ATHABASCA
OIL CORPORATION

Management's Discussion and Analysis

Q1 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 May 11, 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 months ended March 31, 2015. These financial statements, including the comparative figures, were prepared in accordance with International Financial Reporting Standards (“IFRS”). Unless otherwise noted, all financial measures are expressed in Canadian dollars and tabular dollar amounts are in thousands. 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 17 of this MD&A. See "Reserves and Resource information" on page 19 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 20 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 drilling inventory of more than 1,000 drilling locations across the Greater Kaybob area fairway. The Company also has exposure in the Montney Formation throughout the Greater Kaybob area. Development to date has resulted in the booking of approximately 50 MMboe [(1)] of Proved plus Probable Reserves in Athabasca’s Light Oil Division as of December 31, 2014.

Thermal Oil

Athabasca's Thermal Oil Division includes five major project areas in the Athabasca region of Northeastern Alberta with approximately 313 MMbbl[(1)] barrels of Proved plus Probable Reserves and approximately 8.5 billion bbl[(1)] of Company Interest Best Estimate Contingent Resources. The Company’s primary focus is the Hangingstone oil sands project (100% working interest). Other project areas include the Dover West Leduc Carbonates (100% working interest), Dover West Sands (100% working interest) and Birch (100% working interest). 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.

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(1) Based on the reports of Athabasca's independent reserve evaluators effective December 31, 2014. Refer to page 19 and the AIF for additional important information about the Company's Reserves and Contingent Resources.

HIGHLIGHTS FOR THE THREE MONTHS ENDED MARCH 31, 2015

Light Oil Division

- For the three months ended March 31, 2015, Athabasca produced 5,877 boe/d (49% liquids), a 7% decrease compared to 6,299 boe/d (47% liquids) during the same period in the prior year. Lower production during the first quarter was primarily due to natural declines from the Company's Montney and Duvernay wells and planned deferrals associated with the 2014/15 winter drilling program as a result of lower commodity prices. First quarter production exceeded the Company's previously announced production guidance of approximately 5,000 boe/d.

- During the first quarter of 2015, the Company spent $79.2 million in the Light Oil Division primarily in the Greater Kaybob area. Athabasca rig-released seven Duvernay wells (six horizontal, one vertical) and completed one Duvernay well 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 March 31, 2015, Athabasca's Operating Netback was $12.46/boe, compared to $36.95/boe in the prior year. The decrease in the Operating Netback[(1)] was primarily due to lower underlying commodity prices.

Thermal Oil Division

- During the three months ended March 31, 2015, Athabasca completed construction and commissioned its 12,000 bbl/d SAGD project ("Project 1"). On March 23rd, 2015, Athabasca commenced steaming in the first three well pairs and 15 well pairs were steaming by mid-April 2015. First production from Project 1 is expected to be achieved in the third quarter of 2015.

- During the first quarter of 2015, Athabasca spent $64.5 million in the Hangingstone area primarily to complete Project 1. Athabasca's final costs for Project 1 are expected to fall between $740 million and $750 million, which is 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

- On March 2nd, 2015, the first 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 $302.5 million, including accrued interest. The remaining two promissory notes for $150.0 million and $133.9 million mature in August of 2015 and 2016, respectively.

- As at March 31, 2015, Athabasca had Available Funding[(1)] of $1,135 million, consisting of $663.2 million in cash, cash equivalents and short-term investments, $283.9 million in Promissory Notes and $188.4 million of available credit under the Company's Credit Facility and Term Loan agreements.

- 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. During the first quarter of 2015, Athabasca completed its cost structure review and has reduced costs in most areas. The size of its head office workforce has been reduced by approximately 50% since the beginning of 2014. The Company also expects to realize substantial cost savings through streamlining of operations and lower related service costs.

(1) Refer to "Advisories and Other Guidance" beginning on page 15 for additional information on Non-GAAP Financial Measures.

SELECTED FINANCIAL INFORMATION

The following tables summarize selected financial information of the Company as at and for the three months ended March 31, 2015 and 2014:

As at and for the three months ended ($ Thousands, except per share and boe amounts)	March 31, 2015	March 31, 2014
SALES VOLUMES		
Oil (bbl/d)	2,308	2,402
Natural gas (Mcf/d)	18,126	20,021
Natural gas liquids (bbl/d)	548	560
Total (boe/d)	5,877	6,299
REALIZED PRICES		
Oil ($/bbl)	$ 46.75	$ 89.70
Natural gas ($/Mcf)	2.79	6.23
Natural gas liquids ($/bbl)	25.17	79.93
Realized price ($/boe)	29.35	61.12
Royalties ($/boe)	(3.52)	(8.87)
Operating expenses and transportation[2] ($/boe)	(13.37)	(15.30)
Light Oil Operating Netback[1] ($/boe)	$ 12.46	$ 36.95
LIGHT OIL OPERATING INCOME[1]		
Petroleum and natural gas sales	$ 15,511	$ 34,646
Midstream revenue	331	803
Royalties	(1,861)	(5,028)
Operating and transportation expenses	(7,403)	(9,478)
	$ 6,578	$ 20,943
CASH FLOWS		
Funds Flow from Operations[1]	$ 3,162	$ 9,468
Funds Flow from Operations per share (basic and diluted)	$ 0.01	$ 0.02
NET LOSS AND COMPREHENSIVE LOSS		
Net loss and comprehensive loss	$ (25,112)	$ (21,346)
Net loss and comprehensive loss per share (basic and diluted)	$ (0.06)	$ (0.05)
SHARES OUTSTANDING		
Weighted average shares outstanding (basic and diluted)	402,393,806	400,950,225
CAPITAL EXPENDITURES		
Light Oil Division	$ 79,241	$ 77,449
Thermal Oil Division	68,504	157,958
Assets held for sale	—	4,000
Corporate	1,708	1,455
	$ 149,453	$ 240,862
FINANCING AND DIVESTITURES		
Net proceeds from sale of Dover Investment	$ 300,000	$ —
Net proceeds from sale of assets	$ —	$ 56,153
LIQUIDITY		
Available Funding[1]	$ 1,135,470	$ 1,345,990
Net debt[1]	$ 68,005	$ (123,625)
BALANCE SHEET		
Total assets	$ 4,244,486	$ 4,297,803
Long-term debt	$ 810,758	$ 786,649
Shareholder's equity	$ 3,141,453	$ 3,164,186

(1) Refer to “Advisories and Other Guidance” beginning on page 15 for additional information on Non-GAAP Financial Measures.
(2) For the three months ended March 31, 2015, operating expenses and transportation expenses in the Operating Netback figure includes midstream revenues of $0.62/boe (2014 - $1.42/boe).

RESULTS OF OPERATIONS

The following table summarizes the results of operations for the three months ended March 31, 2015 and 2014:

Three months ended ($ Thousands)	March 31, 2015	March 31, 2014
LIGHT OIL OPERATING INCOME[1]		
Petroleum and natural gas sales	$ 15,511	$ 34,646
Midstream revenue	331	803
Royalties	(1,861)	(5,028)
Operating and transportation expenses	(7,403)	(9,478)
	6,578	20,943
CORPORATE AND OTHER		
Interest income and other	4,281	2,400
General and administrative	(8,641)	(11,935)
Restructuring and other charges	(16,988)	(5,636)
Stock-based compensation	(992)	(472)
Financing and interest	(1,578)	(9,295)
Depletion and depreciation	(18,782)	(26,800)
Foreign exchange loss, net	(23,620)	—
Derivative gain, net	25,911	—
Unrealized Put Option gain	—	2,211
Gain on sale of assets	912	—
Loss before income taxes	(32,919)	(28,584)
INCOME TAXES		
Deferred income tax recovery	(7,807)	(7,452)
Loss before the following	(25,112)	(21,132)
Equity loss on investments	—	(214)
Net loss and comprehensive loss	$ (25,112)	$ (21,346)
BASIC LOSS PER SHARE	$ (0.06)	$ (0.05)
DILUTED LOSS PER SHARE	$ (0.06)	$ (0.05)

Operating Results

Three months ended ($ Thousands)	March 31, 2015	March 31, 2014
SALES VOLUMES		
Oil (bbl/d)	2,308	2,402
Natural gas (Mcf/d)	18,126	20,021
Natural gas liquids (bbl/d)	548	560
Total (boe/d)	5,877	6,299
Oil and Natural gas liquids %	49%	47%
REALIZED PRICES		
Oil ($/bbl)	$ 46.75	$ 89.70
Natural gas ($/Mcf)	2.79	6.23
Natural gas liquids ($/bbl)	25.17	79.93
Realized price ($/boe)	$ 29.35	$ 61.12
Royalties[2] ($/boe)	(3.52)	(8.87)
Operating expenses and transportation ($/boe)	(13.37)	(15.30)
LIGHT OIL OPERATING NETBACK[1] ($/boe)	$ 12.46	$ 36.95

(1) Refer to “Advisories and Other Guidance” beginning on page 15 for additional information on Non-GAAP Financial Measures. For the three months ended March 31, 2015, operating expenses and transportation in the Operating Netback figure includes midstream revenues of $0.62/boe (2014 - $1.42/boe).

(2) During the three months ended March 31, 2015, the average royalty rate was 12% of gross petroleum and natural gas sales (March 31, 2014 - 15%).

During the three months ended March 31, 2015, production averaged 5,877 boe/d, compared to 6,299 boe/d during the same period in the prior year. Lower production during the quarter was primarily due to natural declines from the Company's Duvernay and Montney wells and planned drilling deferrals associated with the 2014/15 winter program as a result of lower commodity prices.

Average realized prices decreased by 52% during the three months ended March 31, 2015 to $29.35/boe, compared to the same period in the prior year, 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		March 31, 2015		March 31, 2014
Crude Oil:				
West Texas Intermediate monthly average (US$/bbl)	$	48.63	$	98.68
Edmonton Par monthly average (C$/bbl)	$	51.79	$	99.74
Edmonton Condensate (C5+) (C$/bbl)	$	55.42	$	110.58
Natural gas:				
AECO monthly average (C$/GJ)	$	2.61	$	5.42
NYMEX Henry Hub close monthly average (US$/MMBtu)	$	2.98	$	4.94
Foreign exchange:				
CAD : USD (monthly average)		1.24		1.10

The average royalty rates decreased during the three months ended March 31, 2015 to 12% of gross revenues compared to 15% during the same period in the prior year, primarily due to lower sliding scale royalty rates which decline on lower market commodity prices. The Company also benefited from initial low royalty rates on production from new wells on brought on stream in 2014 and the first quarter of 2015.

For the three months ended March 31, 2015, operating and transportation expenses decreased compared to the same period in the prior year from $15.30/boe to $13.37/boe, primarily due to cost saving initiatives in the first quarter of 2015.

Interest Income and Other

Three months ended ($ Thousands)		March 31, 2015		March 31, 2014
Interest income on cash and cash equivalents	$	1,955	$	982
Interest income on Promissory Notes		2,056		—
Time value of money accretion (Dover Put Option asset)		—		1,231
Other		255		187
TOTAL INTEREST INCOME AND OTHER	$	4,266	$	2,400

For the three months ended March 31, 2015, interest income and other increased by $1.9 million, compared to the same period in the prior year, primarily due to $2.1 million of interest income earned on the Promissory Notes that were issued to Athabasca by Phoenix on the closing of the Dover Divestiture during the third quarter of 2014. The Company also earned higher interest income on cash and short-term investments as average balances were higher during the first quarter of 2015 relative to the prior year. The overall increase in interest income in the first quarter of 2015 was partially offset by time value of money accretion on the Dover Investment in the first quarter of 2014.

General and Administrative ("G&A")

Three months ended ($ Thousands)		March 31, 2015		March 31, 2014
Salaries and benefits	$	10,466	$	17,045
Office costs		4,133		4,994
Legal, accounting and consulting		1,082		1,396
Stakeholder relations		662		507
Capitalized staff costs		(7,702)		(12,007)
TOTAL GENERAL AND ADMINISTRATIVE EXPENSES	$	8,641	$	11,935

During the three months ended March 31, 2015, salaries and benefits declined by $6.6 million, compared to the same period 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. By the first quarter of 2015, Athabasca had completed this initiative and since the beginning of 2014 has reduced the size of its head office workforce by approximately 50%.

Athabasca also undertook a number of other cost efficiency initiatives in 2014 and the first quarter 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 months ended March 31, 2015, compared to the same period in the prior year, primarily due to the staff reductions and a reduction to non-core thermal project activities.

Restructuring and other charges

For the three months ended		March 31, 2015		March 31, 2014
Staff restructuring charges	$	5,985	$	5,636
Office lease provision		7,034		—
Cancellation charges		3,969		—
TOTAL RESTRUCTURING CHARGES AND OTHER CHARGES	$	16,988	$	5,636

For the three months ended March 31, 2015 and 2014, Athabasca incurred non-recurring staff restructuring charges of $6.0 million and $5.6 million, respectively, relating to the Company's cost realignment activities. The Company also recognized a loss of $7.0 million relating to lease commitments on vacated office space as a result of the staff reductions.

As a result of the decline in commodity prices and Athabasca's focused capital allocation priorities toward the Greater Kaybob area and Hangingstone Project 1, expenditures related to the Company's development of the Hangingstone Expansion and appraisal activities for other thermal assets have been significantly reduced. As a result of this reduction, during the first quarter of 2015, Athabasca recognized $4.0 million of cancellation charges relating to Thermal Oil rig commitments associated with the 2014/15 drilling season for which the drilling rigs are not expected to be utilized.

Stock-based Compensation

For the three months ended March 31, 2015, Athabasca incurred stock-based compensation expense of $1.0 million, compared to $0.5 million during the same period in the prior year. Stock-based compensation expense was reduced in both periods primarily due to forfeitures of unvested equity awards as a result of staff reductions that occurred in the first quarters of 2014 and 2015.

Financing and Interest

Three months ended ($ Thousands)		March 31, 2015		March 31, 2014
Interest and fees on indebtedness	$	15,094	$	13,695
Accretion of decommissioning obligations		1,839		1,504
Amortization of debt issuance costs		1,818		2,465
Capitalized financing and interest		(17,173)		(8,369)
TOTAL FINANCING AND INTEREST	$	1,578	$	9,295

Interest and financing expenses are primarily attributable to the three debt instruments held by the Company. Interest expense and amortization of deferred borrowing costs are incurred on the Company’s $550.0 million senior secured second lien notes (“Notes”) issued during the fourth quarter of 2012. The Notes bear interest at a rate of 7.5% per annum. Interest and amortization of deferred borrowing 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.

Compared to the same period in 2014, financing and interest expense decreased by $7.7 million during the first quarter of 2015. The decrease was primarily due to a higher percentage of interest and financing costs being capitalized to Hangingstone Project 1 as the project neared completion. The lower interest expense resulting from lower capitalization rates was partially offset by higher interest on indebtedness as a result of the Company’s Term Loan which was issued during the second quarter of 2014.

For the three months ended March 31, 2015, the Company recognized lower amortization expense on debt issuance costs of $0.6 million compared to the same period in the prior year. The decrease was primarily due to higher deferred issuance cost amortization relating to the Company's previous $350.0 million credit facilities which were replaced in the second quarter of 2014, partially offset by amortization of debt issuance costs on the Term Loan and new Credit Facility issued in the second quarter of 2014. The Company also recognized higher accretion expense from decommissioning obligations recognized on Hangingstone Project 1 and light oil development in the Greater Kaybob area.

Depletion and Depreciation

Three months ended ($ Thousands)		March 31, 2015		March 31, 2014
Light Oil Division				
Depletion of oil and gas assets	$	16,263	$	18,136
Depreciation of infrastructure assets		1,124		1,087
Depreciation of corporate assets		1,395		2,313
Land relinquishments		—		5,264
TOTAL DEPRECIATION, DEPLETION AND IMPAIRMENT	$	18,782	$	26,800

Depletion expense decreased by $1.9 million during the three months ended March 31, 2015, compared to the same period in the prior year, primarily due to lower depletion rates resulting from reserve additions to the Light Oil Division and lower production volumes. Depreciation of corporate assets declined by $0.9 million in the first quarter of 2015 primarily due to reduced information technology expenditures.

Foreign Exchange Loss, Net

Three months ended ($ Thousands)		March 31, 2015		March 31, 2014
Unrealized foreign exchange loss	$	(23,672)	$	—
Realized foreign exchange gain		52		—
FOREIGN EXCHANGE LOSS, NET	$	(23,620)	$	—

Athabasca incurs foreign exchange gains and losses on the Company's US$225.0 million Term Loan which was issued on May 7, 2014. The net foreign exchange loss incurred during the three months ended March 31, 2015 primarily relates to an unrealized loss on the loan principal as a result of a decrease in the value of the Canadian currency relative to the US dollar since the end of 2014.

Derivative Gain, Net

Three months ended ($ Thousands)		March 31, 2015		March 31, 2014
Unrealized derivative gain	$	25,149	$	—
Realized derivative gain		762		—
DERIVATIVE GAIN, NET	$	25,911	$	—

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. The net derivative gains incurred during the three months ended March 31, 2015, primarily related to an unrealized gain as a result of a decline in the value of the Canadian currency since the end of 2014.

Unrealized Put Option Gain and Gain on Sale of Assets

Previously, Athabasca held a put option that would require Phoenix Energy Holdings Limited ("Phoenix") to acquire Athabasca's wholly owned subsidiary, AOC (Dover) Energy Inc., which held a 40% interest in the Dover oil sands project ("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. The unrealized Dover Put Option gain of $2.2 million recognized in the first quarter of 2014 was primarily due to increases in the probability of receiving regulatory approval offset by refined estimates around anticipated closing costs, working capital adjustments, timing of proceeds and planned capital expenditures.

The Dover Put Option was exercised in the second quarter of 2014 and on August 29, 2014, Athabasca sold the Dover Investment for net proceeds of $1,185.2 million, consisting of $601.3 million in cash and other working capital and $583.9 million in three promissory notes. 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.

The gain on sale of assets of $0.9 million recognized in the first quarter of 2015 primarily relates to final working capital adjustments associated with the closing of the sale.

Deferred Income Tax Recovery

The deferred income tax recoveries recognized in the first quarters of 2014 and 2015 were primarily due to non-capital losses incurred. At March 31, 2015, the Company had approximately $2.6 billion in tax pools, including over $0.8 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 months ended March 31, 2015 and 2014:

Three months ended ($ Thousands)	March 31, 2015	March 31, 2014
Light Oil	$ 79,241	$ 77,449
Hangingstone	64,497	152,852
Thermal Oil exploration areas	4,007	5,106
Corporate assets	1,708	1,455
Total expenditures on E&E and PP&E	149,453	236,862
Expenditures included in assets held for sale(1)	—	4,000
TOTAL CAPITAL EXPENDITURES(2)	$ 149,453	$ 240,862

(1) Relates to the Dover Investment that was sold to Phoenix on August 29, 2014.
(2) For the three months ended March 31, 2015, capital expenditures include capitalized staff costs and capitalized interest and financing of $7.7 million and $15.5 million, respectively (March 31, 2014 - $12.2 million, $7.6 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

Three months ended ($ Thousands)	March 31, 2015	March 31, 2014
Light Oil capital expenditures(1)		
Duvernay	$ 56,980	$ 63,215
Montney	13,993	7,707
Operations and other	8,268	6,527
TOTAL LIGHT OIL CAPITAL EXPENDITURES	$ 79,241	$ 77,449

(1) Includes $2.5 million in capitalized staff costs for the three months ended March 31, 2015 (March 31, 2014 - $2.4 million).

For the three months ended March 31, 2015, the Company spent $79.2 million in the Light Oil Division primarily in the Greater Kaybob area. Athabasca spent $56.9 million on its Duvernay assets primarily relating to drilling activities with seven Duvernay wells (six horizontal, one vertical) rig-released in the first quarter of 2015. The Company also completed one Duvernay well that had been rig-released in 2014 and brought one Duvernay well on stream. Given the current low commodity price environment, Athabasca is evaluating the optimal timing to complete and bring on stream its remaining inventory of drilled horizontal Duvernay wells.

With the completion of the 2014/15 winter drilling program, 95% of the Company's core 200,000 acre Duvernay land position has been extended into the intermediate term.

For the three months ended March 31, 2015, the Company spent $13.9 million on its Montney assets rig-releasing one and completing two Montney wells in the Placid region. One of the two wells was brought on stream during the first quarter of 2015.

Hangingstone

Three months ended ($ Thousands)		March 31, 2015		March 31, 2014
Hangingstone capital expenditures				
Central processing facility	$	22,931	$	47,909
Drilling, pads and pipelines		486		40,767
Base infrastructure		1,847		7,774
Total Project 1 base facility		25,264		96,450
Regional infrastructure and production assurance		6,493		31,396
Project support costs(1)		6,176		11,093
Capitalized start-up costs		9,285		—
Capitalized interest and financing(2)		15,456		7,573
Mineral properties – acquisitions and rentals		—		109
Total Hangingstone Project 1		62,674		146,621
Hangingstone Expansion		1,823		6,231
TOTAL HANGINGSTONE CAPITAL EXPENDITURES	$	64,497	$	152,852

(1) Includes geosciences, regulatory and stakeholder costs and delineation/observation drilling. Also included is $4.0 million in capitalized staff costs for the three months ended March 31, 2015 (March 31, 2014 - $7.1 million).
(2) Excludes non-cash capitalized interest and financing.

Hangingstone Project 1

During the three months ended March 31, 2015, Athabasca spent $64.5 million in the Hangingstone area primarily on the completion and commissioning of the Company's first sanctioned thermal oil project, Hangingstone Project 1 ("Project 1"). First steam commenced on March 23, 2015 in line with targeted timelines. Athabasca's final costs for Project 1 are anticipated to fall between $740 million and $750 million, which is 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.

During the first quarter of 2015, Inter Pipeline Polaris Inc. ("IPPI") substantially completed the diluent supply pipeline and facilities for Project 1 with commissioning anticipated in the second quarter of 2015. Enbridge Pipelines (Athabasca) Inc. ("Enbridge") also completed the transportation pipeline for produced bitumen and blended diluents ("dilbit") between the Cheecham terminal and Project 1. Facilities construction at the pump station and receipt point will continue through the third quarter of 2015. Start up of dilbit transportation is expected to occur during the fourth quarter of 2015.

Hangingstone Operations

Athabasca commenced steaming operations at Hangingstone on March 23, 2015 with steam introduced to three well pairs by the end of the first quarter and 15 well pairs steaming by mid-April 2015. Athabasca plans to start up 22 of the 25 well pairs drilled with the remaining seven well pairs expected to be steaming by the end of the third quarter. Conversion of the wells from steam circulation to production is anticipated to occur four to six months after first steam. All 22 well pairs are expected to be on SAGD production before the end of 2015.

Hangingstone Expansion

Athabasca continued working with the AER to progress the Hangingstone Expansion application and a second round of SIRs were received in March 2015. Successful production ramp-up of Hangingstone Project 1 will need to be demonstrated, along with suitable market conditions and funding, before any expansion projects at Hangingstone are sanctioned.

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)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue[1]	$ 18,262	$ 26,574	$ 32,622	$ 34,569	$ 32,821	$ 28,278	$ 28,248	$ 36,762
Sales volume (boe/d)	5,877	6,035	6,381	5,768	6,299	6,697	5,597	7,258
Realized price ($/boe)	$ 29.35	$ 44.66	$ 56.90	$ 65.97	$ 61.12	$ 46.47	$ 54.27	$ 54.08
Light Oil Operating Netback[1] ($/boe)	12.46	22.38	36.03	46.12	36.95	27.15	31.17	36.93
Funds Flow from Operations[2]	$ 3,162	$ (2,520)	$ 7,203	$ 4,882	$ 3,832	$ 7,728	$ (5,343)	$ 1,368
Funds Flow from Operations per share (basic and diluted)	$ 0.01	$ (0.01)	$ 0.02	$ 0.01	$ 0.01	$ 0.02	$ (0.01)	$ —
Net income (loss)	$ (25,112)	$(129,507)	$ (19,939)	$(56,766)	$ (21,346)	$(40,162)	$ (30,501)	$ (29,986)
Net income (loss) per share - basic	$ (0.06)	$ (0.32)	$ (0.05)	$ (0.14)	$ (0.05)	$ (0.01)	$ (0.07)	$ (0.07)
Net income (loss) per share - diluted	$ (0.06)	$ (0.32)	$ (0.05)	$ (0.14)	$ (0.05)	$ (0.01)	$ (0.07)	$ (0.07)
CAPITAL EXPENDITURES	$ 149,453	$ 171,173	$113,779	$109,056	$240,862	$208,355	$146,133	$349,918

(1) Consists of petroleum and natural gas sales, midstream revenue and interest income and other, net of royalties.
(2) Refer to "Advisories and Other Guidance" beginning on page 15 for additional information on Non-GAAP financial measures.

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

2015 Capital budget

Athabasca's 2015 budget remains unchanged at $305 million (excluding capitalized interest and financing). The following table outlines the Company's 2015 capital budget by area:

2015 Budget ($million)	Q1 2015 Actuals	Q2 - Q4 remaining	Full Year budget
Light oil Division			
Duvernay	$ 57	$ 109	$ 166
Montney	14	3	17
Other	6	14	20
	77	126	203
Thermal oil Division			
Hangingstone Project 1	44	24	68
Hangingstone Expansion	1	11	12
Other	3	13	16
	48	48	96
Corporate	2	4	6
TOTAL CAPITAL EXPENDITURES BUDGET	$ 127	$ 178	$ 305
Amounts excluded:			
Capitalized interest and financing	$ 15	$ 16	$ 31
Capitalized general and administrative costs	$ 8	$ 21	$ 29

Light Oil Division budget

During the first quarter, Athabasca substantially completed its 2014/15 winter program which resulted in the drilling of seven horizontal Duvernay wells, three vertical Duvernay wells and two Placid horizontal Montney wells.

The Company's objectives for its second half 2015 Light Oil program include: demonstrating pad drilling cost efficiencies and ongoing appraisal work in the volatile oil window. Athabasca intends to complete and tie-in three previously drilled Duvernay wells. The Company also expects to commence a drilling program in late summer utilizing a single fit-for-purpose rig with the intention of drilling a four well Duvernay pad at Kaybob West and a two well pad at Kaybob East in the volatile oil window. It is expected that four of these additional six wells will be finished drilling by the end of 2015.

The 2015 capital budget for Light Oil remains unchanged at $203 million. The Company has reduced some previously planned non-productive capital expenditures and realized some expected cost savings, allowing the second half program to be completed within the original capital budget. The Company retains significant flexibility to control pace and adjust capital plans to meet its strategic objectives over the medium term.

Athabasca's second quarter production is expected to average approximately 5,000 boe/d. The 2015 year-end Light Oil exit production guidance remains unchanged at 7,000 - 8,000 boe/d, in anticipation of a successful second half 2015 capital program.

Thermal Oil Division budget

The 2015 Thermal Oil budget is unchanged at $96 million with $68 million to be spent on the commissioning and ramp-up of Hangingstone Project 1. The Company remains focused on the successful start-up at Hangingstone and views it as a strategic asset within its Thermal portfolio. The 2015 year-end Hangingstone exit production target remains between 3,000 - 6,000 bbl/d.

Consolidated budget

The 2015 corporate year-end exit target remains between 10,000 - 14,000 boe/d. Based on its current capital spending, production and cash flow outlook, Athabasca anticipates 2015 year-end Available Funding of approximately $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 the continued appraisal and development activities in the Greater Kaybob area and ramp up of Hangingstone Project 1, will be funded with existing cash and cash equivalents, short-term investments, Promissory Notes, cash flow from operations and available credit, and the Company has significant flexibility to adjust its Light Oil capital program in response to commodity price cycles. 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 equity issuances or joint arrangements. The Company cannot guarantee the availability of these sources of additional funding.

The Company's significant outstanding financial liabilities mature as follows: 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 Notes mature on November 19, 2017; and the long term deposit will be held for a period of twelve years. 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 loss over the life of the Notes using the effective interest rate method.

As at March 31, 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 and 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 any time prior to May 7, 2015 at the present value of 102% of the principal amount plus the present value of interest owing from the date of redemption to May 7, 2015. Beyond that date, 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 (including the present value of total proved and probable reserves) to total debt of 3.5 times; and, beginning with the March 31, 2015 quarter-end, if the aggregate of 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 to net first lien debt of 1.5 times.

As at March 31, 2015, Athabasca's adjusted consolidated net tangible assets to total debt ratio was 5.0 times and the Company had a net first lien cash position of $380.0 million. As at March 31, 2015, the Company is 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 year ended

December 31, 2014, the Company paid a rate of 1.00% on the undrawn portion of the Credit Facility (December 31, 2013 - 1.00%). As of March 31, 2015, Athabasca had $0.7 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 balance of $2,750 million. As at March 31, 2015, the Company's shareholders' equity balance was $3,142 million (December 31, 2014 - $3,164 million).

As at March 31, 2015, Athabasca was in compliance with all 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 March 31, 2015 and December 31, 2014 Athabasca's cash, cash equivalents and short-term investments were held with five 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 March 31, 2015, the largest institution held 29% of the balances (December 31, 2014 - 35%).

As at March 31, 2015, 8% of the Company's consolidated accounts receivable balance was due from the Government of Canada for input tax credits (December 31, 2014 - 11%) and 15% 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 44% of accounts receivable (December 31, 2014 - 30%) and additional activity with partners accounts for 16% (December 31, 2014 - 17%). Additionally, 8% relates to accrued interest on the Promissory Notes. Management believes collection risk on the outstanding accounts receivable as at March 31, 2015 is low given the high credit quality of the Company's material counterparties. No material amounts were past due at March 31, 2015, based on the terms with the counterparties.

As at March 31, 2015 Athabasca holds $286.7 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 $520.0 million, from a 1.00% change in interest rates, would be approximately $5.2 million for a twelve month period (year ended December 31, 2014 - $4.4 million).

The Company is 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 twelve 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 $37.8 million would decrease by $16.3 million. Long-term debt would decrease by $14.2 million resulting in a net $2.1 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 $16.3 million and increase long-term debt by $14.2 million resulting in a net $2.1 million gain.

Athabasca is exposed to foreign currency risk on its US dollar denominated Term Loan. In May 2014, to manage the currency exposure, 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 loss and the associated liability or asset is recognized on the balance sheet.

For the three months ended		March 31, 2015		March 31, 2014
Unrealized derivative gain	$	25,149	$	—
Realized derivative gain		762		—
DERIVATIVE GAIN, NET	$	25,911	$	—

As at		March 31, 2015		March 31, 2014
OPENING DERIVATIVE ASSET	$	12,638	$	—
Unrealized derivative gain		25,149		12,638
CLOSING DERIVATIVE ASSET	$	37,787	$	12,638
Presented as:				
Current portion of derivative asset	$	3,119	$	930
Long-term portion of derivative asset	$	34,668	$	11,708

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at March 31, 2015 for the following five years and thereafter:

	2015	2016	2017	2018	2019	Thereafter	Total
Repayment of long-term debt[1]	$ 2,119	$ 2,801	$ 552,773	$ 2,745	$ 272,795	$ —	$ 833,233
Interest expense on long-term debt	56,742	61,632	53,824	19,845	6,801	—	198,844
Transportation	4,971	21,328	24,384	26,990	29,103	484,125	590,901
Office leases	2,916	4,090	4,090	4,090	4,090	22,209	41,485
Purchase commitments and other	9,598	—	—	—	—	—	9,598
Drilling rigs	1,781	4,605	—	—	—	—	6,386
TOTAL COMMITMENTS	$ 78,127	$ 94,456	$ 635,071	$ 53,670	$ 312,789	$ 506,334	$ 1,680,447

(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.

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 has sufficient available funding in place to service any collateral that may be required and any such requirements are not expected to impact the current capital or operating plans of the Company.

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 $142 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 is involved in various claims arising in the normal course of business. Athabasca does not expect that such claims will have a material adverse effect on the Company.

Off Balance Sheet Arrangements

The Company has certain lease agreements which are reflected in the table above under the heading "Commitments and Contingencies", 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 months ended March 31, 2015, the Company issued 0.5 million 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 May 4, 2015	
Common shares issued and outstanding	402,923,753
Convertible securities:	
Stock options outstanding - exercisable and unexercisable	11,177,116
Restricted share units outstanding - exercisable and unexercisable	8,318,024
Performance awards - unexercisable	817,400

ACCOUNTING POLICIES AND ESTIMATES

During the three months ended March 31, 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.

For the three months ended March 31, 2014, G&A expenses have been reduced by $5.6 million from those presented in prior periods to reflect Athabasca's decision to separately present restructuring charges as part of the cost review initiative undertaken by the company throughout 2014 and 2015.

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 4 reconcile back to net income in the consolidated financial statements for the three months ended March 31, 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 months ended March 31, 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:

Three months ended ($ Thousands)		March 31, 2015		March 31, 2014
Cash flow from operating activities	$	(2,610)	$	15,412
Restructuring and other charges, excluding long-term portion of office lease provision		13,520		5,636
Changes in non-cash working capital		(9,855)		(12,851)
Reclamation expenditures		2,107		1,271
FUNDS FLOW FROM OPERATIONS	$	3,162	$	9,468

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.

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, except per share and boe amounts)		March 31, 2015		December 31, 2014
Cash and cash equivalents	$	570,290	$	531,475
Short-term investments		92,873		47,618
Promissory Notes		283,892		583,892
Undrawn credit facilities		125,000		125,000
Term Loans - delayed draw (US$50.0 million)		63,415		58,005
AVAILABLE FUNDING	$	1,135,470	$	1,345,990

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 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, except per share and boe amounts)		March 31, 2015		December 31, 2014
Long-term debt	$	810,758	$	786,649
Current liabilities		129,334		171,097
Current assets		(875,206)		(1,082,301)
Current portion of derivative asset (included in current assets)		3,119		930
NET DEBT	$	68,005	$	(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.

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;
- Expiration of leases, licenses or permits;
- Meeting development schedules and the risk of cost over-runs;
- 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;
- Risk of changes to royalty and income tax regimes;
- 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 Hangingstone Project 1; the expectation that 22 well pairs will be on SAGD production at Hangingstone Project 1 by the end of the 2015; the Company's projection that the costs of the Hangingstone Project 1 will come in within 5% of its sanctioned budget; the timing of the completion and commissioning of diluent pipelines and the 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 June 30, 2015 and 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; changes to royalty regimes; 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.

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
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
SIR	supplemental information request
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.