gain	—	49,946
Realized derivative loss	(21,628)	—
Receipt of proceeds from derivative unwind	(40,956)	—
CLOSING DERIVATIVE ASSET	$ —	$ 62,584
Presented as:		
Current portion of derivative asset	$ —	$ 5,382
Long-term portion of derivative asset	$ —	$ 57,202

Interest Rate Risk

The Company's exposure to interest rate fluctuations on interest earned on its floating rate cash balance of $613.7 million (December 31, 2015 - $480.6 million), from a 1.00% change in interest rates, would be approximately $6.1 million for a 12 month period (year ended December 31, 2015 - $4.8 million).

Off Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements that have or are reasonably likely to have a material current or future effect on the Company's consolidated financial statements.

Equity Instruments

During the nine months ended September 30, 2016, Athabasca issued 2.1 million common shares in respect of the Company's equity-settled share-based compensation plans.

Outstanding Share Data

The following table summarizes the number of share capital instruments outstanding at the date indicated:

As at November 6, 2016	
Common shares issued and outstanding	406,399,346
Convertible securities:	
Stock options	9,470,485
Restricted share units (2010 RSU Plan)	4,413,495
Restricted share units (2015 RSU Plan)	5,052,437
Performance share units	2,691,300
Deferred share units	1,101,664

For additional information regarding these compensation plans, refer to the consolidated financial statements of the Company for the year ended December 31, 2015.

SUMMARY OF QUARTERLY RESULTS

The following table summarizes selected consolidated financial information for the Company for the preceding eight quarters:

	2016			2015				2014
($ Thousands, except share and per barrel amounts)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	44.94	45.59	33.45	42.18	46.43	57.94	48.63	93.00
WTI (C$/bbl)	58.87	58.81	45.83	56.52	60.82	71.27	60.30	107.88
Western Canadian Select (C$/bbl)	41.01	41.62	26.30	36.86	43.29	71.24	60.35	83.03
Edmonton Par (C$/bbl)	54.66	54.78	40.67	52.85	56.17	67.63	51.79	94.49
Edmonton Condensate (C5+) (C$/bbl)	55.31	56.80	46.32	54.52	56.94	69.81	55.42	100.42
NYMEX Henry Hub (US$/MMBtu)	2.81	1.95	2.09	2.27	2.80	2.64	2.98	4.39
AECO (C$/GJ)	2.20	1.32	1.74	2.33	2.75	2.53	2.61	4.25
Foreign exchange (CAD : USD)	1.31	1.29	1.37	1.34	1.31	1.23	1.24	1.16
LIGHT OIL DIVISION								
Sales volumes (boe/d)	3,018	5,743	6,319	5,873	5,145	5,459	5,877	6,035
Realized price ($/boe)	29.84	26.93	21.73	27.39	31.34	34.43	29.35	44.66
Revenues(2) ($)	8,091	13,936	12,440	17,624	14,043	17,666	13,981	21,757
Light Oil Operating Income(1) ($)	5,511	7,215	4,908	10,551	6,096	10,689	6,578	12,431
Light Oil Operating Netback(1) ($/boe)	19.85	13.80	8.53	19.50	12.88	21.51	12.46	22.38
Capital expenditures ($)	18,920	5,518	30,658	50,921	31,465	14,959	79,241	87,870
THERMAL OIL DIVISION								
Bitumen production (bbl/d)(3)(4)	8,830	5,358	7,029	5,708	2,105	—	—	—
Sales volumes (bbl/d)(3)(4)	9,744	4,463	7,176	4,096	1,792	—	—	—
Realized bitumen price ($/bbl)	28.56	24.51	7.27	21.23	17.54	—	—	—
Revenues(2) ($)	45,124	19,386	21,076	15,033	6,145	—	—	—
Thermal Oil Operating Loss(1)(4) ($)	(6,088)	(11,915)	(23,074)	(18,166)	(12,146)	—	—	—
Thermal Oil Operating Netback(1)(4) ($/bbl)	(6.80)	(29.33)	(35.34)	(48.22)	(73.67)	—	—	—
Capital expenditures	3,754	2,187	916	2,257	9,366	33,118	68,504	78,876
OPERATING RESULTS								
Cash Flow from Operations ($)	(18,990)	5,759	(38,017)	(54,496)	(17,933)	8,576	(2,610)	(8,883)
Funds Flow from Operations(1) ($)	(15,778)	(27,304)	(39,982)	(30,141)	(24,223)	5,085	3,162	(2,520)
Net income (loss) ($)	(33,032)	(59,169)	(65,129)	(604,375)	(38,241)	(29,044)	(25,112)	(129,507)
Net income (loss) per share - basic ($)	(0.08)	(0.15)	(0.16)	(1.50)	(0.09)	(0.07)	(0.06)	(0.32)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	535,477	447,282	493,510	559,487	671,447	582,396	570,290	531,475
Short-term investments ($)	35,000	25,533	—	—	—	—	92,873	47,618
Restricted cash ($)	103,827	101,652	—	—	—	—	—	—
Capital-carry receivable(5) ($)	188,448	188,742	—	—	—	—	—	—
Promissory notes(5) ($)	—	133,892	133,892	133,892	133,892	283,892	283,892	583,892
Assets held for sale ($)	—	—	466,159	—	—	—	—	—
Total assets ($)	3,017,285	3,028,938	3,394,367	3,462,442	4,160,344	4,173,704	4,244,486	4,297,803
Long-term debt ($)	545,126	544,042	820,478	838,205	827,773	807,167	810,758	786,649
Shareholders' equity ($)	2,333,523	2,363,396	2,419,651	2,482,140	3,085,499	3,119,224	3,141,453	3,164,186

(1) Refer to "Advisories and Other Guidance" beginning on page 20 for additional information on Non-GAAP financial measures.
(2) Consists of petroleum and natural gas sales and midstream revenues, net of royalties. Excludes interest income and other.
(3) Q3 2015 includes capitalized volumes.
(4) Athabasca capitalized initial operating results of Hangingstone Project 1 until the project was deemed ready for use in the manner intended by management on August 1, 2015. Operating results and sales volumes prior to August 1, 2015 have been capitalized and excluded from the calculation of the Thermal Oil Operating Loss and Netback.
(5) Balances include the current and long-term portions as reported in the consolidated balance sheets.

Refer to the Results of Operations and other sections of this MD&A for detailed financial and operational variances between reporting periods as well as to Athabasca's previously issued annual and quarterly MD&As for changes in prior periods.

ACCOUNTING POLICIES AND ESTIMATES

During the nine months ended September 30, 2016, there were no changes to Athabasca's accounting policies or use of estimates in the preparation of the consolidated financial statements and the notes thereto that had a material impact to the consolidated financial statements. Refer to the December 31, 2015 audited consolidated financial statements of the Company for further guidance regarding Athabasca's accounting policies and use of estimates.

ADVISORIES AND OTHER GUIDANCE

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 "Liquidity" financial measures contained in this MD&A 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.

The following table reconciles cash flow from operating activities in the consolidated financial statements for the three and nine months ended September 30, 2016 and 2015 to Funds Flow from Operations:

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands)	2016	2015	2016	2015
Cash flow from operating activities	$ (18,990)	$ (17,933)	$ (51,297)	$ (12,031)
Receipt of proceeds from derivative unwind	—	—	(40,956)	—
Restructuring and other charges, excluding the change in long-term portion of office lease provision	—	1,661	—	15,181
Changes in non-cash working capital	1,772	(8,803)	3,071	(23,365)
Settlement of provisions	1,440	852	4,560	3,180
FUNDS FLOW FROM OPERATIONS	$ (15,778)	$ (24,223)	$ (84,622)	$ (17,035)

Funds Flow from Operations is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Funds Flow from Operations measure allows management and others to evaluate the Company's ability to fund its capital programs and meet its ongoing financial obligations using cash flow internally generated from ongoing operating related activities. Funds Flow from Operations per share (basic and diluted) are calculated as Funds Flow from Operations divided by the number of weighted average basic and diluted shares outstanding.

The Light Oil Operating Income and Light Oil Operating Netback measures in this MD&A (including the comparatives thereto) 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 Operating Netback (per boe) measures allow management and others to evaluate the production results from the Company's Light Oil assets. The table on page 6 reconciles Light Oil Operating Income to *Note 11 - Segmented Information* in the unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 2016.

The Thermal Oil Operating Income and Thermal Oil Operating Netback measures in this MD&A (including the comparatives thereto) are calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation expenses from blended bitumen sales received. The Thermal Oil Operating Netback measure is presented on a per bbl basis. The Thermal Oil Operating Income and the Thermal Oil Operating Netback (per bbl) measures allow management and others to evaluate the production results from the Company's Thermal Oil assets. The table on page 8 reconciles Thermal Oil Operating Income to *Note 11 - Segmented Information* in the unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 2016.

The Liquidity measure in this MD&A is calculated by adding cash and cash equivalents, short-term investments and the promissory note on the Company's consolidated balance sheets. As at September 30, 2016, there were no promissory notes outstanding. The Liquidity measure allows management and others to evaluate the Company's ability to finance its capital and operating activities in the short-term.

Risk Factors

Factors currently influencing the Company's ability to succeed include, but are not limited to, the following:

- weakness in the oil and gas industry;
- fluctuations in market prices for crude oil, natural gas, condensate and bitumen blend;
- general economic, market and business conditions in Canada, the United States and globally;
- the substantial capital requirements of Athabasca's projects and the ability to obtain the related financing;
- failure to realize anticipated benefits of acquisitions or divestments;
- risks related to hydraulic fracturing;
- extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time;
- insurance risks;
- risks relating to changing royalty regimes;
- additional funding requirements and liquidity risk;
- variations in foreign exchange and interest rates;
- environmental risks and hazards and the cost of compliance with environmental regulations, including the licensee liability rating program, seismic activity regulations, GHG regulations and potential Canadian and U.S. climate change legislation;
- dependence upon Murphy as a working interest participant in its Light Oil assets and as operator of the Greater Kaybob assets;
- risks related to the Credit Facility, the Letter of Credit Facility and the Senior Secured Notes;
- Geopolitical risks;
- uncertainties inherent in estimating quantities of reserves and resources;
- risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources, including the production of oil sands reserves and resources using SAGD, TAGD or other in-situ recovery technologies;
- risks associated with events of force majeure;
- failure to meet development schedules and potential cost overruns;
- aboriginal claims;
- risks related to gathering and processing facilities and pipeline systems;
- availability of drilling and related equipment and limitations on access to Athabasca's assets;
- failure to accurately estimate abandonment and reclamation costs;
- the potential for management estimates and assumptions to be inaccurate;
- reliance on third party infrastructure;
- seasonality;
- risks associated with establishing and maintaining systems of internal controls;
- expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits;
- breaches of confidentiality;
- inaccuracy of forward-looking information;
- expansion into new activities;
- risks related to the Common Shares.

For additional information regarding the risks and uncertainties to which the Company and its business are subject, please see the information under the headings "Forward Looking Information" below, and under the headings "Forward-Looking Statements" and "Risk Factors" in the Company's most recent AIF, on the Company's SEDAR profile at www.sedar.com.

Forward Looking Information

This MD&A 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", "target", "should", "believe", "predict", "pursue" and "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 MD&A should not be unduly relied upon. This information speaks only as of the date of this MD&A. In particular, this MD&A may contain forward-looking information pertaining to the following: the timing of the ramp-up of production and of achieving plateau production from Project 1; the Company's expectation that Thermal Oil Operating Netbacks will improve as production increases; the expectation that the Royalty will not materially impact the economics of future Hangingstone Expansion phases or other future Thermal Oil exploration projects; the timing of receipt of regulatory approval in 2016 for the Hangingstone Expansion; the timing of drilling, completion and tie-in operations in the Company's Light Oil Division; the Company's expected production from the Light Oil and Thermal Oil Divisions during 2016; the expected timing of the Company's Light Oil Division wells coming on-stream; 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; the Company's expected flexibility in its pace of development; the Company's drilling plans, in particular, with respect to the Duvernay and Montney formations; the timing of the Company's well completion operations; the Company's plans for, and results of, exploration and development activities; the Company's estimated future commitments; the Company's expected funding position at the end of 2016; Athabasca's continued balance-sheet strength; reassigning a portion of the Company's transportation agreements in the Light Oil Division to Murphy; the Company's business and financing plans and strategies; expectations regarding the 2016 capital budget; the Company's anticipated sources of funding for 2016 and beyond; the Company's estimate future minimum capital commitments; and the future allocation of capital.

With respect to forward-looking information contained in this MD&A, assumptions have been made regarding, among other things: the regulatory framework governing royalties, taxes and environmental matters in the jurisdiction in which the Company conducts and will conduct business; Athabasca's cash flow break-even commodity price; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the applicability of technologies for the recovery and production of the Company's reserves and resources; 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; future production levels; the Company's ability to obtain financing and/or enter into joint venture arrangements, on acceptable terms; operating costs; compliance of counterparties with the terms of contractual arrangements; impact of increasing competition; collection risk of outstanding accounts receivable from third parties; geological and engineering estimates in respect of the Company's reserves and resources; recoverability of reserves and resources and the geography of the areas in which the Company is conducting exploration and development activities and the quality of its assets.

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 most recent AIF available on SEDAR at www.sedar.com, including, but not limited to: weakness in the oil and gas industry; fluctuations in market prices for crude oil, natural gas and bitumen blend; general economic, market and business conditions in Canada, the United States and globally; insurance risks; claims made in respect of Athabasca's operations, properties or assets; the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements; global financial uncertainty; failure to realize anticipated benefits of acquisitions or divestments; risks related to hydraulic fracturing; factors affecting potential profitability; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time; risks relating to changing royalty regimes; additional funding requirements and liquidity risk; variations in foreign exchange and interest rates; environmental risks and hazards and the cost of compliance with environmental regulations, including the licensee liability rating program, seismic activity regulations, GHG regulations and potential Canadian and U.S. climate change legislation; risks related to the Murphy Transaction, dependence on Murphy as the operator of the Greater Kaybob assets, dependence on Murphy as the Company's joint venture participant in the Company's Greater Kaybob and Greater Placid assets and dependence on Murphy's continued ability to pay the Greater Kaybob carry commitment, reassigning a portion of the Company's transportation commitments in the Light Oil Division to Murphy; risks associated with events of force majeure; risks related to the Credit Facility, the Letter of Credit Facility and the Senior Secured Notes; Geopolitical risks; uncertainties inherent in estimating quantities of reserves and resources; contractual counterparty risks and operational dependence; risks related to future acquisition and joint venture activities; risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources, including the production of oil sands reserves and resources using SAGD, TAGD or other in-situ recovery technologies; failure to meet development schedules and potential cost overruns; aboriginal claims; reliance on, competition for, loss of, and failure to attract key personnel; financial assurance covenants and collateral requirements under the Company's pipeline transportation agreements; 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 operating costs could make Athabasca's projects uneconomic; the effect of diluent and natural gas supply constraints and increases in the costs thereof; costs of new technologies; alternatives to and changing demand for petroleum products; gas over bitumen issues affecting operational results; risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments; failure to accurately estimate abandonment and reclamation costs; the potential for management estimates and assumptions to be inaccurate; long-term reliance on third parties; reliance on third party infrastructure; seasonality; risks associated with establishing and maintaining systems of internal controls; competition for, among other things, capital, the acquisition of reserves and resources, export pipeline capacity and skilled personnel; expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits; breaches of confidentiality; inaccuracy of forward-looking information; expansion into new activities; risks related to the Common Shares.

In addition, information and statements in this MD&A relating to "Reserves" and "Resources" are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future. Certain assumptions related to the Company's Reserves and Resources are contained in the reports of GLJ Petroleum

Consultants Ltd. ("GLJ") and DeGolyer and MacNaughton Canada Limited ("D&M") evaluating Athabasca's Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2015 (which are respectively referred to herein as the "GLJ Report" and the "D&M" Report").

The risks and uncertainties referred to above are described in more detail in Athabasca's most recent AIF, which is available on the Company's SEDAR profile at www.sedar.com. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. The forward-looking information included in this MD&A is expressly qualified by this cautionary statement and is made as of the date of this MD&A. The Company does not undertake any obligation to publicly update or revise any forward-looking information except as required by applicable securities laws.

The Company's financial condition and results of operations discussed in this MD&A will not necessarily be indicative of the Company's future performance, particularly considering that many of the Company's activities are currently in the early stages of their planned exploration and/or development.

Reserves and Resource Information

Both the GLJ Report and the D&M Report were prepared using the assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities,* effective December 31, 2015. 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 the effect of aggregation. The reserves estimates are estimates only, the actual reserves may be greater or less than those calculated and variances could be material. Reserves figures described herein have been rounded to the nearest MMbbl or MMboe. The resource estimates are estimates only. The actual Contingent Resources may be greater than or less than the estimates provided and variances could be material. There is no certainty that it will be commercially viable to produce any portion of the resources. Contingent Resources described herein have been rounded to the nearest billion barrels. For additional information regarding the consolidated reserves and resources of the Company as evaluated by GLJ in the GLJ Report and by D&M in the D&M Report, please refer to the Company's AIF and the Material Change Report that are available on SEDAR at www.sedar.com.

Drilling Locations

The 1,500 Duvernay drilling locations referenced on page 1 of this MD&A include: 15 proved undeveloped or non-producing locations, 27 probable undeveloped locations for a total of 42 undeveloped booked locations with the balance being unbooked locations. The 165 Montney drilling locations referenced on page 1 of this MD&A include: 24 probable undeveloped locations, all of which have a proven component, 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 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.

Definitions

"Company Interest" means the Company's consolidated total working interest share before deduction of royalties and without excluding royalty interests.

"**Contingent Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "Contingent Resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources may be divided into the following project maturity sub-classes: "Development Pending" is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development; "Development On Hold" is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator; "Development Unclarified" is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined; "Development Not Viable" is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development. As at December 31, 2015, the Company is reporting Contingent Resources on a risked and unrisked basis located in its: Hangingstone asset area in the Development Pending project maturity sub-class; and, Hangingstone, Dover West Sands and Birch asset areas for Development On Hold and Development Unclarified project maturity sub-classes.

"Proved Reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves.

"Probable Reserves" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved Reserves plus Probable Reserves.

"**risked**" means the applicable reported volumes or revenues have been risked (or adjusted) based on the chance of commerciality of such resources in accordance with the COGE Handbook. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore risked reported volumes and values of contingent resources reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

"**unrisked**" means applicable reported volumes or values of resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore unrisked reported volumes and values of contingent resources do not reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

Abbreviations

AECO	Physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices.
AER	Alberta Energy Regulator
bbl	barrel
bbl/d	barrels per day
boe(1)	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian Dollars
COGE	Canadian Oil and Gas Evaluation
GAAP	Generally Accepted Accounting Principles
G&A	General and administrative
LIBOR	London interbank offered rate
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	millions of barrels
MMboe	millions of barrels of oil equivalent
MMBtu	million British thermal units
NYMEX	New York Mercantile Exchange
PP&E	Property, plant and equipment
SAGD	steam assisted gravity drainage
SOR	Steam to oil ratio
TAGD	thermal assisted gravity drainage
US$	United states Dollars

(1) Boe may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one bbl of oil (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.