ATHABASCA

OIL CORPORATION

Management's Discussion and Analysis

December 31, 2014

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 March 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. 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 30 of this MD&A. See "Reserves and Resource information" on page 32 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 33 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, the secondary target is the Montney formation. 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 – 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%). Other project areas include the Dover West Leduc Carbonates (100%), Dover West Sands (100%), Birch (100%) and Grosmont (50%). Development targets include oil sands in the McMurray and Wabiskaw formations as well as carbonates in the Leduc and Grosmont formations. 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.

(1) Based on the reports of Athabasca's independent reserve evaluators effective December 31, 2014. Refer to page 32 and the AIF for additional important information about the Company's Reserves and Contingent Resources.

HIGHLIGHTS FOR THE YEAR ENDED DECEMBER 31, 2014

Sale of Dover Oil Sands Project

- On August 29, 2014, Athabasca closed the sale of its wholly owned subsidiary, AOC (Dover) Energy Inc., which held a 40% interest in the Dover oil sands project (the "Dover Investment") to Phoenix Energy Holdings Limited ("Phoenix"), a wholly owned subsidiary of PetroChina International Investment Company Limited, for net proceeds of $1,185 million, consisting of $601.3 million in cash and other working capital and $583.9 million in unconditional promissory notes ("Promissory Notes") which are secured by irrevocable, standby letters of credit issued by HSBC Bank Canada (the "Dover Divestiture").

- On March 2nd, 2015, the first Promissory Note issued from the Dover Divestiture matured and Athabasca received $302.5 million. The remaining Promissory Notes for $150.0 million and $133.9 million mature in August of 2015 and 2016, respectively.

Light Oil Division

- For the quarter ended December 31, 2014, Athabasca produced 6,035 boe/d (52% liquids). During the year ended December 31, 2014, Athabasca produced 6,120 boe/d (51% liquids), a 4% decrease compared to 6,397 boe/d (49% liquids) during the same period in the prior year. Lower production during the year was primarily due to natural well declines from the Company's Montney and Duvernay wells. Declines were partially offset by improved run-times year-over-year on Athabasca's Montney wells.

- For the 12 months ended December 31, 2014, Athabasca's Light Oil Netback(1) was $35.24/boe, a 9% improvement compared to $32.22/boe in the prior year. The increase in the Netback(1) was primarily due to higher underlying commodity prices early in the year and higher liquids weightings as the Duvernay became a more material component of corporate production. For the quarter ended December 31, 2014, Athabasca's Light Oil Netback(1) was $22.38/boe, a decrease of 18% compared to $27.15/boe in the prior year, primarily due to lower commodity prices for petroleum and natural gas.

- During the year ended December 31, 2014, the Company spent $199.9 million in the Light Oil Division. The Company drilled five (four horizontal, one vertical) and completed six horizontal Duvernay wells in the Greater Kaybob area. Four of these wells were brought on stream during the year. The Company completed and tied-in two Montney wells in the Kaybob East area that had been drilled in 2013 and began drilling two Montney wells in the Placid area, one of which was rig-released before the end of the year. The majority of the Company's Duvernay acreage is now held into the intermediate tenure term.

Thermal Oil Division

- During the year ended December 31, 2014, Athabasca spent $400.6 million in the Hangingstone area primarily to advance its 12,000 bbl/d SAGD project, Hangingstone Project 1. Mechanical construction was substantially complete by the end of 2014 with a number of systems handed over to the operations team. Remaining work on electrical, instrumentation and control systems continued into the first quarter of 2015. Construction and commissioning are progressing in line with expectations with targeted first steam near the end of first quarter. At December 31, 2014, Hangingstone Project 1 construction was substantially complete with final project costs anticipated to be within 5% of the sanctioned budget.

Corporate

- On May 7, 2014, Athabasca entered into new credit facilities providing for approximately $425.0 million of committed funding to replace the Company's previous $350.0 million credit facilities which had a maturity date of December 31, 2014. The credit facilities consist of a US$225.0 million senior secured first lien term loan maturing May 7, 2019, or May 19, 2017 if the Company has not redeemed or refinanced its $550.0 million senior secured second lien notes prior to that date, an additional US$50.0 million senior secured first lien delayed term loan from which Athabasca may draw at its option at any time up until May 7, 2016, subject to compliance with covenants and a $125.0 million senior secured first lien revolving credit facility with an initial maturity date of April 30, 2017.

- At December 31, 2014, Athabasca had Available Funding(1) of $1,346 million, consisting of $579.1 million in cash, cash equivalents and short-term investments, $583.9 million in Promissory Notes and $183.0 million of available credit under the Company's Credit Facility and Term Loan agreements.

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(1) Refer to "Advisories and Other Guidance" on page 28 for additional information on Non-GAAP Financial Measures.
(2) Refer to page 32 and the AIF for additional important information about the Company's Reserves and Contingent Resources.

SELECTED FINANCIAL INFORMATION

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

($ Thousands, except per share and boe amounts)	December 31, 2014	December 31, 2013	December 31, 2012
SALES VOLUMES			
Oil (bbl/d)	2,361	2,444	611
Natural gas (Mcf/d)	18,168	19,450	5,984
Natural gas liquids (bbl/d)	734	712	90
Total (boe/d)	6,120	6,397	1,684
REALIZED PRICES			
Oil ($/bbl)	$ 89.20	$ 87.36	$ 76.92
Natural gas ($/Mcf)	4.89	3.56	3.03
Natural gas liquids ($/bbl)	67.90	65.82	64.26
Realized price ($/boe)	57.06	51.55	41.98
Royalties ($/boe)	(6.93)	(4.97)	(2.02)
Operating expenses and transportation[(1)] ($/boe)	(14.89)	(14.36)	(16.47)
Light Oil Netback[(1)] ($/boe)	$ 35.24	$ 32.22	23.49
LIGHT OIL NETBACK[(1)]			
Petroleum and natural gas sales	$ 127,487	$ 120,298	$ 25,797
Midstream revenues	2,667	2,198	-
Royalties	(15,497)	(11,589)	(10,124)
Operating expenses and transportation	(35,923)	(35,649)	(1,242)
	$ 78,734	$ 75,258	$ 14,431
CASH FLOWS			
Funds Flow from Operations[(1)]	$ 13,314	$ (3,739)	$ (22,588)
Funds Flow from Operations per share (basic and diluted)	$ 0.03	$ (0.01)	$ (0.06)
NET LOSS AND COMPREHENSIVE LOSS			
Net loss and comprehensive loss	$ (227,558)	$ (126,138)	$ 260,234
Net loss and comprehensive loss per share (basic & diluted)	$ (0.57)	$ (0.32)	$ 0.65
SHARES OUTSTANDING			
Weighted average shares outstanding – basic	401,512,412	400,111,681	398,801,921
Weighted average shares outstanding – diluted	401,512,412	400,111,681	400,668,005
CAPITAL EXPENDITURES			
Light Oil Division	$ 199,938	$ 282,050	$ 611,337
Thermal Oil Division	416,967	447,819	460,018
Investments and assets held for sale	8,120	17,614	19,550
Corporate	9,953	14,078	9,111
	$ 634,978	$ 761,561	$ 1,100,016
FINANCING AND DIVESTITURES			
Net proceeds from asset sales, including Promissory Notes	$ 1,245,171	$ 173,894	$ 692,413
Net proceeds from long-term debt (net of repayments)	235,394	-	528,520
LIQUIDITY			
Available Funding[(1)]	$ 1,345,990	$ 672,790	$ 1,160,200
Net Debt[(1)]	$ (123,625)	$ (884,970)	$ (621,001)
BALANCE SHEET			
Total assets	$ 4,297,803	$ 4,342,325	$ 4,458,635
Long-term debt, net of debt issuance costs	$ 786,649	$ 533,210	$ 529,011
Shareholders' equity	$ 3,164,186	$ 3,373,957	$ 3,459,720

(1) Refer to "Advisories and Other Guidance" on page 28 for additional information on Non-GAAP Financial Measures. The Net Debt liquidity measure excludes $133.9 million in Promissory Notes due in August 2016. For the year ended December 31, 2014, operating expenses and transportation in the Netback figure includes midstream revenues of $1.19/boe (2013 - $0.94/boe, 2012 – $nil).

INDEPENDENT RESERVES AND RESOURCES EVALUATION

The Company's independent reserve evaluators, GLJ Petroleum Consultants Ltd. ("GLJ") and DeGolyer and MacNaughton Canada Limited ("D&M"), completed independent reserve and resource evaluations effective December 31, 2014. The Company's bitumen reserves are located in the Hangingstone and Dover West Sands areas in the Company's Thermal Oil Division. The Company's light oil, natural gas and natural gas liquids reserves are located primarily in the Greater Kaybob Area within the Company's Light Oil Division.

Reserves

At December 31, 2014, the Company had 362 MMbbl of gross Proved Plus Probable Reserves. The following table shows the Company's reserves by division and project area:

	December 31, 2014		December 31, 2013	
Reserves[1]	**Gross Proved Reserves**	**Gross Proved plus Probable Reserves**	**Gross Proved Reserves**	**Gross Proved plus Probable Reserves**
Hangingstone (MMbbl)	51	226	51	225
Dover West Sands (MMbbl)[2]	-	87	-	87
Thermal Oil Division (MMbbl)	51	313	51	312
Light Oil Division (MMboe)	12	50	15	33
Total Reserves, excluding assets held for sale	63	362	66	345
Dover (MMbbl)[3]	-	-	-	138
Consolidated Reserves (MMboe)	63	362	66	482

(1) Refer to "Advisories and Other Guidance" beginning on page 28 for important information regarding the Reserve estimates and assumptions. Some totals may not add due to rounding.

(2) Athabasca previously submitted a regulatory application to the ERCB and Alberta Environment in respect of Dover West Sands Project 1 in December 2011. As at December 31, 2014, regulatory approval had not been received and the Company's management is now contemplating withdrawing the regulatory application during 2015 given the present shift in focus to Athabasca's principal development properties in the immediate future. If the Dover West Sands Project 1 regulatory application is withdrawn, it is likely to result in conversion of the Probable Reserves to Contingent Resources. While management believes that the Dover West Sands are an attractive and viable long-term development opportunity, it is not expected that Athabasca will fully develop the Dover West Sands without first securing another suitable means of financing.

(3) The Company's investment in Dover as at December 31, 2013 was accounted for using the equity method and the Reserve estimates set out above reflect the Company's indirect undivided 40% working interest in the Dover Investment prior to the Dover Divestiture. At December 31, 2013, the Dover Investment was classified as an asset held for sale. The Dover Investment was sold to Phoenix on August 29, 2014.

As at December 31, 2014, Athabasca's Proved Reserves decreased by 3 MMBoe to 63 MMBoe primarily due to production and lower price forecasts in the Light Oil Division.

Athabasca's gross Proved plus Probable Reserves decreased by 25% to 362 MMboe compared to December 31, 2013 estimates primarily due to the disposition of the Dover Investment which reduced the Proved Plus Probable Reserves by 138 MMbbl. Aside from the Dover Divestiture, Thermal Oil Proved Plus Probable Reserves remained consistent. In the Light Oil Division, Proved Plus Probable Reserves increased by 52% to 50 MMBoe, compared to the prior year, primarily due to 2014 Duvernay drilling activities in the Greater Kaybob Area, partially offset by production and lower price forecasts.

Contingent Resources

At December 31, 2014, the Company had 8.5 billion bbl of Company Interest Best Estimate Contingent Resources. The table below summarizes the Company Interest Best Estimate Contingent Resources from five of Athabasca's thermal oil projects as evaluated by GLJ and D&M. The following table does not include the gross Proved plus Probable Reserve volumes assigned to Hangingstone and Dover West, which are set out above:

Company Interest Best Estimate Contingent Resources (MMbbl)[1]	December 31, 2014	December 31, 2013
D&M REPORT		
Hangingstone	782	782
Birch	2,111	2,111
Total D&M Report	2,893	2,893
GLJ REPORT		
Dover West Sands	2,894	2,957
Dover West Leduc Carbonates[3]	2,756	3,001
Grosmont[3][4]	-	418
Total GLJ Report, excluding assets held for sale	5,650	6,376
Dover[2]	-	1,222
Total GLJ Report	5,650	7,599
Total Company Interest Contingent Resources[1]	8,543	10,492

(1) Refer to the "Advisories and Other Guidance" beginning on page 28 and the AIF for important information regarding the Company's Contingent Resources estimates.
(2) The Company's investment in Dover as at December 31, 2013 was accounted for by the equity method and the Reserve estimates set out above reflect the Company's indirect undivided 40% working interests in the Dover Investment prior to the Dover Divestiture. At December 31, 2013, the Dover Investment was classified as an asset held for sale. The Dover Investment was sold to Phoenix on August 29, 2014.
(3) The Best Estimate Contingent Resources assigned to the Dover West Leduc Carbonates by GLJ were assessed using CSS in 2014 and SAGD in 2013.
(4) As at December 31, 2014, GLJ considered the Contingent Resources of Grosmont uneconomic based upon a 10% discount factor and Grosmont was excluded from the Company's Contingent Resources (Best Estimate). As at December 31, 2013, GLJ considered the estimated Contingent Resources of 418 MMbbls (Best Estimate) to be sub-economic based upon a 10% discount factor.

During the year, Athabasca's Company Interest Best Estimate Contingent Resources declined by 1.9 billion bbl primarily due to the sale of the Dover Investment (1.2 billion bbl). Athabasca's Company Interest Best Estimate Contingent Resources also declined due to the classification of the Grosmont area being uneconomic (0.4 billion bbl) and a downwards technical revision in the Dover West Carbonates due to a change in the recovery process from SAGD to CSS[1] (0.2 billion bbl). Declines in Company Interest Best Estimate Contingent Resources in the Dover West Sands project area were due to the disposal of 0.2 billion bbl during first quarter of 2014, partially offset by positive technical revisions (0.1 billion bbl).

[1] In management's opinion, the work performed in the Dover West Carbonates suggests that multiple recovery processes may be suitable for use in the Dover West Carbonate (SAGD, CSS or TAGD). The existing Contingent Resources assigned by GLJ to the Dover West Carbonates assume that the assets will be developed using CSS based on positive field test results from competitors. However, Athabasca believes TAGD could be a superior in-situ recovery process, which could take better advantage of the Dover West Carbonates' reservoir characteristics. Athabasca continues to devote resources to determining the optimal development and production methods from the Dover West Carbonates.

RESULTS OF OPERATIONS

The following table summarizes the results of operations for the years ended December 31, 2014 and 2013:

Year ended ($ Thousands)	December 31, 2014	December 31, 2013
LIGHT OIL NETBACK[1]		
Petroleum and natural gas sales	$ 127,487	$ 120,298
Midstream revenue	2,667	2,198
Royalties	(15,497)	(11,589)
Operating and transportation expenses	(35,923)	(35,649)
	78,734	75,258
CORPORATE AND OTHER		
Interest income and other	11,929	14,162
General and administrative	(58,929)	(65,485)
Stock-based compensation	(9,413)	(22,085)
Financing and interest	(28,407)	(44,616)
Depletion, depreciation and impairment	(243,492)	(135,973)
Foreign exchange loss, net	(15,704)	-
Derivative gain, net	12,694	-
Unrealized Put Option loss	-	(51,980)
Gain (loss) on sale of assets	(38,751)	71,010
Loss before income taxes	(291,339)	(159,709)
INCOME TAXES		
Current income tax expense	-	660
Deferred income tax recovery	(64,171)	(35,791)
Loss before the following	(227,168)	(124,578)
Equity loss on investments	(390)	(1,560)
Net loss and comprehensive loss	$ (227,558)	$ (126,138)
BASIC LOSS PER SHARE	$ (0.57)	$ (0.32)
DILUTED LOSS PER SHARE	$ (0.57)	$ (0.32)

Light Oil Netback

Year ended ($ Thousands)	December 31, 2014	December 31, 2013
SALES VOLUMES		
Oil (bbl/d)	2,361	2,444
Natural gas (Mcf/d)	18,168	19,450
Natural gas liquids (bbl/d)	734	712
Total (boe/d)	6,120	6,397
Oil and Natural gas liquids %	51%	49%
REALIZED PRICES		
Oil ($/bbl)	$ 89.20	$ 87.36
Natural gas ($/Mcf)	4.89	3.56
Natural gas liquids ($/bbl)	67.90	65.82
Realized price ($/boe)	57.06	51.55
Royalties[2] ($/boe)	(6.93)	(4.97)
Operating expenses and transportation[1] ($/boe)	(14.89)	(14.36)
Light Oil Netback[1] ($/boe)	$ 35.24	$ 32.22

(1) Refer to "Advisories and Other Guidance" beginning on page 28 for additional information on Non-GAAP Financial Measures. For the year ended December 31, 2014, operating expenses and transportation in the Netback figure includes midstream revenues of $1.19/boe (2013 - $0.94/boe).

(2) During the year ended December 31, 2014, the average royalty rate was 12% of gross petroleum and natural gas sales (December 31, 2013 – 10%).

During the 12 months ended December 31, 2014, production averaged 6,120 boe/d, compared to 6,397 boe/d during the same period in the prior year. Lower production during the year was primarily due to natural well decline from the Company's Montney and Duvernay wells. Declines were partially offset by improved run-times year-over-year on Montney wells.

Realized prices increased by 11% during the year ended December 31, 2014 to $57.06/boe, compared to the same period in the prior year, primarily due to an increase in liquids content from 49% to 51% and higher market prices for oil, natural gas and natural gas liquids for most of the year. The following table summarizes the key commodity price benchmarks:

Year ended	December 31, 2014	December 31, 2013
Crude Oil:		
Edmonton Par monthly average (C$/bbl)	$ 94.49	$ 93.04
West Texas Intermediate monthly average (US$/bbl)	$ 93.00	$ 98.00
Edmonton Condensate monthly average (C5+) (C$/bbl)	$ 100.42	$ 101.81
Natural gas:		
AECO monthly average (C$/GJ)	$ 4.25	$ 3.01
NYMEX Henry Hub close monthly average (US$/MMBtu)	$ 4.39	$ 3.65

The average royalty rates increased during the year ended December 31, 2014 to 12% of gross revenues compared to 10% during the same period in the prior year, primarily due to the expiry of low initial royalty rates on a number of producing Montney wells drilled in prior years, partially offset by lower royalty rates on new production from Duvernay wells brought on stream and higher gas cost allowances received. During the year ended December 31, 2014, operating and transportation expenses increased compared to the same period in the prior year from $14.36/boe to $14.89/boe, primarily due to fixed costs on lower production and work-over expenditures on the Company's Montney wells during the year.

Interest Income and Other

Year ended ($ Thousands)	December 31, 2014	December 31, 2013
Interest income on cash and cash equivalents	$ 5,228	$ 8,154
Interest income on Promissory Notes	3,235	-
Time value of money accretion (Dover Put Option asset)	3,341	5,622
Other	125	386
TOTAL INTEREST INCOME AND OTHER	$ 11,929	$ 14,162

For the year ended December 31, 2014, interest income and other decreased by $2.2 million, compared to the same period in the prior year, primarily due to lower interest income earned on cash and short-term investments as average balances were lower during the first eight months of 2014. Athabasca also recognized a full year of time value of money accretion on the Dover Investment in 2013 compared to eight months of accretion in 2014. The overall decrease in interest income in 2014 was partially offset by $3.2 million of interest income earned on the Promissory Notes that were issued to Athabasca by Phoenix as part of the purchase price for the Dover Divestiture during the third quarter of 2014.

General and Administrative ("G&A")

Year ended ($ Thousands)	December 31, 2014	December 31, 2013
Salaries and benefits	$ 65,720	$ 76,678
Restructuring costs	10,468	-
Office costs	17,601	19,977
Legal, accounting and consulting	5,693	8,846
Stakeholder relations	1,570	3,095
Cancellation charges and other	183	3,637
Capitalized staff costs	(42,306)	(46,748)
TOTAL GENERAL AND ADMINISTRATIVE EXPENSES	$ 58,929	$ 65,485

General and administrative expenses are comprised of non-project salaries and benefits, office rent, consulting fees and other administrative costs. Compared to the same period in the prior year, salaries and benefits declined by $11.0 million during the year ended December 31, 2014 primarily due to staff reductions that occurred in March and November of 2014. The reductions, which represented approximately 26% of the Company's workforce, were largely related to staff associated with projects for which limited funding had been allocated in the short-term. Athabasca incurred $10.5 million in restructuring costs associated with the staff reductions.

Athabasca undertook a number of cost efficiency initiatives during the year that resulted in lower office costs. Legal, accounting and consulting expenses also declined in 2014 primarily due to a lower level of business development activities. Capitalized staff and environment costs decreased during the year ended December 31, 2014, compared to the same periods in the prior year, primarily due to the staff reductions as well as lower capital activity in the Thermal Oil Division exploration areas.

Stock-based Compensation

For the year ended December 31, 2014, stock-based compensation expense decreased by $12.7 million compared to the prior year primarily due to forfeitures of unvested equity awards as a result of staff reductions that occurred in March and November of 2014 and lower fair values per award on new grants.

Financing and Interest

Year ended ($ Thousands)	December 31, 2014	December 31, 2013
Interest and fees on indebtedness	$ 60,005	$ 44,341
Accretion of decommissioning obligations	6,149	4,330
Amortization of debt issuance costs	11,441	6,519
Capitalized financing and interest	(49,188)	(10,574)
TOTAL FINANCING AND INTEREST	$ 28,407	$ 44,616

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") that were 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") that was 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"). The Term Loan also includes an additional US$50.0 million delayed-draw facility for which Athabasca also incurs standby fees.

Compared to the same period in 2013, financing and interest expense decreased by $16.2 million in 2014. The decrease was primarily due to a higher percentage of interest and financing costs being capitalized in association with Hangingstone Project 1 as the project advanced. The lower interest expense resulting from capitalization rates was partially offset by higher interest expense as a result of the Company's Term Loans issued during the second quarter of 2014.

During the year ended December 31, 2014, the Company recognized higher amortization expense on debt issuance costs of $4.9 million compared to the same period in the prior year. The increase was primarily due to $3.9 million in accelerated deferred issuance cost amortization, relating to the Company's previous $350.0 million credit facilities which were replaced in the second quarter of 2014. The Company also recorded higher amortization of debt issuance costs on the Term Loan issued in the second quarter of 2014. The Company also recognized higher accretion expense from decommissioning obligations recognized on Hangingstone Project 1.

Depletion, Depreciation and Impairment

Year ended ($ Thousands)	December 31, 2014	December 31, 2013
Light Oil Division		
Depletion of oil and gas assets	$ 69,438	$ 82,767
Depreciation of infrastructure assets	4,410	5,047
Land expiries and impairments	102,244	33,735
	176,092	121,549
Thermal Oil land expiries and impairments	58,821	-
Depreciation of Corporate assets	8,579	14,424
TOTAL DEPRECIATION, DEPLETION AND IMPAIRMENT	$ 243,492	$ 135,973

At each financial reporting date, the Company considers potential indicators of impairment for both its Light Oil and Thermal Oil Divisions. This assessment includes an analysis of current market conditions as well as a review of pending land expiries and future development plans for each of the Company's assets. In the fourth quarter of 2014, it was determined that the significant decline in commodity prices was an indicator of impairment across all of the Company's assets, and Athabasca tested all of its CGUs for impairment.

In the Light Oil Division, there was no impairment of the Greater Kaybob Area CGU. In its Light Oil Exploration Areas, the Company recognized a full impairment loss of $74.4 million. During 2014, Athabasca also recognized $27.8 million of land expires in the Light Oil Exploration Areas, bringing the total Light Oil expiration and impairment charges for the year ended December 31, 2014 to $102.2 million (December 31, 2013 - $33.7 million).

In the Thermal Oil Division, there were no impairments of the Hangingstone, Dover West or Birch CGUs. In its Grosmont exploration area, the Company recognized a full impairment loss of $53.5 million. Athabasca also relinquished $5.3 million in non-commercial Grosmont leases during 2014 bringing the total Thermal Oil relinquishment and impairment charges to $58.8 million for the year ended December 31, 2014 (December 31, 2013 - $nil).

Depletion expense declined by $13.3 million during the year ended December 31, 2014, 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 during the year. Depreciation of corporate assets declined by $5.8 million in 2014 primarily due to reduced expenditures on the Company's information technology assets.

Foreign Exchange Loss, Net

Year ended ($ Thousands)	December 31, 2014	December 31, 2013
Unrealized foreign exchange loss	$ (15,353)	$ -
Realized foreign exchange loss	(351)	-
FOREIGN EXCHANGE LOSS	$ (15,704)	$ -

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 losses incurred during the year ended December 31, 2014 primarily relates to an unrealized loss incurred on the loan principal as a result of a decrease in the value of the Canadian currency relative to the US dollar since the Term Loan was issued.

Derivative Gain, Net

Year ended ($ Thousands)	December 31, 2014	December 31, 2013
Unrealized derivative gain	$ 12,638	-
Realized derivative gain	56	-
DERIVATIVE GAIN	$ 12,694	$ -

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 year ended December 31, 2014, primarily related to an unrealized gain as a result of a decline in the value of the Canadian currency since the forward contract was entered into.

Unrealized Put Option Loss

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 loss recognized in 2013 was primarily due to refined estimates around anticipated closing costs, working capital adjustments, timing of proceeds and planned capital expenditures, offset by increases in the likelihood of receiving the needed regulatory approval that would trigger Athabasca's right to exercise the Dover Put Option and the probability of the Dover Put Option, in fact, being exercised. The Dover Put Option was exercised in the second quarter of 2014 and sale of the Dover Investment was completed on August 29, 2014 (discussed below).

Gain (loss) on Sale of Assets

On February 10, 2010, the Company entered into a series of agreements pursuant to which, among other things, Phoenix, a wholly owned subsidiary of PetroChina International Investment Company Limited acquired a 60% working interest in the Company's MacKay River and Dover oil sands projects for gross proceeds of $1,884 million and recognized a gain of $1,645 million (the "PetroChina Transaction"). The PetroChina Transaction also included loan agreements and Put/Call Options over the Company's remaining 40% working interest in the MacKay River and the Dover oil sands projects. Athabasca exercised its Put Option to sell the MacKay River oil sands project following receipt of the project's regulatory approval in December of 2011 and Athabasca's remaining interest in the MacKay River oil sands project was sold to Phoenix in the first quarter of 2012 for gross proceeds of $681.7 million. Athabasca recognized a net gain of $216.1 million on the disposal.

In the fourth quarter of 2012, Athabasca was required to value its put option under the Put/Call Option Agreement in respect of the Dover oil sands project (the "Dover Put Option") given greater clarity around regulatory approval and potential exercise of the option. Regulatory approval for the Dover oil sands project was received on April 16, 2014, triggering Athabasca's right to exercise the Dover Put Option, which it did on April 17, 2014. On August 29, 2014, Athabasca closed the sale of its wholly owned subsidiary AOC (Dover) Energy Inc., which held a 40% interest in the Dover oil sands project to Phoenix for net proceeds of $1,185 million.

The following table summarizes the net proceeds received from the sale of assets on August 29, 2014:

Sale of 40% interest in Dover		Net proceeds
Gross proceeds	$	1,320,000
Closing adjustments		(136,108)
Net purchase price		1,183,892
Working capital adjustments		1,304
NET PROCEEDS ON SALE		1,185,196
Consisting of:		
Cash and net working capital		601,304
Promissory Note #1 (maturing March 2, 2015)		300,000
Promissory Note #2 (maturing August 28, 2015)		150,000
Promissory Note #3 (maturing August 29, 2016)		133,892
	$	1,185,196

The interest bearing Promissory Notes issued by Phoenix mature at various times in 2015 and 2016 and yield an average interest rate of 1.67%. The notes are unconditional and secured by irrevocable, standby letters of credit issued by HSBC Bank Canada. On March 2, 2015, the first Promissory Note issued from Dover Divestiture matured and Athabasca received $302.5 million, representing the principal amount plus accrued interest. The remaining Promissory Notes for $150.0 million and $133.9 million mature in August of 2015 and 2016, respectively.

The Dover Divestiture resulted in a cumulative net gain on the sale of assets for Athabasca of $1,050 million, the majority of which was recognized in Athabasca's retained earnings prior to 2014. At the inception of the joint venture in February of 2010, Athabasca valued its 40% interest in the Dover Investment at fair value based on the implied value of the 60% interest sold. In the fourth quarter of 2012, Athabasca recognized its Dover Put Option Asset at fair value given additional clarity surrounding

Athabasca's intention to exercise the Dover Put Option based on the residual value of the Dover Investment's carrying value and the anticipated net Dover Divestiture proceeds, adjusted for timing and the expected probability of receiving the Put Option proceeds. Losses incurred in 2013 and 2014 primarily related to the recognition of transaction costs associated with the closing of the sale, partially offset by gains in the probability of receiving the Dover Divestiture proceeds.

In the third quarter of 2013, Athabasca entered into an Option Agreement with a third party giving Athabasca the right to sell up to a 50% interest in its Kaybob Light Oil infrastructure for cash consideration of up to $145.0 million. In the fourth quarter of 2013, Athabasca exercised its option and completed the sale of a 50% interest in certain sections of its Kaybob light oil infrastructure assets before the end of that year. Athabasca recognized the following gain on the sale of these infrastructure assets:

Sale of 50% interest in Light Oil Kaybob Infrastructure		
Gross proceeds from sale of assets	$	145,000
Closing adjustments		958
Net book value of assets sold		(76,977)
GAIN ON SALE OF KAYBOB INFRASTRUCTURE ASSETS	$	68,981

During 2013, Athabasca also sold two segments of non-core pipeline and other excess pipeline infrastructure in the Kaybob and Hangingstone areas for gross proceeds of $7.9 million and recognized a gain of $2.1 million in net income.

Deferred Income Tax Recovery

The deferred income tax recoveries recognized in 2013 and 2014 were primarily due to non-capital losses incurred. The deferred income tax recovery in 2014 increased by $28.4 million, compared to the prior year, primarily due to higher depletion, depreciation and impairment expense as a result of land expiries and impairments recognized in 2014. At December 31, 2014, the Company had approximately $2,445 million in tax pools, including over $800.0 million in tax pools available for immediate deduction against future income.

Equity Loss on Investments

Athabasca accounted for the interest it held in the Dover Investment using equity accounting. The equity loss on investment recognized in 2014 and 2013 primarily relates to the Company's share of the Dover oil sands project's G&A expenses. The Dover Investment was sold on August 29, 2014.

CAPITAL EXPENDITURES

The following table summarizes the consolidated capital expenditures made by the Company for the periods ended December 31, 2014 and 2013:

Year ended ($ Thousands)		**December 31, 2014**		**December 31, 2013**
Light Oil	$	199,938	$	282,050
Hangingstone		400,625		404,172
Thermal Oil exploration areas		16,342		43,647
Corporate assets		9,953		14,078
Total expenditures on E&E and PP&E		626,858		743,947
Expenditures included in assets held for sale[(1)]		8,120		17,614
Total capital expenditures[(2)]	$	634,978	$	761,561

(1) Relates to the Dover Investment that was sold to Phoenix on August 29, 2014.
(2) Includes $42.3 million in capitalized staff costs for the year ended December 31, 2014 (year ended December 31, 2013 - $46.7 million). Excludes non-cash capitalized costs consisting of capitalized stock-based compensation, decommissioning obligations assets and non-cash interest and financing.

Light Oil Division

The following table summarizes the Light Oil Division capital expenditures by activity:

Year ended ($ Thousands)	December 31, 2014	December 31, 2013
Light Oil capital expenditures		
Mineral properties – acquisitions and rentals	$ 6,133	$ 8,807
Geological and geophysical	4,547	21,007
Drilling and completions	153,014	175,030
Infrastructure and well equipment[1]	36,244	77,206
	$ 199,938	$ 282,050

(1) Includes $9.1 million in capitalized staff costs for the year ended December 31, 2014 (year ended December 31, 2013 - $9.2 million).

For the 12 months ended December 31, 2014, capital expenditures in the Light Oil Division primarily related to the development of the Company's Duvernay assets in the Greater Kaybob area. The Company spent $148.4 million on its Duvernay assets during the year. Athabasca drilled five (four horizontal, one vertical) and completed six horizontal Duvernay wells. Four of the six completed wells were brought on-stream before the end of the year with the remaining two wells expected to be on stream in the first quarter of 2015. The Company was drilling three Duvernay as at December 31, 2014 as part of its winter drilling program.

Upon completion of the 2014/15 winter drilling program, Athabasca anticipates that 95% of its 200,000 commercially prospective acres of Duvernay rights, containing greater than 20 metres of shale pay in the Kaybob fairway, will be extended into the intermediate term. Refer to the Outlook below for information on the Company's 2015 capital budget.

During the 12 months ended December 31, 2014, the Company spent $29.3 million developing its Montney assets. Athabasca completed and brought on stream two Montney wells that were drilled in 2013 in the Kaybob area. The Company also began drilling two Montney wells in the fourth quarter of 2014 in the Placid area, one of which was rig-released before the end of the year.

During 2014, Athabasca spent a further $22.2 million in the Light Oil Division relating to infrastructure, maintenance capital, and capitalized salaries. Athabasca completed the installation of a pipeline from its Kaybob West facility to the SemCAMS KA Plant. The pipeline connects the Company's facilities to a second large midstream plant in the Greater Kaybob area. Access to dual egress provides Athabasca with additional options for processing its production to maximize run times. The cost of the pipeline was borne by third parties with Athabasca receiving a 10% working interest.

Thermal Oil Division

Hangingstone

The following table summarizes the capital expenditures in the Hangingstone area:

Year ended($ Thousands)	December 31, 2014	December 31, 2013
Hangingstone capital expenditures		
Central processing facility	$ 144,561	$ 154,354
Drilling, pads and pipelines	70,566	93,081
Base infrastructure	14,872	18,018
Total Project 1 base facility	229,999	265,453
Regional infrastructure and production assurance	62,152	74,414
Project support costs[1]	36,854	30,040
Capitalized interest and financing[2]	44,513	9,645
Mineral properties – acquisitions and rentals	221	187
Total Hangingstone Project 1	373,739	379,739
Hangingstone Expansion[1]	26,886	24,433
	$ 400,625	$ 404,172

(1) Includes geosciences, regulatory and stakeholder costs and delineation/observation drilling. Also included is $26.5 million in capitalized staff costs for the year ended December 31, 2014 (year ended December 31, 2013 - $24.3 million).
(2) Excludes non-cash capitalized interest and financing.

Hangingstone Project 1

During the 12 months ended December 31, 2014, Athabasca spent $400.6 million in the Hangingstone area primarily to advance the Company's first sanctioned thermal oil project, Hangingstone Project 1. Significant milestones were achieved in 2014 including the completion of the SAGD drilling program, pad construction, regional infrastructure and substantial completion of the Central Processing Facility's mechanical construction.

The SAGD drilling program met the expected cost and schedule performance and the reservoir quality is in conformance with Athabasca's expectations. The well pairs were drilled as targeted to maximize the steam chamber effectiveness. After the drilling program was completed, well pad equipment and flow lines to the central processing plant were installed and all five pads were turned over to operations for commissioning in the fourth quarter of 2014.

Mechanical construction of the Central Processing Facility progressed throughout the year and was substantially complete by year end. All required regional infrastructure required for start-up was substantially completed, including a 12-inch-diameter, 32-kilometer-long pipeline to supply fuel gas from the TransCanada Pipeline, power lines and a substation for power supply. The source water system that supplies make-up water for steam generation was also completed during the fourth quarter. Construction of both the diluent supply pipeline and the dilbit sales pipeline are progressing as expected with commissioning dates of March and December 2015, respectively.

Completion of remaining work on electrical, instrumentation and controls systems will continue through the first quarter of 2015 with the remaining systems being handed over to operations for commissioning and start-up. First steam continues to be anticipated near the end of the first quarter of 2015 and sanctioned project costs are expected to be fall within 5% of budgeted costs.

Hangingstone Expansion

Athabasca completed work on the FEED for a potential 8,000 bbl/d Hangingstone Project 2A Expansion, ("Project 2A"). Athabasca also continued to work with the AER to progress the Hangingstone Expansion application with a second round of SIRs expected in the first quarter of 2015. Future expansions at Hangingstone, including Project 2A, will not be sanctioned until the Company demonstrates a successful production ramp-up profile for Hangingstone Project 1.

Thermal Oil Exploration Areas

The following table summarizes the capital expenditures in the Thermal Oil Exploration areas:

Year ended ($ Thousands)	December 31, 2014	December 31, 2013
Thermal Oil Exploration expenditures[1]		
Dover West Carbonates	$ 8,940	$ 17,932
Dover West Sands	2,769	11,320
Infrastructure, lease rentals and other	4,633	14,395
	$ 16,342	$ 43,647

(1) Included is $6.7 million in capitalized staff costs for the year ended December 31, 2014 (year ended December 31, 2013 - $13.2 million).

During the second quarter of 2014, the Company initiated a fourth production cycle of the Dover West Carbonates TAGD Field Test. The fourth production cycle is anticipated to provide additional information that will be used to enhance the design of a possible future TAGD Pilot and Demonstration Project in the Dover West Carbonates. The also Company also continues to advance its TAGD heater cable technology at the Company's fully operational Heater Assembly Facility.

Athabasca is reviewing development scenarios for its interests in other Thermal Oil asset areas. The Company will continue technical progression within its Thermal Oil exploration areas and will continue to assess partnership and project funding strategies to facilitate future development of these assets. The Company's Birch, Dover West Carbonates, Dover West Sands and Hangingstone Expansion projects have not been sanctioned for development.

Capital Expenditures Included in Assets Held for Sale

Athabasca contributed $8.1 million to the Dover Investment during the year ended December 31, 2014, primarily for engineering costs related to the Dover Commercial Project. The Dover Investment was sold on August 29, 2014.

SUMMARY OF QUARTERLY RESULTS

Results of Operations

The following table summarizes the results of operations for the quarters ended December 31, 2014 and 2013:

Quarter ended ($ Thousands)	December 31, 2014	December 31, 2013
LIGHT OIL NETBACK[1]		
Petroleum and natural gas sales	$ 24,804	$ 28,621
Midstream revenue	509	1,491
Royalties	(3,556)	(4,263)
Operating and transportation expenses	(9,326)	(9,132)
	12,431	16,717
CORPORATE AND OTHER		
Interest income and other	4,817	2,429
General and administrative	(17,211)	(16,984)
Stock-based compensation	(2,619)	(4,933)
Financing and interest	(4,138)	(9,872)
Depletion, depreciation and impairment	(165,792)	(60,339)
Foreign exchange loss, net	(8,471)	-
Derivative gain, net	9,546	-
Unrealized put option gain (loss)	-	(48,426)
Gain (loss) on sale of assets	(274)	68,553
Net loss before income taxes	(171,711)	(52,855)
INCOME TAXES		
Current income tax expense	-	660
Deferred income tax recovery	(42,204)	(13,992)
Net income (loss) before the following	(129,507)	(39,523)
Equity loss on investments	-	(639)
Net income (loss) and comprehensive income (loss)	$ (129,507)	$ (40,162)
BASIC LOSS PER SHARE	$ (0.32)	$ (0.10)
DILUTED LOSS PER SHARE	$ (0.32)	$ (0.10)

(1) Refer to "Advisories and Other Guidance" beginning on page 28 for additional information on Non-GAAP Financial Measures.

Light Oil Netback

Quarter ended ($ Thousands)	December 31, 2014	December 31, 2013
SALES VOLUMES		
Oil (bbls/d)	2,458	2,206
Natural gas (mcf/d)	17,428	22,019
Natural gas liquids (bbls/d)	672	821
Total (boe/d)	6,035	6,697
Oil and Natural gas liquids %	52%	45%
REALIZED PRICES		
Oil ($/bbl)	$ 72.17	$ 78.51
Natural gas ($/mcf)	$ 3.81	$ 3.84
Natural gas liquids ($/bbl)	$ 38.32	$ 65.00
Realized price ($/boe)	$ 44.66	$ 46.47
Royalties[2] ($/boe)	$ (6.40)	$ (6.92)
Operating expenses and transportation ($/boe)	$ (15.88)	$ (12.40)
Light Oil Netback[1] ($/boe)	$ 22.38	$ 27.15

(1) Refer to "Advisories and other Guidance" beginning on page 28 for conversion factors.
(2) During the quarter ended December 31, 2014, the average royalty rate was 14% of gross petroleum and natural gas sales (December 31, 2013 – 15%).

Light Oil production was lower during the fourth quarter of 2014 compared to the fourth quarter of 2013, primarily due to natural well declines on the Company's Montney wells. Declines were partially offset by improved run-times year-over-year on Montney wells. Petroleum and natural gas sales revenue declined primarily due to lower production volumes and lower market prices for oil and natural gas liquids which significantly declined late in the fourth quarter of 2014. Royalties remained consistent at 14-15% of revenue with new Duvernay production with initial lower royalty rates offsetting increased rates on longer producing Montney wells where initial royalty holidays have expired. Gross operating and transportation expenses increased quarter over quarter primarily due to additional wells being brought on stream during the fourth quarter of 2014.

Interest income and other increased in the fourth quarter of 2014, compared to the same quarter in the prior year, primarily due to higher interest income earned on higher average balances on cash, cash equivalents, short-term investments and Promissory Notes held in the period, offset by the time value of money accretion earned on the valuation of the Dover Put Option in the fourth quarter of 2013. General and administrative costs decreased in the fourth quarter of 2014, compared to the same quarter in the prior year, primarily due to staff reductions and other cost savings initiatives that occurred in 2014, partially offset by one-time restructuring cost associated with staff reductions that occurred in November. Stock-based compensation expense declined during the fourth quarter of 2014, compared to the fourth quarter of 2013, primarily due to forfeitures and lower fair values per award on new equity awards granted. Financing and interest expense was lower in the fourth quarter of 2014 primarily due to an increase in the amount of interest capitalized in 2014 to Hangingstone Project 1. The reduction was partially offset by incremental interest expense incurred on the Term Loan put into place during the second quarter of 2014.

In the fourth quarter of 2014, depletion, depreciation and impairment expense increased primarily due to expiries and impairment losses recognized on the Company's Grosmont and Light Oil exploration assets. Athabasca tested these assets for impairment and recognized an impairment loss of $127.9 million. The Company also recognized $19.5 million in land expiries during the fourth quarter. Depletion expense declined during the fourth quarter of 2014 primarily due to lower depletion rates resulting from reserve additions to the Light Oil Division and lower production volumes.

The net foreign exchange loss incurred in 2014 relates primarily to an unrealized loss on the Company's US dollar denominated Term Loan as a result of a decrease in the value of the Canadian currency. Concurrent with the Term Loan, 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 fourth quarter of 2014 primarily related to an unrealized gain as a result of an decline in the value of the Canadian currency since the forward contract was entered into. The unrealized Put Option loss in the fourth quarter of 2013 was primarily due to the refined estimates around anticipated closing costs and working capital adjustments, offset by an increase in the probability of receiving regulatory approval. Athabasca also recognized a gain of $68.6 million in the fourth quarter of 2013 primarily due to the sale of 50% of certain sections of its Light Oil Kaybob infrastructure. The deferred income tax recoveries in the fourth quarters of 2013 and 2014 relate primarily to net operating losses.

Capital Expenditures

The following table summarizes the consolidated capital expenditures made by the company for the quarters ended December 31, 2014 and 2013:

Quarter ended ($ Thousands)	December 31, 2014	December 31, 2013
Light Oil	$ 87,870	$ 40,103
Hangingstone	72,780	156,181
Thermal Oil exploration areas	6,096	5,631
Corporate assets	4,427	3,240
Total expenditures on E&E and PP&E	171,173	205,155
Expenditures included in investments and assets held for sale[1]	-	3,200
Total capital expenditures[2]	$ 171,173	$ 208,355

(1) Relates to the Dover Investment that was sold to Phoenix on August 29, 2014.
(2) Includes $10.9 million in capitalized staff costs for the quarter ended December 31, 2014 (year ended December 31, 2013 - $12.5 million). Excludes non-cash capitalized costs consisting of capitalized stock-based compensation, decommissioning obligations assets and non-cash interest and financing.

Expenditures in the Light Oil Division during the fourth quarter of 2014 and 2013 relate primarily to the Duvernay and Montney drilling programs. Capital expenditures in Hangingstone during the fourth quarters of 2014 and 2013 relate primarily to construction of Hangingstone Project 1. Expenditures incurred in the Thermal Oil exploration areas during the fourth quarters of

2014 and 2013 primarily relate to lease rentals, infrastructure and continued development of the Dover West Carbonates TAGD technology.

Quarterly Results

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

	2014				2013			
($ Thousands, Except Per Share Amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue[1]	$ 26,574	32,622	34,569	32,821	28,278	28,248	36,762	31,781
Sales volume (boe/d)	6,035	6,381	5,768	6,299	6,697	5,597	7,258	6,024
Realized price ($/boe)	44.66	56.90	65.97	61.12	46.47	54.27	54.08	51.65
Light Oil Netback[1] ($/boe)	22.38	36.03	46.12	36.95	27.15	31.17	36.93	33.27
Funds Flow from Operations[2]	$ (2,520)	7,203	4,882	3,832	7,728	(5,343)	1,368	(7,497)
Funds Flow from Operations per share (basic and diluted)	$ (0.01)	0.02	0.01	0.01	0.02	(0.01)	0.00	(0.02)
Net income (loss)	$ (129,507)	(19,939)	(56,766)	(21,346)	(40,162)	(30,501)	(29,986)	(25,489)
Net income (loss) per share - basic	$ (0.32)	(0.05)	(0.14)	(0.05)	(0.10)	(0.07)	(0.07)	(0.06)
Net income (loss) per share - diluted	$ (0.32)	(0.05)	(0.14)	(0.05)	(0.10)	(0.07)	(0.07)	(0.06)
Capital expenditures	$ 171,173	113,779	109,056	240,862	208,355	146,133	349,918	264,361

(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 28 for additional information on Non-GAAP financial measures.

Please 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&A for changes in prior periods.

OUTLOOK

2015 Capital budget

Athabasca's Board of Directors has approved a full year 2015 capital budget of $305 million ($266 million initial budget and $39 million of carryover capital not spent in 2014). A core objective of Athabasca's 2015 capital program is to maintain balance sheet strength and the Company retains flexibility to adjust the program as needed through the balance of year.

2015 Capital Budget[1]		**$ Millions**
LIGHT OIL (full year)		
Duvernay (drill & completion)	$	166
Montney (drill & completion)	$	17
Other (facilities, equipment and roads)	$	20
Total Light Oil (includes $35.6 million of 2014 carryover capital)	$	203
THERMAL OIL		
Hangingstone Project 1 (capital & capitalized start-up costs)	$	68
Hangingstone Expansion (pre-engineering)	$	12
Other	$	16
Total Thermal Oil (includes $3.6 million of 2014 carryover capital)	$	96
CORPORATE	$	6
TOTAL CAPITAL SPENDING (excluding capitalized G&A and interest)[2]	**$**	**305**

(1) The budget is based on commodity prices assumptions of US$50/bbl WTI and C$2.80/mcf AECO and foreign exchange of 0.78 US/CAD
(2) Capitalized G&A and interest is estimated at approximately $60 million

Light Oil budget

Athabasca's 2014/15 winter program includes ten Duvernay wells and two Montney appraisal wells at Placid. The Board has approved a total 2015 Light Oil budget of $203 million including $36 million of carryover capital from the 2014 fiscal year that was previously approved as part of the 2014/15 winter program. The Company has deferred approximately $60 million of capital related to the completion and tie-in of four wells and one drilling location originally planned to be completed before spring break-up until the second half of 2015. Final spending decisions will be based on service cost structures and the commodity price outlook later in the year.

The Company remains on track to meet or exceed Q1 2015 production guidance of approximately 5,000 boe/d. The 2015 year-end Light Oil exit production target of 7,000 – 8,000 boe/d is unchanged assuming the deferred completion activity is completed during 2015.

Thermal Oil budget

The Board has approved a 2015 Thermal Oil budget of $96 million with $68 million focused on the commissioning and ramp-up of Hangingstone Project 1. 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 is between 10,000 – 14,000 boe/d. Based on its current capital spending, production and cash flow outlook, Athabasca anticipates 2015 year-end funding in place of approximately $800 million.

Strategic Initiatives

In the fall, Athabasca outlined some near-term priorities which included refocusing activities on its core Hangingstone and Kaybob assets, a thorough cost structure review and the initiation of a Board of Directors renewal process. An initiative to streamline costs is ongoing with the goal to align the organization to the current operating environment, its capital plans and growth profile. In January, Mr. Carlos Fierro and Mr. Paul Haggis were appointed as independent directors to the Board. Both individuals bring extensive financial and energy sector experience that will be of great value to shareholders.

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.

It is anticipated that Athabasca's 2015 capital and operating budgets, including the appraisal and development of the Duvernay and completion of Hangingstone Project 1, will be funded with existing cash, short-term investments, Promissory Notes, cash flow from operations and available credit. Other longer term projects will require additional capital to develop and Athabasca believes it will fund these other projects through some combination of cash, short-term investments, Promissory Notes, cash flow from operations, a reasonable level of debt and other external financing options including possible 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 Loans mature 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. 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 $550.0 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 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. As at December 31, 2014, Athabasca was in compliance with all of the Notes 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 over the life of the Notes using the effective interest rate method.

Senior Secured Term Loans

On May 7, 2014, Athabasca entered into a credit agreement providing for US$225.0 million term loan which was fully funded at closing and an additional US$50.0 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 (the "Term Loans"). Borrowings 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$50.0 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 Loans 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 Loans 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 December 31, 2014, Athabasca's adjusted consolidated net tangible assets to total debt ratio was 5.2 times. The Company is in compliance with all of the covenants related to the Term Loans.

Revolving Senior Secured Credit Facility

On December 16, 2013 the Company entered into a $350.0 million amended and restated credit agreement with a syndicate of financial institutions, replacing its previous $200.0 million credit facility.

On May 7, 2014, concurrent with entering into the Term Loans, the Company entered into a $125.0 million amended and restated credit agreement with a syndicate of financial institutions to replace the previous $350.0 million 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 December 31, 2014, Athabasca had $0.5 million in issued letters of credit secured by the Credit Facility (December 31, 2013 -

$0.1 million) and no amounts had been drawn under the Credit Facility (December 31, 2013 - $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 December 31, 2014, the Company's shareholders' equity balance was $3,163 million (December 31, 2013 – $3,374 million).

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 December 31, 2014 and December 31, 2013 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 December 31, 2014, the largest institution held 35% of the balances (December 31, 2013 – 45%).

As at December 31, 2014, 11% of the Company's consolidated accounts receivable balance was due from the Government of Canada for input tax credits (December 31, 2013 - 17%) and 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, 2013 – 27%). Joint interest billings due from partners account for 30% of accounts receivable (December 31, 2013 – 41%) and additional activity with partners accounts for 17% (December 31, 2013 – 10%). Additionally, 8% relates to accrued interest on the Promissory Notes. Management believes collection risk on the outstanding accounts receivable as at December 31, 2014 is low as the Company deals with high quality counterparties. No material amounts were past due at December 31, 2014, based on the terms with the counterparties.

As at December 31, 2014 Athabasca has recognized $583.9 million in Promissory Notes. 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.

Interest Rate Risk

The Company's exposure to interest rate fluctuations on interest earned on the floating rate cash balance of $436.3 million, from a 1.00% change in interest rates, would be approximately $4.4 million for a twelve month period (year ended December 31, 2013 - $2.0 million). The Company is exposed to interest rate cash flow risk on its floating rate Term Loans. However, given that the Company has a 1.00% LIBOR floor on its Term Loans, 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 ($0.7 million) increase in interest expense for a twelve month period (year ended December 31, 2013 - $nil).

Foreign exchange risk

The Company is exposed to foreign exchange risk on its US dollar denominated Term Loans 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 $12.6 million would be de-recognized and a $2.5 million derivative liability would be recognized. Long-term debt would decrease by $12.9 million resulting in a net $3.7 million loss. A 5% decrease in the Canadian dollar relative to the US dollar, holding all other variables constant, would increase the derivative asset by $15.1 million and increase long-term debt by $12.9 million resulting in a net $2.2 million gain.

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 income and the associated liability or asset is recognized on the balance sheet.

For the year ended,	December 31, 2014	December 31, 2013
Unrealized derivative gain	$ 12,638	$ -
Realized derivative gain	56	
DERIVATIVE GAIN, NET	$ 12,694	$ -

As at	December 31, 2014	December 31, 2013
OPENING DERIVATIVE ASSET	$ -	$ -
Unrealized derivative gain	12,638	
CLOSING DERIVATIVE ASSET	$ 12,638	$ -
Presented as:		
Current portion of derivative asset	$ 930	$ -
Long-term portion of derivative asset	$ 11,708	$ -

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at December 31, 2014 for the following five years and thereafter:

	2015	2016	2017	2018	2019	Thereafter	Total
Repayment of long-term debt[1]	$ 2,587	$ 2,562	$ 552,536	$ 2,511	$ 249,523	$ -	$ 809,719
Interest expense on long-term debt	62,078	61,871	52,603	18,152	6,221	-	200,925
Transportation	6,479	21,328	24,384	26,990	29,103	484,125	592,409
Office leases	5,587	5,803	5,398	4,580	4,580	23,803	49,751
Purchase commitments and other	17,519	-	-	-	-	-	17,519
Drilling rigs	6,360	2,650	-	-	-	-	9,010
TOTAL COMMITMENTS	$ 100,610	$ 94,214	$ 634,921	$ 52,233	$ 289,427	$ 507,928	$ 1,679,333

(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 sanctioned the development of its first thermal oil project at Hangingstone which includes the construction of a $538 million base facility and the expenditure of $27 million for supporting infrastructure. Athabasca has also sanctioned the installation of regional infrastructure to accommodate future expansions at an additional $108 million above the Hangingstone Project 1 base costs. In addition, a fifth well pad, consisting of five injector-producer lateral well pairs has been sanctioned for $35 million. At December 31, 2014, the facilities, infrastructure and fifth well pad were substantially complete and the final cost of the project is anticipated to be within 5% of the sanctioned value. As at December 31, 2014, $713.9 million had been incurred in respect of the development with purchase commitments related to the sanctioned project excluded from the table above.

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 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 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 amount of the commitment is anticipated to be greater than $122 million over the initial term of the agreement. The initial term of the agreement is 25 years with the option to extend over five renewal terms of five years each.

The Company 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 the outcome of these proceedings 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 year ended December 31, 2014, the Company issued 0.8 million common shares, net of shares re-purchased and held in trust. Issuances of Athabasca's common shares in 2014 relates to the Company's equity-settled and cash-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 March 3, 2015	
Common shares issued and outstanding	402,543,922
Convertible securities:	
Stock options outstanding – exercisable and unexercisable	12,577,400
Restricted share units outstanding – exercisable and unexercisable	9,547,394
Performance awards – unexercisable	400,600

During the second quarter of 2014, the Company approved a performance award plan. Under the terms of the performance award plan the Company may grant performance awards to employees. Performance awards will vest over a period of three years and vested awards will be settled, at the Company's discretion, with cash, in shares purchased in the open market or in shares issued from treasury. The settlement value is based on a multiplier which ranges based on the Company's total shareholder return, relative to a performance peer group consisting of other industry peers, over the vesting period.

The first awards under this plan were granted in the third quarter of 2014. The performance award plan has been accounted for as a cash settled share-based payment plan. At December 31, 2014 the fair value of the performance awards outstanding was estimated at $0.6 million (December 31, 2013 – $nil) considering Athabasca's historical and expected future performance relative to peers.

For additional information regarding this compensation plan, refer to the Company's Information Circular filed on SEDAR dated March 20, 2014.

Related party transactions

Some members of Athabasca's staff were utilized by Brion Energy Corporation, the entity that had been jointly owned by Athabasca and Phoenix to operate the Dover oil sands project ("Brion"), under a shared services arrangement. For the year ended December 31, 2014, Athabasca charged Brion $0.6 million to recover the costs of these shared services staff (December 31, 2013 - $4.8 million). The charges are recorded as a reduction in general and administrative expense. Additionally, Athabasca charges Brion for the use of the Dover West permanent access road as per a road use agreement. For the year ended December 31, 2014, Athabasca charged Brion $2.1 million (December 31, 2013 - $0.2 million). These transactions were in the normal course of operations and were measured at the exchange amount.

As at December 31, 2014, accounts receivable included $0.2 million owing from Brion in respect of road use and no amounts owing for shared services staff (December 31, 2013 - $0.9). As a result of the sale of Dover, Brion is no longer a related party.

In the fourth quarter of 2014, through the normal course of operations, Athabasca sold a parcel of land to an energy company that has a director, who is also an officer for that company, in common with Athabasca for consideration of $0.7 million. The transaction was measured at the exchange amount.

Athabasca has determined that the Company's key management personnel consist of the Company's directors and officers. The compensation and other benefits paid to key management personnel are as follows:

Executive compensation (year ended)	December 31, 2014	December 31, 2013
Salaries, fees and short-term employee benefits	$ 5,688	$ 7,543
Termination benefits	2,029	1,446
Share-based compensation	5,625	2,011
TOTAL EXECUTIVE COMPENSATION	$ 13,342	$ 11,000

EQUITY INVESTMENT

The Company had an indirect undivided 40% working interest in the Dover oil sands project through its 100% wholly-owned subsidiary, AOC (Dover) Energy Inc. The Dover joint venture was an investment in which the Company had significant influence and was accounted for as a long-term investment using the equity method of accounting whereby the carrying value of the investment was increased or decreased for the Company's percentage of net income or loss, reduced by dividends paid to the Company, and increased or decreased to reflect the Company's share of capital transactions. The equity investment did not generate any material revenue in the 2014 or 2013 nor were any dividends paid.

On August 29, 2014, Athabasca closed the sale of its 40% interest in the Dover oil sands project to Phoenix. The following historical cost table summarizes the financial information of the Athabasca's share of the equity investment as at December 31, 2014 and the prior year comparatives thereto:

DOVER INVESTMENT (As at) ($ Thousands)	December 31, 2014	December 31, 2013
TOTAL ASSETS	$ -	$ 912,764
Liabilities	-	37,277
Shareholders' equity	-	875,487
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ -	$ 912,764
NET LOSS (YEAR ENDED)	$ (390)	$ (1,560)

ACCOUNTING POLICIES AND ESTIMATES

During the year ended December 31, 2014, there were no changes to the Athabasca`s accounting policies or use of estimates in the preparation of the consolidated financial statements and the notes thereto that had a material impact to the consolidated financial statements. The following significant accounting policies were used during the year:

Significant Accounting Estimates and Judgments

The preparation of the consolidated financial statements requires management to use estimates, judgments and assumptions. These estimates, judgments and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the applicable reporting period. These estimates relate to unsettled transactions and events as of the date of the consolidated financial statements and may differ from actual results as future confirming events occur. Estimates and underlying assumptions are reviewed by management on an ongoing basis. Revisions to accounting estimates are recognized prospectively in the year in which the estimates are revised. Changes in the Company's accounting estimates and judgments could have a significant impact on net income.

Prior to the closing of the sale of Dover on August 29, 2014, valuation of the Dover Put Option included estimates as to the expected timing and probability of regulatory approval as well as the probability of the Company exercising the option. Judgment was also applied in determining the appropriate discount rate to be used in the valuation and additional costs to be incurred prior to closing. At each reporting date the fair value of the Dover Put Option was assessed based on the most recent information with regards to the estimates discussed above. The accretion of the time value of money was recognized through interest income and any unrealized gains or losses were recognized through net income.

The carrying value of property, plant and equipment ("PP&E") is related to reserve amounts used for impairment and depletion calculations which are based on estimates of oil and gas and bitumen reserves and resources, future commodity prices and future costs required to develop and produce the reserves and resources. The Company expects that reserve estimates and future cash flows could be revised either upwards or downwards based on updated information from drilling and operating results as well as changes to future commodity price estimates. The rates used to discount future cash flows are based on judgment of economic and operating factors. Changes in these factors could increase or decrease the rate which may result in material changes to the estimated recoverable amount of the assets. Exploration and evaluation assets require judgment as to whether future economic benefits exist, including the existence of proven reserves and the ability to finance exploration and evaluation ("E&E") projects, where technical feasibility and commercial viability has not yet been determined.

The provision for decommissioning obligations is based upon numerous assumptions including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Actual costs and cash outflows could differ from the estimates as a result of changes in any of the above noted assumptions.

The provision for income taxes is based on judgments in applying income tax law and estimates on the timing and likelihood of reversal of temporary differences between the accounting and tax bases of assets and liabilities. The provision for income taxes is based on Athabasca's interpretation of the tax legislation and regulations which is also subject to change. Athabasca recognizes a tax provision when a payment to tax authorities is considered more likely than not. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations of the standards may result in a material increase or decrease in the Company's provision for income taxes.

The Company is using a derivative financial instrument to manage risks related to its US dollar denominated debt. The fair value of the derivative is determined using valuation models which require assumptions concerning the amount of timing of future cash flows, discount rates and foreign exchange rates. Athabasca's assumptions rely on external observable market data and data obtained from third parties. The resulting fair value estimates may not be indicative of the amount realized or settled in current market transactions and as such are subject to measurement uncertainty.

Stock-based compensation includes volatility, option life and forfeiture rates which are based on management's assumptions and estimates.

Commitment disclosures relating to post-sanction thermal oil projects include estimates of the total cost of the long-term projects and could be revised either upwards or downwards based on the actual results of developing the project.

All of these estimates are subject to measurement uncertainty and changes in these estimates could materially impact the financial statements of future periods and have a significant impact on net income.

Principles of Consolidation

The consolidated financial statements reflect the activities of the Company and its wholly owned subsidiaries. Intercompany transactions and balances are eliminated upon consolidation. The Company accounted for its investment in the Dover joint arrangement as an equity investment up to the date of sale in accordance with IAS 28 *Investments in Associates*. Management had made an assessment under IFRS 10 *Consolidated Financial Statements* and IFRS 11 *Joint Arrangements* and determined that Athabasca did not control or jointly control its interests in the Dover joint arrangement as Athabasca did not have exposure to the majority of associated benefits or risks.

The Dover joint arrangement was an investment in which the Company had significant influence, as the Company held a 40% interest in the joint arrangement up until August 29, 2014 at which point the remaining interest was sold. The arrangement was accounted for as a long-term investment using the equity method of accounting whereby the carrying value of the investment was increased or decreased for the Company's percentage of net income or loss, reduced by dividends paid to the Company, and increased or decreased to reflect the Company's share of capital transactions.

Financial Instruments

All financial instruments are initially recognized at fair value on the consolidated balance sheet. The Company has classified each financial instrument into the following categories: "held-for-trading"; "loans and receivables"; "held-to-maturity" and "other financial assets or liabilities." Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on held-for-trading financial instruments are recognized in the statement of loss. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method. The Company has classified its financial instruments as follows:

Financial Assets and Liabilities	Classification
Cash and cash equivalents	Held-for-trading
Short-term investments	Held-for-trading
Dover Put/Call Option	Held-for-trading
Derivative asset	Held-for-trading
Accounts receivable	Loans and receivables
Income tax receivable	Loans and receivables
Promissory Notes	Held-to-maturity
Accounts payable and accrued liabilities	Other financial liabilities
Long-term debt	Other financial liabilities

Transaction costs for all financial assets and liabilities are expensed as incurred, with the exception of long-term debt. Transaction costs related to long-term debt are included in the initial fair value and the instruments are carried at amortized cost using the effective interest rate method. The fair value of Athabasca's long-term debt is derived from quoted prices provided by financial institutions or derived from quoted prices serving as a proxy.

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. Athabasca's loans and receivables are comprised of accounts receivable, income tax receivable and the Promissory Notes. These have been recognized at the amount expected to be received less any required discount to reduce their value to fair value.

Derivative financial instruments may be used periodically by the Company to manage risks related to its US denominated rate debt. All derivatives have been classified at fair value though income or loss. Derivative financial instruments are included on the balance sheet and are classified as current or non-current based on the contractual terms specific to the instrument. Gains and losses on re-measurement of derivatives are shown separately on the income statement in the period in which they arise.

At each reporting date, the Company assesses whether there are any indicators that its financial assets are impaired. An impairment loss is only recognized if there is evidence of impairment and the loss event has an impact on future cash flow and can be reliably estimated.

Fair value

The Company classifies its financial instruments measured at fair value according to the following hierarchy based on the amount of observable inputs used to value the instrument. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

• Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities;
• Level 2 – Inputs other than quoted prices that are observable for the asset or liability either directly or indirectly; and
• Level 3 – Inputs that are not based on observable market data.

The Company's cash and cash equivalents and short-term investments have been assessed on the fair value hierarchy described above and have been classified as Level 1, except for investments in Guaranteed Investment Certificates ("GICs"). At December 31, 2014, Athabasca held no short-term GIC investments. The fair value of Athabasca's derivative financial asset of $14.1 million has been classified as Level 2. The fair value was determined using a third party model which was verified for reasonableness by the Company by comparing it to other external market data. The fair value of the Promissory Notes of $587.1 million and the Notes of $464.1 million have been classified as Level 2. The fair values were based on observable quoted prices from financial institutions. The Term Loans have a fair value of $228.9 million (US$197.3 million) and have been classified as Level 3. As the Term Loans are not actively traded, the value of the Notes, adjusted for the senior priority of the loan, was used as a proxy.

The fair value of the Dover Put Option was classified as Level 3. The fair value was determined to be the residual of the fixed exercise price, adjusted for estimated closing costs, and the anticipated carrying value of the Dover Investment at the time of exercise, discounted for the duration to the expected transaction close date using a risk-free rate given PetroChina's investment grade credit rating. The fair value of the Dover Put Option was adjusted based on refined estimates of anticipated closing costs, working capital adjustments, the timing of proceeds and planned capital expenditures. Athabasca exercised the Dover Put Option in April 2014 and closed the sale in August 2014.

Segment Reporting

The Company's operating segments are determined based on differences in the nature of their operations, products sold, economic characteristics, regulatory environments and management responsibility. Operating segments have been aggregated based on similar characteristics as follows:

- Light Oil - includes the Company's assets, liabilities and operating results for the exploration, development and production of unconventional oil, natural gas and natural gas liquids located in various regions in the province of Alberta.
- Thermal Oil - includes the Company's assets, liabilities and operating results for the exploration, development and production of bitumen from sand and carbonate rock formations located in the Athabasca region of Northern Alberta.

Segment results, assets and liabilities include items directly attributable to a segment and those items that can be allocated on a reasonable basis. Unallocated items are comprised mainly of corporate assets, head office expenses, interest income, finance and interest expense, and income tax assets and liabilities. There were no changes to the Company's operating segments during the year.

Property, Plant and Equipment

Items of PP&E are measured using historical cost less any accumulated impairment losses. The initial cost of an asset comprises its purchase price, any cost directly attributable to bringing the asset to the location and condition necessary for its intended use and an initial estimate of the cost of dismantling and removing the item and restoring the site on which it is located. Included in PP&E are assets that have been transferred from E&E upon the establishment of commercial viability and technical feasibility. Once Athabasca's projects are available for use in the manner intended by management, they will either be depleted or depreciated over their useful life depending on the nature of the asset. For assets that are depleted the net carrying value of the related conventional petroleum and natural gas PP&E assets are depleted using the unit of production method based on the ratio of production in the year to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production.

The Company is in the early stages of developing its thermal oil assets and the assets are not yet ready for use; therefore, no depletion or depreciation has been recorded with respect to the related thermal oil capitalized expenditures to date. Light oil assets that are ready for use in the manner intended by management have had depletion recorded against their related capitalized expenditures. Depreciation of Light oil Infrastructure assets is calculated using the straight-line method over the

estimated useful life of the assets, which range from three to fifty years. Depreciation of corporate assets is calculated using the straight-line method over the estimated useful life of the asset, ranging from one to five years.

Exploration and Evaluation ("E&E") Assets

Costs of exploring for and evaluating oil and gas activities, including lease acquisition costs, exploratory drilling to delineate resource formations, geological and geophysical costs, engineering, licensing and regulatory fees, carrying charges on non-productive assets and employee salaries and stock-based compensation directly related to E&E activities are initially capitalized. Exploration and evaluation costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area, these costs are expensed directly to the statement of income as they are incurred.

Tangible assets acquired and utilized to develop an E&E asset are recorded as part of the cost of the E&E asset. When a tangible asset is disposed of in the E&E phase the proceeds of the assets sold are de-recognized from the E&E asset pool with no gain or loss recognized.

E&E assets are carried at cost until both the technical feasibility and commercial viability of extracting a mineral resource is established. Technical feasibility and commercial viability of unconventional petroleum and natural gas activities is considered achieved when proved reserves are determined to exist and the Company has received approval to proceed with commercial development by the Board of Directors. The technical feasibility and commercial viability of thermal oil activities is considered to be achieved when proved reserves are determined to exist and the Company has received approvals to proceed with commercial development by the Board of Directors and regulatory authorities. Upon technical feasibility and commercial viability being established, E&E assets are first tested for impairment and then reclassified from E&E assets to PP&E.

Impairment

Impairment tests are performed on cash-generating units ("CGUs") which are determined by the Company to be at the area level for light oil assets and thermal oil assets. CGUs are not larger than an operating segment.

Exploration and evaluation assets and PP&E are tested for impairment at each reporting date when facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The recoverable amount is determined as the greater of the CGU's value in use ("VIU") and fair value less costs to sell ("FVLCTS"). In assessing VIU, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. FVLCTS is defined as the amount obtainable from the sale of an asset or CGU in an arm's length transaction between knowledgeable parties, less the costs to dispose of the CGU.

The calculations identified above require the use of estimates and assumptions and are subject to changes as new information becomes available. Factors that are subject to change include estimates of future commodity prices, expected production volumes, land values, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related E&E and PP&E assets and CGU's.

Future Accounting Pronouncements

The International Accounting Standards Board issued IFRS 15 *Revenue from Contracts with Customers* in May 2014. This IFRS replaces IAS 18 *Revenue*, IAS 11 *Construction Contracts* and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework which requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. The new standard is effective for periods beginning on or after January 1, 2017, with earlier adoption permitted. The Company is currently evaluating the impact of adopting IFRS 15 on the consolidated financial statements.

In November 2009, the International Accounting Standards Board ("IASB") issued IFRS 9 Financial Instruments to replace IAS 39 Financial Instruments: Recognition and Measurement. The standard was expanded in October 2010 and will be published in three phases, of which two phases have been published. The first phase replaces the current approach to classification and measurement of financial assets and liabilities and uses a model of only two classification categories: fair value or amortized cost. The second phase, amended in 2013 by the IASB, incorporates a new general hedge accounting model which will allow reporting entities more opportunities to apply hedge accounting. The third phase clarifies the use of a single impairment method when evaluating financial instruments. A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer

to completion. Early adoption of phases one and two is permitted only if adopted in their entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the consolidated financial statements.

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

The "Light Oil Netback", "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 Netback measure in this MD&A (including the comparatives thereto) is calculated by subtracting royalties and operating and transportation expenses from petroleum and natural gas sales and midstream revenues received. The Light Oil Netback tables on page 7 and 15 reconcile back to net income in the consolidated financial statements for the 12 and three months ended December 31, 2014 and 2013, respectively. The Light Oil Netback measure allows 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 and reclamation expenditures on the Company's cash flow statement in the consolidated financial statements for the year ended December 31, 2014. The Funds Flow from Operations consists of the Company's Light Oil Netback, 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, respectively. The following table reconciles cash flow from operating activities to Funds Flow from Operations:

	Three months ended		12 months ended	
Year ended ($ Thousands)	**December 31, 2014**	**December 31, 2013**	**December 31, 2014**	**December 31, 2013**
Cash flow from operating activities	$ (8,883)	$ (14,884)	$ 18,177	$ (11,513)
Changes in non-cash working capital	5,931	22,385	(6,619)	6,830
Reclamation expenditures	432	227	1,756	944
Funds Flow from Operations	$ (2,520)	$ 7,728	$ 13,314	$ (3,739)

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 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 Loan 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)	**December 31, 2014**	**December 31, 2013**	**December 31, 2012**
Cash and cash equivalents	$ 531,475	$ 298,995	$ 426,013
Short-term investments	47,618	23,795	536,787
Promissory notes	583,892	-	-
Undrawn credit facilities	125,000	350,000	197,400
Term Loan – delayed draw (US$50.0 million)	58,005	-	-
Available Funding	$ 1,345,990	$ 672,790	$ 1,160,200

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)	December 31, 2014	December 31, 2013	December 31, 2012
Long-term debt	$ 786,649	$ 533,210	$ 529,011
Current liabilities	171,097	201,410	229,617
Current assets	(1,082,301)	(1,619,590)	(1,379,629)
Current portion of derivative asset (included in current assets)	930	-	-
Net Debt	$ (123,625)	$ (884,970)	$ (621,001)

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 ability to repay its liabilities in the short term using available liquidity.

Disclosure Controls and Procedures

Disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under the applicable Canadian securities regulatory requirements. For the year ended December 31, 2014, an evaluation was carried out under the supervision of and with the participation of Athabasca's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer of the Company concluded that the design and operation of the Company's disclosure controls and procedures were effective to ensure that the information required by Canadian securities regulatory authorities, will be recorded, processed, summarized and reported within the prescribed timelines.

Management's Report on Internal Control over Financial Reporting

Management of Athabasca is responsible for establishing and maintaining adequate "internal control over financial reporting" as such term is defined in the applicable Canadian securities regulations. The Company's policies and procedures regarding internal controls over financial reporting were designed by the Company's management, with the oversight of the Chief Executive Officer and the Chief Financial Officer, to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of the Company's financial statements in accordance with IFRS.

The Company has policies and procedures with respect to internal control over financial reporting that:

- pertain to the maintenance of records, to ensure that dispositions of assets and other material transactions involving the Company are accurately and fairly reflected in a reasonable level of detail in the Company's records;
- provide reasonable assurance that transactions are recorded as necessary to ensure that the preparation of the financial statements is done in accordance with IFRS; and
- provide reasonable assurance regarding the timely detection and prevention of unauthorized acquisitions, uses or dispositions of the Company's assets which could have a material impact on the Company and its financial statements.

Athabasca's policies and procedures regarding internal control over financial reporting may not detect or prevent all inaccuracies, omissions or misstatements. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management, including the Chief Executive Officer and Chief Financial Officer, must assess the effectiveness of the Company's internal control over financial reporting as of December 31, 2014, based on *the Internal Control – Integrated Framework* (the "Framework") established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). On May 14, 2013, COSO released an updated version of the Framework, from its original 1992 version release. In making its assessment, Management used the COSO 2013 Framework in order to evaluate the design and effectiveness of internal control over financial reporting in accordance with the transitional requirements. Based upon management's assessment of the effectiveness of the

Company's internal control over financial reporting, the Company has maintained effective internal control over financial reporting as of December 31, 2014.

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 expected timing of commissioning of, and first steam into, Hangingstone Project 1; the expected timing of the first production from Hangingstone Project 1; the anticipated regulatory review/approval process in respect of the Hangingstone Expansion; the timing of completion of construction of the facilities and infrastructure related to the Hangingstone Projects; percentage estimated for deviation from the sanctioned budget for Hangingstone Project 1; the potential withdrawal of the Dover West Sands Project 1 regulatory application; estimated construction timelines for pipelines from the Hangingstone Projects and expected capacity thereof; diluent transportation arrangements and timing; estimated production and production goals in respect of the Company's projects, including the

anticipated production capacity of the Hangingstone Projects with the addition of the Hangingstone Expansion; estimations of production guidance and exit production targets for both the light oil and thermal oil divisions; the estimated quantity of the Company's Proved and Probable Reserves and Contingent Resources; the expected in-situ recovery methods to be utilized in respect of the Company's Thermal Oil projects, including CSS, SAGD and TAGD; the potential for future joint venture opportunities, the receipt of proceeds from the Promissory Notes; forecasted year-end funding in place amounts; the Company's proposed cost streamlining initiatives to align with current operating environment, capital plans and growth profile; the Company's drilling and development plans, including in particular with respect to the Montney and Duvernay formations; the Company's capital expenditure programs and expected future capital expenditures; the timing and number of wells to be tied-in in 2015; the additional information to be obtained from the fourth production cycle of the TAGD Field Test and the utilization of the information in a future TAGD Pilot and Demonstration Project in the Dover West Carbonates, the Company's other plans for, and results of, exploration and development activities with respect to the Thermal Oil and Light Oil assets and the expected benefits to be received by Athabasca from such assets; allocations of capital; the Company's estimated future commitments, including the take or pay commitments associated with the Enbridge and IPPI agreements, office leases, decommissioning obligations and interest payments and repayment of the Notes and the Term Loan; and the Company's business plans.

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; 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.
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
FEED	front end engineering and design
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.