Management's Discussion and Analysis

December 31, 2016

ATHABASCA OIL CORPORATION

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Management's Discussion and Analysis

This Management's Discussion and Analysis of the financial condition and results of operations ("MD&A") of Athabasca Oil Corporation ("Athabasca" or the "Company") is dated March 9, 2017 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2016 and 2015. These financial statements, including the comparative figures, were prepared in accordance with International Financial Reporting Standards ("IFRS"). This MD&A contains forward looking information based on the Company's current expectations and projections. For information on the material factors and assumptions underlying such forward looking information, refer to the "Forward Looking Information" advisory on page 32 of this MD&A. See "Reserves and Resource information" on page 33 for important information regarding the Company's reserves and resource information included in this MD&A. For a listing of abbreviations, refer to "Abbreviations" on page 35 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 9, 2017 ("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 Division

Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs utilizing horizontal drilling and multi-stage hydraulic fracturing technology. Development has been focused in Saxon/Placid ("Greater Placid area") and Kaybob ("Greater Kaybob area") near the town of Fox Creek, Alberta.

Athabasca has a 70% operated working interest in over 65,000 gross acres of Montney lands within the Greater Placid area, of which greater than 30,000 acres are considered commercially prospective, with a potential inventory estimated between 150 - 200[(1)] gross drilling locations. Athabasca also has a 30% non-operated interest in over 200,000 gross acres of commercially prospective Duvernay lands in the Greater Kaybob area with exposure to both liquids-rich gas and volatile oil opportunities and an inventory of approximately 1,500[(1)] gross drilling locations. During the year ended December 31, 2016, the Light Oil Division produced 4,597 boe/d (net) and as at December 31, 2016 had approximately 42 MMboe of Proved plus Probable Reserves (net)[(2)].

Thermal Oil Division

Athabasca's Thermal Oil Division consists of four legacy project areas in the Athabasca region of northeastern Alberta. The primary development focus has been in the Hangingstone area where the Company is currently ramping up its first project, a 12,000 bbl/d SAGD project (the "Hangingstone Project"). The Hangingstone area has Proved plus Probable Reserves bookings of approximately 222 MMbbl[(2)] and 0.6 billion barrels (risked)[(2)] (0.8 billion barrels unrisked)[(2)] of Best Estimate Contingent Resources. During the year ended December 31, 2016, the Thermal Oil Division produced 7,384 bbl/d.

In early 2017, Athabasca completed an acquisition of Canadian oil sands assets from Statoil Canada Ltd. and its wholly-owned affiliate KKD Oil Sands Partnership, both subsidiaries of Statoil ASA (collectively "Statoil"). The acquired assets include the operating Leismer Thermal Oil Project (the "Leismer Project"), the delineated Corner exploration area and related strategic infrastructure (the "Leismer Corner Acquisition"). The Leismer Corner Acquisition enhances the Company's Reserve base by adding 855 MMbbl of Proved plus Probable Reserves[(2)] and 0.5 billion barrels (risked)[(2)] (0.7 billion barrels unrisked)[(2)] of Best Estimate Contingent Resources.

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

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information regarding the Company's drilling locations.
(2) Based on the reports of Athabasca's independent reserve evaluators effective December 31, 2016. Refer to page 33 and the AIF for additional important information about the Company's Reserves and Contingent Resources and Reserves and Contingent Resources acquired as part of the Leismer Corner Acquisition.

FINANCIAL & OPERATIONAL HIGHLIGHTS

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

($ Thousands, except volume, boe and share amounts)	December 31, 2016	December 31, 2015	December 31, 2014
CONSOLIDATED PRODUCTION			
Petroleum and natural gas volumes (boe/d)	11,981	7,560	6,120
LIGHT OIL DIVISION			
Petroleum and natural gas sales volumes (boe/d)	4,597	5,587	6,120
Light Oil Operating Income[1]	$ 23,784	$ 33,928	$ 78,734
Light Oil Operating Netback[1] ($/boe)	$ 14.13	$ 16.63	$ 35.24
Capital expenditures	$ 117,090	$ 175,977	$ 199,938
Recovery of capital-carry through capital expenditures	$ (5,812)	$ —	$ —
THERMAL OIL DIVISION			
Bitumen production (bbl/d)	7,384	1,973	—
Bitumen sales volumes (bbl/d)	7,358	1,526	—
Thermal Oil Operating Loss[1][2]	$ (45,796)	$ (30,200)	$ —
Thermal Oil Operating Netback ($/bbl)[1][2]	$ (17.01)	$ (55.74)	$ —
Capital expenditures	$ 10,945	$ 114,150	$ 416,967
CASH FLOW AND FUNDS FLOW			
Cash flow from operating activities	$ (70,968)	$ (67,826)	$ 18,177
Cash flow from operating activities per share (basic and diluted)	$ (0.17)	$ (0.17)	$ 0.05
Funds Flow from Operations[1]	$ (101,502)	$ (47,003)	$ 23,782
Funds Flow from Operations per share (basic and diluted)[1]	$ (0.25)	$ (0.12)	$ 0.06
NET LOSS AND COMPREHENSIVE LOSS			
Net loss and comprehensive loss	$ (936,734)	$ (696,771)	$ (227,558)
Net loss and comprehensive loss per share (basic and diluted)	$ (2.31)	$ (1.73)	$ (0.57)
SHARES OUTSTANDING			
Weighted average shares outstanding (basic and diluted)	405,621,706	403,214,050	401,512,412
FINANCING AND DIVESTITURES			
Proceeds from sale of assets	$ 702,736	$ 451,788	$ 661,278
Issuance (repayment) of long-term debt	$ (285,441)	$ (2,921)	$ 235,394
Derivative proceeds upon repayment of long-term debt	$ 40,956	$ —	$ —

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

(2) Negative Operating Income and Netback are customary during ramp-up of a SAGD project as revenues from lower initial production are more than offset by operating and transportation costs which are largely fixed in nature regardless of production volumes.

As at ($ Thousands)	December 31, 2016	December 31, 2015	December 31, 2014
BALANCE SHEET ITEMS			
Cash and cash equivalents	$ 650,301	$ 559,487	$ 531,475
Short-term investments	$ —	$ —	$ 47,618
Promissory note(s)	$ —	$ 133,892	$ 583,892
Restricted cash	$ 107,012	$ 3,044	$ 3,000
Capital-carry receivable (current and long-term portion - discounted)	$ 191,174	$ —	$ —
Total assets	$ 2,257,887	$ 3,462,442	$ 4,297,803
Long-term debt (current and long-term portion)[1]	$ 546,209	$ 841,273	$ 789,246
Shareholders’ equity	$ 1,557,097	$ 2,482,140	$ 3,164,186

(1) As at December 31, 2016, the face value of the Company's long-term debt was $550.0 million (December 31, 2015 - $856.8 million, December 31, 2014 - $809.7 million).

HIGHLIGHTS FOR THE YEAR ENDED DECEMBER 31, 2016

- **Consolidated Production** - During the year ended December 31, 2016, the Company's corporate production averaged 11,981 boe/d, in-line with guidance and, compared to 7,560 boe/d during the prior year. Including production from the newly acquired Leismer Project, Athabasca anticipates its consolidated production to average 36,000 - 40,000 boe/d in 2017 (>90% liquids), with a low overall base decline of approximately 7.5%. Athabasca has a fully funded five-year development outlook capable of delivering approximately a 30% per share production CAGR.

- **Light Oil Development** - During the year ended December 31, 2016, Athabasca spent $103.0 million (net) in the Greater Placid area. A 20-well (gross) winter drilling program was commenced during the third quarter, and by the end of the year, 10 of the 20 wells were rig-released with three of the wells completed and brought on stream. An additional eight wells are anticipated to be completed and brought on stream before spring break-up. Placid area infrastructure development was also advanced with the completion of a pipeline network that connects the Company's Placid wells to its regional infrastructure at Saxon and the commencement of construction of a gas battery to accommodate future production growth. Athabasca spent $8.3 million (net of carry) in the Greater Kaybob area primarily to complete and bring on stream a four-well (gross) Duvernay pad. Murphy also commenced the drilling of a two-well pad which is expected to be completed in the first quarter of 2017 and plans to spud 16 Duvernay wells (gross) in 2017.

- **Leismer Corner Acquisition** - On January 31, 2017, Athabasca completed the acquisition of Statoil's Canadian oil sands assets including the operating Leismer Project, the delineated Corner exploration area and related strategic infrastructure. Consideration included $431 million cash (after purchase price adjustments) and 100 million Athabasca common shares. Athabasca also agreed to a series of annual contingent value payments triggered at oil prices above US$65/bbl WTI for a four year term ending in 2020. The payments are capped at $75 million annually and $250 million over the term. The Leismer Corner Acquisition immediately drives a larger cash flow base and accelerates the Company's transition to sustainable free cash flow generation which is expected in 2018 at current strip prices.

- **Hangingstone Project** - During the year ended December 31, 2016, the Hangingstone Project averaged 7,384 bbl/d of bitumen production compared to 1,973 bbl/d during the prior year. Athabasca exited the fourth quarter of 2016 with December average production of 8,670 bbl/d. Athabasca achieved first oil at its Hangingstone Project during the third quarter of 2015 and continues to ramp-up the project toward its design capacity of 12,000 bbl/d.

- **Contingent Bitumen Royalty** - During 2016, the Company raised $307.0 million of cash proceeds by granting a Contingent Bitumen Royalty (the "Royalty") on its legacy Thermal Oil assets. The Royalty is based on a linear-scale of 0% - 12% determined relative to a WCS benchmark price. The trigger for payment of the Royalty is prices of US$60/bbl WCS for Hangingstone and US $70/bbl WCS for each of Dover West, Birch and Grosmont. In early 2017, Athabasca granted an additional Royalty on each of its newly acquired Leismer and Corner assets for an incremental $90.0 million of cash proceeds.

- **Joint Venture with Murphy** - On May 13, 2016, Athabasca closed a strategic joint venture with Murphy Oil Company Ltd. ("Murphy") to develop the Montney and Duvernay formations in the Greater Kaybob and Greater Placid areas. As part of the transaction, Athabasca sold an operated 70% interest in its Greater Kaybob area assets and a non-operated 30% interest in its Greater Placid area assets for gross proceeds of $486.5 million. Consideration included $219.0 million (undiscounted) in the form of a capital-carry in the Greater Kaybob area. The carry supports approximately $1 billion of Duvernay investment over the next four years of which Athabasca's financial exposure is limited to $75 million to retain its 30% working interest.

- **Balance Sheet Refinancing** - In early 2017, Athabasca completed a balance sheet refinancing which is expected to provide multi-year funding certainty, a strong liquidity outlook and allow the Company to advance its strategic objectives and maintain business flexibility. The refinancing, which closed on February 24, 2017, included the issuance of US$450.0 million (C$589.0 million) of Senior Secured Second Lien Notes (due in 2022) (the "New Notes"), the proceeds of which will be used to repay the Company's existing $550.0 million Senior Secured Second Lien Notes (the "Notes"). The Company also replaced its existing $44.5 million Revolving Senior Secured Credit Facility (the "Credit Facility") with a new $120.0 million reserve-based Revolving Senior Secured Credit Facility (the "New Credit Facility").

- **Trans Mountain Pipeline Expansion** - On March 6, 2017, Athabasca acquired firm service on the Trans Mountain Pipeline Expansion (the "TMX Pipeline") by entering into a long-term transportation service agreement with Trans Mountain Pipeline L.P. to deliver up to 20,000 bbl/d of the Company's blended bitumen from Edmonton, Alberta to Burnaby, B.C. The expansion project is federally approved and is expected to be in-service in late 2019. The Company believes securing firm take-away capacity to multiple end markets is essential to its long-term strategy. The TMX Pipeline will provide Athabasca exposure to global oil demand growth.

- **2017 Hedging Program** - During the first quarter of 2017, Athabasca commenced a risk management program designed to protect a base level of cash flow and support its capital plans. Athabasca has currently hedged 12,000 bbl/d at an average WCS price of $52.70/bbl. The Company intends to hedge up to 50% of its corporate production for the remainder of 2017.

ACQUISITION OF ASSETS

Acquisition of Thermal Oil assets

On December 14, 2016, Athabasca entered into agreements with Statoil to acquire its Canadian oil sands assets including the operating Leismer Project, the delineated Corner exploration area and related strategic infrastructure. The Leismer Corner Acquisition had an effective date of January 1, 2017 and was completed on January 31, 2017.

On closing, Athabasca paid Statoil $431.3 million in cash, consisting of the initial purchase price of $435.0 million, net of $3.7 million in purchase price adjustments, and issued 100 million Athabasca common shares which were valued at $166.0 million based on Athabasca's January 31, 2017 closing share price of $1.66/share. Athabasca also agreed to a series of annual contingent value payments triggered at oil prices above US$65/bbl WTI for a four year term ending in 2020. Each annual payment is calculated on one-third of the Leismer Project bitumen production multiplied by an oil price factor (Monthly Average US$WTI/bbl less US$65/bbl, adjusted for inflation). The payments are capped at $75.0 million annually and $250.0 million over the term.

The Leismer Project was commissioned in 2010 and has Proved Reserves(2) in place to support a flat production profile for over 30 years and a Reserve Life Index of approximately 70 years (utilizing Proved plus Probable Reserves). Athabasca intends to maintain a stable production base for the foreseeable future. The Leismer Project and Corner assets have received regulatory approval for future development phases of up to a combined 80,000 bbl/d.

The acquired assets are high quality and resilient to lower commodity prices. The Leismer Project's steam oil ratio (“SOR”) of less than 3.0x ranks it as one of the lowest among operating projects in the basin and operating income break-even is estimated at approximately US$44/bbl WTI(3).

Strategic infrastructure acquired as part of the acquisition includes ownership of dilbit and diluent pipelines from Leismer to the Cheecham Terminal, 300,000 barrels of storage capacity at the Cheecham Terminal and access to multiple sales points with marketing agreements on the Enbridge Waupisoo transportation pipeline.

SALE OF ASSETS

Sale of Light Oil assets to Murphy

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

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

The following table summarizes the net proceeds from the sale of assets to Murphy:

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

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

(2) Refer to “Advisories and Other Guidance” beginning on page 29 for additional information on the Company's Reserves and Resources.
(3) Based on a WCS differential of US$15/bbl and a foreign exchange rate of 0.8 US$/C$.

Sale of Contingent Bitumen Royalty to Burgess

During the year ended December 31, 2016, Athabasca granted a Royalty on its legacy Thermal Oil assets to Burgess Energy Holdings L.L.C. ("Burgess") for gross cash proceeds of $307.0 million. Athabasca will pay Burgess a linear-scale Royalty of 0% - 12%, relative to a WCS benchmark price, applied to Athabasca's realized bitumen price (C$), which is determined net of diluent, transportation and storage costs.

On February 24, 2017, Athabasca granted an additional Royalty to Burgess on its newly acquired Leismer and Corner assets for additional cash proceeds of $90.0 million, bringing the total gross proceeds received by the Company from the sale of the Royalty to $397.0 million.

The Royalty has been structured so that the assets will not be encumbered at lower pricing levels nor is it expected to materially impact the economics of future Leismer or Hangingstone expansion phases or other future Thermal Oil exploration projects. The Royalty has no associated commitments to develop future expansions or projects and Burgess has the option of either receiving the Royalty in cash or in kind.

The following table summarizes the Royalty rates applicable at different WCS benchmark prices:

Hangingstone, Leismer and Corner WCS benchmark price (US$/bbl)	Royalty rate
Below $60/bbl	--
$60/bbl to $139.99/bbl[(1)]	2% - 12%
$140/bbl and above	12%

Dover West, Birch and Grosmont WCS benchmark price (US$/bbl)	Royalty rate
Below $70/bbl	--
$70/bbl to $149.99/bbl[(1)]	2% - 12%
$150/bbl and above	12%

(1) The WCS benchmark price is used to determine the linear sliding-scale royalty rate.

With respect to Hangingstone, Leismer and Corner, the minimum trigger for a 2% Royalty rate is a WCS price of US$60/bbl. Beyond a WCS benchmark price of $140/bbl, the Royalty rate is capped at 12%. For Dover West, Birch and Grosmont, the minimum trigger for a 2% Royalty rate is a WCS price of US$70/bbl. Beyond a WCS benchmark price of $150/bbl, the Royalty rate is capped at 12%.

INDEPENDENT RESERVES AND RESOURCES EVALUATION

The Company's qualified independent reserve evaluators, GLJ Petroleum Consultants Ltd. ("GLJ") and DeGoyler and MacNaughton Canada Limited ("D&M"), completed independent reserve and resource evaluations effective December 31, 2016. Athabasca's light oil, natural gas and natural gas liquids reserves are located in the Greater Placid and Greater Kaybob areas within the Company's Light Oil Division. The Company's bitumen reserves and resources are located in the Hangingstone, Dover West and Birch areas of the Company's Thermal Oil Division. In the first quarter of 2017, Athabasca acquired reserves and resources in the Leismer and Corner areas.

Reserves

At December 31, 2016, the Company had 264 MMbbl of Proved plus Probable Reserves. The following table shows the Company's reserves by division and project area:

	December 31, 2016		December 31, 2015	
Reserves	Proved	Proved plus Probable	Proved	Proved plus Probable
Light Oil Division (MMboe)	20	42	27	65
Hangingstone (MMbbl)	92	222	95	225
Consolidated reserves (MMboe)	112	264	122	290

In the Light Oil Division, Proved plus Probable Reserves decreased by 35% from 65 MMboe to 42 MMBoe for the year ended December 31, 2016. The decrease was primarily due to the sale of 37 MMboe of Proved plus Probable Reserves as part of the Murphy Transaction and production of 2 MMboe of Proved plus Probable Reserves, partially offset by 16 MMboe of Proved plus Probable Reserves booked in the year as a result of continued delineation drilling and development within Greater Placid and Greater Kaybob.

The declines in the Hangingstone Proved and Proved plus Probable Reserves during 2016 were primarily due to production.

The Leismer Corner Acquisition enhances the Company's Reserve base by adding 290 MMbbl of Proved Reserves and 855 MMbbl of Proved plus Probable Reserves. The following table shows the Company's pro forma Reserves as at December 31, 2016, after giving effect to the Leismer Corner Acquisition and as if the Leismer Corner Acquisition was completed on December 31, 2016. Although Athabasca did not acquire the Leismer and Corner assets until January 31, 2017, the information presented below is shown for convenience of reference, on a pro forma basis, effective December 31, 2016:

	December 31, 2016	
Pro forma Reserves[(1)]	**Proved**	**Proved plus Probable**
Light Oil Division (MMboe)	20	42
Hangingstone (MMbbl)	92	222
Leismer (MMbbl)	290	613
Corner (MMbbl)	—	242
Pro forma consolidated reserves (MMboe)	402	1,120

(1) Table may not add due to rounding.

Refer to advisories and other guidance starting on page 29, and the Company's AIF dated March 9, 2017, for further details including in respect of the Company's pro forma reserves attributable to the Leismer Corner Acquisition.

Contingent Resources

As at December 31, 2016, Athabasca had 0.6 billion risked barrels (0.8 billion unrisked barrels) of Best Estimate Contingent Resources in the Hangingstone area which included 0.3 billion barrels of risked Contingent Resources on hold and 0.2 billion barrels of risked pending Contingent Resources. In the Dover West Sands area, Athabasca had 1.6 billion risked barrels (3.0 billion unrisked barrels) of Best Estimate Contingent Resources of which 0.1 billion barrels were risked on hold Contingent Resources and the remainder were unclarified Contingent Resources. In the Birch area, Athabasca had 1.3 billion risked barrels (2.1 billion unrisked barrels) of Best Estimate Contingent Resources, consisting of 1.0 billion barrels of risked on hold and 0.3 billion barrels of risked unclarified Contingent Resources.

As part of the Leismer Corner Acquisition, Athabasca acquired 0.2 billion risked barrels (0.3 billion unrisked barrels) of unclarified Best Estimate Contingent Resources in the Leismer area and 0.3 billion risked barrels (0.4 billion unrisked barrels) of unclarified best Estimate Contingent Resources in the Corner area.

Refer to advisories and other guidance starting on page 29, and the Company's AIF dated March 9, 2017, for further details.

RESULTS OF OPERATIONS

Business Environment

The following table summarizes the key commodity price benchmarks for the years ended December 31, 2016 and 2015:

Year ended (annual average)	December 31, 2016	December 31, 2015	Change
Crude oil:			
West Texas Intermediate (WTI) (US$/bbl)	$ 43.37	$ 48.80	(11)%
West Texas Intermediate (WTI) (C$/bbl)	$ 57.25	$ 62.46	(8)%
Western Canadian Select (WCS) (C$/bbl)	$ 38.94	$ 44.82	(13)%
Edmonton Par (C$/bbl)	$ 52.97	$ 57.11	(7)%
Edmonton Condensate (C5+) (C$/bbl)	$ 55.26	$ 59.17	(7)%
Differential:			
WTI vs. WCS (US$/bbl)	$ (13.87)	$ (13.78)	(1)%
WTI vs. WCS (C$/bbl)	$ (18.31)	$ (17.64)	(4)%
Natural gas:			
NYMEX Henry Hub (US$/MMBtu)	$ 2.46	$ 2.67	(8)%
AECO (C$/GJ)	$ 2.05	$ 2.55	(20)%
Foreign exchange:			
USD : CAD	1.32	1.28	3 %

The price of WTI for crude oil sales at Cushing, Oklahoma is the primary benchmark for crude oil pricing in North America. The price Athabasca receives for its oil production in both its Light Oil and Thermal Oil Divisions is primarily driven by the price of WTI, the foreign exchange rate, transportation costs and quality differentials. For the year ended December 31, 2016, the WTI price declined by 11% compared to the prior year primarily due to continuing global over-supply of petroleum production. The majority of the WTI price decline occurred during the first quarter of 2016.

As North American crude oil prices are primarily set by US benchmark prices, declines in the value of the Canadian dollar relative to the US dollar partially offset the negative impact of declining oil prices. For the year ended December 31, 2016, the value of the Canadian dollar declined relative to the US dollar by 3% compared to the prior year.

The WCS price at Hardisty, Alberta is the primary benchmark for Athabasca's blended bitumen sales. The WCS price trades at a wider differential to the WTI price compared to lighter crude oil products. Compared to the prior year, the Canadian dollar WCS price declined by 13% during the year ended December 31, 2016.

The Edmonton Par price is the primary benchmark for crude oil sales in the Company's Light Oil Division. For the year ended December 31, 2016, the average Edmonton Par price declined by 7% compared to the prior year.

The Edmonton Condensate (C5+) price is the primary benchmark for condensate and natural gas liquids sales in the Company's Light Oil Division. In the Thermal Oil Division, the Edmonton Condensate (C5+) price is the primary benchmark for diluent purchases which Athabasca utilizes in the blending process at its Hangingstone Project in order to deliver produced bitumen to the market. For the year ended December 31, 2016, the average Edmonton Condensate (C5+) price declined 7% compared to 2015.

For the year ended December 31, 2016, the AECO price declined by 20% compared to the prior year. In the Thermal Oil Division, the AECO price is the primary benchmark for natural gas purchases consumed by Athabasca in order to generate steam which is used for the SAGD recovery process. The AECO gas price was also the primary benchmark for Athabasca's natural gas sales in the Light Oil Division during the first nine months of 2015 as Athabasca primarily delivered its sales product on the Alliance pipeline. In the fourth quarter of 2015, Athabasca began delivering sales product on the Fort Chicago pipeline and the average NYMEX gas price became the primary benchmark for natural gas sales in the Light Oil Division. For the year ended December 31, 2016, the average NYMEX price declined by 8% compared to the prior year.

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

Light Oil Division

Operating Results

The following tables summarize the Light Oil operating results for the years ended December 31, 2016 and 2015:

Year ended	December 31, 2016	December 31, 2015
SALES VOLUMES		
Oil (bbl/d)	1,904	2,083
Natural gas (Mcf/d)	13,858	17,178
Natural gas liquids (bbl/d)	383	642
Total (boe/d)	4,597	5,587
Consisting of:		
Greater Placid area (boe/d)	1,827	912
% liquids	50%	45%
Greater Kaybob area (boe/d)	2,770	4,675
% liquids	50%	49%
REALIZED PRICES		
Oil ($/bbl)	$ 47.07	$ 52.24
Natural gas ($/Mcf)	2.03	2.66
Natural gas liquids ($/bbl)	20.03	26.08
Realized price ($/boe)	27.28	30.65
Royalties ($/boe)	(1.07)	(0.58)
Operating and transportation expenses(1) ($/boe)	(12.08)	(13.44)
LIGHT OIL OPERATING NETBACK(2) ($/boe)	$ 14.13	$ 16.63

(1) For the year ended December 31, 2016, operating and transportation expenses include midstream revenues of $0.58/boe (December 31, 2015 - $0.97).
(2) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

Year ended ($ Thousands)	December 31, 2016	December 31, 2015
Petroleum and natural gas sales	$ 45,899	$ 62,547
Midstream revenue	965	1,970
Royalties	(1,792)	(1,189)
Operating and transportation expenses	(21,288)	(29,400)
LIGHT OIL OPERATING INCOME(1)	$ 23,784	$ 33,928

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

During the year ended December 31, 2016, Athabasca's Light Oil production averaged 4,597 boe/d, an 18% reduction compared to the prior year. The lower production was primarily due to the sale of the Light Oil joint venture assets to Murphy on May 13, 2016, partially offset by production from four Duvernay wells brought on stream in the fourth quarter of 2015 and 13 wells (seven Montney, six Duvernay) brought on stream during 2016.

Athabasca's realized price decreased by 11% to $27.28/boe during the year ended December 31, 2016 as compared to the prior year. The decline was primarily due to lower underlying benchmark prices for oil, natural gas and natural gas liquids.

Compared to the same period in the prior year, 2016 operating and transportation expenses per boe decreased by 10% to $12.08/boe. The declines were primarily due to cost saving initiatives, equalizations and lower trucking costs.

Segment Loss

Year ended ($ Thousands)	December 31, 2016	December 31, 2015
Light Oil Operating Income[1]	$ 23,784	$ 33,928
Impairment loss	—	(456,732)
Depletion of oil and gas assets	(28,923)	(57,490)
Depreciation of infrastructure assets	(1,289)	(3,155)
Loss on sale of assets	(4,471)	(1,486)
Exploration expense and other	(54)	(748)
LIGHT OIL SEGMENT LOSS	$ (10,953)	$ (485,683)

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

For the year ended December 31, 2015, Athabasca recognized an impairment loss of $456.7 million as the fair value of the Light Oil assets imputed from the Murphy Transaction was below the carrying value of the assets.

Depletion of oil and gas assets declined by $28.6 million during the year ended December 31, 2016 compared to the prior year. The decline was primarily due to lower production, lower depletion rates resulting from reserve additions and lower average carrying values of property, plant and equipment as a result of the impairment loss incurred during the fourth quarter of 2015.

During the year ended December 31, 2016, Athabasca recognized a loss on sale of assets of $4.5 million primarily relating to closing adjustments and transaction costs associated with the Murphy Transaction. Athabasca recognized a net loss of $1.5 million in 2015 primarily relating to the disposal of non-core acreage and other tangible equipment.

Thermal Oil Division

Operating results

The following tables summarize the Thermal Oil operating results for the years ended December 31, 2016 and 2015:

Year ended	December 31, 2016	December 31, 2015
VOLUMES		
Bitumen production (bbl/d)	7,384	1,973
Bitumen sales (bbl/d)	7,358	1,526
Blended bitumen sales (bbl/d)	10,262	1,956
Bitumen sales consists of:		
Bitumen sales capitalized (bbl/d)	—	42
Bitumen sales recognized in income (bbl/d)	7,358	1,484
	7,358	1,526
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$ 34.67	$ 30.78
Bitumen sales ($/bbl)	$ 23.58	$ 20.12
Royalties ($/bbl)	(0.21)	(0.22)
Operating expenses - non-energy ($/bbl)	(21.23)	(46.57)
Operating expenses - energy ($/bbl)	(6.42)	(14.55)
Transportation and marketing ($/bbl)	(12.73)	(14.52)
THERMAL OIL OPERATING NETBACK[1] ($/bbl)	$ (17.01)	$ (55.74)

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

Year ended ($ Thousands)		December 31, 2016		December 31, 2015
Blended bitumen sales	$	130,211	$	21,301
Cost of diluent		(66,706)		(10,408)
Total bitumen sales		63,505		10,893
Royalties		(565)		(123)
Operating expenses - non-energy		(57,161)		(25,221)
Operating expenses - energy		(17,297)		(7,884)
Transportation and marketing		(34,278)		(7,865)
THERMAL OIL OPERATING LOSS[1]	$	(45,796)	$	(30,200)

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

During the year ended December 31, 2016, the Company averaged 7,384 bbl/d of bitumen production compared to 1,973 bbl/d during the prior year. Athabasca achieved first oil at its Hangingstone Project during the third quarter of 2015 and continues to ramp-up the project toward its design capacity of 12,000 bbl/d which is anticipated in 2018.

On May 5, 2016, Athabasca shut-down the Hangingstone Project for 19 days due to the regional Fort McMurray wildfires. Athabasca resumed operations at the Hangingstone Project near the end of May with production reaching pre-fire levels by mid-June. The fires caused no damage to the facility, field pipelines or well sites. Athabasca has filed an insurance claim for $8.7 million with respect to business interruption losses and other incremental costs sustained as a result of the wildfires and anticipates that the claim will be recovered in 2017. The insurance claim recovery has not been recognized in Athabasca's financial statements for the year ended December 31, 2016.

For the year ended December 31 2016, the Thermal Oil Operating Netback was $(17.01)/bbl as compared to $(55.74)/bbl during the prior year. The improvement in the Thermal Oil Operating Netback was primarily due to higher production volumes and a higher realized price for bitumen blend. Athabasca's realized bitumen price was higher in 2016 despite declines in the lower underlying benchmark prices for oil when compared to the prior year, primarily due to improved quality differentials for Athabasca's blended bitumen in 2016.

Negative Operating Netbacks are customary during ramp-up of a SAGD project as revenues from lower initial production are more than offset by operating and transportation costs which are largely fixed in nature regardless of production volumes.

During the year ended December 31, 2016, no amounts were payable in respect of the Royalty to Burgess.

Segment Loss

Year ended ($ Thousands)		December 31, 2016		December 31, 2015
Thermal Oil Operating Income[1]	$	(45,796)	$	(30,200)
Impairment loss		(751,585)		(180,000)
Depletion of oil and gas assets		(14,834)		(3,522)
Depreciation of infrastructure assets		(14,023)		(4,445)
Exploration expense		(233)		(980)
Loss on sale of assets		—		(164)
THERMAL OIL SEGMENT LOSS	$	(826,471)	$	(219,311)

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

In the fourth quarter of 2016, Athabasca identified indicators of impairment over its Hangingstone assets primarily due to the pending Leismer Corner Acquisition by the Company which implied that the recoverable value of the Hangingstone assets could be below the assets' carrying value. The Company completed an impairment test which resulted in an estimated recoverable value for the Hangingstone assets of approximately $411.4 million, which was below the carrying value of $1,163.0 million. As a result, Athabasca recognized an impairment loss of $751.6 million for the year ended December 31, 2016.

During the year ended December 31, 2015, Athabasca recognized an impairment loss of $180.0 million in the Dover West area.

During the year ended December 31, 2016, depletion and depreciation expense increased to $28.9 million compared to $8.0 million during the same period in the prior year. The increase in depletion and depreciation expense was primarily due to higher production in 2016. In addition, Athabasca recognized a full year of depletion and depreciation in 2016 compared to five months in the prior year as the Hangingstone Project did not become ready for use in the manner intended by management until the third quarter of 2015.

During the year ended December 31, 2016, depletion and depreciation expense was recognized on the pre-impaired carrying value of the Hangingstone Project. Athabasca anticipates that 2017 depletion and depreciation expense will decline by approximately $5/bbl as a result of the 2016 impairment loss.

Corporate Review

General and Administrative ("G&A")

Year ended ($ Thousands)	December 31, 2016	December 31, 2015
Salaries and benefits	$ 21,495	$ 31,867
Office costs	7,331	12,908
Legal, accounting and consulting	4,407	4,205
Stakeholder relations	768	1,174
Capitalized staff costs	(7,780)	(17,625)
TOTAL GENERAL AND ADMINISTRATIVE	$ 26,221	$ 32,529
Capitalization rate	23%	35%

During the year ended December 31, 2016, salaries and benefits declined by $10.4 million compared to the prior year. The decline was primarily due to restructuring activities undertaken by the Company in 2015 to streamline costs and better align the organization's cost structure to the current operating environment, its capital plans and growth objectives.

Compared to the prior year, office costs declined by $5.6 million during the year ended December 31, 2016, primarily due to provisions taken on under-utilized office space in the second quarter of 2015, ongoing cost saving initiatives and sub-lease recoveries.

Capitalized staff costs decreased to 23% of general and administrative expenses during the year ended December 31, 2016, as compared to 35% in the prior year, primarily due to staff reductions, the completion of the Hangingstone Project and a reduction in Thermal Oil capital activities.

Restructuring and Other Charges

There were no restructuring charges recognized during the year ended December 31, 2016. For the year ended December 31, 2015, Athabasca incurred $22.9 million in restructuring and other charges consisting of staff restructuring charges of $11.3 million, $7.0 million relating to lease commitments on vacated office space and net cancellation charges of $4.6 million primarily relating to Thermal Oil rig commitments.

Stock-based Compensation

During the year ended December 31, 2016, stock-based compensation expense increased by 6% compared to the prior year, from $9.5 million to $10.1 million, primarily due to a higher overall average balance of equity-based compensation units and lower capitalization rates from lower Thermal Oil capital activity. The increase in stock-based compensation expense was mostly offset by lower fair values per award on 2016 grants and a lower average balance of units outstanding under the 2010 RSU compensation plan which had carried higher fair values per award relative to the other plans.

Financing and Interest

Year ended ($ Thousands)	December 31, 2016	December 31, 2015
Financing and interest expense on indebtedness	$ 56,223	$ 65,652
Accretion of provisions	7,543	6,667
Amortization of debt issuance costs	13,129	7,404
Capitalized financing and interest	—	(39,686)
TOTAL FINANCING AND INTEREST	$ 76,895	$ 40,037

During the years ended December 31, 2016 and 2015, financing and interest expenses were primarily attributable to three debt instruments held by the Company. Interest expense and amortization of debt issuance costs were incurred on the Company's $550.0 million senior secured second lien notes (the "Notes") which bore interest at a rate of 7.5% per annum, and on the US$225.0 million Term Loan which bore interest at a rate of LIBOR plus 7.25%, subject to a 1% LIBOR floor. Athabasca also incurred standby fees on its credit facilities and the US$50.0 million delayed-draw Term Loan, and incurred issuance fees on issued letters of credit.

During the second quarter of 2016, Athabasca repaid the Term Loan and canceled its US$50.0 million delayed-draw Term Loan. The Company also amended its undrawn Credit Facility which included a reduction of the facility from $125.0 million to $44.5 million. In conjunction with the Credit Facility amendment, all letters of credit issued and outstanding under the Credit Facility were transferred to the Company's new $110.0 million Letter of Credit Facility. As at December 31, 2016, no amounts were drawn under the Credit Facility and $102.9 million of letters of credit were issued under the Letter of Credit facility.

During the year ended December 31, 2016, Athabasca incurred lower financing and interest expense on indebtedness of $9.4 million compared to the prior year. The decrease was primarily due to the repayment of the Term Loan and the cancellation of the delayed-draw Term Loan during the second quarter of 2016. The declines were partially offset by an increase in letters of credit issued during 2016 as well as financing costs relating to the Company's 2016 debt restructuring activities.

During the 12 months ended December 31, 2016, amortization of debt issuance costs increased by $5.7 million compared to the same period in the prior year, primarily due to the acceleration of debt issuance costs to net income upon the repayment of the Term Loan and amendments to the Credit Facility completed during the second quarter of 2016.

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

Interest Income and Other

Year ended ($ Thousands)	December 31, 2016	December 31, 2015
Interest on cash, cash equivalents and short-term investments	$ 6,282	$ 7,243
Interest on promissory notes	1,555	4,864
Accretion of capital-carry receivable	7,967	—
Other	14	409
TOTAL INTEREST INCOME AND OTHER	$ 15,818	$ 12,516

During the year ended December 31, 2016, interest income on cash, cash equivalents, short-term investments and promissory notes decreased by $4.3 million compared to the prior year. The decrease was primarily due to lower average balances of cash, cash equivalents, short-term investments and promissory notes during 2016. Athabasca also earned higher interest income in 2015 due to higher interest rates.

During the year ended December 31, 2016, Athabasca recognized $8.0 million in non-cash interest income from the time value of money accretion on the Company's capital-carry receivable from Murphy.

Foreign Exchange Gain (Loss), Net

Year ended ($ Thousands)	December 31, 2016	December 31, 2015
Unrealized foreign exchange gain (loss)	$ —	$ (49,121)
Realized foreign exchange gain (loss)	19,875	(114)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 19,875	$ (49,235)

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

During the year ended December 31, 2016, Athabasca recognized a net foreign exchange gain primarily due to a realized gain on the loan principal as the average value of the Canadian dollar increased relative to the US dollar by 7% from 1.38:1 to 1.29:1 from the beginning of the year until the date of the repayment of the Term Loan. Athabasca recognized a net foreign exchange loss during the year ended December 31, 2015 primarily due to an unrealized loss on the loan principal as the value of the Canadian dollar declined relative to the US dollar from 1.16:1 to 1.38:1.

Derivative Gain (Loss), Net

Year ended ($ Thousands)	December 31, 2016	December 31, 2015
Unrealized derivative gain (loss)	$ —	$ 49,946
Realized derivative gain (loss)	(21,628)	3,945
DERIVATIVE GAIN (LOSS), NET	$ (21,628)	$ 53,891

Concurrent with the issuance of the US$225.0 million Term Loan in May 2014, Athabasca entered into a three year foreign exchange par forward contract expiring on March 31, 2017. In anticipation of the repayment of the Term Loan, on June 15, 2016, Athabasca unwound its foreign exchange par forward contract and received net cash proceeds of $41.0 million.

During the year ended December 31, 2016, Athabasca recognized a realized derivative loss as the value of the Canadian dollar increased relative to the US dollar by 7% from 1.38:1 to 1.28:1 from the beginning of the year until the date that the foreign exchange par forward contract was settled. Athabasca recognized a net derivative gain during the year ended December 31, 2015 as the value of the Canadian dollar declined relative to the US dollar.

Deferred income tax recovery

As at December 31, 2016 and 2015, Athabasca was in a net unrecognized deferred tax asset position. The deductible temporary differences in excess of taxable temporary differences are approximately $1.3 billion (December 31, 2015 - $0.3 billion). Since Athabasca has not recognized the benefit of these deductible temporary differences, no deferred tax recovery was recognized during the year ended December 31, 2016. The deferred income tax recovery of $108.4 million recognized during the year ended December 31, 2015 was primarily due to non-capital losses incurred largely as a result of impairment losses recognized during the year.

As at December 31, 2016, the Company has approximately $2.2 billion in tax pools, including $1.5 billion in non-capital losses and exploration pools available for immediate deduction against future income. Following the completion of the Leismer Corner Acquisition and the grant of the new Leismer and Corner Royalty in the first quarter of 2017, Athabasca's tax pools increased to approximately $2.7 billion.

CAPITAL EXPENDITURES

Light Oil Division

Year ended ($ Thousands)	December 31, 2016	December 31, 2015
Greater Placid area		
Drilling, completion and equipping	$ 88,650	$ 35,229
Land acquisitions	6,903	1,500
Facilities and project support	7,427	8,347
	102,980	45,076
Greater Kaybob area		
Drilling, completion and equipping	13,731	112,120
Land acquisitions	72	11,665
Facilities and project support	307	7,116
	14,110	130,901
TOTAL LIGHT OIL CAPITAL EXPENDITURES(1)(2)	$ 117,090	$ 175,977
Less: Greater Kaybob capital carry	(5,812)	—
Net cash outflow from Light Oil capital expenditures	$ 111,278	$ 175,977

(1) For the year ended December 31, 2016, capital expenditures included $4.9 million in capitalized staff costs (December 31, 2015 - $7.2 million).
(2) During the year ended December 31, 2016, $10.2 million of Light Oil PP&E expenditures related to assets sold as part of the Murphy Transaction.

Greater Placid area

Following the Murphy Transaction, Athabasca continues to hold an operated 70% interest in the Greater Placid area primarily targeting the development of the Montney formation. Athabasca's Greater Placid assets are supported by jointly-owned regional infrastructure primarily consisting of the pipeline-connected Saxon battery and gas-processing facility.

During the year ended December 31, 2016, Athabasca spent $103.0 million (net) in the Greater Placid area. In the first half of 2016, Athabasca completed three, and brought on stream four, Montney wells (gross) that had been drilled in the prior year. During the third quarter of 2016, Athabasca commenced a 20-well (gross) winter drilling program. By the end of the year, 10 of the 20 wells were rig-released with three of the wells completed and brought on stream. Athabasca anticipates that an additional eight wells will be completed and brought on stream before spring break-up.

In the first quarter of 2016, Athabasca completed construction and commissioning of a pipeline network that connects the Company's Montney wells in the Greater Placid area to its regional infrastructure at Saxon. During the year, Athabasca also commenced construction of a gas battery in the Placid area to accommodate future production growth. The Placid battery has an initial design capacity of 36 mmcf/d of natural gas, will utilize the previously constructed pipeline for sales egress and is expected to be in operation during the first half of 2017. Oil and water production will be pumped to the existing Saxon battery for treating, water disposal and oil delivery into the Pembina pipeline system.

Greater Kaybob area

Following the Murphy Transaction, Athabasca retains a non-operated 30% interest in the Greater Kaybob area primarily targeting the development of the Duvernay formation. Athabasca's Greater Kaybob assets are supported by jointly-owned regional infrastructure primarily consisting of the Kaybob East and Kaybob West batteries and a network of gas pipelines which connect the facilities to two regional third party gas processing plants.

During the year ended December 31, 2016, Athabasca spent $14.1 million (net) in the Greater Kaybob area primarily to complete and bring on stream a four-well (gross) Duvernay pad. Including the recovery of the capital-carry, Athabasca's net cash outflow from capital expenditures in the Greater Kaybob area was $8.3 million during the year ended December 31, 2016. In the fourth quarter of 2016, Murphy commenced the drilling of a two-well pad which is expected to be completed in the first quarter of 2017. The Company also brought two Duvernay wells (gross) on stream that had been drilled and completed in the prior year.

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

Thermal Oil Division

Year ended ($ Thousands)	December 31, 2016	December 31, 2015
Hangingstone Project	$ 6,293	$ 101,237
Hangingstone expansion	1,528	3,738
Other Thermal Oil exploration	3,124	9,175
TOTAL THERMAL OIL CAPITAL EXPENDITURES[(1)]	$ 10,945	$ 114,150

(1) For the year ended December 31, 2016, Thermal Oil capital expenditures include $2.9 million in capitalized staff costs (December 31, 2015 - $10.4 million).

There were minimal capital expenditures in the Thermal Oil Division during the year ended December 31, 2016. During 2015, capital expenditures on the Hangingstone assets primarily related to completing the project and commencing operations.

OUTLOOK

The following tables reflect Athabasca's 2017 capital budget and corporate production guidance which includes the impact of the Leismer Corner Acquisition and refinancing activities completed during the first quarter of 2017:

2017 Capital Budget ($ millions)		Full year
Light Oil Division		
Greater Placid area (Montney)(1)	$	120
Greater Kaybob area (Duvernay)(2)		15
		135
Thermal Oil Division		
Leismer		84
Hangingstone		15
Other thermal		6
		105
Total capital expenditures(3)	$	240

(1) The Greater Placid area capital expenditures reflect Athabasca's 70% working interest.
(2) The Greater Kaybob area capital expenditures reflect Athabasca's 30% working interest, net of anticipated recovery from the capital-carry receivable.
(3) The 2017 capital budget of $240 million excludes capitalized staff costs of $5 million.

2017 Operational & Financial Guidance ($ millions, unless otherwise noted)		Full year
Light Oil (net)		
Production (boe/d)		6,500 - 7,500
Light Oil Operating Income(1)	$	79
Capital expenditures	$	135
Thermal Oil		
Bitumen production (bbl/d)(2)		29,000 - 32,500
Thermal Oil Operating Income(1)	$	104
Capital expenditures	$	105
Corporate		
Production (boe/d)(2)		36,000 - 40,000
Liquids weighting (%)		90%
Funds Flow from Operations(2)	$	93
Commodity assumptions(3)		
WTI (US$/bbl)	$	54.55
Edmonton Par (C$/bbl)	$	67.41
Western Canadian Select (C$/bbl)	$	51.97
AECO Gas (C$/mcf)	$	2.66
FX (US$/C$)		0.76

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.
(2) Production guidance reflects a January 31, 2017 closing date for the Leismer Corner Acquisition with the Leismer Project's volumes reported from February - December 2016.
(3) Commodity assumptions reflects strip pricing as at February 6, 2017.

Light Oil Division

Athabasca's 2017 Light Oil capital budget is $135 million with production guidance of 6,500 - 7,500 boe/d.

In the Greater Placid area, Athabasca currently has two rigs active in the field completing the Company's winter drilling program. A total of 20 wells (gross) are expected to be rig-released before spring breakup and drilling operations are underway on the final two pads. Construction of the Placid infrastructure and battery remains on track to be in-service early in the second quarter of 2017 and is designed to handle near-term production growth.

In the Greater Kaybob area, Murphy and Athabasca have finalized 2017 capital plans which are consistent with the development plan contained in the joint development agreement. Core objectives of the program include near-term production and cash flow growth, delineation across all phase windows, optimizing well design and maximizing land retention. The 2017 program includes the spudding of 16 wells (gross). The program include a mix of pad development locations and delineation wells throughout the volatile oil window.

Thermal Oil Division

Athabasca's 2017 Thermal Oil budget is $105 million with production guidance of 29,000 - 32,500 bbl/d, adjusted for the Leismer Corner Acquisition effective February 1, 2017.

The Company plans to spend $84 million at the Leismer Project primarily relating to production optimization and drilling of sustaining and infill wells. The Company has a well-defined development plan for the mid-term which includes the start-up of four pre-drilled infill wells, additional infill drilling on up to two other production pads and operational readiness to expand an existing pad. Athabasca also plans to spend $15 million at the Hangingstone Project primarily to support ongoing project operations.

Financial Outlook

In the first quarter of 2017, Athabasca completed a comprehensive balance sheet refinancing transaction which included the issuance of the US$450.0 million New Notes, the establishment of the $120.0 million New Credit Facility and the repayment of its existing $550.0 million Notes which is expected to be completed by March 27, 2017.

Athabasca is positioned with multi-year funding certainty and a strong liquidity outlook that will allow the Company to continue to advance its strategic objectives and maintain business flexibility. The Company anticipates sustainable free cash flow generation in 2018 under current strip pricing.

Athabasca has commenced a risk management program designed to protect a base level of cash flow and support its capital plans. The Company intends to hedge a minimum of 20,000 bbl/d for the balance of 2017 with 12,000 bbl/d of WCS hedges already in place at an average price of C$52.70/bbl. Going forward, a multi-year hedging program is expected to form a part of the Company's risk management strategy.

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 in time. The Company expects to achieve this objective through disciplined capital spending, an active commodity risk management program and by maintaining sufficient funds for anticipated short-term spending in cash, cash equivalent and short-term investment accounts.

Funding

As at December 31, 2016, Athabasca had $650.3 million of cash and cash equivalents (excluding restricted cash). Including the completion of the Leismer Corner Acquisition, the grant of the Leismer and Corner Royalty, the issuance of the New Notes and repayment of the existing Notes, Athabasca had cash and cash equivalents of approximately $255 million as at February 28, 2017. The Company also had available credit of approximately $103 million under its New Credit Facility (discussed below) and additional funding available through the capital-carry receivable from Murphy of approximately $206 million (undiscounted).

Balance sheet strength and flexibility continues to remain a key priority for Athabasca. It is anticipated that Athabasca's 2017 Light Oil and Thermal Oil capital and operating activities will be funded through cash flow from operations, the capital-carry receivable and existing cash and cash equivalents. Beyond 2017, the Company anticipates that its operating and capital activities, at current spending levels, will be funded primarily through operating cash flow and the capital-carry receivable. Any significant acceleration of Light Oil development activities or future expansion of the Company's Thermal Oil projects will potentially require additional funding which could include debt, equity, joint ventures or other external financing. The availability of any additional future funding will depend on, among other things, the current commodity price environment, operating performance, the Company's credit rating at the time and the current state of the equity and debt capital markets.

Indebtedness

As at ($ Thousands)		December 31, 2016		December 31, 2015
Senior Secured Second Lien Notes (a)	$	550,000	$	550,000
Senior Secured Term Loan (b)[1]		—		306,759
Debt issuance costs		(21,664)		(31,644)
Amortization of debt issuance costs		17,873		16,158
TOTAL LONG-TERM DEBT	$	546,209	$	841,273
Presented as:				
Current portion of long-term debt	$	546,209	$	3,068
Long-term debt	$	—	$	838,205

(1) The Term Loan was repaid on June 17, 2016. As at December 31, 2015, the US dollar denominated Senior Secured Term Loan of US$221.6 million and associated deferred borrowing costs were translated into Canadian dollars at the period end exchange rate of US$1.00 : C$1.38.

C$550.0 million Senior Secured Second Lien Notes ("Notes")

On November 19, 2012, Athabasca issued the Notes in an aggregate principal amount of $550 million. The Notes bore interest at a rate of 7.50% per annum and had a term of five years maturing on November 19, 2017. Interest payments were required semi-annually on May 19 and November 19 of each year.

On February 9, 2017, Athabasca commenced a cash tender offer for any and all of the outstanding Notes and $439.5 million of Notes were settled on the February 24, 2017 early tender deadline. Any additional Notes tendered under the tender offer will be settled on, or about, March 10, 2017. Any Notes that remain outstanding following completion of the tender offer will be redeemed by the Company on, or about, March 27, 2017.

US$450.0 million Senior Secured Second Lien Notes ("New Notes")

On February 24, 2017, Athabasca issued New Notes in an aggregate principal amount of US$450 million (C$589.0 million). The New Notes bear interest at a rate of 9.875% per annum, payable semi-annually, and have a term of five years maturing on February 24, 2022. Proceeds from the New Notes will be used to refinance the Company's existing Notes and pay related fees and expenses.

The New Notes are not subject to any maintenance or financial covenants and are secured by a second priority lien on substantially all of the assets of Athabasca. Subject to certain exceptions and qualifications, the New Notes contain certain covenants that limit the Company's ability to, among other things: incur additional indebtedness; create or permit liens to exist; and make certain restricted payments, dispositions and transfers of assets. The New Notes also contain certain minimum hedging requirements for 2017 and maximum hedging requirements over the term of the New Notes.

At any time prior to February 24, 2019, Athabasca has the option to redeem the New Notes at the make whole redemption price set forth in the New Notes indenture. On or after February 24, 2019, Athabasca may redeem the New Notes at the following specified redemption prices:

- February 24, 2019 to February 23, 2020 - 104.9% of principal
- February 24, 2020 to February 23, 2021 - 102.5% of principal
- February 24, 2021 to Maturity - 100% of principal

US$225.0 million Senior Secured Term Loans ("Term Loans")

On May 7, 2014, Athabasca entered into a US$225.0 million Term Loan which was fully drawn and a US$50 million committed delayed draw term loan which remained undrawn. The Term Loan amortized in equal quarterly installments in an aggregate annual amount equal to 1.00% of the original principal amount. Borrowings on drawn amounts under the Term Loan bore interest at a floating rate based on LIBOR plus 7.25%, subject to a LIBOR floor of 1.00%. On June 17, 2016, Athabasca repaid the principal outstanding on the Term Loan at par for $285.4 million (US$221.1 million). The delayed draw term loan was also canceled during the second quarter of 2016.

Revolving Senior Secured Credit Facilities

During the second quarter of 2016, Athabasca amended its $125.0 million Credit Facility which included a reduction of the amount of available credit to $44.5 million. In conjunction with the Credit Facility reduction, on June 17, 2016, all letters of credit issued and outstanding under the Credit Facility were transferred to a new Letter of Credit Facility (discussed below) and no letters of credit remained outstanding. During the first quarter of 2017, Athabasca replaced the Credit Facility with the New Credit Facility, a $120.0 million reserve based facility.

The New Credit Facility is a 364 day committed facility available on a revolving basis until February 24, 2018, at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and any amount outstanding would be required to be repaid at the end of the non-revolving term, being February 24, 2019. The New Credit Facility is subject to a semi-annual borrowing base review of the Company's Light Oil and Thermal Oil properties with the first semi-annual review occurring in the second quarter of 2017. The borrowing base of the New Credit Facility will be based on the lender's evaluation of the Company's petroleum and natural gas reserves at the time and their commodity price outlook.

The New Credit Facility is secured by a first priority security interest on all present and after acquired property of the Company and is senior in priority to the New Notes. The New Credit Facility contains certain covenants that limit the Company's ability to, among other things: incur additional indebtedness; create or permit liens to exist; and make certain restricted payments, dispositions and transfers of assets. The New Credit Facility also contains certain minimum hedging requirements in 2017 and maximum hedging requirements over the term of the New Credit Facility.

Amounts borrowed under the New 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 4.50% depending on the type of borrowing and the Company's debt to EBITDA ratio. The Company incurs a standby fee on the undrawn portion of the New Credit Facility of between 0.50% and 1.125% based on the Company's debt to EBITDA ratio.

C$110.0 million Bilateral Cash-Collateralized Letter of Credit Facility

During the second quarter of 2016, Athabasca established a new $110.0 million Letter of Credit Facility with a Canadian bank for issuing letters of credit to counterparties. The facility is available on a demand basis and letters of credit issued under the Letter of Credit Facility bear an issuance fee of 0.25%. Letters of credit issued under the Letter of Credit Facility are used to satisfy certain financial assurance requirements under Athabasca's long-term transportation agreements. Under the terms of the Letter of Credit Facility, Athabasca is required to contribute cash to a cash-collateral account equivalent to 101% of the value of all letters of credit issued under the facility. As at December 31, 2016, Athabasca had $102.9 million in letters of credit issued under the Letter of Credit Facility.

The terms of the Letter of Credit Facility were substantially unchanged following completion of the Company's refinancing activities in the first quarter of 2017.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at December 31, 2016 for the following five years and thereafter:

($ Thousands)	2017	2018	2019	2020	2021	Thereafter	Total
Transportation	$ 51,093	$ 53,322	$ 55,299	$ 54,431	$ 50,835	$ 797,828	$ 1,062,808
Repayment of long-term debt	550,000	—	—	—	—	—	550,000
Interest expense on long-term debt	36,094	—	—	—	—	—	36,094
Office leases	2,452	2,452	2,452	2,452	2,452	9,356	21,616
Purchase commitments and other	14,274	2,976	—	—	—	—	17,250
TOTAL COMMITMENTS	$ 653,913	$ 58,750	$ 57,751	$ 56,883	$ 53,287	$ 807,184	$ 1,687,768

Athabasca filed an insurance claim for $8.7 million with respect to business interruption losses and other incremental costs sustained as a result of the evacuation at Hangingstone due to regional wildfires in the Fort McMurray area during the second quarter of 2016. The likelihood of the recovery of the claim is considered probable. No amounts have been recognized in the consolidated financial statements.

Excluded from the table above is a commitment for $120.0 million of office leases which were assigned to an investment-grade third party in December 2013.

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

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

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

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

During the first quarter of 2017, Athabasca entered into a long-term transportation service agreement with Trans Mountain Pipeline L.P. to deliver up to 20,000 bbl/d of the Company's blended bitumen on the TMX Pipeline. Certain Thermal Oil transportation commitments were also reassigned to Athabasca as part of the Leismer Corner Acquisition. These commitments have not been reflected in the table above.

Credit Risk

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

As at December 31, 2016 and December 31, 2015, Athabasca's cash, cash equivalents and restricted cash were held with five counterparties and four counterparties, respectively. All counterparties were large reputable financial institutions. The Company believes that credit risk associated with these investments is low. At December 31, 2016, no institution held more than 30% of the balances (December 31, 2015 - 32%). Management believes collection risk on the outstanding accounts receivable as at December 31, 2016 is low given the high credit quality of the Company's material counterparties. No material amounts were past due at December 31, 2016.

The capital-carry receivable is considered to have low credit risk given the high credit quality of the Murphy subsidiary that has guaranteed the obligation.

As at December 31, 2016, all of the interest bearing Promissory Notes had matured and were fully collected.

Foreign exchange risk

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

The following tables summarizes the change in the derivative asset during the year ended December 31, 2016 and 2015:

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

During the first quarter of 2017, Athabasca became exposed to foreign currency risk on its US dollar denominated New Notes.

Interest Rate Risk

The Company's exposure to interest rate fluctuations on interest earned on its floating rate cash balance of $757.3 million (December 31, 2015 - $483.7 million), from a 1.00% change in interest rates, would be approximately $7.6 million for a 12 month period (year ended December 31, 2015 - $4.8 million).

Off Balance Sheet Arrangements

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

Equity Instruments

During the year ended December 31, 2016, Athabasca issued 2.2 million common shares in respect of the Company's equity-settled share-based compensation plans.

Outstanding Share Data

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

As at February 28, 2017	
Common shares issued and outstanding	506,644,327
Convertible securities:	
Stock options	8,572,219
Restricted share units (2010 RSU Plan)	4,063,546
Restricted share units (2015 RSU Plan)	6,294,698
Performance share units	2,426,500
Deferred share units	1,132,727

On January 31, 2017, Athabasca issued 100 million common shares to Statoil in respect of the Leismer Corner Acquisition.

For additional information regarding these compensation plans, refer to the consolidated financial statements of the Company for the year ended December 31, 2016.

SUMMARY OF QUARTERLY RESULTS

Light Oil Operating results

The following table summarizes the Light Oil operating results for the three months ended December 31, 2016 and 2015:

Three months ended	December 31, 2016	December 31, 2015
SALES VOLUMES		
Oil (bbl/d)	1,542	2,347
Natural gas (Mcf/d)	9,260	17,664
Natural gas liquids (bbl/d)	252	583
Total (boe/d)	3,337	5,873
Oil and Natural gas liquids %	54%	50%
REALIZED PRICES		
Oil ($/bbl)	$ 57.08	$ 46.23
Natural gas ($/Mcf)	2.88	2.24
Natural gas liquids ($/bbl)	21.38	27.12
Realized price ($/boe)	35.99	27.89
Royalties ($/boe)	(1.84)	2.67
Operating and transportation expenses[1] ($/boe)	(14.11)	(11.06)
LIGHT OIL OPERATING NETBACK[2] ($/boe)	$ 20.04	$ 19.50

(1) For the three months ended December 31, 2016, operating and transportation in the Light Oil Operating Netback includes midstream revenues of $0.40/boe (2015 - $2.03).
(2) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

Three months ended ($ Thousands)	December 31, 2016	December 31, 2015
Petroleum and natural gas sales	$ 11,049	$ 15,085
Midstream revenue	123	1,099
Royalties	(565)	1,440
Operating and transportation expenses	(4,455)	(7,073)
LIGHT OIL OPERATING INCOME[(1)]	$ 6,152	$ 10,551

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

Light Oil production was lower during the fourth quarter of 2016, compared to the fourth quarter of 2015, primarily due to the sale of the Light Oil joint venture assets to Murphy on May 13, 2016, partially offset by production from 13 wells (gross) brought on stream during 2016. The realized oil and gas price increased by 29% during the fourth quarter of 2016, compared to the same period in the prior year, primarily due to higher benchmark commodity prices for oil and natural gas.

Royalties increased during the fourth quarter of 2016, compared to the same period in the prior year, primarily due to prior period gas cost allowance adjustments recognized in 2015. Operating expenses and transportation expenses per boe increased primarily due to higher trucking, disposal and processing fees associated with the start-up of the 7-30 Placid Montney pad which commenced operations during the fourth quarter of 2016.

The following table summarizes the Light Oil Segment income (loss) for the three months ended December 31, 2016 and 2015:

Three months ended ($ Thousands)	December 31, 2016	December 31, 2015
Light Oil Operating Income[(1)]	$ 6,152	$ 10,551
Impairment loss	—	(456,732)
Depletion of oil and gas assets	(3,907)	(11,638)
Depreciation of infrastructure assets	(249)	(690)
Gain (loss) on sale of assets	3,200	(2,319)
Exploration expense and other	(30)	4
LIGHT OIL SEGMENT INCOME (LOSS)	$ 5,166	$ (460,824)

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

In the fourth quarter of 2015, Athabasca recognized an impairment loss of $456.7 million in the Light Oil Division. Depletion and depreciation declined during the fourth quarter of 2016, compared to the same period in the prior year, primarily due to lower production, lower depletion rates resulting from reserve additions and lower average carrying values of property, plant and equipment as a result of impairment losses incurred during the fourth quarter of 2015. The gain on sale of assets for the three months ended December 31, 2016 primarily relates to closing adjustments associated with the Murphy Transaction. The loss on sale of assets incurred during the fourth quarter of 2015 primarily relates to the disposal of non-core acreage and excess capital inventory.

Thermal Oil Operating results

The following table summarizes the Thermal Oil operating results for the three months ended December 31, 2016 and 2015:

Three months ended	December 31, 2016	December 31, 2015
VOLUMES		
Bitumen production (bbl/d)	8,293	5,708
Bitumen sales (bbl/d)	8,015	4,096
Blended bitumen Sales (bbl/d)	11,184	5,243
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$ 43.09	$ 31.38
Bitumen sales ($/bbl)	$ 31.46	$ 21.23
Royalties ($/bbl)	(0.37)	(0.28)
Operating expenses - non-energy ($/bbl)	(18.06)	(42.07)
Operating expenses - energy ($/bbl)	(8.37)	(12.07)
Transportation and marketing ($/bbl)	(11.07)	(15.03)
THERMAL OIL OPERATING NETBACK(1) ($/bbl)	$ (6.41)	$ (48.22)

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

Three months ended ($ Thousands)	December 31, 2016	December 31, 2015
Blended bitumen sales	$ 44,332	$ 15,138
Cost of diluent	(21,131)	(7,137)
Total bitumen sales	23,201	8,001
Royalties	(274)	(105)
Operating expenses - non-energy	(13,315)	(15,853)
Operating expenses - energy	(6,171)	(4,547)
Transportation and marketing	(8,160)	(5,662)
THERMAL OIL OPERATING LOSS(1)	$ (4,719)	$ (18,166)

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

Thermal Oil operating results consist of operating results from the Hangingstone Project which commenced operations during the first quarter of 2015 and achieved first oil during the third quarter of 2015. The Company continues to ramp-up the project which is anticipated to reach targeted production capacity of 12,000 bbl/d in 2018.

The Thermal Oil Operating Netback for the quarter ended December 31, 2016 improved to $(6.41)/bbl compared to $(48.22) during the same period in 2015 primarily due to higher volumes and higher market prices for bitumen blend. The Operating Netback also improved due to lower per barrel transportation and marketing costs as the Company transitioned from trucking to pipeline transportation of bitumen blend during the first quarter of 2016. Negative Operating Netbacks are customary during ramp-up of a SAGD project as revenues from lower initial production are more than offset by operating and transportation costs which are largely fixed in nature regardless of production volumes.

The following table summarizes the Thermal Oil Segment income (loss) for the three months ended December 31, 2016 and 2015:

Three months ended ($ Thousands)	December 31, 2016	December 31, 2015
Thermal Oil Operating Income(1)	$ (4,719)	(18,166)
Impairment loss	(751,585)	(180,000)
Depletion of oil and gas assets	(5,140)	(2,633)
Depreciation of infrastructure assets	(3,636)	(2,810)
Loss on sale of assets	—	(164)
Exploration expense	2	(368)
THERMAL OIL SEGMENT INCOME (LOSS)	$ (765,078)	$ (204,141)

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP Financial Measures.

In the fourth quarter of 2016, Athabasca recognized an impairment loss of $751.6 million relating to the Hangingstone assets as a result of the pending Leismer Corner Acquisition which implied the recoverable value of the Hangingstone assets was below the carrying value. In the fourth quarter of 2015, Athabasca recognized an impairment loss of $180.0 million relating to the Company's Dover West area. Depletion and depreciation relates to production from the Hangingstone Project. The depletion and depreciation expense was higher in the fourth quarter of 2016, compared to the fourth quarter of 2015, primarily due to higher production volumes. The loss on sale of assets incurred during the fourth quarter of 2015 primarily related to the disposal of excess capital inventory.

Results of Operations

The following table summarizes Athabasca's consolidated results of operations for the quarters ended December 31, 2016 and 2015:

Three months ended ($ Thousands)	December 31, 2016	December 31, 2015
LIGHT OIL SEGMENT INCOME (LOSS)	$ 5,166	$ (460,824)
THERMAL OIL SEGMENT INCOME (LOSS)	(765,078)	(204,141)
CORPORATE		
Interest income and other	4,901	2,274
Financing and interest	(13,758)	(20,661)
General and administrative	(7,789)	(7,158)
Restructuring and other charges	—	(4,264)
Stock-based compensation	(3,091)	(851)
Depreciation	(402)	(729)
Foreign exchange gain (loss), net	(6)	(9,892)
Derivative gain (loss), net	—	9,747
Gain (loss) on provisions	652	(2,387)
Deferred income tax recovery	—	94,511
NET LOSS AND COMPREHENSIVE LOSS	$ (779,405)	$ (604,375)

Interest income and other increased in the fourth quarter of 2016, compared to the same quarter in the prior year, primarily due to the time value of money accretion income on the capital-carry receivable in 2016. Financing and interest expense was lower in the fourth quarter of 2016, compared to 2015, primarily due to the repayment of the Term Loan during the second quarter of 2016.

General and administrative costs increased in the fourth quarter of 2016, compared to the same quarter in the prior year, primarily due to lower capitalization rates as a result of staff reductions and lower Thermal Oil capital activity. Stock-based compensation expense increased during the fourth quarter of 2016, compared to the fourth quarter of 2015, primarily due to new equity-based compensation grants in 2016 and higher forfeitures from staff restructuring during the fourth quarter of 2015.

The net foreign exchange loss incurred in the fourth quarter of 2015 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 dollar during the fourth quarter of 2015. 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 gain incurred during the fourth quarter of 2015 primarily relates to unrealized gain as a result of a decline in the value of the Canadian dollar in the fourth quarter of 2015. The Term Loan was repaid and the derivative contract was unwound during the second quarter of 2016.

The gain (loss) on provisions in the fourth quarters of 2016 and 2015 primarily relate to refined estimates of the timing and amount of expected cash inflows used to determine the Company's office lease provision liability. The deferred income tax recovery in the fourth quarter of 2015 primarily relates to net operating losses. As at December 31, 2015 and 2016, Athabasca elected to not recognize deductible temporary differences in respect of income tax assets from non-capital losses and, therefore, deferred income tax recoveries from 2016 operating losses were not recognized in net income during the year.

Capital expenditures

The following table summarizes the capital expenditures of the Company for the quarters ended December 31, 2016 and 2015:

Three months ended ($ Thousands)	December 31, 2016	December 31, 2015
Light Oil Division	$ 62,003	$ 50,921
Thermal Oil Division	4,088	2,257
Corporate assets	48	—
TOTAL CAPITAL EXPENDITURES(1)	$ 66,139	$ 53,178
Less: Greater Kaybob capital carry	$ (52)	$ —
Net cash outflow from Light Oil capital expenditures	$ 66,087	$ 53,178

(1) For the three months ended December 31, 2016, capital expenditures includes capitalized staff costs of $1.9 million (December 31, 2015 - $2.2 million). Excluded are non-cash capitalized costs consisting of capitalized stock-based compensation and decommissioning obligations assets.

For the three months ended December 31, 2016, capital expenditures in the Light Oil Division primarily relate to the 20-well (gross) winter drilling program. By the end of the year, 10 of the 20 Montney wells were rig-released with three of the wells completed and brought on stream. For the three months ended December 31, 2015, capital expenditures in the Light Oil Division primarily relate to drilling and completion activities related to six Duvernay wells in the Greater Kaybob area and three Montney wells in the Greater Placid area.

Minimal capital expenditures were incurred in the Thermal Oil Division during the three months ended December 31, 2016 and 2015 as construction of the Hangingstone Project was completed in the first quarter of 2015.

Quarterly Results

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

	2016				2015			
($ Thousands, except share and per barrel amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	49.29	44.94	45.59	33.45	42.18	46.43	57.94	48.63
WTI (C$/bbl)	65.56	58.87	58.81	45.83	56.52	60.82	71.27	60.30
Western Canadian Select (C$/bbl)	46.61	41.01	41.62	26.30	36.86	43.29	71.24	60.35
Edmonton Par (C$/bbl)	61.59	54.66	54.78	40.67	52.85	56.17	67.63	51.79
Edmonton Condensate (C5+) (C$/bbl)	63.38	55.31	56.80	46.32	54.52	56.94	69.81	55.42
NYMEX Henry Hub (US$/MMBtu)	2.98	2.81	1.95	2.09	2.27	2.80	2.64	2.98
AECO (C$/GJ)	2.93	2.20	1.32	1.74	2.33	2.75	2.53	2.61
Foreign exchange (CAD : USD)	1.33	1.31	1.29	1.37	1.34	1.31	1.23	1.24
LIGHT OIL DIVISION								
Sales volumes (boe/d)	3,337	3,018	5,743	6,319	5,873	5,145	5,459	5,877
Realized price ($/boe)	35.99	29.84	26.93	21.73	27.39	31.34	34.43	29.35
Revenues ($)[2]	10,607	8,091	13,936	12,440	17,624	14,043	17,666	13,981
Light Oil Operating Income ($)[1]	6,152	5,511	7,215	4,908	10,551	6,096	10,689	6,578
Light Oil Operating Netback ($/boe)[1]	20.04	19.85	13.80	8.53	19.50	12.88	21.51	12.46
Capital expenditures ($)	62,003	18,920	5,518	30,658	50,921	31,465	14,959	79,241
Recovery of the capital-carry receivable ($)	(52)	(4,286)	(1,474)	—	—	—	—	—
THERMAL OIL DIVISION								
Bitumen production (bbl/d)[3][4]	8,293	8,830	5,358	7,029	5,708	2,105	—	—
Sales volumes (bbl/d)[3][4]	8,015	9,744	4,463	7,176	4,096	1,792	—	—
Realized bitumen price ($/bbl)	31.46	28.56	24.51	7.27	21.23	17.54	—	—
Revenues ($)[2]	44,058	45,124	19,386	21,076	15,033	6,145	—	—
Thermal Oil Operating Loss ($)[1][4]	(4,719)	(6,088)	(11,915)	(23,074)	(18,166)	(12,146)	—	—
Thermal Oil Operating Netback ($/bbl)[1][4]	(6.41)	(6.80)	(29.33)	(35.34)	(48.22)	(73.67)	—	—
Capital expenditures	4,088	3,754	2,187	916	2,257	9,366	33,118	68,504
OPERATING RESULTS								
Cash Flow from Operations ($)	(19,656)	(18,990)	5,759	(38,017)	(54,496)	(17,933)	8,576	(2,610)
Funds Flow from Operations ($)[1]	(16,867)	(15,778)	(27,304)	(39,982)	(30,141)	(24,223)	5,085	3,162
Net income (loss) ($)	(779,405)	(33,032)	(59,169)	(65,129)	(604,375)	(38,241)	(29,044)	(25,112)
Net income (loss) per share - basic ($)	(1.92)	(0.08)	(0.15)	(0.16)	(1.50)	(0.09)	(0.07)	(0.06)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	650,301	535,477	447,282	493,510	559,487	671,447	582,396	570,290
Short-term investments ($)	—	35,000	25,533	—	—	—	—	92,873
Restricted cash ($)	107,012	103,827	101,652	—	—	—	—	—
Capital-carry receivable ($)[5]	191,174	188,448	188,742	—	—	—	—	—
Promissory notes ($)[5]	—	—	133,892	133,892	133,892	133,892	283,892	283,892
Assets held for sale ($)	—	—	—	466,159	—	—	—	—
Total assets ($)	2,257,887	3,017,285	3,028,938	3,394,367	3,462,442	4,160,344	4,173,704	4,244,486
Long-term debt ($)	546,209	545,126	544,042	820,478	838,205	827,773	807,167	810,758
Shareholders' equity ($)	1,557,097	2,333,523	2,363,396	2,419,651	2,482,140	3,085,499	3,119,224	3,141,453

(1) Refer to "Advisories and Other Guidance" beginning on page 29 for additional information on Non-GAAP financial measures.
(2) Consists of petroleum and natural gas sales and midstream revenues, net of royalties. Excludes interest income and other.
(3) Q3 2015 includes capitalized volumes.
(4) Athabasca capitalized initial operating results of the Hangingstone Project until it was deemed ready for use in the manner intended by management on August 1, 2015. Operating results and sales volumes prior to August 1, 2015 have been capitalized and excluded from the calculation of the Thermal Oil Operating Loss and Netback.
(5) Balances include the current and long-term portions as reported in the consolidated balance sheets.

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

ACCOUNTING POLICIES AND ESTIMATES

During the year ended December 31, 2016, there were no changes to Athabasca's accounting policies or use of estimates in the preparation of the consolidated financial statements and the notes thereto that had a material impact to the consolidated financial statements. During the year ended December 31, 2016, Athabasca's significant accounting policies were as follows:

Segment Reporting

The Company's operating segments are determined based on differences in the nature of 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 primarily in the Greater Kaybob and Greater Placid areas.

- 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 only 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 and financing and interest expense. There were no changes to the Company's operating segments during the year.

Property, Plant and Equipment ("PP&E")

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 exploration and evaluation assets upon the establishment of technical feasibility and commercial viability. Once Athabasca's projects are available for use in the manner intended by management, they will either be depleted or depreciated over their useful lives depending on the nature of the asset. When an asset is disposed of in the PP&E phase, the carrying value of the assets sold are de-recognized from the PP&E asset pool with any difference, relative to the proceeds from the disposal, recognized as a gain or loss in net income.

Light Oil assets that are ready for use in the manner intended by management are depleted using the unit-of-production method based on the production in the year relative to the proved plus probable reserve base, taking into account estimated future development costs necessary to bring those reserves into production. Depreciation of the Light Oil infrastructure assets is calculated using the straight-line method over the estimated useful life of the assets, which ranges from three to fifty years.

During the third quarter of 2015, Athabasca began recognizing depletion and depreciation of the Hangingstone Project. The central processing facilities are depreciated on a unit-of-production basis over the total productive capacity of the facility. The supporting infrastructure is depreciated using a straight-line basis over the estimated useful life of the components. The producing oil sands properties, including estimated future development costs, are depleted using the unit-of-production method based on estimated proved reserves.

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 are initially capitalized and primarily consist of lease acquisition costs, exploratory drilling to delineate resource formations, geological and geophysical costs, engineering, licensing and regulatory fees, carrying charges on non-productive assets, estimates of the reclamation and abandonment obligations incurred as a result of the exploration activities, employee salaries and stock-based compensation directly related to E&E activities. Tangible assets acquired and utilized to develop an E&E asset are also recorded as part of the cost of the E&E asset. When an 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 costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area, and as a result, these costs are expensed directly to the statement of income as they are incurred.

E&E assets are carried at cost on the consolidated balance sheet until both the technical feasibility and commercial viability of extracting a mineral resource is established. Upon technical feasibility and commercial viability being established, E&E assets are tested for impairment and then reclassified from E&E assets to PP&E. Technical feasibility and commercial viability of Light Oil and Thermal Oil activities are considered achieved when proved reserves are determined to exist and the Company has received approval to proceed with commercial development by its Board of Directors and, in some cases, approval from regulatory authorities.

If the technical feasibility and commercial viability cannot be proved or if a full impairment is recognized, subsequent expenditures are no longer capitalized and will be recognized as exploration expense.

Impairment

E&E and PP&E assets are tested for impairment at the cash-generating unit ("CGU") level at each reporting date when facts and circumstances suggest that the carrying amount may exceed 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"). CGUs are not larger than an operating segment. 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.

Athabasca combines E&E and PP&E assets that are in the same CGU together for the purposes of testing for impairment. The Company uses fair value less costs of disposal to calculate the recoverable amount of its CGUs. The recoverable amounts of the CGUs are estimated based on after-tax discounted cash flows from the Company's Proved plus Probable Reserves (Level 3) and/or imputed from relevant sales transactions on assets with similar geologic and geographic characteristics (Level 3). Future cash flows are estimated using an appropriate inflation rate and discount rate based on the nature of the properties included in the CGU and the extent of future funding and development risk.

Impairment test calculations 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 resources, discount rates, recovery rates, timing of anticipated ramp-up of production, and future development and operating costs. Changes in assumptions used in determining the recoverable amount could have a material effect on the carrying value of the related E&E and PP&E assets and CGU's.

At each reporting period, E&E and PP&E assets are tested for impairment reversal at the CGU level when facts and circumstances suggest that the recoverable amount of the CGU may significantly exceed the carrying value due to significant changes in the technological, market, economic or legal environment.

Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

The Company's oil and gas activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provisions are made for the estimated cost of site restoration and capitalized to the corresponding asset. Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the obligation discounted using the Company's credit-adjusted discount rate. Subsequent to initial measurement, the obligation is adjusted at the end of each reporting period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation and changes in discount rates. The increase in the obligation due to the passage of time is recognized as a finance cost whereas changes due to revisions in the estimated future cash flows and discount rate are capitalized to the extent the related asset is not impaired. If the related asset is impaired, the change in estimate is recognized as exploration expense. Actual costs incurred upon settlement of the obligations are charged against the provision.

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"; or "other financial assets or liabilities." The Company has classified its financial instruments as follows:

Financial Assets and Liabilities	Classification
Cash and cash equivalents	Held-for-trading
Restricted cash	Held-for-trading
Derivative asset	Held-for-trading
Accounts receivable	Loans and receivables
Capital-carry receivable	Loans and receivables
Promissory Notes	Held-to-maturity
Accounts payable and accrued liabilities	Other financial liabilities
Long-term debt	Other financial liabilities

Subsequent measurement of 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 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.

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 carrying value of the debt and the debt is subsequently 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 on debt instruments with similar credit risk and yield profiles.

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 various accounts receivables and the capital-carry receivable. The capital-carry receivable has been discounted due to the long-term nature of the instrument in order to reflect its fair value.

Derivative financial instruments are used by the Company to manage risks related to its US dollar denominated debt. All derivatives are 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. As at December 31, 2016, Athabasca held no derivative instruments on the balance sheet.

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.

Significant Accounting Estimates and Judgments

The preparation of the consolidated financial statements requires management to use estimates, judgments and assumptions. These 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.

Included in the carrying value of property, plant and equipment are accumulated depletion, depreciation and impairment charges that are determined, in part, by utilizing estimates based on Athabasca's reserves, resources and land acreage values. The estimates of reserves and resources include estimates of the recoverable volumes of oil, gas and bitumen, future commodity prices and future costs required to develop and produce the assets. Reserve and resource 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, changes in cost estimates and changes to the anticipated timing of project development. 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 discount 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 estimated recoverability of contingent resources, technology uncertainty and the ability to finance exploration and evaluation projects, where technical feasibility and commercial viability has not yet been determined.

The capital-carry receivable includes estimates for the anticipated timing of capital expenditures and the credit-adjusted discount rate. The timing of actual cash inflows could differ from the estimates as a result of changes in the timing of the Greater Kaybob area development plan.

The Company evaluates the carrying value of its inventory at the lower of cost and net realizable value. The net realizable value is estimated based on anticipated current market prices that Athabasca would expect to receive from the sale of its inventory.

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 the office lease is based upon numerous assumptions including inflation factors, credit-adjusted discount rates, actual settlement amounts and estimates of future recoveries. 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 are 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 which may result in a material increase or decrease in the Company's provision for income taxes. As at December 31, 2016 and as at December 31, 2015, Athabasca did not recognize deductible temporary differences in respect of income tax assets.

The Company previously held a derivative financial instrument to manage risks related to its US dollar denominated debt. The fair value of the derivative was determined using valuation models which require assumptions concerning the amount and 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.

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.

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

The "Funds Flow from Operations", "Light Oil Operating Income", "Light Oil Operating Netback", "Thermal Oil Operating Income" and "Thermal Oil Operating Netback" financial measures contained in this MD&A do not have standardized meanings which are prescribed by IFRS and they are considered to be non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS.

The following table reconciles cash flow from operating activities in the consolidated financial statements for the years ended December 31, 2016 and 2015 to Funds Flow from Operations:

Year ended ($ Thousands)		December 31, 2016		December 31, 2015
Cash flow from operating activities	$	(70,968)	$	(67,826)
Receipt of proceeds from derivative unwind		(40,956)		—
Restructuring and other charges, excluding the change in long-term portion of office lease provision		—		20,373
Changes in non-cash working capital		4,577		(3,031)
Settlement of provisions		5,845		3,481
FUNDS FLOW FROM OPERATIONS	$	(101,502)	$	(47,003)

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

The Light Oil Operating Income and Light Oil Operating Netback measures in this MD&A (including the comparatives thereto) are calculated by subtracting royalties and operating and transportation expenses from petroleum and natural gas sales and midstream revenues received. The Light Oil Operating Netback measure is presented on a per boe basis. The Light Oil Operating Income and the Light Oil Operating Netback (per boe) measures allow management and others to evaluate the production results from the Company's Light Oil assets. The table on page 9 reconciles Light Oil Operating Income to *Note 14 - Segmented Information* in the consolidated financial statements for the year ended December 31, 2016.

The Thermal Oil Operating Income and Thermal Oil Operating Netback measures in this MD&A (including the comparatives thereto) are calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation expenses from blended bitumen sales received. The Thermal Oil Operating Netback measure is presented on a per bbl basis. The Thermal Oil Operating Income and the Thermal Oil Operating Netback (per bbl) measures allow management and others to evaluate the production results from the Company's Thermal Oil assets. The table on page 10 reconciles Thermal Oil Operating Income to *Note 14 - Segmented Information* in the consolidated financial statements for the year ended December 31, 2016.

Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P") 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.

Part 1 of NI 52-109 defines DC&P as 'Controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure'.

For the year ended December 31, 2016, 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 DC&P. 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 DC&P 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, 2016, based on *the Internal Control - Integrated Framework* (the "Framework") established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In making its assessment, Management used the COSO 2013 Framework in order to evaluate the design and effectiveness of internal control over financial reporting. Based upon management's assessment, the Company has maintained effective internal control over financial reporting as of December 31, 2016.

Risk Factors

Factors currently influencing the Company's ability to succeed include, but are not limited to, the following:
- the performance of the Company's assets;
- the business strategy, objectives and business strengths of Athabasca;
- Athabasca's growth strategy and opportunities;
- Athabasca's 2017 exploration and development budget and Athabasca's capital expenditure programs;
- future market prices for crude oil, natural gas, condensate and bitumen blend;
- Athabasca's projections of commodity prices, costs and netbacks;
- general economic, market and business conditions in Canada, the United States and globally;
- the substantial capital requirements of Athabasca's projects and the Company's ability to raise capital;
- failure to realize anticipated benefits of acquisitions or divestments, including the Leismer Corner Acquisition;
- Athabasca's plans to submit additional regulatory applications;
- uncertainties inherent in estimating quantities of Proved Reserves, Probable Reserves and Contingent Resources;
- the timing of certain of Athabasca's operations and projects, including the commencement of its planned Thermal Oil division development projects, the exploration and development of Athabasca's Light Oil assets and the levels and timing of anticipated production;
- the timing of the project activities related to the Hangingstone Project and the Hangingstone expansion, included the timing of the ramp-up of Hangingstone Project production to nameplate capacity;
- the potential for future joint venture arrangements;
- insurance risks;
- hedging risks;
- the regulatory framework governing royalties, taxes, environmental matters and foreign investment in the jurisdictions in which Athabasca conducts and will conduct its business;
- actions taken by the new American administration, including the potential renegotiation of the terms of the North American Free Trade Agreement, the withdrawal of the United States from the Trans-Pacific Partnership and the imposition of taxes on the importation of goods into the United States;
- variations in foreign exchange and interest rates;
- dependence upon Murphy as a working interest participant in its Light Oil assets and as operator of the Greater Kaybob assets;
- risks related to the New Credit Facility, the Letter of Credit Facility and the New Notes;
- risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources;
- risks associated with events of force majeure;
- risks related to gathering and processing facilities and pipeline systems;

- Athabasca's drilling plans and plans and results regarding the completion of wells that have been drilled and other exploration and development activities;
- failure to accurately estimate abandonment and reclamation costs;
- the potential for management estimates and assumptions to be inaccurate;
- reliance on third party infrastructure;
- risks associated with establishing and maintaining systems of internal controls;
- expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits;
- aboriginal claims;
- inaccuracy of forward-looking information;
- risks related to the Common Shares.

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

Forward Looking Information

This MD&A contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words "anticipate," "plan," "continue", "estimate", "expect", "may", "will", "project", "target", "should", "believe", "predict", "pursue" and "potential" and similar expressions are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company's current plans, objectives, goals, strategies, estimates, assumptions and projections about the Company's industry, business and future financial results. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this MD&A should not be unduly relied upon. This information speaks only as of the date of this MD&A. In particular, this MD&A may contain forward-looking information pertaining to the following: the Company's five-year growth outlook and that such growth outlook is fully funded; the benefits expected to be realized by the Company from offering of New Notes and the New Credit Facility; the benefits expected to be realized by the Company from the Leismer Corner Acquisition; estimates of sustainable free cash flow generation, cash and cash equivalents and liquidity, for certain future periods; expectations with respect to future production hedging levels; estimates of 2017 corporate, Thermal Oil and Light Oil production levels and base decline rates; estimates of future depletion rates on the Hangingstone Project; estimates of 2017 funds flow from operations, operating income and capital expenditures; the capability of the Company's five-year development outlook to deliver potential growth in per share production; the estimated impact of the Royalty on the economics of future expansion phases and development projects; future drilling and completion plans; the timing for achievement of name plate capacity at the Hangingstone Project the timing of facilities construction and in service dates and the capacity thereof; the timing of completion operations; wells coming on-stream; the Company's expected flexibility in its pace of development; the Company's plans for, and results of, exploration and development activities; the Company's estimated future commitments; Athabasca's continued balance-sheet strength; the Company's business and financing plans and strategies; expectations regarding the 2017 capital budget; the Company's anticipated sources of funding for 2017 and beyond; the Company's estimate future minimum capital commitments; the future allocation of capital; and other matters.

Information relating to "reserves" is also deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

With respect to forward-looking information contained in this MD&A, assumptions have been made regarding, among other things: that Athabasca and its security holders will obtain the anticipated benefits from the New Notes and the New Credit Facility; commodity prices, including for petroleum and natural gas; the regulatory framework governing royalties, taxes and environmental matters in the jurisdiction in which the Company conducts and will conduct business and the effects that such regulatory framework will have on the Company, including on the Company's financial condition and results of operations; the Company's financial and operational flexibility; the Company's financial sustainability; Athabasca's cash flow break-even commodity price; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the applicability of technologies for the recovery and production of the Company's reserves and resources; future capital expenditures to be made by the Company; future sources of funding for the Company's capital programs; the Company's future debt levels; future production levels; the Company's ability to obtain financing and/or enter into joint venture arrangements, on acceptable terms; operating costs; compliance of counterparties with the terms of contractual arrangements; impact of increasing competition; collection risk of outstanding accounts receivable from third parties; geological and engineering estimates in respect of the Company's reserves and resources; recoverability of reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities and the quality of its assets.

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

In addition, information and statements in this MD&A relating to "Reserves" and "Resources" are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future. Certain assumptions related to the Company's Reserves and Resources are contained in the reports of GLJ and D&M evaluating Athabasca's Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2016 (which are respectively referred to herein as the "GLJ Report" and the "D&M" Report").

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

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

Reserves and Resource Information

Both the GLJ Report and the D&M Report were prepared using the assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities,* effective December 31, 2016. There are numerous uncertainties inherent in estimating quantities of bitumen, crude oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. There is no certainty that it will be commercially viable to produce any portion of the resources. Reserves figures described herein have been rounded to the nearest MMbbl or MMboe. Contingent Resources described herein have been rounded to the nearest billion barrels. For additional information regarding the consolidated reserves and resources of the Company as evaluated by GLJ in the GLJ Report and by D&M in the D&M Report, please refer to the Company's AIF that is available on SEDAR at www.sedar.com.

Additionally, the reserves and resources data relating to the Leismer and Corner assets is based on a report prepared by GLJ dated January 5, 2017 reporting the reserves attributable to such assets as at December 31, 2016, and was prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook.

Oil and Gas Information

"Boe" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (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.

Drilling Locations

The 1,500 Duvernay drilling locations referenced on page 1 of this MD&A include: 31 proved undeveloped or non-producing locations and 42 probable undeveloped locations for a total of 73 undeveloped booked locations with the balance being unbooked locations. The 150-200 Montney drilling locations referenced on page 1 of this MD&A include: 34 proved undeveloped and 12 probable undeveloped locations, for a total of 46 undeveloped booked locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by GLJ as of December 31, 2016 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur over the next two decades based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, oil and natural gas prices, provincial fiscal and royalty policies, costs, actual drilling results and additional reservoir information that is obtained and other factors.

Definitions

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

"**Contingent Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "Contingent Resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources may be divided into the following project maturity sub-classes: "Development Pending" is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development); "Development On Hold" is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator; "Development Unclarified" is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined; "Development Not Viable" is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development. As at December 31, 2016, the Company is reporting Contingent Resources on a risked and unrisked basis located in its: Hangingstone asset area in the Development Pending project maturity subclass; and, Hangingstone, Dover West Sands and Birch asset areas for Development On Hold and Development Unclarified project maturity sub-classes.

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

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

"Reserve Life Index" is a measure of the estimated length of time it will take to deplete the Company's oil and gas reserves (typically reported in number of years).

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

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

Abbreviations

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