ATHABASCA

OIL CORPORATION

Management's Discussion and Analysis

Q3 2015

FOCUSED | EXECUTING | DELIVERING

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 4, 2015 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2014 and 2013 and unaudited condensed interim consolidated financial statements of the Company for the three and nine months ended September 30, 2015. 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 21 of this MD&A. See "Reserves and Resource information" on page 22 for important information regarding the Company's reserves and resources 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 11, 2015 ("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. Initial developments have been focused in the Kaybob and Saxon/Placid areas near the town of Fox Creek, Alberta (the "Greater Kaybob area"). Athabasca has a diverse land position including over 200,000 acres of commercially prospective lands in the Greater Kaybob area at various stages of delineation and development. The primary target is the Duvernay formation where the Company has identified a potential inventory of more than 1,000 drilling locations (gross)(1) across the fairway. The Company also has exposure in the Montney Formation throughout the Placid area. Development to date has resulted in the booking of approximately 50 MMboe(2) of Proved plus Probable Reserves in Athabasca's Light Oil Division as of December 31, 2014.

Thermal Oil

Athabasca's Thermal Oil Division includes four major project areas in the Athabasca region of Northeastern Alberta with approximately 313 MMbbl(2) barrels of Proved plus Probable Reserves and approximately 8.5 billion bbl(2) of Company Interest Best Estimate Contingent Resources. The Company's primary focus is the Hangingstone oil sands project. Other project areas include the 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 using in-situ recovery methods such as SAGD or other suitable experimental technologies such as TAGD. The Company produced its first significant production from the Thermal Oil Division during the third quarter of 2015 at Hangingstone Project 1, the Company's first thermal oil project ("Project 1") which is anticipated to reach 12,000 bbl/d in 2016.

(1) Refer to Advisories and Other Guidance beginning on page 19 for additional information regarding the Company's drilling locations.
(2) Based on the reports of Athabasca's independent reserve evaluators effective December 31, 2014. Refer to page 22 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 for the three and nine months ended September 30, 2015 and 2014:

($ Thousands, except volume, boe and share amounts)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
CONSOLIDATED PRODUCTION				
Petroleum and natural gas volumes (boe/d)(1)	7,250	6,381	6,207	6,149
LIGHT OIL DIVISION				
Petroleum and natural gas sales volumes (boe/d)	5,145	6,381	5,491	6,149
Light Oil Operating Income(2)	$ 6,096	$ 21,154	$ 23,376	$ 66,303
Light Oil Operating Netback(2) ($/boe)	$ 12.88	$ 36.03	$ 15.60	$ 39.49
Capital expenditures	$ 31,465	$ 19,772	$ 125,667	$ 112,068
THERMAL OIL DIVISION				
Bitumen production (bbl/d) (including capitalized volumes)(1)	2,105	—	716	—
Bitumen sales volumes (bbl/d) (including capitalized volumes)(1)	1,956	—	660	—
Thermal Oil Operating Income (Loss)(2)(3)	$ (12,146)	$ —	$ (12,146)	$ —
Thermal Oil Operating Netback ($/bbl)(2)(3)	$ (73.67)	$ —	$ (73.67)	$ —
Capital expenditures	$ 9,366	$ 89,455	$ 111,073	$ 337,968
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ (17,933)	$ 30,371	$ (12,031)	$ 26,953
Cash flow from operating activities per share (basic and diluted)	$ (0.04)	$ 0.08	$ (0.03)	$ 0.07
Funds Flow from Operations(2)	$ (24,223)	$ 7,203	$ (17,035)	$ 21,482
Funds Flow from Operations per share (basic and diluted)	$ (0.06)	$ 0.02	$ (0.04)	$ 0.05
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss	$ (38,241)	$ (19,939)	$ (92,398)	$ (98,054)
Net loss and comprehensive loss per share (basic and diluted)	$ (0.09)	$ (0.05)	$ (0.23)	$ (0.24)
SHARES OUTSTANDING				
Weighted average shares outstanding (basic and diluted)	403,396,304	401,718,942	402,933,671	401,564,195
FINANCING AND DIVESTITURES				
Net proceeds from sale of Dover Investment	150,000	601,323	450,000	601,323
Net proceeds from sale of oil and gas assets	610	—	646	56,654
Net proceeds (repayment of) from long-term debt	$ (746)	$ (630)	$ (2,082)	$ 236,045
	$ 149,864	$ 600,693	$ 448,564	$ 894,022

(1) For the three and nine months ended September 30, 2015, Thermal Oil bitumen production and sales volumes on a bbl/d basis represent all Hangingstone sales and production volumes (including capitalized volumes) for the period averaged over 92 days and 273 days, respectively.
(2) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.
(3) Hangingstone Project 1 was ready for use in the manner intended by management on August 1, 2015. Operating results prior to August 1, 2015 have been capitalized and excluded from the calculation of the Thermal Oil Operating Loss and Netback.

As at ($ Thousands)	September 30, 2015	December 31, 2014
LIQUIDITY		
Available Funding(1)	$ 990,789	$ 1,345,454
Net Debt(1)	$ 55,433	$ (123,625)
BALANCE SHEET		
Total assets	$ 4,160,344	$ 4,297,803
Long-term debt	$ 827,773	$ 786,649
Shareholders' equity	$ 3,085,499	$ 3,164,186

(1) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

HIGHLIGHTS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2015

Corporate

- For the three months ended September 30, 2015, Athabasca produced 7,250 boe/d from the Company's Light Oil and Thermal Oil Divisions, compared to 6,381 boe/d during the same period in the prior year. The net increase in production volumes in 2015 was primarily due to commencement of production from Hangingstone Project 1, the Company's first thermal oil project.

- On August 29th, 2015, the second 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 $152.6 million, including accrued interest. The final remaining promissory note for $133.9 million matures in August of 2016.

- As at September 30, 2015, Athabasca had Available Funding[1] of $990.8 million, consisting of $671.4 million in cash and cash equivalents, a $133.9 million promissory note and $185.5 million of available credit under the Company's credit facility and term loan agreements.

Light Oil Division

- For the three and nine months ended September 30, 2015, Athabasca produced 5,145 boe/d (48% liquids) and 5,491 boe/d (48% liquids), respectively, compared to 6,381 boe/d (51% liquids) and 6,149 (50% liquids) during the same periods in the prior year. Lower production during the first nine months of 2015 was primarily due to natural well declines and service interruptions on the Alliance pipeline, partially offset by new wells brought on stream. Third quarter production exceeded the Company's previously announced production guidance of approximately 5,000 boe/d, despite a 370 boe/d impact to the quarter from the unplanned Alliance pipeline service interruptions.

- Athabasca spent $31.5 million in the Light Oil Division during the three months ended September 30, 2015 primarily to rig release one and complete two Duvernay wells and commence activities related to the 2015/16 winter drilling program. During the nine months ended September 30, 2015, the Company spent $125.7 million in the Light Oil Division primarily in the Greater Kaybob area. Athabasca rig-released eight Duvernay wells (six horizontal, two vertical) and completed five Duvernay wells. The Company also rig-released one and completed two Montney wells in the Placid area.

- For the three months ended September 30, 2015, Athabasca's Light Oil Operating Netback[1] was $12.88/boe, compared to $36.03/boe during the same period in the prior year. For the nine months ended September 30, 2015, Athabasca's Light Oil Operating Netback[1] was $15.60/boe, compared to $39.49/boe in the prior year. The decreases in the Light Oil Operating Netback[1] were primarily due to lower underlying commodity prices partially offset by lower royalties.

Thermal Oil Division

- For the three months ended September 30, 2015, production averaged 2,105 bbl/d. During the one month ended September 30, 2015, production averaged 3,518 bbl/d and Athabasca exited the quarter with daily production in excess of 4,000 bbl/d. Athabasca completed Project 1 during the first quarter of 2015 and commenced steaming 15 of the 25 well pairs. First oil was achieved in July and 15 well pairs were converted to production by the end of the third quarter of 2015. During the third quarter of 2015, Athabasca also commenced steaming of six additional well pairs which are anticipated to be converted to production before the end of the year.

- Athabasca spent $9.4 million in the Thermal Oil Division during the three months ended September 30, 2015 primarily on start-up operations at Hangingstone. Initial operating results from Project 1 were capitalized until August 1, 2015 when the project was deemed to be ready for use in the manner intended by management. During the nine months ended September 30, 2015, Athabasca spent $111.1 million in the Thermal Oil Division primarily to complete Project 1 and to begin ramping-up operations.

(1) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

RESULTS OF OPERATIONS

Business Environment

The following table summarizes the key commodity price benchmarks for the three and nine months ended September 30, 2015 and 2014:

Monthly average	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Crude Oil:				
West Texas Intermediate (WTI) (US$/bbl)	$ 46.43	$ 97.19	$ 51.00	$ 99.61
Western Canadian Select (WCS) (C$/bbl)	$ 43.29	$ 83.86	$ 47.47	$ 85.93
Differential - WTI vs. WCS (US$/bbl)	$ 13.38	$ 20.25	$ 13.33	$ 21.49
Edmonton Par (C$/bbl)	$ 56.17	$ 97.03	$ 58.53	$ 100.79
Edmonton Condensate (C5+) (C$/bbl)	$ 56.94	$ 99.87	$ 60.72	$ 107.68
Natural gas:				
NYMEX Henry Hub close (US$/MMBtu)	$ 2.80	$ 4.07	$ 2.77	$ 4.51
AECO (C$/GJ)	$ 2.75	$ 3.82	$ 2.63	$ 4.56
Foreign exchange:				
CAD : USD	1.31	1.09	1.26	1.10

The price of WTI for crude oil sales at Cushing, Oklahoma is the primary benchmark for crude oil production 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, adjusted to Western Canada. The WTI price is also used by the Province of Alberta for determining royalty rates on Athabasca's bitumen sales. For the three months ended September 30, 2015, the WTI price declined by US$50.76/bbl, or 52%, compared to the same period in the prior year. For the nine months ended September 30, 2015, the WTI price declined by US$48.61/bbl, or 49%, compared to the same period in the prior year primarily due to a global over-supply of petroleum and natural gas production.

The WCS price at Hardisty, Alberta is the primary benchmark for Athabasca's blended bitumen sales. The WCS price normally trades at a higher differential to the WTI price compared to lighter crude oil products. For the three and nine months ended September 30, 2015 and 2014, WCS traded at an average differential below the WTI benchmark price of US$13.38/bbl (2014 - $20.25/bbl) and $13.33/bbl (2014 - $21.49/bbl), respectively.

During the three and nine months ended September 30, 2015, the value of the Canadian dollar declined relative to the US dollar by 20% and 15%, respectively. Since 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 offsets the negative impact of declining oil prices.

The Edmonton Par price and Edmonton Condensate (C5+) prices are the primary benchmarks for crude oil, condensate and natural gas liquids sales from the Greater Kaybob Area 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 consumes 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, 2015, the average Edmonton par price declined by $40.86/bbl and $42.26/bbl, respectively, compared to the same periods in the prior year. For the three and nine months ended September 30, 2015, the average Edmonton Condensate (C5+) price declined by $42.93/bbl and $46.96/bbl, respectively, compared to the same periods in the prior year.

The AECO gas price is the primary benchmark for Athabasca's natural gas sales in the Greater Kaybob Area of the Light Oil Division. In the Thermal Oil Division, the AECO price is the benchmark for natural gas purchases consumed by Athabasca in order to generate steam which is used for the SAGD recovery process. For the three months ended September 30, 2015, the AECO price was $2.75/GJ (2014 - $3.82/GJ). For the nine months ended September 30, 2015, the AECO price was $2.63/GJ (2014 - $4.56/GJ).

Athabasca typically realizes lower prices for its oil and gas sales compared to benchmark prices as a result of discounts received due to limited North American pipeline capacity, limited delivery routes to external markets outside of the United States and quality differentials.

Light Oil Division

Operating Results

The following table summarizes the Light Oil operating results for the three and nine months ended September 30, 2015 and 2014:

($ Thousands, except bbl, Mcf and boe amounts)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
SALES VOLUMES				
Oil (bbl/d)	1,682	2,398	1,993	2,328
Natural gas (Mcf/d)	15,902	18,634	17,014	18,401
Natural gas liquids (bbl/d)	812	877	662	755
Total (boe/d)	5,145	6,381	5,491	6,149
Oil and Natural gas liquids %	48%	51%	48%	50%
LIGHT OIL OPERATING INCOME(1)				
Petroleum and natural gas sales	$ 14,832	$ 33,411	$ 47,462	$ 102,683
Midstream revenue	203	600	871	2,158
Royalties	(992)	(4,119)	(2,629)	(11,941)
Operating and transportation expenses	(7,947)	(8,738)	(22,328)	(26,597)
	$ 6,096	$ 21,154	$ 23,376	$ 66,303
REALIZED PRICES				
Oil ($/bbl)	$ 59.25	$ 92.80	$ 54.63	$ 95.26
Natural gas ($/Mcf)	2.78	4.40	2.81	5.24
Natural gas liquids ($/bbl)	21.29	66.76	25.94	76.78
Realized price ($/boe)	31.34	56.90	31.66	61.16
Royalties ($/boe)	(2.10)	(7.01)	(1.75)	(7.11)
Operating and transportation expenses(2) ($/boe)	(16.36)	(13.86)	(14.31)	(14.56)
LIGHT OIL OPERATING NETBACK(1) ($/boe)	$ 12.88	$ 36.03	$ 15.60	$ 39.49

(1) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.
(2) For the three months ended September 30, 2015, operating and transportation expenses in the Light Oil Operating Netback figure includes midstream revenues of $0.43/boe (2014 - $1.02) and for the nine months ended September 30, 2014, $0.58/boe (2014 - $1.28/boe).

During the three months ended September 30, 2015, Athabasca produced 5,145 boe/d (48% liquids), a 19% decrease compared to 6,381 boe/d (51% liquids) during the same period in the prior year. For the nine months ended September 30, 2015, Athabasca produced 5,491 boe/d (48% liquids), compared to 6,149 boe/d (50% liquids) during the same period in the prior year. Lower production was primarily due to natural well declines from the Company's Montney and Duvernay wells, partially offset by new wells brought on stream during 2015. The Company also experienced unplanned service interruptions on the Alliance pipeline during the third quarter of 2015. A 12-day service interruption on the Alliance pipeline resulted in lower sales volumes of approximately 370 boe/d for the quarter ended September 30, 2015.

Realized prices decreased by 45% and 48% during the three and nine months ended September 30, 2015 to $31.34/boe and $31.66/boe, respectively, compared to the same periods in the prior year. The declines were primarily due to lower underlying market commodity prices for oil, natural gas and natural gas liquids.

Royalty expenses for the three months ended September 30, 2015 were $1.0 million (7% percent of revenue) compared to $4.1 million (12% of revenue) during the same period in the prior year. For the nine months ended September 30, 2015, Athabasca incurred royalty expenses of $2.6 million (6% of gross revenue) compared to $11.9 million (12% of gross revenues) during the same period in 2014. Declines in royalties expenses were primarily due to lower sliding scale royalty rates which declined due to lower market commodity prices as well as prior period adjustments to gas cost allowances received during the second quarter of 2015.

During the three months ended September 30, 2015, operating expenses increased from $13.86/boe to $16.36/boe, compared to the same period in the prior year, primarily due to pipeline service interruptions and lower volumes from natural declines. For the nine months ended September 30, 2015, operating expenses declined from $14.56/boe to $14.31/boe with ongoing cost savings initiatives undertaken in the first half of 2015 largely offset by lower production volumes.

Segment Income (Loss)

The following table summarizes the Light Oil Segment income (loss) for the three and nine months ended September 30, 2015 and 2014:

($ Thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Light Oil Operating Income(1)	$ 6,096	$ 21,154	$ 23,376	$ 66,303
Depletion and depreciation	(15,193)	(28,300)	(48,317)	(65,339)
Exploration expense	(142)	—	(753)	—
Gain on sale of assets	—	—	—	182
LIGHT OIL SEGMENT INCOME (LOSS)	$ (9,239)	$ (7,146)	$ (25,694)	$ 1,146

(1) Refer to “Advisories and Other Guidance” beginning on page 19 for additional information on Non-GAAP Financial Measures.

Depletion and Depreciation

($ Thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Depletion of oil and gas assets	$ 14,509	$ 18,820	$ 45,852	$ 53,675
Depreciation of infrastructure assets	684	1,105	2,465	3,289
Land expiries	—	8,375	—	8,375
TOTAL LIGHT OIL DEPLETION AND DEPRECIATION	$ 15,193	$ 28,300	$ 48,317	$ 65,339

In the Light Oil Division, depletion and depreciation declined during the three and nine months ended September 30, 2015 compared to the same periods in the prior year, primarily due to lower depletion rates resulting from reserve additions in the Light Oil Division and lower production volumes. 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. The producing light oil properties, including estimated future development costs, are depleted using the unit of production based on estimated proved plus probable reserves.

During the nine months ended September 30, 2014, Athabasca recognized a loss of $8.4 million on non-core light oil exploration acreage in the Grande Prairie area that expired.

Exploration Expense

During the three and nine months ended September 30, 2015, Athabasca incurred exploration expenses of $0.1 million and $0.8 million, respectively, which primarily relate to land retention costs in the Company's Light Oil exploration areas which were fully impaired in the fourth quarter of 2014. These exploration costs were capitalized to exploration and evaluation assets during the three and nine months ended September 30, 2014.

Thermal Oil Division

Operating results

The following table summarizes the Thermal Oil operating results for the three and nine months ended September 30, 2015 and 2014:

($ Thousands, except bbl, mcf and boe amounts)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
VOLUMES (including capitalized volumes)(1)(2)				
Bitumen production (bbl/d)	2,105	—	716	—
Bitumen sales (bbl/d)	1,956	—	660	—
Dilbit Sales (bbl/d)	2,514	—	848	—
Bitumen sales consists of:				
Bitumen sales capitalized (bbl/d)	164	—	56	—
Bitumen sales recognized in income (bbl/d)	1,792	—	604	—
	1,956	—	660	—
THERMAL OIL OPERATING INCOME (LOSS)(1)(3)				
Blended bitumen sales	$ 6,163	$ —	$ 6,163	$ —
Cost of diluent	(3,272)	—	(3,272)	—
Total bitumen sales	2,891	—	2,891	—
Royalties	(18)	—	(18)	—
Operating expenses - non-energy	(9,493)	—	(9,493)	—
Operating expenses - energy	(3,323)	—	(3,323)	—
Transportation and marketing	(2,203)	—	(2,203)	—
	$ (12,146)	$ —	$ (12,146)	$ —
REALIZED PRICES				
Total bitumen sales ($/bbl)	$ 17.54	$ —	$ 17.54	$ —
Royalties ($/bbl)	(0.11)	—	(0.11)	—
Operating expenses - non-energy ($/bbl)	(57.58)	—	(57.58)	—
Operating expenses - energy ($/bbl)	(20.16)	—	(20.16)	—
Transportation and marketing ($/bbl)	(13.36)	—	(13.36)	—
THERMAL OIL OPERATING NETBACK ($/bbl)	$ (73.67)	$ —	$ (73.67)	$ —

(1) 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.
(2) For the three and nine months ended September 30, 2015, Thermal Oil bitumen production and sales volumes on a bbl/d basis represent all Hangingstone sales and production volumes (including capitalized volumes) for the period averaged over 92 days and 273 days, respectively.
(3) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

During the nine months ended September 30, 2015, Athabasca completed construction and commissioning of Project 1. Athabasca completed Project 1 during the first quarter of 2015 and commenced steaming 15 of the 25 well pairs. The Company achieved first oil in July and 15 well pairs were converted to production by the end of the third quarter of 2015. Athabasca also commenced steaming on six additional well pairs which are anticipated to be converted to production before the end of the year. Initial operating results from Project 1 were capitalized until August 1, 2015 when the project had been deemed to be ready for use in the manner intended by management.

During the third quarter of 2015, Athabasca continued to monitor the reservoir from which Project 1 is producing, using fiber optic well bore sensors and a distributed pressure and temperature data network and conducted temperature fall-off tests on circulating wells to confirm readiness of conversion to production. Temperature and pressure response in the reservoir continues to align with management's expectations and supports ongoing production and ramp-up. Facility availability for the quarter exceeded 99% providing steady steam supply to the wells.

For the three months ended September 30, 2015, Athabasca averaged 2,105 bbl/d of bitumen production and had an exit rate of over 4,000 bbl/d by the end of the quarter. Production is anticipated to ramp-up throughout the remainder of 2015 and into 2016 with plateau production of 12,000 bbl/d expected in the fourth quarter of 2016.

The Thermal Oil Operating Netback for the three and nine months ended was $(73.67)/bbl due to a higher component of fixed operating costs relative to low initial production volumes. Negative Operating Netbacks are customary during ramp up of a SAGD project and Athabasca anticipates Netbacks from Project 1 will improve as production ramps up.

Operating costs consist of energy and non-energy related operating costs. Energy operating costs consist of the electricity costs used to power the facilities as well as the consumption of natural gas which is used to create steam for the SAGD recovery process. Non-energy operating costs represent all other lifting costs and other indirect expenditures associated with Project 1 in the production process. Total cost of operations are in line with Athabasca's expectations for the third quarter of 2015.

Transportation and marketing expenditures consist of the costs incurred to deliver the dilbit product from the plant facility to market. During the three months ended September 30, 2015, transportation and marketing primarily consisted of trucking costs to various sales points as the dilbit pipeline connecting Project 1 to the Cheecham Terminal will not be placed into service until December 2015.

Segment Income (Loss)

The following table summarizes the Thermal Oil Segment income (loss) for the three and nine months ended September 30, 2015 and 2014:

($ Thousands)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Thermal Oil Operating Income[(1)]	$ (12,146)	$ —	$ (12,146)	$ —
Depletion and depreciation	(2,524)	—	(2,524)	(5,264)
Exploration expense	(471)	—	(611)	—
Gain on sale of assets	—	2,449	—	(38,659)
Equity loss on investment	—	(71)	—	(390)
THERMAL OIL SEGMENT INCOME (LOSS)	$ (15,141)	$ 2,378	$ (15,281)	$ (44,313)

(1) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

Depletion and depreciation

($ Thousands)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Depletion of oil and gas assets	$ 889	$ —	$ 889	$ —
Depreciation of infrastructure assets	1,635	—	1,635	—
Land relinquishments and expiries	—	—	—	5,264
TOTAL THERMAL OIL DEPLETION AND DEPRECIATION	$ 2,524	$ —	$ 2,524	$ 5,264

During the third quarter of 2015, Project 1 became ready for use in the manner intended by management and Athabasca began depreciating the project components over their useful lives. The central processing facilities are 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, included estimated future development costs, are depleted using the unit of production method based on estimated proved reserves.

During the nine months ended September 30, 2014, Athabasca recognized a loss of $5.3 million on non-core peripheral oil sands leases relinquished in the thermal oil Grosmont area.

Exploration Expense

During the three and nine months ended September 30, 2015, Athabasca incurred exploration expenses of $0.5 million and $0.6 million, respectively, which primarily relate to land retention costs in the Company's Thermal Oil Grosmont area assets which were fully impaired in the fourth quarter of 2014. These exploration costs were capitalized to exploration and evaluation assets during the three and nine months ended September 30, 2014.

Gain (Loss) on Sale of Assets

Previously, Athabasca held a put option that would require Phoenix Energy Holdings Ltd. ("Phoenix") to acquire Athabasca's 40% interest in the Dover commercial project (the "Dover Investment") for $1.32 billion, before transaction costs and other working capital adjustments. The put option was exercisable once regulatory approval for the project had been received (the "Dover Put Option"). In the fourth quarter of 2012, Athabasca was required to measure its Dover Put Option given greater clarity around regulatory approval and potential exercise of the option.

On August 29, 2014, Athabasca sold its 40% interest in the Dover joint venture for net proceeds of $1,183.9 million consisting of $601.3 million in cash and $583.9 million in three promissory notes (the "Promissory Notes"). Athabasca recognized a net loss of $38.5 million during the nine months ended September 30, 2014, primarily related to transaction costs of $49.0 million in respect of the settlement of certain claims made by Phoenix relating to future abandonment costs associated with petroleum and natural gas wells located in the Dover and MacKay River areas. The net loss incurred was offset by the de-recognition of certain decommissioning obligation liabilities previously recognized by Athabasca and working capital and other adjustments associated with the closing of the Dover investment.

The gain on sale of asset during the three months ended September 30, 2014, primarily relates to working capital and other adjustments. The Company received $2.3 million in final working capital adjustments associated with the closing of the sale, including $1.0 million that was received during the nine months ended September 30, 2015.

On March 2nd, 2015, the first Promissory Note matured and Athabasca received a cash payment of $302.5 million, including accrued interest. The second Promissory Note matured on August 30, 2015 and Athabasca received a cash payment for $152.6 million, including accrued interest. The remaining Promissory Note of $133.9 million matures in August of 2016.

Corporate Review

General and Administrative ("G&A")

	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Salaries and benefits	$ 8,070	$ 15,724	$ 27,049	$ 49,390
Office costs	2,518	4,198	9,834	12,811
Legal, accounting and consulting	877	1,235	3,123	3,974
Stakeholder relations	243	260	686	1,154
Capitalized staff costs	(3,039)	(9,268)	(15,326)	(31,372)
TOTAL GENERAL AND ADMINISTRATIVE EXPENSES	$ 8,669	$ 12,149	$ 25,366	$ 35,957
Capitalization rate	26%	43%	38%	47%

During the three and nine months ended September 30, 2015, salaries and benefits declined by $7.7 million and $22.3 million, respectively, compared to the same periods in the prior year. In 2014 and 2015, the Company has undertaken initiatives to streamline costs and better align the organization's cost structure to the current operating environment, its capital plans and growth objectives. As a result, Athabasca has significantly reduced the size of its head office workforce since the beginning of 2014. Athabasca also undertook a number of other cost efficiency initiatives in 2014 and 2015 that have resulted in lower office costs and legal, accounting and consulting related expenses.

Capitalized staff and environment costs decreased during the three and nine months ended September 30, 2015 compared to the same periods in the prior year, primarily due to the staff reductions, the completion of Project 1 and a reduction in other Thermal Oil and Light Oil project activities.

Restructuring and Other Charges

($ Thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Staff restructuring charges	$ 2,104	$ —	$ 8,089	$ 5,754
Office lease provision	—	—	7,034	—
Cancellation charges	(443)	—	3,526	—
TOTAL RESTRUCTURING CHARGES AND OTHER CHARGES	$ 1,661	$ —	$ 18,649	$ 5,754

For the nine months ended September 30, 2015 and 2014, Athabasca incurred staff restructuring charges of $8.1 million and $5.8 million, respectively, relating to the Company's cost reduction activities. The Company also recognized a loss of $7.0 million for the nine months ended September 30, 2015, relating to lease commitments on vacated office space primarily as a result of the staff reductions. For the nine months ended September 30, 2015, Athabasca also recognized net cancellation charges of $3.5 million relating to Thermal Oil rig commitments associated with the 2014/15 drilling season.

Stock-based Compensation

For the three ended September 30, 2015, Athabasca incurred stock-based compensation expense of $2.7 million compared to $3.9 million during the same period in the prior year. The decrease was primarily due to lower equity awards outstanding as a result of forfeitures from restructuring activities in the first quarter of 2015. For the nine months ended September 30, 2015, Athabasca incurred stock-based compensation expense of $8.6 million compared to $6.8 million during the same period in the prior year. The increase was primarily due to new equity awards granted during the third quarter of 2014 and the second quarter of 2015 and lower capitalization rates due to lower Thermal Oil and Light Oil project activities in 2015.

Financing and Interest

($ Thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Interest and fees on indebtedness	$ 16,952	$ 15,931	$ 48,580	$ 43,802
Accretion of provisions	1,584	1,587	5,002	4,646
Amortization of debt issuance costs	1,857	1,751	5,480	9,685
Capitalized financing and interest	(5,773)	(13,930)	(39,686)	(33,856)
TOTAL FINANCING AND INTEREST	$ 14,620	$ 5,339	$ 19,376	$ 24,277

Interest and financing expenses are primarily attributable to the three debt instruments held by the Company. Interest expense and amortization of debt issuance costs are incurred on the Company's $550.0 million senior secured second lien notes ("Notes") which were issued during the fourth quarter of 2012. The Notes bear interest at a rate of 7.5% per annum. Interest and amortization of debt issuance costs are also incurred on the Company's US$225.0 million senior secured first lien term loan (the "Term Loan") issued in the second quarter of 2014. The Term Loan currently bears interest at a rate of approximately 8.25% per annum. Athabasca also incurs standby fees on its $125.0 million credit facility ("Credit Facility") and its US$50.0 million delayed-draw Term Loan.

During the three and nine months ended September 30, 2015, Athabasca incurred higher interest and fees on indebtedness of $1.0 million and $4.8 million, respectively, compared to the same periods in the prior year. The increase was primarily due to the Company's Term Loan which was issued during the second quarter of 2014.

Compared to the same period in 2014, capitalized financing and interest increased by $5.8 million during the nine months ended September 30, 2015. The increase was primarily due to a higher percentage of interest and financing costs being capitalized to Project 1 as the project neared completion during the first half of 2015, partially offset by the discontinuance of interest and financing cost capitalization in August of 2015 when Project 1 became ready for use. For the three months ended September 30, 2015, capitalized financing and interest costs declined by $8.2 million primarily due to discontinuance of interest and financing cost capitalization in August of 2015 when Project 1 became ready for use.

Interest income and other

($ Thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Interest income on cash and cash equivalents	$ 1,561	$ 1,335	$ 5,573	$ 2,803
Interest income on Promissory Notes	1,009	813	4,300	813
Time value of money accretion	—	582	—	3,342
Other	—	—	479	153
TOTAL INTEREST INCOME AND OTHER	$ 2,570	$ 2,730	$ 10,352	$ 7,111

Interest income and other increased during the nine months ended September 30, 2015 by $3.2 million, compared to the same period in the prior year. The increase was primarily due to interest income earned on the Promissory Notes issued to Athabasca by Phoenix on the closing of the sale of the Dover Investment during the third quarter of 2014. The Company also earned higher interest income on cash, cash equivalents and short-term investments as average balances were higher during the first nine months of 2015 relative to the prior year. The overall increase in interest income was partially offset by time value of money accretion on the Dover Investment during the first nine months of 2014.

For the three months ended September 30, 2015, interest income decreased by $0.2 million primarily due to lower interest rates in 2015 compared to the same period in the prior year as well as the time value accretion earned on the Dover Investment during the third quarter of 2014, which more than offset higher interest income from higher average balances held of cash, cash equivalents, short term investments and Promissory Notes during the third quarter of 2015.

Foreign Exchange Loss, Net

($ Thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Unrealized foreign exchange gain (loss)	$ (20,067)	$ (11,970)	$ (39,313)	$ (7,020)
Realized foreign exchange gain (loss)	(176)	(133)	(31)	(213)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ (20,243)	$ (12,103)	$ (39,344)	$ (7,233)

Athabasca incurs foreign exchange gains and losses on the Company's US$225.0 million Term Loan, which was issued on May 7, 2014. Athabasca recognized a net foreign exchange loss during the first nine months of 2015 and 2014 primarily due to an unrealized loss on the loan principal as the value of the Canadian dollar declined relative to the US dollar.

Derivative Gain (Loss), Net

($ Thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Unrealized derivative gain (loss)	$ 22,271	$ 13,134	$ 41,577	$ 3,297
Realized derivative gain (loss)	1,147	—	2,568	(150)
DERIVATIVE GAIN (LOSS), NET	$ 23,418	$ 13,134	$ 44,145	$ 3,147

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 to reduce the Company's exposure to fluctuations in foreign exchange rates on its US dollar denominated long-term debt. Athabasca recognized a net derivative gain during the first nine months of 2015 and 2014 as the value of the Canadian dollar declined relative to the US dollar.

Loss on Provisions

During the three and nine months ended September 30, 2015, Athabasca recognized a net loss on provisions of $4.7 million and $6.1 million, respectively, primarily relating to refined estimates of the timing and amount of expected cash inflows associated with the Company's office lease provision liability. Further softening of the downtown Calgary real estate market during the second and third quarters of 2015 from an increasing supply of available office space lowered Athabasca's anticipated cash inflows associated with the office lease provision.

Deferred Income Tax Recovery

During the second quarter of 2015, the Alberta Government announced a 2% increase to the 2015 provincial tax rate effective July 1, 2015. For the nine months ended September 30, 2015, Athabasca recognized a deferred income tax recovery of $13.9 million which was primarily due to non-capital losses incurred, partially offset by a tax expense of approximately $12.6 million from the impact of the tax rate increase. The deferred income tax recoveries recognized during the three and nine months ended September 30, 2014 and for the three months ended September 30, 2015 were primarily due to non-capital losses incurred.

At September 30, 2015, the Company had approximately $2.7 billion in tax pools, including over $1.0 billion in pools available for immediate deduction against future income.

CAPITAL EXPENDITURES

The following table summarizes the consolidated capital expenditures made by the Company for the three and nine months ended September 30, 2015 and 2014:

($ Thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Light Oil Division	$ 31,465	$ 19,772	125,667	$ 112,068
Thermal Oil Division	9,366	89,455	111,073	337,968
Corporate assets	231	3,032	2,275	5,534
Total expenditures on E&E and PP&E	41,062	112,259	239,015	455,570
Expenditures included in assets held for sale(1)	—	1,520	—	8,120
TOTAL CAPITAL EXPENDITURES(2)	$ 41,062	$ 113,779	$ 239,015	$ 463,690

(1) Relates to the Dover Investment that was sold to Phoenix on August 29, 2014.

(2) For the three and nine months ended September 30, 2015, capital expenditures includes capitalized staff costs of $3.0 million and $15.3 million, respectively (September 30, 2014 - $9.3 million, $31.4 million) and capitalized interest and financing of $5.2 million and $35.9 million, respectively (September 30, 2014 - $12.6 million, $30.6 million). Excluded are non-cash capitalized costs consisting of capitalized stock-based compensation, decommissioning obligations assets and non-cash interest and financing.

Light Oil Division

($ Thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Light Oil capital expenditures(1)				
Duvernay	$ 22,170	$ 12,269	$ 86,986	$ 80,644
Montney	2,472	3,005	16,016	14,243
Operations and other	5,108	3,053	10,596	12,251
Land and lease rentals	1,715	1,445	12,069	4,930
TOTAL LIGHT OIL CAPITAL EXPENDITURES	$ 31,465	$ 19,772	$ 125,667	$ 112,068

(1) For the three and nine months ended September 30, 2015, capital expenditures includes $1.5 million and $5.5 million in capitalized staff costs, respectively (September 30, 2014 - $2.0 million, $6.5 million).

For the three months ended September 30, 2015, the Company spent $22.2 million primarily to rig release one and complete two Duvernay wells and commence activities related to the 2015/16 winter drilling program. During the nine months ended September 30, 2015, the Company spent $125.7 million in the Light Oil Division primarily in the Greater Kaybob area. Athabasca spent $87.0 million on the Duvernay Formation to drill eight wells (six horizontal, two vertical). Athabasca also completed five Duvernay wells and brought two Duvernay wells on stream. With the completion of the 2014/15 winter drilling program, 95% of the Company's 200,000 commercially prospective Duvernay acres were extended into the intermediate term.

For the nine months ended September 30, 2015, Athabasca spent $16.0 million on the Montney Formation in Placid within the Greater Kaybob Area. The Company drilled one and completed two Montney horizontal wells during the period. Athabasca also brought one Placid well on stream. At the end of the third quarter of 2015, Athabasca also commenced drilling a three well pad in the Placid area.

For the nine months ended September 30, 2015, Athabasca spent $12.1 million primarily to retain lands and acquire additional acreage in the Greater Kaybob Area. The Company also spent $10.6 million primarily to support the Division's major Light Oil infrastructure and ongoing project operations.

Thermal Oil Division

($ Thousands)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Hangingstone capital expenditures				
Central processing facility	$ —	$ 36,747	$ 28,239	$ 114,534
Drilling, pads and pipelines	—	9,339	1,273	67,067
Base infrastructure	—	2,612	356	12,619
Total Project 1 base facility	—	48,698	29,868	194,220
Regional infrastructure and production assurance	—	10,151	839	53,002
Project support costs(1)	—	7,783	8,864	26,945
Capitalized start-up costs	1,527	—	24,978	—
Capitalized interest and financing(2)	5,224	12,606	35,826	30,638
Mineral properties – acquisitions and rentals	—	86	—	215
Total Project 1	6,751	79,324	100,375	305,020
Hangingstone Expansion	582	7,892	2,659	22,704
Other Thermal Oil exploration	2,033	2,239	8,039	10,244
TOTAL THERMAL OIL CAPITAL EXPENDITURES	$ 9,366	$ 89,455	$ 111,073	$ 337,968

(1) Includes geosciences, regulatory and stakeholder costs and delineation/observation drilling. For the three and nine months ended September 30, 2015, capital expenditures include $1.6 million and $9.9 million in capitalized staff costs, respectively (September 30, 2014 - $7.4 million, $24.8 million).

(2) Excludes non-cash capitalized interest and financing.

Project 1

During the nine months ended September 30, 2015, Athabasca spent $100.4 million on Project 1 primarily to complete the project and commence operations. The Company completed Project 1 construction during the first quarter of 2015 and transitioned to operations during the second quarter. The project became ready for use during the third quarter of 2015 at which time the Company discontinued the capitalization of initial net operating costs as well as the capitalization of interest and financing costs associated with the project. The Company plans to continue to ramp-up operations throughout the remainder of 2015 and 2016.

Third party construction of the transportation facilities is also substantially complete. The diluent pipeline is operational and the start-up of the dilbit pipeline to the Cheecham terminal remains on track for the end of the fourth quarter of 2015.

Hangingstone Expansion

The application for the expansion development of Hangingstone for an incremental 70,000 bbl/d has been confirmed as technically complete by the AER and Athabasca anticipates receiving final regulatory approval in 2016. Prior to the sanctioning of any expansion projects at Hangingstone, successful production ramp-up of Project 1 will need to be demonstrated, along with suitable market conditions and project funding.

Other Thermal Oil Exploration

For the nine months ended September 30, 2015, Athabasca spent $8.0 million on other Thermal Oil exploration areas primarily relating to ongoing Thermal Oil infrastructure operations as well as land retention costs.

OUTLOOK

Athabasca's consolidated budget stands at $256 million (excluding capitalized interest and G&A), a reduction of 10% from $291 million. The reduction was driven by operational efficiencies and through a reduction of non-productive capital. The following table summarizes the Company's revised 2015 capital budget as at September 30, 2015:

2015 budget(1) ($ millions)	Q1	Q2	Q3	Q4e	Full year
Light Oil Division					
Duvernay	$ 57	$ 8	$ 22	$ 42	$ 128
Montney	14	—	2	27	43
Other	2	—	4	7	12
	73	8	28	75	184
Thermal Oil Division					
Hangingstone Project 1	44	14	—	—	59
Hangingstone Expansion	1	—	—	—	3
Other	3	2	2	2	8
	48	15	3	3	69
Corporate	2	—	—	—	3
TOTAL CAPITAL EXPENDITURES	$ 123	$ 23	$ 31	$ 79	$ 256
Capitalized interest and G&A	$ 23	$ 20	$ 8	$ 2	$ 54
Land	$ 4	$ 6	$ 2	$ —	$ 12

(1) Figures may not add due to rounding.

Light Oil budget

The revised 2015 capital budget for Light Oil stands at $184 million (down from $203 million). Fourth quarter production is expected to average approximately 5,500 - 6,000 boe/d. Exit guidance is maintained at 7,000 - 8,000 boe/d (December average), however ongoing constraints on the TCPL pipeline system have the potential to impact volumes by up to 1,000 boe/d.

The fourth quarter 2015 program includes the following activity:

- Duvernay Volatile Oil Window:
  - *Completion of 00/16-6-65-18W5 and 102/16-6-65-18W5*
  - *Begin producing 16-36-63-25W5 at Simonette*
- Duvernay Condensate Rich Gas Window:
  - *Commence drilling operations on a four well pad in Section 36-63-20W5 at Kaybob West*
  - *Begin producing 1-36-63-20W5 and 8-36-63-20W5 at Kaybob West*
  - *Begin producing 12-28-62-23W5 at Saxon*
- Placid Montney:
  - *Continue drilling operations on a 3 well pad*
  - *Commence construction of the Placid inter-connect to Saxon*

Thermal Oil budget

The revised 2015 Thermal Oil budget is $69 million (down from $82 million), reflecting reduced expenditures during Hangingstone Project 1 start-up and reduced spending on Hangingstone Expansion pre-engineering and other thermal assets. Thermal Oil capital expenditures are largely complete for the year.

The 2015 year-end Thermal oil exit production guidance has been upwardly revised to 5,000 bbl/d - 7,000 bbl/d (from 3,000 - 6,000 bbl/d, December average).

Consolidated budget and financial outlook

Athabasca’s updated 2015 corporate year-end exit guidance is between 12,000 - 15,000 boe/d (December average, from 10,000 - 14,000 boe/d) based on a $256 million capital program.

Maintaining a strong financial position continues to be a top priority for Athabasca. As at November 1, the Company has approximately $970 million of funding in place including approximately $790 million of cash, cash equivalents and proceeds from the last promissory note issued by Phoenix. The 2016 budget will be released in early December and the Company expects to implement a capital budget of less than $100 million. Minimal capital spending will be used as a lever to protect the Company's balance sheet and liquidity position in light of the current commodity price environment.

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 and cash equivalent accounts. Until required, excess cash will be invested in short-term investments.

Funding

The following table summarizes the Company's Available Funding as at September 30, 2015 and December 31, 2014:

($ Thousands)	September 30, 2015	December 31, 2014
Cash and cash equivalents	$ 671,447	$ 531,475
Short-term investments	—	47,618
Promissory Notes	133,892	583,892
Undrawn credit facilities[1]	118,480	124,464
Term Loans - delayed draw (US$50.0 million)	66,970	58,005
AVAILABLE FUNDING[2]	$ 990,789	$ 1,345,454

(1) As at September 30, 2015, Athabasca has issued $6.5 million in letters of credit under the Company's credit facilities (December 31, 2014 - $0.5 million).
(2) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

It is anticipated that Athabasca's 2015 capital and operating budgets, including continued appraisal and development activities in the Greater Kaybob area and the ramp up of Project 1, will be funded with existing cash and cash equivalents, short-term investments, the Promissory Note, cash flows from operations and available credit. The Company's current liquidity and available credit will also be sufficient to fund any collateral that may be required under the Company's pipeline and transportation agreements with third parties. Beyond 2015, the Company will require additional capital to fully develop its assets and Athabasca believes it will fund its capital programs through some combination of cash and cash equivalents, short-term investments, receipts of the amounts owing under the final Promissory Note, cash flow from operations, a reasonable level of debt and other external financing options which could include joint ventures or equity issuances. 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, performance in both the Light Oil Division and at Hangingstone, the Company's credit rating at the time and the current state of the equity and debt capital markets. The Company has significant flexibility to adjust its Light Oil capital program in response to commodity price cycles or other constraints and is prepared to implement a minimal 2016 capital budget to protect its balance sheet and liquidity position.

Indebtedness

The following table summarizes Athabasca's Net Debt as at September 30, 2015 and December 31, 2014:

($ Thousands)	September 30, 2015	December 31, 2014
Long-term debt	$ 827,773	$ 786,649
Current liabilities	74,329	171,097
Current assets	(851,212)	(1,082,301)
Current portion of derivative asset (included in current assets)	4,543	930
NET DEBT[1]	$ 55,433	$ (123,625)

(1) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

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.

On May 7, 2014, Athabasca entered into a credit agreement providing for a US$225 million term loan (the "Term Loan"), which was fully funded at closing, plus an additional US$50 million committed delayed draw term loan, which the Company may draw at its option at any time up until May 7, 2016, subject to compliance with certain conditions precedent and covenants (collectively the “Term Loans”). As of September 30, 2015, the delayed draw term loan was undrawn.

On May 7, 2014, concurrent with entering into the Term Loans, the Company entered into a $125 million amended and restated credit agreement with a syndicate of financial institutions to replace its previous $350 million credit facility. The amended and restated credit facility (the “Credit Facility”) is available on a revolving basis until April 30, 2017. As of September 30, 2015, $6.5 million of letters of credit had been issued under the Credit Facility, with the balance of the facility undrawn.

The Company’s significant outstanding financial liabilities mature as follows: the Notes mature on November 19, 2017; the Term Loan matures on May 7, 2019 or on May 19, 2017 if the Company has not redeemed or refinanced the Notes prior to that date. The ability to draw on the delayed draw term loan expires on May 7, 2016 and the undrawn Credit Facility matures on April 30, 2017.

Refer to Athabasca's consolidated financial statements for the three and nine months ended September 30, 2015 for additional information regarding the Company's long-term debt and credit facilities.

Commitments and Contingencies

The following table summarizes Athabasca’s estimated future minimum commitments as at September 30, 2015 for the following five years and thereafter:

($ Thousands)	2015	2016	2017	2018	2019	Thereafter	Total
Repayment of long-term debt(1)(2)	$ 744	$ 2,958	$ 552,928	$ 2,899	$ 288,088	$ —	$ 847,617
Interest expense on long-term debt(2)	16,588	65,989	60,837	24,182	8,444	—	176,040
Transportation	2,876	32,578	33,759	28,853	31,587	499,650	629,303
Office leases	1,079	4,291	4,291	4,291	4,291	28,173	46,416
Purchase commitments and other(3)	11,646	—	—	—	—	—	11,646
Drilling rigs	1,705	4,656	—	—	—	—	6,361
TOTAL COMMITMENTS	$ 34,638	$ 110,472	$ 651,815	$ 60,225	$ 332,410	$ 527,823	$ 1,717,383

(1) The Term Loan is required to be repaid on May 19, 2017 if the Company has not redeemed or refinanced the Notes prior to this date.
(2) Estimated future interest and principal repayments relating to the Term Loan have been translated a rate of US$1.00 = C$1.3394 in the table above which is based on the current spot rate as at September 30, 2015.
(3) Purchase commitments and other primarily relates to Thermal Oil camp costs and long-lead equipment in the Light Oil Division.

Transportation commitments

Athabasca has entered into two transportation services agreements which will support the Hangingstone projects. The first agreement was signed with Enbridge Pipelines (Athabasca) Inc. (“Enbridge”) for the transportation of produced bitumen and blended diluents from Hangingstone. Included in the table above under Transportation are the minimum take or pay commitments for terminalling and transportation from Cheecham to Edmonton. No amounts have been recognized in the table for the transportation from Hangingstone to Cheecham as that commitment takes effect upon the completion of a lateral pipeline, which is anticipated to be completed in the fourth quarter of 2015. The amount of the commitment for the transportation from Hangingstone to Cheecham is anticipated to be greater than $475 million over the initial term of the agreement, but the final commitment depends on the actual costs incurred by Enbridge to construct the lateral pipeline. The initial term of the agreement is 25 years with Athabasca having the option to extend over four renewal terms of five years each.

The second agreement was signed with Inter Pipeline Polaris Inc. (“IPPI”) for the transportation of condensate to the Hangingstone project using the IPPI owned and operated Polaris Condensate Pipeline System. Included in the table above under Transportation are the minimum take or pay commitments under the agreement. The initial term of the agreement is 25 years with Athabasca having the option to extend over five renewal terms of five years each.

Athabasca is subject to certain financial assurance provisions under its pipeline transportation agreements which will likely require the Company to provide financial collateral which could include letters of credit and/or certain security interests in line-fill and product sales receivables beginning in the fourth quarter of 2015. The amount of collateral that may be required under these agreements is approximately $90.0 million.

Other Commitments

Athabasca is responsible for the retirement of its resource assets at the end of their useful lives.

Excluded from the table above is a commitment for $133.7 million in office leases which were assigned to a third party in December 2013.

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.

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

Credit Risk

The maximum exposure to credit risk is represented by the carrying amounts of cash and cash equivalents, short-term investments, accounts receivable, income tax receivable, derivative assets and Promissory Notes on the consolidated balance sheets. Cash and cash equivalents and short-term investments 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, 2015 and December 31, 2014 Athabasca's cash, cash equivalents and short-term investments were held with four counterparties. The Company holds investments in term deposits with large reputable financial institutions. The Company's management believes that credit risk associated with these investments is low. At September 30, 2015, the largest institution held 34% of the balances (December 31, 2014 - 35%).

As at September 30, 2015, 36% of the accounts receivable balance relates to the sale of petroleum and natural gas and was substantially collected within 30 days after the end of the period (December 31, 2014 - 23%). Joint interest billings and equipment disposals with partners account for 33% of accounts receivable (December 31, 2014 - 47%). 20% of the accounts receivable balance relates to GST and other receivables (December 31, 2014 - 22%). Additionally, 11% relates to accrued interest on the Promissory Note (December 31, 2014 - 8%). Management believes collection risk on the outstanding accounts receivable as at September 30, 2015 is low given the high credit quality of the Company's material counterparties. No material amounts were past due at September 30, 2015.

As at September 30, 2015 Athabasca holds $136.4 million in a remaining Promissory Note including the note principal and accrued interest. The Promissory Note is unconditional and secured by an irrevocable, standby letter of credit issued by HSBC Bank Canada ("HSBC"). Management believes that credit risk associated with this receivable is low as Phoenix is a wholly owned subsidiary of PetroChina, an investment grade rated corporation, and HSBC is a large reputable financial institution. The first and second Promissory Notes, which matured on March 2, 2015 and August 28, 2015 respectively, were fully collected on maturity.

Foreign exchange risk

The Company is exposed to foreign exchange risk on its US dollar denominated Term Loan and US dollar forward contract as described below. If the Canadian dollar strengthened by 5% relative to the US dollar, holding all other variables constant, the derivative asset of $54.2 million would decrease by $16.6 million. Long-term debt would decrease by $14.9 million resulting in a net $1.7 million loss. A 5% decrease in the Canadian dollar relative to the US dollar, holding all other variables constant, would increase the derivative asset by $16.6 million and increase long-term debt by $14.9 million resulting in a net $1.7 million gain.

Athabasca is exposed to foreign currency risk on its US dollar denominated Term Loan. To manage the currency exposure, 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 is accounted for as a derivative instrument and changes in the valuation are recognized in net income (loss) and the associated liability or asset is recognized on the balance sheet.

($ Thousands)		September 30, 2015		December 31, 2014
OPENING DERIVATIVE ASSET	$	12,638	$	—
Unrealized derivative gain		41,577		12,638
CLOSING DERIVATIVE ASSET	$	54,215	$	12,638
Presented as:				
Current portion of derivative asset	$	4,543	$	930
Long-term portion of derivative asset	$	49,672	$	11,708

Interest Rate Risk

The Company's exposure to interest rate fluctuations on interest earned on the floating rate cash balance of $592.8 million, from a 1.00% change in interest rates, would be approximately $5.9 million for a 12 month period (year ended December 31, 2014 - $4.4 million). The Company is also exposed to interest rate cash flow risk on its floating rate Term Loan. However, given that the Company has a 1.00% LIBOR floor on its Term Loan, a decrease in the rate would have no impact. A 1.00% increase in LIBOR above the existing rate would result in a US$0.7 million ($1.0 million) increase in interest expense for a 12 month period (year ended December 31, 2014 - US$0.6 million ($0.7 million)).

Off Balance Sheet Arrangements

The Company has certain office lease agreements which are reflected in the table above under the heading "Commitments and Contingencies", and which were entered into in the normal course of operations. Payments pursuant to these leases, which have been treated as operating leases, have been recorded as G&A expenses. No asset or liability value has been assigned to these agreements on the Company's balance sheet. The Company has no other off balance sheet arrangements.

Equity Instruments

During the nine months ended September 30, 2015, the Company issued 1.5 million common shares. Issuances of Athabasca's common shares in 2015 relate to 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 October 28, 2015	
Common shares issued and outstanding	403,934,372
Convertible securities:	
Stock options - exercisable and unexercisable	10,742,004
Restricted share units (2010 RSU Plan) - exercisable and unexercisable	6,845,753
Restricted share units (2015 RSU Plan)	2,662,050
Performance share units	1,365,900
Deferred share units	653,687

During the nine months ended September 30, 2015, the Company established two new stock-based compensation award plans. The Company created a deferred share unit plan for non-management directors of the Company (the "DSU Plan"). Athabasca also created a new restricted share unit plan (the "2015 RSU Plan") which replaced the Company's previous restricted share unit plan (the "2010 RSU Plan"). All RSUs granted after April 1, 2015 are issued under the 2015 RSU Plan. Previously awarded grants under the 2010 RSU Plan remain issued and outstanding in accordance with that plan's terms.

For additional information regarding these compensation plans, refer to the Company's most recent Information Circular filed on SEDAR dated March 17, 2015 and the unaudited condensed interim consolidated financial statements of the Company for the three and nine months ended September 30, 2015.

SUMMARY OF QUARTERLY RESULTS

Quarterly Results

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

	2015			2014				2013
($ Thousands, Except Share and Per Barrel Amounts)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	$ 46.43	$ 57.94	$ 48.63	$ 93.00	$ 97.19	$ 102.96	$ 98.68	$ 98.00
Western Canadian Select (C$/bbl)	$ 43.29	$ 71.24	$ 60.35	$ 83.03	$ 105.84	$ 112.31	$ 108.89	$ 102.08
Edmonton Par (C$/bbl)	$ 56.17	$ 67.63	$ 51.79	$ 94.49	$ 97.03	$ 106.67	$ 99.74	$ 93.04
Edmonton Condensate (C5+) (C$/bbl)	$ 56.94	$ 69.81	$ 55.42	$ 100.42	$ 99.87	$ 112.49	$ 110.58	$ 101.81
AECO (C$/GJ)	$ 2.75	$ 2.53	$ 2.61	$ 4.25	$ 3.82	$ 4.71	$ 5.42	$ 3.01
NYMEX Henry Hub (US$/MMBtu)	$ 2.80	$ 2.64	$ 2.98	$ 4.39	$ 4.07	$ 4.59	$ 4.94	$ 3.65
Foreign exchange (CAD : USD)	$ 1.31	$ 1.23	$ 1.24	$ 1.16	$ 1.12	$ 1.09	$ 1.10	$ 1.06
LIGHT OIL DIVISION								
Sales volumes (boe/d)	5,145	5,459	5,877	6,035	6,381	5,768	6,299	6,697
Realized price ($/boe)	$ 31.34	$ 34.43	$ 29.35	$ 44.66	$ 56.90	$ 65.97	$ 61.12	$ 46.47
Revenues[2]	$ 14,043	$ 17,666	$ 13,981	$ 21,757	$ 29,892	$ 32,587	$ 30,421	$ 25,848
Light Oil Operating Income[1]	$ 6,096	$ 10,689	$ 6,578	$ 12,431	$ 21,154	$ 24,207	$ 20,943	$ 16,717
Light Oil Operating Netback[1] ($/boe)	$ 12.88	$ 21.51	$ 12.46	$ 22.38	$ 36.03	$ 46.12	$ 36.95	$ 27.15
Capital expenditures	$ 31,465	$ 14,959	$ 79,241	$ 87,870	$ 19,772	$ 14,847	$ 77,449	$ 40,103
THERMAL OIL DIVISION								
Bitumen production (bbl/d)[3]	2,105	—	—	—	—	—	—	—
Sales volumes (bbl/d)[3]	1,792	—	—	—	—	—	—	—
Realized price ($/bbl)	$ 17.54	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Revenues[2]	$ 6,145	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Thermal Oil Operating Income[1]	$ (12,146)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Thermal Oil Operating Netback[1] ($/bbl)	$ (73.67)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Capital expenditures	$ 9,366	$ 33,118	$ 68,504	$ 78,876	$ 89,454	$ 90,556	$ 157,958	$ 160,892
OPERATING RESULTS								
Cash Flow from Operations	$ (17,933)	$ 8,576	$ (2,610)	$ (8,883)	$ 30,371	$ (18,641)	$ 15,412	$ (14,896)
Funds Flow from Operations[1]	$ (24,223)	$ 5,085	$ 3,162	$ (2,520)	$ 7,203	$ 51,016	$ 9,468	$ 7,728
Net income (loss)	$ (38,241)	$ (29,044)	$ (25,112)	$ (129,507)	$ (19,939)	$ (56,766)	$ (21,346)	$ (40,162)
Net income (loss) per share - basic	$ (0.09)	$ (0.07)	$ (0.06)	$ (0.32)	$ (0.05)	$ (0.14)	$ (0.05)	$ (0.01)
Net income (loss) per share - diluted	$ (0.09)	$ (0.07)	$ (0.06)	$ (0.32)	$ (0.05)	$ (0.14)	$ (0.05)	$ (0.01)
BALANCE SHEET								
Available Funding ($)[1]	990,789	1,052,329	1,135,470	1,345,990	1,487,679	360,879	499,735	672,790
Net Debt ($)[1]	55,433	109,713	68,005	(123,625)	(305,161)	(555,789)	(700,788)	(884,970)
Total assets ($)	4,160,344	4,173,704	4,244,486	4,297,803	4,413,935	4,459,943	4,327,802	4,342,325
Long-term debt ($)	827,773	807,167	810,758	786,649	777,528	764,788	534,293	533,210
Shareholders' equity ($)	3,085,499	3,119,224	3,141,453	3,164,186	3,289,083	3,301,011	3,353,444	3,373,957

(1) Refer to "Advisories and Other Guidance" beginning on page 19 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) For the three and nine months ended September 30, 2015, production and sales volumes on a bbl/d basis include capitalized volumes.

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, 2015, there were no changes to the Athabasca's accounting policies or use of estimates in the preparation of the unaudited condensed interim consolidated financial statements and the notes thereto that had a material impact to the consolidated financial statements. Refer to the December 31, 2014 audited consolidated financial statements and the September 30, 2015 condensed interim consolidated financial statements of the Company for further guidance regarding Athabasca's accounting policies and use of estimates.

In the second quarter of 2015, Athabasca began acquiring inventory to support its Project 1 operations. Inventory consists of crude oil products and other consumables. The carrying value of inventory also includes transportation. Athabasca values its inventory using the weighted average cost method and inventory is held at the lower of cost and net realizable value at each reporting period.

During the third quarter of 2015, Athabasca began recognizing depletion and depreciation of Project 1. The central processing facilities are depreciated on a unit-of-production basis over the total productive capacity of the facility. The supporting infrastructure is depreciated using 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.

General and administrative expenses for the nine month period ended September 30, 2014, have been reduced by $5.8 million from those presented in prior periods to reflect Athabasca's decision to separately present costs incurred as part of the Company's cost structure reductions throughout 2014 and 2015 as restructuring and other charges. There were no restructuring costs for the three months ended September 30, 2014.

At each financial reporting date, the Company considers potential indicators of impairment for both its Light Oil and Thermal Oil Divisions. This assessment includes an analysis of current market conditions and activities as well as a review of pending land expiries and future development plans for each of the Company’s assets. As at September 30, 2015, as a result of the reduced outlook for long term commodity prices and continuing softness in the equity markets, Athabasca performed impairment tests on all of its cash generating units ("CGUs"). The results of the impairment tests indicated that the fair value of each CGU exceeded its carrying value and no impairment was identified. Athabasca combines E&E and PP&E assets that are in the same CGU together for the purposes of testing for impairment. The Company uses fair value less costs of disposal to calculate the recoverable amount of its CGUs.

The recoverable amounts of the CGUs are estimated based on after-tax discounted cash flows from the Company’s Proved plus Probable Reserves and Contingent Resources and relevant transactions and trading multiples in the industry on assets and companies with similar geologic and geographic characteristics. Future cash flows are estimated using a two percent inflation rate and a discount rate of 10% to 14% based on the nature of the properties included in the CGU and the extent of future funding and development risk. A significant change to discounted cash flow assumptions, including forecasted price assumptions, cost estimates, recovery rates and discount rates, could have a material impact on these fair value estimates and lead to an impairment. Valuation metrics implied by future transactions could also have a material impact on the Company’s estimate of recoverable amounts.

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

The “Light Oil Operating Netback”, "Light Oil Operating Income", "Thermal Oil Operating Netback", "Thermal Oil Operating Income", “Funds Flow from Operations”, “Available Funding” and “Net Debt” 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 Available Funding measure in this MD&A (including the comparatives thereto) is determined by adding cash, cash equivalents, short-term investments and Promissory Notes on the Company’s consolidated balance sheets to the undrawn amounts under Athabasca’s Term Loans and available credit under the Credit Facility. The table on page 15 reconciles the Available Funding measure to the Company’s consolidated balance sheets. The Available Funding measure allows management and others to evaluate the Company’s access to capital and ability to finance its capital and operating activities in the short-term. The 2014 comparative figures have been adjusted to exclude the letters of credit issued against credit facilities included in the Available Funding non-GAAP financial measure.

The Net Debt measure in this MD&A (including the comparatives thereto) is calculated by subtracting the current assets (excluding the current portion of derivative assets) from Company’s current liabilities and long-term debt. The table on page 15 reconciles the Net Debt non-GAAP financial measure to the Company’s consolidated balance sheet. The Net Debt measure is not intended to represent other measures of financial position on the Company’s balance sheet that are calculated in accordance with IFRS. The Net Debt financial measure allows management and others to evaluate the Company's funding position and utilization of debt within its capital structure.

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

($ Thousands)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Cash flow from operating activities	$ (17,933)	$ 30,371	$ (12,031)	$ 26,953
Restructuring and other charges, excluding change in long-term portion of office lease provision	1,661	—	15,181	5,754
Changes in non-cash working capital	(8,803)	(23,231)	(23,365)	(12,550)
Reclamation expenditures	852	63	3,180	1,325
FUNDS FLOW FROM OPERATIONS	$ (24,223)	$ 7,203	$ (17,035)	$ 21,482

The 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 finance its capital programs and repay debt using cash flow internally generated from operating related activities.

On page 28 of the 2014 Management's Discussion and Analysis, restructuring charges and other was included in the Funds Flow From Operations non-GAAP financial measure. In 2015, the Company began excluding the restructuring charges and other from the non-GAAP financial measure in order to exclude non-recurring corporate costs of the Company. The 2014 comparative figures above and in the Summary of Quarterly Results have been adjusted to also exclude the restructuring charges and other in the Funds Flow from Operations non-GAAP financial measure. 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 9 - Segmented Information* in the consolidated financial statements for the three and nine months ended September 30, 2015.

The Thermal Oil Operating Income and Thermal Oil Operating Netback measures in this MD&A (including the comparatives thereto) are calculated by subtracting 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 oil and gas assets. The table on page 8 reconciles Thermal Oil Operating Income to *Note 9 - Segmented Information* in the consolidated financial statements for the three and nine months ended September 30, 2015.

Risk Factors

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

- Fluctuations in market prices of crude oil, bitumen blend and natural gas;
- Adverse changes to economic, market, business conditions, currency and interest rate fluctuations;
- Substantial capital requirements and ability to obtain financing;
- Risk of changes to royalty and income tax regimes;
- Meeting development schedules and the risk of cost over-runs;
- Operational and business interruption risks associated with facilities;
- Risks related to future acquisition and joint venture activities;
- Receipt of regulatory approvals and compliance with applicable regulations;
- Lower than expected reservoir performance, including lower oil production rates and higher steam-to-oil ratios;
- Risks related to existing credit facilities, term loans and senior secured notes;
- Changes to status given the current stages of development;
- Uncertainties associated with estimating reserves and resources volumes;
- Uncertainties inherent in current and developing bitumen recovery processes;
- Counterparty risks;
- Claims made by aboriginal peoples;

- Reliance on, competition for, loss of and failure to attract key personnel;
- Risks related to hydraulic fracturing;
- Risks related to gathering and processing facilities and pipeline systems;
- Financial covenants contained in pipeline transportation agreements;
- Diluent, natural gas and utility supply and costs;
- Expiration of leases, licenses or permits;
- Hedging risks;
- Risk of reassessments of the Company's tax filings by taxation authorities;
- Long-term production transportation solutions;
- Litigation risks;
- Title to assets;
- Costs associated with new technologies;
- Availability of and access to suppliers;
- Environmental risks and hazards; and
- Risks related to 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 expectation that 21 well pairs will be on SAGD production at Project 1 by the end of the 2015; the timing of the completion and start-up of the dilbit pipeline to the Cheecham terminal; the Company's expectation that Netbacks will improve as production increases; the timing of drilling, completion and tie-in operations in the Company's Light Oil division; the benefits expected to be realized from placing the Company's Light Oil division Duvernay wells on a soak period; the Company's expected production from the Light Oil and Thermal Oil divisions at December 31, 2015; 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 anticipation of lower service costs in the second half of 2015; 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 receipt of remaining proceeds from the Promissory Note; the Company's expected funding-in-place at the end of 2015; the Company's business and financing plans; the Company's business and financing strategies; expectations regarding the 2016 capital budget; 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 regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct its business; 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; the Company's ability to obtain financing and/or enter into joint venture arrangements, on acceptable terms; geological and engineering estimates in respect of the Company's 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 dated March 11 2015, available on SEDAR at www.sedar.com, including, but not limited to: fluctuations in the market price of crude oil, natural gas and bitumen blend; political conditions and general economic, market and business conditions in Canada, the United States and globally; the Company's credit rating; changes to royalty regimes; the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements; global financial uncertainty; potential profitability being dependent on factors beyond the control of the Company; expiration of leases, licenses or permits; regulatory approvals and compliance; development schedules and cost over-runs; variations in foreign exchange rates and interest rates; failure by counterparties to perform their operational or other obligations to the Company in compliance with the terms of contractual arrangements between the Company and such counterparties, including in compliance with the expressed or implied time schedules set out in such contractual arrangements, and the possible consequences thereof; risks related to future acquisition and joint venture activities; geopolitical risks; uncertainties associated with estimating reserve and resource volumes; risks associated with the amended credit facility, term loans and the senior secured notes; risks 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 CSS, SAGD, TAGD or other in-situ technologies; status and stage of development; aboriginal claims; reliance on, competition for, loss of, and failure to retain key personnel; risks associated with hydraulic fracturing; uncertainties inherent in CSS, SAGD, TAGD and other bitumen recovery processes; risks related to gathering and processing facilities and pipeline systems; pipeline transportation contract covenants; impact of royalty regimes on operating cash flow; availability of drilling equipment and access; increases in operating costs could make Athabasca's projects uneconomic; diluent, natural gas and utility supply constraints and increases in the costs thereof; gas over bitumen issues affecting operational results; environmental risks and hazards and the cost of compliance with environmental regulations, including greenhouse gas regulations and potential Canadian and U.S. climate change legislation; 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; estimation of abandonment and reclamation costs; risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments; exploration, development and production risks inherent in crude oil and natural gas operations, including the production of crude oil and natural gas using multi-stage hydraulic fracture and other stimulation technologies; the potential for management estimates and assumptions to be inaccurate, including the Company's assumptions regarding the production potential of its Duvernay and Montney wells; long-term reliance on third parties; reliance on third party infrastructure for project facilities; seasonality; hedging risks; risks associated with establishing and maintaining systems of internal controls; insurance risks; claims made in respect of Athabasca's operations, properties or assets; competition for, among other things, capital, the acquisition of reserves and resources, export pipeline capacity and skilled personnel; the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits; breaches of confidentiality; inaccuracy of forward looking information, costs of new technologies; alternatives to and changing demand for petroleum products; 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, 2014 (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

Of Athabasca's approximately 8.5 billion barrels of Best Estimate Contingent Resources (on a Company Interest basis) estimated by GLJ and D&M as at December 31, 2014, approximately 2.8 billion barrels are contained in carbonate reservoirs in Athabasca's Dover West Carbonates assets. Although the existing Best Estimate Contingent Resources assigned by GLJ to the Dover West Carbonates assumes that they will be developed using CSS based on positive field test results from competitors, either CSS or TAGD could be used to develop the Dover West Carbonates asset. Athabasca believes TAGD could become a superior in-situ recovery process which could take better advantage of the Dover West Carbonates' reservoir characteristics; however, it is an experimental technology. The commercial viability of CSS technology has been demonstrated successfully for application to certain non-carbonate reservoirs. There are, however, no successful commercial projects that use CSS or TAGD to recover bitumen from carbonates. The successful development of Athabasca's carbonate reservoirs depends on, among other things, the successful development and application of CSS, TAGD or other recovery processes to the subject reservoirs. Presently, there exists a large range in the expected recoverable volumes, the lower end of which may not be economically viable. The principal risks associated with CSS and/or TAGD recovery in carbonate reservoirs are: (a) the possibility of unexpected steam channeling which would increase steam requirements resulting in increased costs and potentially reduced economically recoverable bitumen volumes; (b) the ability to efficiently drain the matrix porosity; and (c) uncertainty as to whether the technologies may be economically applied on a commercial scale. Although the technical risks associated with CSS have been accounted for in the GLJ Report, the timeline for verification of the viability of these technologies has inherent uncertainty. Development will involve significant capital expenditures and a lengthy time to project payout, and project payout is not assured. If a pilot and/or demonstration project does not demonstrate potential commerciality in the subject reservoirs, then Athabasca's projects on these assets may not proceed and this may occur only after significant expenditures have been incurred by Athabasca.

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, 2014. 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 MMbbl. 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 1,000+ Duvernay drilling locations referenced on page 1 of this MD&A includes: 5 proved undeveloped locations, 33 probable undeveloped locations, with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by GLJ as of December 31, 2014 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

"Best Estimate" is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

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

"Contingent Resources" are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology, technology under development or experimental technology but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include economic matters, further facility design and the preparation of Company development plans, regulatory matters, including regulatory applications and associated reservoir studies, delineation drilling, Company approvals and other factors such as legal, environmental and political matters or 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 further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. The volumes of bitumen Contingent Resources were calculated at the outlet of the proposed extraction plant.

"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.

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
CSS	Cyclic Steam stimulations
DCP	Dover Commercial Project
E&E	Exploration and evaluation assets
GAAP	Generally Accepted Accounting Principles
G&A	General and administrative
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
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.