ATHABASCA OIL CORPORATION

Management's Discussion and Analysis

Q2 2015

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Management’s Discussion and Analysis

This Management’s Discussion and Analysis of financial condition and results of operations (“MD&A”) of Athabasca Oil Corporation (“Athabasca” or the “Company”) is dated July 30, 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 six months ended June 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 19 of this MD&A. See "Reserves and Resource information" on page 21 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 22 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 Greater Kaybob area 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 first significant production from the Thermal Oil Division is expected in the latter part of 2015 from Hangingstone Project 1, a 12,000 bbl/d SAGD project ("Project 1").

(1) Refer to Advisories and Other Guidance beginning on page 21 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 21 and the AIF for additional important information about the Company's Reserves and Contingent Resources.

HIGHLIGHTS FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2015

Light Oil Division

- For the three and six months ended June 30, 2015, Athabasca produced 5,459 boe/d (48% liquids) and 5,667 boe/d (48% liquids), respectively, compared to 5,767 boe/d (52% liquids) and 6,032 (49% liquids) during the same periods in the prior year. Lower production during the first half of 2015 was primarily due to natural well declines, partially offset by new wells brought on stream. Second quarter production exceeded the Company's previously announced production guidance of approximately 5,000 boe/d by approximately 9%.

- Athabasca spent $15.0 million in the Light Oil Division during the three months ended June 30, 2015 primarily to prepare for the Company's Duvernay drilling and completions program planned for the second half of 2015. During the first six months ended June 30, 2015, the Company spent $94.2 million in the Light Oil Division primarily in the Greater Kaybob area. Athabasca rig-released seven Duvernay wells (six horizontal, one vertical) and completed three Duvernay wells that had been rig-released in the prior year. The Company also rig-released one and completed two Montney wells in the Placid area.

- For the three months ended June 30, 2015, Athabasca's Operating Netback was $21.51/boe, compared to $46.12/boe during the same period in the prior year. For the six months ended June 30, 2015, Athabasca's Operating Netback was $16.84/boe, compared to $41.36/boe in the prior year. The decreases in the Operating Netback(1) were primarily due to lower underlying commodity prices partially offset by lower operating and transportation expense due to ongoing cost savings initiatives.

Thermal Oil Division

- During the six months ended June 30, 2015, Athabasca completed construction and commissioning of Project 1. In late March 2015, the Company commenced steaming 15 of the planned 22 well pairs with an expected circulation phase of four to six months. The Company achieved first oil in July with the conversion of its first six well pairs to production. The remaining nine well pairs on circulation are expected to be converted to production during the third quarter and the seven final well pairs are anticipated to be put on circulation during the third quarter and converted to production before year-end.

- During the six months ended June 30, 2015, Athabasca spent $101.7 million in the Thermal Oil Division primarily to complete Project 1 and to begin ramping-up operations. Athabasca's final costs for Project 1 are within approximately 5% of the sanctioned budget. The sanctioned budget included over $140 million in regional infrastructure and a production assurance pad that will be used to support current and future phases of the Hangingstone project.

Corporate

- As at June 30, 2015, Athabasca had Available Funding(1) of $1,052 million, consisting of $582.4 million in cash, cash equivalents and short-term investments, $283.9 million in Promissory Notes and $186.0 million of available credit under the Company's Credit Facility and Term Loan agreements.

(1) Refer to "Advisories and Other Guidance" beginning on page 17 for additional information on Non-GAAP Financial Measures.

SELECTED FINANCIAL INFORMATION

The following tables summarize selected financial information for the three and six months ended June 30, 2015 and 2014:

($ Thousands, except per share and boe amounts)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
SALES VOLUMES				
Oil (bbl/d)	1,997	2,184	2,151	2,297
Natural gas (Mcf/d)	17,038	16,563	17,579	18,282
Natural gas liquids (bbl/d)	622	823	586	688
Total (boe/d)	5,459	5,767	5,667	6,032
Oil and Natural gas liquids %	48%	52%	48%	49%
REALIZED PRICES				
Oil ($/bbl)	$ 59.68	$ 104.04	$ 52.79	$ 96.50
Natural gas ($/Mcf)	2.85	5.01	2.82	5.67
Natural gas liquids ($/bbl)	32.51	85.46	29.21	83.37
Realized price ($/boe)	34.43	65.97	31.81	63.45
Royalties ($/boe)	0.45	(5.32)	(1.60)	(7.16)
Operating and transportation expenses[2] ($/boe)	(13.37)	(14.53)	(13.37)	(14.93)
Light Oil Operating Netback[1] ($/boe)	$ 21.51	$ 46.12	$ 16.84	$ 41.36
LIGHT OIL OPERATING INCOME[1]				
Petroleum and natural gas sales	$ 17,105	$ 34,626	$ 32,630	$ 69,272
Midstream revenue	338	755	668	1,558
Royalties	223	(2,794)	(1,637)	(7,822)
Operating and transportation expenses	(6,977)	(8,380)	(14,380)	(17,859)
	$ 10,689	$ 24,207	$ 17,281	$ 45,149
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	8,576	(18,641)	5,922	(3,229)
Cash flow from operating activities per share (basic and diluted)	$ 0.02	$ (0.05)	$ 0.01	$ (0.01)
Funds Flow from Operations[1]	$ 5,085	$ 5,016	$ 8,201	$ 14,483
Funds Flow from Operations per share (basic and diluted)	$ 0.01	$ 0.01	$ 0.02	$ 0.04
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss	$ (29,044)	$ (56,766)	$ (54,156)	$ (78,119)
Net loss and comprehensive loss per share (basic and diluted)	$ (0.07)	$ (0.14)	$ (0.13)	$ (0.19)
SHARES OUTSTANDING				
Weighted average shares outstanding (basic and diluted)	402,981,471	401,334,034	402,698,520	401,144,341
CAPITAL EXPENDITURES				
Light Oil Division	$ 14,959	$ 14,847	$ 94,200	$ 92,296
Thermal Oil Division	33,118	90,556	101,685	248,514
Assets held for sale	—	2,600	—	6,600
Corporate	421	1,053	2,065	2,508
	$ 48,498	$ 109,056	$ 197,950	$ 349,918
FINANCING AND DIVESTITURES				
Net proceeds from sale of Dover Investment	—	—	300,000	—
Net proceeds (repayment of) from long-term debt	$ (626)	$ 236,675	$ (1,336)	$ 236,675
Net proceeds from sales of assets	—	319	—	56,472
	$ (626)	$ 236,994	$ 298,664	$ 293,147

(1) Refer to "Advisories and Other Guidance" beginning on page 17 for additional information on Non-GAAP Financial Measures.
(2) For the three months ended June 30, 2015, operating and transportation expenses in the Operating Netback figure includes midstream revenues of $0.68/boe (2014 - $1.44) and for the six months ended June 30, 2014, $0.65/boe (2014 - $1.43/boe).

As at ($ Thousands)	June 30, 2015	December 31, 2014
LIQUIDITY		
Available Funding[1]	$ 1,052,329	$ 1,345,454
Net Debt[1]	$ 109,713	$ (123,625)
BALANCE SHEET		
Total assets	$ 4,173,704	$ 4,297,803
Long-term debt	$ 807,167	$ 786,649
Shareholders' equity	$ 3,119,224	$ 3,164,186

RESULTS OF OPERATIONS

The following table summarizes the results of operations for the three and six months ended June 30, 2015 and 2014:

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	2015	2014	2015	2014
LIGHT OIL OPERATING INCOME[1]				
Petroleum and natural gas sales	$ 17,105	$ 34,626	$ 32,630	$ 69,272
Midstream revenue	338	755	668	1,558
Royalties	223	(2,794)	(1,637)	(7,822)
Operating and transportation expenses	(6,977)	(8,380)	(14,380)	(17,859)
	10,689	24,207	17,281	45,149
CORPORATE AND OTHER				
Interest income and other	3,422	1,981	7,689	4,381
General and administrative	(8,270)	(11,853)	(16,640)	(23,796)
Restructuring and other charges	—	(134)	(16,988)	(5,769)
Stock-based compensation	(4,940)	(2,386)	(5,932)	(2,857)
Financing and interest	(3,178)	(9,643)	(4,756)	(18,938)
Depletion and depreciation	(16,757)	(20,384)	(35,539)	(47,184)
Exploration expense	(480)	—	(751)	—
Foreign exchange gain (loss), net	4,519	4,870	(19,101)	4,870
Derivative gain (loss), net	(5,185)	(9,986)	20,726	(9,986)
Unrealized put option gain	—	1,770	—	3,981
Loss on provisions	(1,365)	(45,092)	(1,365)	(45,092)
Gain on sale of assets	—	182	912	182
Loss before income taxes	(21,545)	(66,468)	(54,464)	(95,059)
INCOME TAXES				
Deferred income tax expense (recovery)	7,499	(9,807)	(308)	(17,259)
Loss before the following	(29,044)	(56,661)	(54,156)	(77,800)
Equity loss on investments	—	(105)	—	(319)
Net loss and comprehensive loss	$ (29,044)	$ (56,766)	$ (54,156)	$ (78,119)
BASIC LOSS PER SHARE	$ (0.07)	$ (0.14)	$ (0.13)	$ (0.19)
DILUTED LOSS PER SHARE	$ (0.07)	$ (0.14)	$ (0.13)	$ (0.19)

(1) Refer to "Advisories and Other Guidance" beginning on page 17 for additional information on Non-GAAP Financial Measures.

Operating Results

($ Thousands)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
SALES VOLUMES				
Oil (bbl/d)	1,997	2,184	2,151	2,297
Natural gas (Mcf/d)	17,038	16,563	17,579	18,282
Natural gas liquids (bbl/d)	622	823	586	688
Total (boe/d)	5,459	5,767	5,667	6,032
Oil and Natural gas liquids %	48%	52%	48%	49%
REALIZED PRICES				
Oil ($/bbl)	$ 59.68	$ 104.04	$ 52.79	$ 96.50
Natural gas ($/Mcf)	2.85	5.01	2.82	5.67
Natural gas liquids ($/bbl)	32.51	85.46	29.21	83.37
Realized price ($/boe)	$ 34.43	$ 65.97	$ 31.81	$ 63.45
Royalties[2] ($/boe)	0.45	(5.32)	(1.60)	(7.16)
Operating and transportation expenses ($/boe)	(13.37)	(14.53)	(13.37)	(14.93)
LIGHT OIL OPERATING NETBACK[1] ($/boe)	$ 21.51	$ 46.12	$ 16.84	$ 41.36

(1) Refer to "Advisories and Other Guidance" beginning on page 17 for additional information on Non-GAAP Financial Measures. For the three months ended June 30, 2015, operating and transportation expenses in the Operating Netback figure includes midstream revenues of $0.68/boe (2014 - $1.44) and for the six months ended June 30, 2014, $0.65/boe (2014 - $1.43/boe).

(2) During the three months ended June 30, 2015, the average royalty rate was -1% of gross petroleum and natural gas sales (2014 - 8%) and for the six months ended June 30, 2015, 5% (2014 - 11%).

During the three months ended June 30, 2015, Athabasca produced 5,459 boe/d (48% liquids), a 5% decrease compared to 5,767 boe/d (52% liquids) during the same period in the prior year. Lower production during the second quarter was primarily due to natural well declines. For the six months ended June 30, 2015, Athabasca produced 5,667 boe/d (48% liquids), compared to 6,032 boe/d (49% 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 the first quarter.

Realized prices decreased by 48% and 50% during the three and six months ended June 30, 2015 to $34.43/boe and $31.81/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. The following table summarizes the key commodity price benchmarks:

	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Crude Oil:				
West Texas Intermediate monthly average (US$/bbl)	$ 57.94	$ 102.96	$ 53.29	$ 100.82
Edmonton Par monthly average (C$/bbl)	$ 67.63	$ 106.67	$ 59.71	$ 103.42
Edmonton Condensate (C5+) (C$/bbl)	$ 69.81	$ 112.49	$ 62.61	$ 111.53
Natural gas:				
AECO monthly average (C$/GJ)	$ 2.53	$ 4.71	$ 2.71	$ 5.17
NYMEX Henry Hub close monthly average (US$/MMBtu)	$ 2.64	$ 4.59	$ 2.81	$ 4.66
Foreign exchange:				
CAD : USD (monthly average)	1.23	1.09	1.24	1.10

Royalty expenses for the three months ended June 30, 2015 were a recovery of $0.2 million compared to an expense of $2.8 million (8% of revenue) during the same period in the prior year. For the six months ended June 30, 2015, Athabasca incurred royalty expenses of $1.6 million (5% of gross revenue) compared to $7.8 million (11% of gross revenues) during the same period in 2014. Declines in royalties expenses were primarily due to lower sliding scale royalty rates which declined on lower market commodity prices as well as prior period adjustments to gas cost allowances received during the second quarter.

During the three months ended June 30, 2015, operating and transportation expenses decreased from $14.53/boe to $13.37/boe, compared to the same period in the prior year, and from $14.93/boe to $13.37/boe for the six months ended June 30, 2015. The decreases were primarily due to ongoing cost savings initiatives undertaken in the first half of 2015.

Interest Income and Other

($ Thousands)	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
Interest income on cash and cash equivalents	$ 2,058	$ 486	$ 4,014	$ 1,468
Interest income on Promissory Notes	1,235	—	3,291	—
Time value of money accretion	—	1,263	—	2,494
Other	129	232	384	419
TOTAL INTEREST INCOME AND OTHER	$ 3,422	$ 1,981	$ 7,689	$ 4,381

Interest income and other increased during the three and six months ended June 30, 2015 by $1.4 million, and $3.3 million, respectively, compared to the same periods in the prior year. The increases were primarily due to interest income earned on the Promissory Notes (defined below) issued to Athabasca by Phoenix Energy Holdings Ltd. ("Phoenix") on the closing of the sale of Athabasca's 40% interest in the Dover commercial project (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 and second quarters of 2015 relative to the prior year. The overall increase in interest income during the first and second quarters of 2015 was partially offset by time value of money accretion on the Dover Investment during the first six months of 2014.

General and Administrative ("G&A")

($ Thousands)	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
Salaries and benefits	$ 8,667	$ 15,752	$ 19,132	$ 32,792
Office costs	3,089	4,094	7,070	9,094
Legal, accounting and consulting	1,009	1,345	2,245	2,741
Stakeholder relations	89	382	480	896
Capitalized staff costs	(4,584)	(9,720)	(12,287)	(21,727)
TOTAL GENERAL AND ADMINISTRATIVE EXPENSES	$ 8,270	$ 11,853	$ 16,640	$ 23,796
Capitalization rate	36%	45%	42%	48%

During the three and six months ended June 30, 2015, salaries and benefits declined by $7.1 million and $13.7 million, respectively, compared to the same periods in the prior year. In 2014, the Company undertook an initiative to complete a thorough cost structure review with a goal to streamline costs and better align the organization to the current operating environment, its capital plans and growth objectives. As a result, Athabasca has reduced the size of its head office workforce by approximately 50% since the beginning of 2014.

Athabasca also undertook a number of other cost efficiency initiatives in 2014 and the first half of 2015 that has resulted in lower office costs and legal, accounting and consulting related expenses.

Capitalized staff and environment costs decreased during the three and six months ended June 30, 2015 compared to the same periods in the prior year, primarily due to the staff reductions and a reduction in thermal oil project activities.

Restructuring and Other Charges

($ Thousands)	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
Staff restructuring charges	$ —	$ 134	$ 5,985	$ 5,769
Office lease provision	—	—	7,034	—
Cancellation charges	—	—	3,969	—
TOTAL RESTRUCTURING CHARGES AND OTHER CHARGES	$ —	$ 134	$ 16,988	$ 5,769

For the six months ended June 30, 2015 and 2014, Athabasca incurred non-recurring staff restructuring charges of $6.0 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 six months ended June 30, 2015, relating to lease commitments on vacated office space primarily as a result of the staff reductions.

As a result of the decline in commodity prices and Athabasca's focused capital allocation priorities towards the Greater Kaybob area and Project 1, expenditures related to the Company's expansion development of Hangingstone and appraisal activities for other thermal assets have been significantly reduced. As a result of this reduction, for the six months ended June 30, 2015, Athabasca recognized $4.0 million of cancellation charges relating to Thermal Oil rig commitments associated with the 2014/15 drilling season.

Stock-based Compensation

For the three and six months ended June 30, 2015, Athabasca incurred stock-based compensation expense of $4.9 million and $5.9 million, respectively, compared to $2.4 million and $2.9 million during the same periods in the prior year. The increase in stock-based compensation expense was primarily due to new equity awards granted to employees and directors during the third quarter of 2014 and the second quarter of 2015.

Financing and Interest

($ Thousands)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Interest and fees on indebtedness	$ 16,533	$ 14,176	$ 31,629	$ 27,871
Accretion of provisions	1,580	1,556	3,418	3,059
Amortization of debt issuance costs	1,805	5,468	3,623	7,933
Capitalized financing and interest	(16,740)	(11,557)	(33,914)	(19,925)
TOTAL FINANCING AND INTEREST	$ 3,178	$ 9,643	$ 4,756	$ 18,938

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 undrawn $125.0 million credit facility ("Credit Facility") and the US$50.0 million delayed-draw Term Loan.

During the three and six months ended June 30, 2015, Athabasca incurred higher interest and fees on indebtedness of $2.4 million and $3.8 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 periods in 2014, capitalized financing and interest increased by $5.2 million and $14.0 million during the three and six months ended June 30, 2015, respectively. The increase was primarily due to a higher percentage of interest and financing costs being capitalized to Project 1 as the project neared completion. Capitalization of these costs will be discontinued when Project 1 is ready for use in the manner intended by management, currently anticipated to occur during the third quarter of 2015.

Depletion and Depreciation

($ Thousands)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Depletion of oil and gas assets	$ 15,081	$ 16,719	$ 31,344	$ 34,855
Depreciation of infrastructure assets	656	1,097	1,780	2,183
Depreciation of corporate assets	1,020	2,568	2,415	4,882
Land relinquishments	—	—	—	5,264
TOTAL DEPLETION AND DEPRECIATION	$ 16,757	$ 20,384	$ 35,539	$ 47,184

Depreciation and depletion declined during the three and six months ended June 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. Declines in the depreciation of corporate assets during the three and six months ended June 30, 2015 compared to the same periods in the prior year were primarily due to reduced information technology expenditures.

Exploration Expense

During the three and six months ended June 30, 2015, Athabasca incurred exploration expenses of $0.5 million and $0.8 million, respectively, which primarily relate to land retention costs in the Company's Light Oil exploration areas and the 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 six months ended June 30, 2014.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Unrealized foreign exchange gain (loss)	$ 4,426	$ 4,950	$ (19,246)	$ 4,950
Realized foreign exchange gain (loss)	93	(80)	145	(80)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 4,519	$ 4,870	$ (19,101)	$ 4,870

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 six months of 2015 primarily due to an unrealized loss on the loan principal as the value of the Canadian dollar declined relative to the US dollar. Athabasca incurred a net foreign exchange gain during three months ended June 30, 2015 and for the three and six months ended June 30, 2014 as a result of a increase in the value of the Canadian dollar relative to the US dollar. The net foreign exchange gain recognized in the second quarter of 2015 partially offset the overall net foreign exchange loss that was recognized during the six months ended June 30, 2015.

Derivative Gain (Loss), Net

($ Thousands)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Unrealized derivative gain (loss)	$ (5,844)	$ (9,837)	$ 19,305	$ (9,837)
Realized derivative gain (loss)	659	(149)	1,421	(149)
DERIVATIVE GAIN (LOSS), NET	$ (5,185)	$ (9,986)	$ 20,726	$ (9,986)

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 six months of 2015 as the value of the Canadian dollar declined relative to the US dollar. Athabasca recognized a net derivative loss during three months ended June 30, 2015 and for the three and six months ended June 30, 2014, primarily due to an increase in the value of the Canadian dollar relative to the US dollar. The net derivative loss recognized in the second quarter of 2015 partially offset the overall net derivative gain that was recognized during the six months ended June 30, 2015.

Unrealized Put Option Gain and Gain (Loss) on Sale of Assets

Previously, Athabasca held a put option that would require Phoenix to acquire the Dover Investment for $1.3 billion, before transaction costs and other working capital adjustments, which 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. The unrealized Dover Put Option gains recognized during the first six months of 2014 were primarily due to increases in the probability of receiving regulatory approval partially offset by refined estimates around anticipated closing costs, working capital adjustments, timing of receipt of proceeds and planned capital expenditures. Time value of money accretion of $2.5 million was recognized in interest income for the six months ended June 30, 2014.

The Dover Put Option was exercised in the second quarter of 2014 and on August 29, 2014, Athabasca sold the Dover Investment for a net purchase price of $1,183.9 million, consisting of $600.0 million in cash and $583.9 million in three promissory notes (the "Promissory Notes"). The Company also received $2.3 million in final working capital adjustments associated with the closing of the sale, including $0.9 million that was received during the six months ended June 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 remaining two Promissory Notes of $150.0 million and $133.9 million mature in August of 2015 and 2016, respectively.

Loss on Provisions

The net loss on provisions of $1.4 million recognized during the second quarter of 2015 primarily relates to refined estimates of the timing and amount of expected cash inflows associated with the Company's office lease provision liability. In the first quarter of 2015, the Company recognized a provision for lease commitments associated with vacated office space which was largely the result of staff reductions that occurred as part of Athabasca's restructuring activities in 2014 and 2015.

For the six months ended June 30, 2014, Athabasca recognized a net loss of $45.1 million primarily relating to a $49.0 million provision in respect of the settlement of certain claims made by Phoenix for indemnification of future thermal abandonment costs associated with petroleum and natural gas wells located in the Dover and MacKay River areas. The provision was based on the potential future settlement amount, less related decommissioning obligations previously recognized. The settlement of the provision occurred upon the successful closing of the Dover Investment during the third quarter of 2014.

Deferred Income Tax (Expense) 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 three months ended June 30, 2015, Athabasca recognized a deferred income tax expense of $7.5 million including a tax expense of approximately $12.6 million from the impact of the rate increase, partially offset by non-capital losses incurred. For the six months ended June 30, 2015, Athabasca recognized an income tax recovery of $0.3 million, which was primarily due to non-capital losses incurred, offset by the $12.6 million tax expense incurred as a result of the provincial income tax rate changes.

The deferred income tax recoveries recognized during the three and six months ended June 30, 2014 for $9.8 million and $17.3 million, respectively, were primarily due to non-capital losses incurred.

At June 30, 2015, the Company had approximately $2.6 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 six months ended June 30, 2015 and 2014:

($ Thousands)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Light Oil	$ 14,959	$ 14,847	94,200	$ 92,296
Hangingstone	31,721	87,656	96,219	240,507
Thermal Oil exploration areas	1,397	2,900	5,466	8,007
Corporate assets	421	1,053	2,065	2,508
Total expenditures on E&E and PP&E	48,498	106,456	197,950	343,318
Expenditures included in assets held for sale(1)	—	2,600	—	6,600
TOTAL CAPITAL EXPENDITURES(2)	$ 48,498	$ 109,056	$ 197,950	$ 349,918

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

(2) For the three and six months ended June 30, 2015, capital expenditures includes capitalized staff costs of $4.6 million and $12.3 million, respectively (June 30, 2014 - $9.7 million, $21.7 million) and capitalized interest and financing of $15.1 million and $30.6 million, respectively (June 30, 2014 - $10.5 million, $18.0 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 June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Light Oil capital expenditures(1)				
Duvernay	$ 7,816	$ 5,160	$ 64,796	$ 68,376
Montney	—	3,362	13,544	11,068
Operations and other	7,143	6,325	15,860	12,852
TOTAL LIGHT OIL CAPITAL EXPENDITURES	$ 14,959	$ 14,847	$ 94,200	$ 92,296

(1) For the three and six months ended June 30, 2015, capital expenditures includes $1.6 million and $4.0 million in capitalized staff costs, respectively (June 30, 2014 - $2.2 million, $4.5 million).

During the second quarter of 2015, Athabasca had limited spending in the Light Oil Division as the winter program concluded and operations were scheduled to resume following spring break-up. In the first quarter of 2015, Athabasca re-defined the capital priorities of the Company in response to the current low commodity price environment which resulted in the deferral of one drill and three completions originally planned for the first half of 2015 to the second half of the year when the cost environment is expected to be more beneficial.

For the six months ended June 30, 2015, the Company spent $94.2 million in the Light Oil Division primarily in the Greater Kaybob area. Athabasca spent $64.8 million in the Duvernay to drill seven wells (six horizontal, one vertical), complete three Duvernay wells that had been drilled in 2014 and bring one Duvernay well on stream. In the Montney Formation at Placid, $13.5 million was spent to drill one well and complete and bring on-stream a second well that had been drilled in 2014.

With the completion of the 2014/15 winter drilling program, 95% of the Company's 200,000 commercially prospective Duvernay acres, containing greater than 20 metres of shale pay in the Kaybob fairway, have been extended into the intermediate term.

Hangingstone

($ Thousands)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Hangingstone capital expenditures				
Central processing facility	$ 1,559	$ 29,877	$ 24,490	$ 77,786
Drilling, pads and pipelines	27	16,962	513	57,729
Base infrastructure	(1,063)	2,232	784	10,006
Total Project 1 base facility	523	49,071	25,787	145,521
Regional infrastructure and production assurance	(2,746)	11,455	3,748	42,851
Project support costs(1)	3,871	8,069	10,047	19,162
Capitalized start-up costs	14,157	—	23,441	—
Capitalized interest and financing(2)	15,148	10,458	30,605	18,031
Mineral properties – acquisitions and rentals	—	22	—	130
Total Project 1	30,953	79,075	93,628	225,695
Hangingstone Expansion	768	8,581	2,591	14,812
TOTAL HANGINGSTONE CAPITAL EXPENDITURES	$ 31,721	$ 87,656	$ 96,219	$ 240,507

(1) Includes geosciences, regulatory and stakeholder costs and delineation/observation drilling. For the three and six months ended June 30, 2015, capital expenditures include $2.6 million and $6.6 million in capitalized staff costs, respectively (June 30, 2014 - $6.3 million, $13.4 million).
(2) Excludes non-cash capitalized interest and financing.

Project 1

Athabasca spent $31.0 million and $93.6 million on Project 1 during the three and six months ended June 30, 2015, respectively. Athabasca completed Project 1 construction during the first quarter of 2015 and transitioned to operations during the second quarter. The Company plans to continue to ramp-up operations throughout the remainder of the year. Operating costs associated with Project 1 will be capitalized until the facility is ready for use in the manner intended by management, which is currently anticipated to occur during the third quarter of 2015.

Hangingstone Operations

During the second quarter of 2015, steaming of the initial well pairs proceeded as planned. In late March, the Company commenced steaming 15 of the planned 22 well pairs with an expected circulation phase of four to six months. Athabasca is monitoring the reservoir using fiber optic well bore sensors and a distributed pressure and temperature data network. Temperature fall-off tests and reservoir monitoring are being used to confirm readiness of conversion to production. Initial temperature and pressure response in the reservoir along with plant reliability is in-line with management's expectations.

The Company achieved first oil in July with the conversion of its first six well pairs to production. Nine additional well pairs are expected to be converted to production during the third quarter. The remaining seven well pairs are anticipated to be put on circulation during the third quarter and converted to production before the end of the year.

Third party construction of transportation facilities is also substantially complete. The diluent pipeline is now 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

Athabasca continued working with the AER to progress the application for the expansion development of Hangingstone and anticipates receiving 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.

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 Per Share and Per Barrel Amounts)	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Sales volume (boe/d)	5,459	5,877	6,035	6,381	5,767	6,299	6,697	5,597
Realized price ($/boe)	$ 34.43	$ 29.35	$ 44.66	$ 56.90	$ 65.97	$ 61.12	$ 46.47	$ 54.27
Light Oil Operating Netback[1] ($/boe)	21.51	12.46	22.38	36.03	46.12	36.95	27.15	31.17
Revenue[2]	$ 21,088	$ 18,262	$ 26,574	$ 32,622	$ 34,568	$ 32,821	$ 28,278	$ 28,248
Cash Flow from Operations	$ 8,576	$ (2,610)	$ (8,883)	$ 30,371	$ (18,641)	$ 15,412	$ (14,896)	$ 14,361
Cash Flow from Operations per share (basic and diluted)	0.02	$ (0.01)	$ (0.02)	$ 0.08	$ (0.05)	$ 0.04	$ (0.04)	$ 0.04
Funds Flow from Operations[1]	$ 5,085	$ 3,162	$ 2,195	$ 7,203	$ 5,016	$ 9,468	$ 7,728	$ (5,343)
Funds Flow from Operations per share (basic and diluted)	$ 0.01	$ 0.01	$ (0.01)	$ 0.02	$ 0.01	$ 0.01	$ 0.02	$ (0.01)
Net income (loss)	$ (29,044)	$ (25,112)	$ (129,507)	$ (19,939)	$ (56,766)	$ (21,346)	$ (40,162)	$ (30,501)
Net income (loss) per share - basic	$ (0.07)	$ (0.06)	$ (0.32)	$ (0.05)	$ (0.14)	$ (0.05)	$ (0.01)	$ (0.07)
Net income (loss) per share - diluted	$ (0.07)	$ (0.06)	$ (0.32)	$ (0.05)	$ (0.14)	$ (0.05)	$ (0.01)	$ (0.07)
CAPITAL EXPENDITURES	$ 48,498	$ 149,453	$ 171,173	$ 113,779	$ 109,056	$ 240,862	$ 208,355	$ 146,133

(1) Refer to "Advisories and Other Guidance" beginning on page 17 for additional information on Non-GAAP financial measures.
(2) Consists of petroleum and natural gas sales, midstream revenue and interest income and other, net of royalties.

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.

OUTLOOK

During the second quarter of 2015, Athabasca's 2015 capital budget was decreased from $305 million to $291 million due to reductions in planned expenditures in the Thermal Oil Division. The following table outlines the Company's 2015 capital budget by area (excluding capitalized interest and financing):

2015 Budget[1] ($ million)	Q1 2015 Actuals	Q2 2015 Actuals	Q3 - Q4 2015	Full Year
Light Oil Division[2]				
Duvernay	$ 57	$ 8	$ 101	$ 166
Montney	14	—	3	17
Other	6	6	8	20
	77	13	112	203
Thermal Oil Division[3]				
Hangingstone Project 1 (capital & capitalized start-up costs)[4]	44	14	9	67
Hangingstone expansion (pre-engineering)	1	—	5	6
Other	3	2	4	9
	48	15	18	82
Corporate	1	—	5	6
TOTAL CAPITAL EXPENDITURES	$ 127	$ 29	$ 135	$ 291
Capitalized interest and G&A	$ 23	$ 20	$ 17	$ 60

(1) Figures may not add due to rounding.
(2) Q1 and Q2 2015 Light Oil capital expenditures excludes $2.5 million and $1.6 million of capitalized G&A, respectively.
(3) Q1 2015 Thermal Oil capital expenditures excludes $5.3 million of capitalized G&A and $15.5 million of cash capitalized interest (Q2 2015 - $3.0 million, $15.1 million).
(4) Operating expenses for Hangingstone Project 1 will be capitalized until Q3 2015 and will be expensed thereafter once the project is ready for use in the manner intended by management.

Light Oil Budget

The 2015 capital budget for Light Oil remains unchanged at $203 million. The core objectives for the second half of 2015 Light Oil program include demonstrating pad drilling cost efficiencies and ongoing appraisal work in the volatile oil window. Previously announced second half activity includes:

- The completion and tie-in of three previously drilled Duvernay wells (1-36-63-20W5, 8-36-63-20W5, 12-28-62-23W5);
- An on-stream date in Q4 of 16-36-63-25W5 at Simonette;
- Drilling and completion operations on a two well pad at Kaybob East in the volatile oil window (Surface 1-5-65-18W5); and
- Commencing drilling operations on a four well Duvernay pad at Kaybob West (Surface 4-36-63-20W5).

Athabasca's third quarter production is expected to average approximately 5,000 boe/d and 2015 year-end Light Oil exit production guidance remains unchanged at 7,000 - 8,000 boe/d (December average).

Thermal Oil budget

The revised 2015 Thermal Oil budget is $82 million, down from $96 million, reflecting a reduction in planned pre-engineering for the Hangingstone expansion development as well as other Thermal Oil asset activities. $67 million of capital is directed to the commissioning and ramp-up of Hangingstone Project 1. Thermal Oil capital expenditures are largely complete for the year. Operating costs associated with Project 1 will be capitalized until the third quarter of 2015 when the project is ready for use in the manner intended by management.

The 2015 year-end Hangingstone exit production target remains between 3,000 - 6,000 bbl/d (December average). The project is anticipated to reach design capacity of 12,000 bbl/d by late 2016.

Consolidated Budget and Financial Outlook

The 2015 corporate year-end exit target remains between 10,000 - 14,000 boe/d (December average) with total capital spend of $291 million (excluding capitalized interest and G&A).

Maintaining a strong financial position continues to be a top priority for Athabasca. Based on its current capital spending, production and cash flow outlook, Athabasca anticipates exiting 2015 with funding in place in excess of $800 million.

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 through short-term investments.

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, Promissory Notes, cash flows from operations and available credit. The Company has significant flexibility to adjust its Light Oil capital programs in response to commodity price cycles or other constraints. 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, Promissory Notes, 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.

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; and the long-term deposit will be held until December 31, 2026. 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. All other financial liabilities mature within one year.

Long-term Debt

Senior Secured Second Lien Notes

On November 19, 2012, Athabasca issued Senior Secured Second Lien Notes (the "Notes") in an aggregate principal amount of $550 million. The Notes bear interest at a rate of 7.50% per annum and have a term of five years maturing on November 19, 2017. Interest payments are required semi-annually on May 19 and November 19 of each year. These notes are secured by a second priority security interest on all present and after acquired property of the Company. Subject to certain exceptions and qualifications the Notes contain certain covenants that limit the Company's ability to, among other things: incur additional indebtedness; create or permit liens to exist and make certain restricted payments, dispositions and transfers of assets. The Notes do not include any financial covenants.

Athabasca has the option to redeem the Notes at a price of 107.50%, 103.75% and 100.00% in the 12-month periods beginning November 19, 2014, 2015 and 2016, respectively. Debt issuance costs associated with the transaction were initially capitalized and are amortized to net income (loss) over the life of the Notes using the effective interest rate method.

As at June 30, 2015, Athabasca was in compliance with all of the Notes covenants.

Senior Secured Term Loans

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"). Borrowings on drawn amounts under the Term Loans bear interest at a floating rate based on LIBOR plus 7.25%, subject to a LIBOR floor of 1.00%. The Company incurs standby fees on the undrawn portion of the US$50 million delayed draw term loan equal to 1.00% per annum. The Term Loans will amortize in equal quarterly installments in an aggregate annual amount equal to 1.00% of the original principal amount with the balance payable on May 7, 2019, or on May 19, 2017 if the Company has not redeemed or refinanced the Notes prior to that date. The Term Loans are secured by a first priority security interest on all present and after acquired property of the Company.

Athabasca has the option to redeem the Term Loan at a price of 102% for the 12-month period beginning May 7, 2015, 101% for the 12-month period beginning May 7, 2016 and at par thereafter.

The Term Loans are subject to substantially the same restrictive covenants as the Notes and certain additional restrictive covenants including: hedging restrictions; certain business operating requirements; a requirement to maintain a minimum ratio of adjusted consolidated net tangible assets ("ACNTA") to total debt of 3.5 times; and, beginning with the March 31, 2015 quarter-end, if the aggregate of the Company's unrestricted cash, cash equivalents and short-term investments do not exceed the amount of outstanding total debt, the Company must maintain a minimum ratio of the present value of proved reserves, discounted at 10%, to net first lien debt of 1.5 times.

ACNTA consists of the aggregate of the present value of the Company's Proved plus Probable Reserves (discounted at 10%), Athabasca's net working capital, the carrying value of the Promissory Notes, the carrying value of equity investments and the carrying value of oil and gas assets without Proved Plus Probable Reserves assigned in the Company's consolidated balance sheet. Total debt consists of the aggregate of the Company's Notes and Term Loan. Net First Lien Debt is defined as the carrying value of the Term Loan less the Company's cash, cash equivalents and short-term investments.

As at June 30, 2015, Athabasca's ACNTA to total debt ratio was 5.3 times and the Company had a net first lien cash position of $304.5 million. As at June 30, 2015, the Company was in compliance with all of the covenants related to the Term Loan.

Debt issuance costs associated with the Term Loans were initially capitalized and are amortized to net income over the life of the Term Loans using the effective interest rate method.

Revolving Senior Secured Credit Facility

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. The Credit Facility may be extended subject to lender consent and provided the term of the facility does not exceed three years from the date of extension.

Amounts borrowed under the Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, LIBOR or bankers' acceptance rate, plus a margin of between 1.00% and 4.00% depending on the type of borrowing and the Company's indebtedness to consolidated cash flow ratio. The Company incurs a standby fee on the undrawn portion of the Credit Facility of between 0.50% and 1.00% based on the Company's indebtedness to consolidated cash flow ratio. For the six months ended June 30, 2015, the Company paid a rate of 1.00% on the undrawn portion of the Credit Facility (June 30, 2013 - 1.00%). As of June 30, 2015, Athabasca had $1.3 million in letters of credit secured by the Credit Facility (December 31, 2014 - $0.5 million) and no amounts had been drawn under the Credit Facility (December 31, 2014 - $ nil). If drawn, the credit facility is collateralized by a first priority security interest on all present and after acquired property of the Company and is effectively senior in priority to the Term Loans and the Senior Secured Second Lien Notes.

The Credit Facility is subject to substantially the same covenants as the Notes and Term Loans plus, among others, the requirement to maintain a minimum tangible net worth based on the Company's shareholders' equity of $2,750 million. As at June 30, 2015, the Company's shareholders' equity was $3,119 million (December 31, 2014 - $3,164 million).

As at June 30, 2015, Athabasca was in compliance with all of the Credit Facility covenants.

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 June 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 June 30, 2015, the largest institution held 31% of the balances (December 31, 2014 - 35%).

As at June 30, 2015, 23% 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 due from partners account for 53% of accounts receivable (December 31, 2014 - 30%) and additional activity with partners accounts for 7% (December 31, 2014 - 17%). Additionally, 10% relates to accrued interest on the Promissory Notes (December 31, 2014 - 8%). Management believes collection risk on the outstanding accounts receivable as at June 30, 2015 is low given the high credit quality of the Company's material counterparties. No material amounts were past due at June 30, 2015.

As at June 30, 2015 Athabasca holds $287.9 million in remaining Promissory Notes including the note principal and accrued interest. The Promissory Notes are unconditional and secured by irrevocable, standby letters 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 Promissory Note, which matured on March 2, 2015 was fully collected on maturity.

Interest Rate Risk

The Company's exposure to interest rate fluctuations on interest earned on the floating rate cash balance of $478.7 million, from a 1.00% change in interest rates, would be approximately $4.8 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$0.6 million ($0.8 million) increase in interest expense for a 12 month period (year ended December 31, 2014 - US$0.6 million ($0.7 million)).

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 $31.9 million would decrease by $15.7 million. Long-term debt would decrease by $13.9 million resulting in a net $1.8 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 $15.7 million and increase long-term debt by $13.9 million resulting in a net $1.8 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)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Unrealized derivative gain (loss)	$ (5,844)	$ (9,837)	$ 19,305	$ (9,837)
Realized derivative gain (loss)	659	(149)	1,421	(149)
DERIVATIVE GAIN (LOSS), NET	$ (5,185)	$ (9,986)	$ 20,726	$ (9,986)

($ Thousands)	June 30, 2015	December 31, 2014
OPENING DERIVATIVE ASSET	$ 12,638	$ —
Unrealized derivative gain	19,305	12,638
CLOSING DERIVATIVE ASSET	$ 31,943	$ 12,638
Presented as:		
Current portion of derivative asset	$ 2,672	$ 930
Long-term portion of derivative asset	$ 29,271	$ 11,708

Commitments and Contingencies

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

($ Thousands)	2015	2016	2017	2018	2019	Thereafter	Total
Repayment of long-term debt(1)	$ 1,411	$ 2,801	$ 552,773	$ 2,745	$ 272,795	$ —	$ 832,525
Interest expense on long-term debt	30,979	61,632	53,824	19,845	6,801	—	173,081
Transportation	4,396	32,578	33,759	26,990	29,103	484,125	610,951
Office leases	492	4,291	4,291	4,291	4,291	27,101	44,757
Purchase commitments and other(2)	12,151	—	—	—	—	—	12,151
Drilling rigs	1,704	4,656	—	—	—	—	6,360
TOTAL COMMITMENTS	$ 51,133	$ 105,958	$ 644,647	$ 53,871	$ 312,990	$ 511,226	$ 1,679,825

(1) The Term Loans may be required to be repaid on May 19, 2017 if the Company has not redeemed or refinanced the Notes prior to this date.
(2) Purchase commitments and other primarily relates to Thermal Oil camp costs and long-lead equipment in the Light Oil Division.

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 second half 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 beginning in the first quarter of 2016. The ultimate amount of collateral required is not yet determinable and will be based on the Company's capitalization, liquidity position and operational performance at the end of 2015, but could be material.

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 $136.5 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.

Off Balance Sheet Arrangements

The Company has certain 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 three and six months ended June 30, 2015, the Company issued 0.6 million and 1.2 million, respectively, of common shares. Issuances of Athabasca's common shares in 2015 relates 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 July 23, 2015	
Common shares issued and outstanding	403,344,986
Convertible securities:	
Stock options - exercisable and unexercisable	12,173,309
Restricted share units (2010 RSU Plan) - exercisable and unexercisable	7,764,428
Restricted share units (2015 RSU Plan)	2,849,750
Performance share units	1,763,200
Deferred share units	642,368

During the six months ended June 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 replaces the existing 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 the plan terms.

For additional information regarding these compensation plans, refer to the Company's most recent Information Circular filed on SEDAR dated March 20, 2015.

ACCOUNTING POLICIES AND ESTIMATES

During the six months ended June 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 of the Company for further guidance regarding Athabasca's accounting policies and use of estimates.

In 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 and other costs necessary to bring its products to market. 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.

General and administrative expenses for the three and six month periods ended June 30, 2014, have been reduced by $0.1 million and $5.8 million, respectively, from those presented in prior periods to reflect Athabasca's decision to separately present costs incurred as part of the Company's cost structure realignment throughout 2014 and 2015 as restructuring and other charges.

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

The “Operating Netback”, "Light 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 Light Oil Operating Income and 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 Income table on page 5 reconciles back to net income in the consolidated financial statements for the three and six months ended June 30, 2015 and 2014, respectively. The 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 oil and gas assets.

The Funds Flow from Operations measure in this MD&A (including the comparatives thereto) is calculated based on cash flow from operating activities before changes in non-cash working capital, reclamation expenditures and restructuring and other charges on the Company’s cash flow statement in the consolidated financial statements for the three and six months ended June 30, 2015 and 2014, respectively. The Funds Flow from Operations consists of the Company’s Light Oil Operating Income, interest income and other, general and administrative expenses and financing and interest expenses, excluding any non-cash transactions. 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 following table reconciles cash flow from operating activities to Funds Flow from Operations:

($ Thousands)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Cash flow from operating activities	$ 8,576	$ (18,641)	$ 5,922	$ (3,229)
Restructuring and other charges, excluding change in long-term portion of office lease provision	(180)	134	13,340	5,769
Changes in non-cash working capital	(3,532)	23,532	(13,389)	10,681
Reclamation expenditures	221	(9)	2,328	1,262
FUNDS FLOW FROM OPERATIONS	$ 5,085	$ 5,016	$ 8,201	$ 14,483

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. In 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.

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 following table reconciles the Available Funding measure to the Company's consolidated balance sheets:

($ Thousands)	June 30, 2015	December 31, 2014
Cash and cash equivalents	$ 582,396	$ 531,475
Short-term investments	—	47,618
Promissory Notes	283,892	583,892
Undrawn credit facilities(1)	123,671	124,464
Term Loans - delayed draw (US$50.0 million)	62,370	58,005
AVAILABLE FUNDING	$ 1,052,329	$ 1,345,454

(1) As at June 30, 2015, Athabasca issued $1.3 million in letters of credit issued against the Company's credit facilities (December 31, 2014 - $0.5 million).

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 above 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 Net Debt measure excludes long-term Promissory Notes. The following table reconciles the Net Debt non-GAAP financial measure to the Company's consolidated balance sheet:

($ Thousands)	June 30, 2015	December 31, 2014
Long-term debt	$ 807,167	$ 786,649
Current liabilities	72,851	171,097
Current assets	(772,977)	(1,082,301)
Current portion of derivative asset (included in current assets)	2,672	930
NET DEBT	$ 109,713	$ (123,625)

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 Net Debt financial measure excludes $133.9 million in Promissory Notes that are due in August 2016.

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 22 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 reductions in Duvernay well drilling and completion costs expected to be realized by the Company; 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 expected cost efficiencies expected to realized from pad drilling; 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 proceeds from the Promissory Notes; 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 2015 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 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 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. The existing Best Estimate Contingent Resources assigned by GLJ to the Dover West Carbonates will be developed using CSS based on positive field test results from competitors. 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.* 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
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
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.