Management's Discussion and Analysis

December 31, 2018

ATHABASCA OIL CORPORATION

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 6, 2019 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2018 and 2017. 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 "Advisories and Other Guidance" section within this MD&A. Also see the "Advisories and Other Guidance" section within this MD&A for important information regarding the Company's reserves and resource information and abbreviations included in 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 6, 2019 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "ATH".

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ATHABASCA'S STRATEGY

Athabasca is a liquids-weighted intermediate producer with exposure to Canada's most active resource plays (Montney, Duvernay, Oil Sands). The Company offers investors excellent exposure to improving oil prices and is focused on maximizing profitability through prudent capital activity in its Light Oil and Thermal Oil operations. The Company's strategy is guided by:

- Light Oil - Montney at Placid ("Greater Placid") and Duvernay at Kaybob ("Greater Kaybob"): High Margin Liquids Rich Returns
- Thermal Oil: Low Decline Production
- Financial Sustainability: Flexible Capital, Strong Liquidity

The Company's strategy is intended to ensure both its Light Oil and Thermal Oil businesses are financially robust and competitive, with exceptional future growth potential. The Company will continue its strategic emphasis on generating strong margins to maximize shareholder return and generate free cash flow into the future.

HIGHLIGHTS FOR THE YEAR ENDED DECEMBER 31, 2018

Corporate

- 2018 production of 39,203 boe/d, an increase of 11% over the prior year despite planned fourth quarter Thermal Oil production curtailments and the Leismer turnaround in May which, combined, impacted annual production by approximately 2,000 boe/d.
- 2018 Consolidated Operating Income(1) of $94.1 million and 2018 Adjusted Funds Flow(1) of $6.2 million; 2018 financial results were significantly impacted by unprecedented Canadian differential volatility caused by market egress constraints.
- 2018 consolidated operating expenses of $12.17/boe, an 11% reduction year over year.
- Enhanced Company liquidity by approximately $339 million with the closing of the $265 million Leismer infrastructure transaction in early 2019 and other strategic balance sheet optimization activities.
- Strong balance sheet position with funding capacity of approximately $550 million on closing of the Leismer Infrastructure Transaction including $341 million of cash and cash equivalents, $127 million of available credit and letter of credit facilities and an $82 million (undiscounted) capital-carry balance.

Light Oil Division

- Record fourth quarter and full year 2018 production of 12,609 boe/d and 11,280 boe/d, representing growth of 10% and 50% over the comparable prior year periods.
- 2018 Operating Netback(1) of $26.02/boe driven by a high liquids weighting of 51% and low operating expenses of $8.22/boe.
- 2018 Operating Income(1) of $107.1 million, an increase of 68% over the prior year.
- 2018 Capital Expenditures Net of Capital-Carry(1) of $110.1 million with thirty-seven (gross) wells placed on production, including eleven (gross) wells at Greater Placid and twenty-six (gross) wells at Greater Kaybob.

Thermal Oil Division

- 2018 production of 27,923 bbl/d, consistent with the prior year despite the impact of the Thermal Oil production curtailments (November/December) and the Leismer turnaround (May) which impacted the annual average by approximately 2,000 bbl/d.
- 2018 Operating Netback(1) of $1.03/bbl with 2018 operating expenses of $13.75/bbl. Financial results were severely impacted by constrained market egress in western Canada which drove unprecedented WCS differentials and product basis spreads.
- 2018 Operating Income(1) of $10.7 million ($49.1 million at Leismer and $(38.4) million at Hangingstone).
- 2018 capital expenditures of $83.7 million, including the tie-in of four standing infill wells, the Norlite diluent pipeline tie-in, installation of a fifth steam generator, and commencement of Pad 7 drilling operations.

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

FINANCIAL & OPERATIONAL HIGHLIGHTS

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

($ Thousands, unless otherwise noted)[1]	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
CONSOLIDATED				
Petroleum and natural gas production (boe/d)	37,984	42,064	39,203	35,421
Operating Income (Loss)[1][2]	$ (53,180)	$ 65,002	$ 94,118	$ 180,348
Operating Netback[1][2] ($/boe)	$ (14.80)	$ 17.25	$ 6.52	$ 14.06
Capital expenditures[3]	$ 65,399	$ 52,418	$ 276,328	$ 262,048
Capital Expenditures Net of Capital-Carry[1][3]	$ 46,042	$ 33,236	$ 193,980	$ 212,601
LIGHT OIL DIVISION				
Oil, condensate and natural gas liquids production (bbl/d)	6,891	5,856	5,763	4,054
Natural gas production (Mcf/d)	34,309	33,905	33,104	20,890
Petroleum and natural gas production (boe/d)	12,609	11,507	11,280	7,535
Operating Income[1]	$ 22,121	$ 26,696	$ 107,144	$ 63,697
Operating Netback[1] ($/boe)	$ 19.07	$ 25.22	$ 26.02	$ 23.16
Capital expenditures	$ 39,569	$ 40,988	$ 192,495	$ 203,101
Capital Expenditures Net of Capital-Carry[1]	$ 20,212	$ 21,806	$ 110,147	$ 153,654
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	25,375	30,557	27,923	27,886
Operating Income (Loss)[1]	$ (84,544)	$ 45,385	$ 10,669	$ 117,039
Operating Netback[1] ($/bbl)	$ (34.72)	$ 16.75	$ 1.03	$ 11.62
Capital expenditures[3]	$ 25,703	$ 11,368	$ 83,696	$ 56,744
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ (2,253)	$ 37,060	$ 83,844	$ 61,697
per share (basic)	$ —	$ 0.07	$ 0.16	$ 0.12
Adjusted Funds Flow[1]	$ (75,296)	$ 41,808	$ 6,175	$ 102,123
per share (basic)	$ (0.15)	$ 0.08	$ 0.01	$ 0.20
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss	$ (488,479)	$ (209,588)	$ (569,657)	$ (209,407)
per share (basic and diluted)	$ (0.95)	$ (0.41)	$ (1.11)	$ (0.42)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding (basic and diluted)	515,862,850	509,901,413	514,151,731	500,136,092

As at ($ Thousands)	December 31, 2018	December 31, 2017
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 73,898	$ 163,321
Restricted cash	$ 111,056	$ 113,406
Available credit facilities[4]	$ 126,491	$ 61,899
Capital-carry receivable (current and long-term portion - undiscounted)	$ 81,675	$ 164,023
Face value of long-term debt[5]	$ 614,070	$ 563,310

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

(2) Includes realized gain (loss) on commodity risk management contracts of $9.2 million and $(23.7) million for the three months and year ended December 31, 2018, respectively ($(7.1) million and $(0.4) million for the three months and year ended December 31, 2017, respectively).

(3) 2017 capital expenditures excludes the cost of the Leismer Corner Acquisition (see page 10).

(4) Includes available credit under its Credit Facility and Unsecured Letter of Credit Facility (see page 15).

(5) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the December 31, 2018 exchange rate of US$1.00 = C$1.3646.

INDEPENDENT RESERVES AND RESOURCES EVALUATION

The Company's qualified independent reserve evaluators, McDaniel & Associates Consultants Ltd. ("McDaniel"), completed independent reserve and resource evaluations effective December 31, 2018 and 2017. 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 Leismer, Corner, Hangingstone and Dover West areas of the Company's Thermal Oil Division.

Reserves

At December 31, 2018, the Company had 1,279 MMboe of Proved plus Probable Reserves (December 31, 2017 - 1,246 MMboe). The following table shows the Company's reserves by division:

	December 31, 2018			December 31, 2017		
Reserves	Proved Developed Producing	Proved	Proved plus Probable	Proved Developed Producing	Proved	Proved plus Probable
Light Oil Division						
Greater Placid (MMboe)	9	36	50	6	39	50
Greater Kaybob (MMboe)	6	13	24	2	14	27
Total Light Oil Division (MMboe)	15	49	74	8	53	77
Thermal Oil Division						
Leismer (MMbbl)	26	322	675	26	304	657
Corner (MMbbl)	—	—	353	—	—	331
Hangingstone (MMbbl)	37	82	177	38	91	181
Total Thermal Oil Division (MMbbl)	63	404	1,205	64	395	1,169
Consolidated reserves (MMboe)	78	453	1,279	72	448	1,246

In the Light Oil Division, Proved Developed Producing (“PDP”) reserves increased 88% to 15 MMboe as Proved Undeveloped and Probable locations were converted to producing wells.

In the Thermal Oil Division, Proved plus Probable Reserves increased 3% from 1,169 MMbbl to 1,205 MMbbl for the year ended December 31, 2018 despite minimal capital activity in 2018. PDP reserves were consistent year over year as a result of strong production in 2018 driving higher recovery factors.

Contingent Resources

As at December 31, 2018, Athabasca had 0.3 billion risked barrels (0.3 billion unrisked barrels) of Best Estimate Development Pending Contingent Resources in the Leismer area. In the Corner area, Athabasca had 0.4 billion risked barrels (0.5 billion unrisked barrels) of Best Estimate Development Pending Contingent Resources. In the Dover West Sands area, Athabasca had 1.6 billion risked barrels (2.6 billion unrisked barrels) of Best Estimate Development On Hold Contingent Resources.

Refer to the "Advisories and Other Guidance" section within this MD&A and the Company's AIF dated March 6, 2019, for further details relating to Athabasca's reserves and contingent resources.

BUSINESS ENVIRONMENT

The Canadian energy industry was negatively impacted by unprecedented macro conditions in the fourth quarter of 2018. Producers experienced extreme differential and basis spread volatility across both heavy and light product streams due to pipeline capacity constraints. This culminated in Western Canadian Select ("WCS") heavy and Edmonton Light differentials trading to record levels of approximately US$55 and US$35 respectively in the fourth quarter.

In December, the Alberta Government announced mandatory industry production curtailments ("the Industry Curtailments") starting in January 2019 to alleviate the high differential situation until additional egress is added. Athabasca is supportive of these actions and views them as a necessary step to rebalance inventories in the near term and provide a bridge to permanent market access initiatives.

Following the Alberta Government's announcement, the WCS outlook has markedly improved and differentials are expected to be supported by the ramp-up in crude by rail and tightness in the global heavy market.

Athabasca continues to optimize netbacks through financial hedges matched with direct refinery sales. The Company has approximately 40% of its blended Thermal Oil production hedged with apportionment protection for the balance of 2019 at an average differential of approximately US$20.50. The Company has access to 130,000 bbl of storage at Edmonton to manage and optimize product sales. Athabasca has secured long term egress to multiple end markets with 25,000 bbl/d of capacity on TransCanada Keystone XL and 20,000 bbl/d of capacity on the Trans Mountain Expansion Project.

The Company is a net consumer of gas and is a beneficiary of the low Alberta gas pricing environment.

The following table highlights the benchmark prices that are the most relevant to Athabasca's realized pricing. Athabasca's realized pricing will also reflect quality differentials relative to the benchmark prices.

Benchmark prices

	Three months ended December 31,			Year ended December 31,		
(Average)	2018	2017	Change	2018	2017	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 58.81	$ 55.40	6 %	$ 64.77	$ 50.93	27 %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 77.70	$ 70.47	10 %	$ 83.91	$ 66.08	27 %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 25.36	$ 54.87	(54)%	$ 49.66	$ 50.50	(2)%
Edmonton Par (C$/bbl)[3]	$ 42.75	$ 69.02	(38)%	$ 69.36	$ 62.80	10 %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 59.73	$ 73.74	(19)%	$ 78.48	$ 66.45	18 %
WCS Differential:						
WTI vs. WCS (US$/bbl)	$ (39.43)	$ (12.20)	(223)%	$ (26.31)	$ (12.08)	(118)%
WTI vs. WCS (C$/bbl)	$ (52.34)	$ (15.60)	(236)%	$ (34.25)	$ (15.58)	(120)%
Edmonton Par Differential:						
WTI vs. Edmonton Par (US$/bbl)	$ (26.30)	$ (1.05)	(2,405)%	$ (11.12)	$ (2.62)	(324)%
WTI vs. Edmonton Par (C$/bbl)	$ (34.95)	$ (1.45)	(2,310)%	$ (14.55)	$ (3.28)	(344)%
Natural gas:						
AECO (C$/GJ)[5][6]	$ 1.48	$ 1.60	(8)%	$ 1.42	$ 2.04	(30)%
NYMEX Henry Hub (US$/MMBtu)[6]	$ 3.64	$ 2.93	24 %	$ 3.09	$ 3.11	(1)%
Foreign exchange:						
USD : CAD	1.32	1.27	4 %	1.30	1.30	0 %

Primary benchmark for:

(1) Crude oil pricing in North America.
(2) Athabasca's blended bitumen sales.
(3) Crude oil sales in the Company's Light Oil Division.
(4) Condensate sales in the Company's Light Oil Division and for diluent purchases in the Thermal Oil Division.
(5) Natural gas consumed by Athabasca in order to generate steam in the Thermal Oil Division.
(6) Natural gas sales in the Company's Light Oil Division.

OUTLOOK

2019 Operational & Financial Guidance ($ millions, unless otherwise noted)	Full year
Corporate (net)	
Production (boe/d)(1)	37,500 - 40,000
Capital Expenditures Net of Capital-Carry(2)(3)	$95 - $110
Light Oil (net)	
Production (boe/d)	10,000 - 11,000
Capital Expenditures Net of Capital-Carry(2)(3)	$15 - $30
Thermal Oil (net)	
Production (bbl/d)(1)	27,500 - 29,000
Capital expenditures(2)	$80
Adjusted Funds Flow Sensitivity(4)	
US$55 WTI / US$17.50 WCS diff	$110
US$60 WTI / US$17.50 WCS diff	$165
US$65 WTI / US $17.50 WCS diff	$220

(1) The Industry Curtailments are estimated to have up to a 2,000 bbl/d impact on productive capacity through the first quarter of 2019 which equates to approximately 500 bbl/d on an annualized basis. The Company's annual production guidance only incorporates the mandated cuts through the first quarter of 2019.
(2) Excludes capitalized staff costs.
(3) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.
(4) Sensitivity incorporates current hedges, first quarter 2019 strip prices and flat pricing assumptions thereafter (US$10 MSW diffs, US$5 C5 diffs, C$1.50 AECO, 0.75 C$/US$ FX).

Athabasca is reiterating its minimal 2019 capital program with expenditures aligned to forecasted Adjusted Funds Flow and aimed at maintaining base production. Future capital decisions will be evaluated in the context of financial resiliency, corporate Adjusted Funds Flow and external market conditions. The Company has flexibility to direct free cash flow to high returning projects across its portfolio, debt reduction and share buy backs.

The Company has high graded approximately 200 liquids rich Greater Placid Montney (70% operated working interest) locations and is positioned for scalable and flexible development. The completion of a previously drilled multi-well pad (7 gross wells) has been deferred beyond the first half of 2019. Activity in the Greater Kaybob Duvernay (30% non-operated working interest) remains robust with the joint venture partnership planning to execute a 2019 budget of approximately $280 million gross (approximately $20 million net of capital carry). Activity is focused on continued resource delineation in the volatile oil window with an initial emphasis on the Two Creeks area.

At Leismer, the Company recently completed drilling the L7 sustaining pad which included five SAGD well pairs with four observation wells. The Company expects initial steaming to commence this summer with production early in the fourth quarter of 2019. Sustaining operations are expected to support productive capacity of approximately 20,000 bbl/d over the next several years.

With the mandated Industry Curtailments the Company expects the first quarter 2019 Thermal Oil production to average approximately 27,500 bbl/d. The Company anticipates that the financial impact of its curtailed volumes will be more than offset by an expected improvement in realized WCS prices, resulting in a positive impact on its Adjusted Funds Flow for 2019.

Athabasca has taken a number of steps to enhance liquidity to ensure financial resiliency including the closing of the $265 million Leismer infrastructure transaction on January 15, 2019. On closing the Company had funding capacity of $550 million (cash and cash equivalents, available credit facilities and Duvernay capital carry) and liquidity of $468 million (cash & available credit facilities). Athabasca's existing term debt is in place until 2022 with no maintenance covenants. Athabasca also reduced its head office staff by 25% in the fourth quarter of 2018 resulting in forecasted 2019 G&A to be approximately $22 million ($1.50/boe).

CONSOLIDATED RESULTS

For analysis of operating results see the Light Oil Division and Thermal Oil Division sections within this MD&A. For further details related to commodity risk management gains/losses see the Risk Management Contracts section within this MD&A.

Consolidated Operating Results

	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
PRODUCTION				
Oil and condensate (bbl/d)	5,820	4,809	4,714	3,549
Natural gas (Mcf/d)	34,309	33,905	33,104	20,890
Natural gas liquids (bbl/d)	1,071	1,047	1,049	505
Bitumen (bbl/d)	25,375	30,557	27,923	27,886
Total (boe/d)	37,984	42,064	39,203	35,421

($ Thousands, unless otherwise noted)	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
Petroleum and natural gas sales	$ 96,885	$ 238,835	$ 809,637	$ 784,032
Royalties	(2,872)	(3,684)	(18,696)	(11,625)
Cost of diluent	(88,021)	(99,611)	(413,525)	(343,742)
Operating expenses	(46,326)	(43,013)	(175,520)	(175,661)
Transportation and marketing	(22,089)	(20,446)	(84,083)	(72,268)
	$ (62,423)	$ 72,081	$ 117,813	$ 180,736
Realized gain (loss) on commodity risk management contracts	9,243	(7,079)	(23,695)	(388)
Consolidated Operating Income (Loss)(1)	$ (53,180)	$ 65,002	$ 94,118	$ 180,348
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 45.47	$ 69.30	$ 68.02	$ 61.93
Natural gas ($/Mcf)	3.06	2.30	2.78	3.03
Natural gas liquids ($/bbl)	34.89	48.09	47.95	36.81
Blended bitumen sales ($/bbl)	17.19	50.99	43.81	47.38
Realized price (net of cost of diluent) ($/boe)	2.47	36.95	27.46	34.33
Royalties ($/boe)	(0.80)	(0.98)	(1.30)	(0.91)
Operating expenses ($/boe)	(12.89)	(11.42)	(12.17)	(13.70)
Transportation and marketing ($/boe)	(6.15)	(5.42)	(5.83)	(5.63)
	$ (17.37)	$ 19.13	$ 8.16	$ 14.09
Realized gain (loss) on commodity risk management contracts ($/boe)	2.57	(1.88)	(1.64)	(0.03)
CONSOLIDATED OPERATING NETBACK(1) ($/boe)	$ (14.80)	$ 17.25	$ 6.52	$ 14.06

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Consolidated Segments Loss

($ Thousands)	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
Consolidated Operating Income (Loss)(1)	$ (53,180)	$ 65,002	$ 94,118	$ 180,348
Unrealized loss on commodity risk management contracts	(15,623)	(5,836)	(8,155)	(3,548)
Impairment loss	(356,674)	(189,535)	(356,674)	(189,535)
Depletion and depreciation	(39,537)	(38,475)	(160,466)	(113,697)
Acquisition expense	—	—	—	(11,047)
Gain on sale of assets	—	515	—	143
Exploration expense and other	(168)	(14)	(960)	(320)
CONSOLIDATED SEGMENTS LOSS	$ (465,182)	$ (168,343)	$ (432,137)	$ (137,656)

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Consolidated Capital Expenditures

($ Thousands)	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
Light Oil Division	$ 39,569	$ 40,988	$ 192,495	$ 203,101
Thermal Oil Division[1]	25,703	11,368	83,696	56,744
Corporate assets	127	62	137	2,203
TOTAL CAPITAL EXPENDITURES[2]	$ 65,399	$ 52,418	$ 276,328	$ 262,048
Less: Greater Kaybob capital-carry	(19,357)	(19,182)	(82,348)	(49,447)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[3]	$ 46,042	$ 33,236	$ 193,980	$ 212,601

(1) 2017 Thermal Oil capital expenditures in the table above exclude the cost of the Leismer Corner Acquisition (as defined on page 10).
(2) For the three months and year ended December 31, 2018, capital expenditures include $2.7 million and $11.7 million of capitalized staff costs, respectively (December 31, 2017 - $3.2 million, $12.6 million).
(3) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

LIGHT OIL DIVISION

Overview

Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs. Development has been focused on the Montney and Duvernay in the Greater Placid and Greater Kaybob areas near the town of Fox Creek, Alberta.

In Greater Placid, Athabasca has a 70% operated working interest in approximately 80,000 gross Montney acres. An inventory of over 200[1] high-graded gross drilling locations positions the Company for multi-year growth in this area. Athabasca also has a 30% non-operated interest in over 200,000 gross acres of commercially prospective Duvernay lands in Greater Kaybob with exposure to both liquids-rich gas and volatile oil opportunities and an inventory of approximately 1,000[1] gross drilling locations. Athabasca's Light Oil Division assets are supported by jointly-owned regional infrastructure primarily consisting of four batteries and a network of gas pipelines which connect the facilities to two regional third party gas processing plants. As at December 31, 2018, the Light Oil Division had approximately 74 MMboe of Proved plus Probable Reserves[2].

In Greater Kaybob, 75% of Athabasca’s development capital is funded by its joint venture partner Murphy Oil Company Ltd. ("Murphy") under a $219 million (undiscounted) capital-carry commitment which has a maximum period of five years. The carry was designed to support approximately $1 billion of gross Duvernay investment with Athabasca’s financial exposure limited to $75 million to retain its 30% working interest. The capital-carry balance remaining at December 31, 2018 was $81.7 million (undiscounted).

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information regarding the Company's drilling locations.
(2) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2018. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.

Light Oil Operating Results

	Three months ended December 31,		Year ended December 31,	
	2018	2017	2018	2017
PRODUCTION				
Oil and condensate (bbl/d)	5,820	4,809	4,714	3,549
Natural gas (Mcf/d)	34,309	33,905	33,104	20,890
Natural gas liquids (bbl/d)	1,071	1,047	1,049	505
Total (boe/d)	12,609	11,507	11,280	7,535
Consisting of:				
Greater Placid area (boe/d)	7,549	9,556	7,553	5,906
% liquids	51%	48%	46%	52%
Greater Kaybob area (boe/d)	5,060	1,951	3,727	1,629
% liquids	59%	63%	62%	61%

	Three months ended December 31,		Year ended December 31,	
($ Thousands, unless otherwise noted)	2018	2017	2018	2017
Petroleum and natural gas sales	$ 37,434	$ 42,456	$ 169,017	$ 110,121
Royalties	(1,575)	(1,629)	(6,304)	(5,483)
Operating expenses	(8,332)	(7,732)	(33,826)	(25,569)
Transportation and marketing	(5,406)	(6,399)	(21,743)	(15,372)
Light Oil Operating Income(1)	$ 22,121	$ 26,696	$ 107,144	$ 63,697
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 45.47	$ 69.30	$ 68.02	$ 61.93
Natural gas ($/Mcf)	3.06	2.30	2.78	3.03
Natural gas liquids ($/bbl)	34.89	48.09	47.95	36.81
Realized price ($/boe)	32.27	40.10	41.05	40.04
Royalties ($/boe)	(1.36)	(1.54)	(1.53)	(1.99)
Operating expenses ($/boe)	(7.18)	(7.30)	(8.22)	(9.30)
Transportation and marketing ($/boe)	(4.66)	(6.04)	(5.28)	(5.59)
LIGHT OIL OPERATING NETBACK(1) ($/boe)	$ 19.07	$ 25.22	$ 26.02	$ 23.16

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Athabasca's Light Oil production averaged 12,609 boe/d during the fourth quarter of 2018, an increase of 10% compared to the fourth quarter of 2017. During the year ended December 31, 2018 production averaged 11,280 boe/d, an increase of 50%. Production growth year over year was primarily a result of continued development in the Montney at Greater Placid and in the Duvernay at Greater Kaybob.

Athabasca’s Light Oil Operating Netback was $19.07/boe in the fourth quarter of 2018, a 24% decrease from the prior year fourth quarter. The decrease was primarily due to significantly higher Canadian pricing differentials which impacted realized liquids prices, partially offset by higher realized gas prices and lower transportation & marketing expenses. Athabasca's 2018 Light Oil Operating Netback was $26.02/boe, a 12% increase from the prior year, driven by higher realized liquids pricing with stronger WTI prices more than offsetting the higher Canadian differentials. Operating expenses per boe in the 2018 periods have decreased relative to the prior year periods as a result of higher production and a continued emphasis on operational efficiencies including more efficient water disposal solutions.

As a result of higher production and a higher netback, Athabasca generated Light Oil Operating Income of $107.1 million in 2018, a 68% increase over 2017.

Light Oil Segment Income

($ Thousands)	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
Light Oil Operating Income[1]	$ 22,121	$ 26,696	$ 107,144	$ 63,697
Depletion and depreciation	(21,775)	(15,721)	(74,188)	(40,515)
Gain on sale of assets	—	530	—	429
Exploration expense and other	(26)	(9)	(66)	(86)
LIGHT OIL SEGMENT INCOME	$ 320	$ 11,496	$ 32,890	$ 23,525

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Depletion and depreciation increased $6.1 million in the fourth quarter of 2018 and $33.7 million for the year ended December 31, 2018, compared to the same periods in the prior year, primarily due to higher production volumes.

Light Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
Greater Placid				
Drilling, completion and equipping	$ 12,665	$ 12,003	$ 75,651	$ 100,387
Facilities	(399)	4,300	2,187	33,111
Other	1,216	2,088	5,422	7,701
	13,482	18,391	83,260	141,199
Greater Kaybob				
Drilling, completion and equipping	25,539	21,784	100,129	59,610
Facilities	329	636	8,847	1,735
Other	219	177	259	557
	26,087	22,597	109,235	61,902
TOTAL LIGHT OIL CAPITAL EXPENDITURES[1]	$ 39,569	$ 40,988	$ 192,495	$ 203,101
Less: Greater Kaybob capital-carry	(19,357)	(19,182)	(82,348)	(49,447)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[2]	$ 20,212	$ 21,806	$ 110,147	$ 153,654

(1) For the three months and year ended December 31, 2018, capital expenditures include $1.2 million and $5.0 million of capitalized staff costs, respectively (December 31, 2017 - $1.6 million, $6.0 million).
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Including recovery of the capital-carry, Athabasca's net cash outflow from capital expenditures in Greater Kaybob was $6.7 million and $26.9 million for the three months and year ended December 31, 2018, respectively.

The following table summarizes Athabasca's well activity for the three months and years ended December 31, 2018 and 2017:

	Three months ended December 31,				Year ended December 31,			
	2018		2017		2018		2017	
Well activity[1]	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Greater Placid								
Wells drilled	5	3.5	6	4.2	13	9.1	16	11.2
Wells completed	—	—	—	—	11	7.7	17	11.9
Wells brought on production	6	4.2	5	3.5	11	7.7	16	11.2
Greater Kaybob								
Wells drilled	2	0.6	4	1.2	25	7.5	13	3.9
Wells completed	4	1.2	5	1.5	23	6.9	12	3.6
Wells brought on production	5	1.5	4	1.2	26	7.8	11	3.3

(1) Drilling counts are based on rig release date and brought on production counts are based on first production date of in-line test or tie-in to permanent facilities.

THERMAL OIL DIVISION

Overview

Athabasca's Thermal Oil Division consists of two operating oil sands projects and a large resource base of expansion and exploration areas in the Athabasca region of northeastern Alberta.

On January 31, 2017, Athabasca completed the acquisition of Canadian oil sands assets from Statoil Canada Ltd. and its wholly-owned affiliate KKD Oil Sands Partnership, both subsidiaries of Equinor (formally Statoil ASA; collectively "Equinor"). The acquired assets include the operating Leismer Thermal Oil Project (the "Leismer Project"), the delineated Corner lease and related strategic infrastructure (the "Leismer Corner Acquisition"). The acquisition had an effective date of January 1, 2017.

The Leismer Project was commissioned in 2010 and has proven reserves in place to support a flat production profile for over 40 years and a reserve life index of approximately 85 years (proved plus probable). The Leismer Project has Proved plus Probable Reserves of approximately 675 MMbbl(1) and 0.3 billion barrels (risked)(1) (0.3 billion barrels unrisked)(1) of Best Estimate Development Pending Contingent Resources. The Corner lease has Proved plus Probable Reserves of approximately 353 MMbbl(1) and 0.4 billion barrels (risked)(1) (0.5 billion barrels unrisked)(1) of Best Estimate Development Pending Contingent Resources. The Leismer Project and Corner assets have received regulatory approval for future development phases of up to a combined 80,000 bbl/d.

Consideration for the Leismer Corner Acquisition included cash of $435.9 million and the issuance of 100 million common shares which were valued at $166.0 million. Athabasca also agreed to a series of annual contingent payments which are only triggered at oil prices above US$65/bbl WTI for a four year term ending in 2020. Each annual payment is calculated on one-third of the Leismer Project bitumen production multiplied by an oil price factor (yearly average US$WTI/bbl less US$65/bbl, adjusted for inflation). The payments are capped at $75.0 million annually. No amounts were payable by Athabasca in respect of the annual contingent payment obligation for the years ended December 31, 2018 and 2017.

Infrastructure acquired as part of the acquisition included ownership of dilbit and diluent pipelines from Leismer to the Cheecham Terminal and 300,000 barrels of storage capacity at the Cheecham Terminal. On December 10, 2018, Athabasca entered into an agreement with Enbridge Inc. ("Enbridge") for the sale of these assets ("Leismer Infrastructure Transaction") for $265.0 million of cash consideration. The Leismer Infrastructure Transaction was completed on January 15, 2019 and provides Athabasca with priority service on the pipelines and access to the dilbit/diluent tanks with an annual toll of approximately $26.0 million, and a discounted toll for any excess volumes.

Athabasca also operates the Hangingstone Thermal Oil Project (the “Hangingstone Project"). Hangingstone has Proved plus Probable Reserves of approximately 177 MMbbl(1).

Athabasca’s Thermal Oil Division has access to multiple sales points with marketing agreements on the Enbridge Waupisoo transportation pipeline. Athabasca has also secured 20,000 bbl/d of blended bitumen capacity on the Trans Mountain pipeline expansion and 25,000 bbl/d of blended bitumen capacity on the TransCanada Keystone XL pipeline which will provide the Company with long term access to multiple end markets.

Athabasca's other Thermal Oil exploration areas consist of Dover West Leduc Carbonates, Dover West Sands, Birch and Grosmont. Future development targets include oil sands in the McMurray and Wabiskaw formations as well as carbonates in the Leduc formation.

In 2016 and 2017, Athabasca granted Contingent Bitumen Royalties (the "Royalty") on its Thermal Oil assets to Burgess Energy Holdings L.L.C. ("Burgess") for gross cash proceeds of $397.0 million. Under the terms of the Royalty, Athabasca will pay Burgess a linear-scale Royalty of 0% - 12%, relative to WCS benchmark prices ranging from US$60/bbl to US$150/bbl. The Royalty is applied to Athabasca’s realized bitumen price (C$), which is determined net of diluent, transportation and storage costs. The Royalty has no associated commitments to develop future expansions or projects. No amounts have been paid or are currently payable in respect of the Royalty to Burgess.

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2018. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.

Leismer Operating Results

	Three months ended December 31,		Year ended December 31,	
	2018	2017	2018	2017
VOLUMES[1]				
Bitumen production (bbl/d)	17,315	20,991	18,926	18,948
Bitumen sales (bbl/d)	17,196	20,408	19,033	18,776
Blended bitumen sales (bbl/d)	24,113	29,037	26,662	26,563

($ Thousands, unless otherwise noted)	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
Blended bitumen sales	$ 41,490	$ 136,026	$ 425,474	$ 460,033
Cost of diluent	(54,433)	(70,139)	(270,149)	(236,348)
Total bitumen sales	(12,943)	65,887	155,325	223,685
Royalties	(967)	(1,446)	(8,946)	(4,323)
Operating expenses - non-energy	(13,267)	(15,232)	(53,370)	(60,611)
Operating expenses - energy	(6,019)	(5,564)	(22,296)	(23,245)
Transportation and marketing	(5,413)	(4,983)	(21,616)	(19,088)
Leismer Operating Income (Loss)[1][2]	$ (38,609)	$ 38,662	$ 49,097	$ 116,418
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 18.70	$ 50.92	$ 43.72	$ 47.45
Bitumen sales ($/bbl)	$ (8.18)	$ 35.09	$ 22.36	$ 32.64
Royalties ($/bbl)	(0.61)	(0.77)	(1.29)	(0.63)
Operating expenses - non-energy ($/bbl)	(8.39)	(8.11)	(7.68)	(8.84)
Operating expenses - energy ($/bbl)	(3.80)	(2.96)	(3.21)	(3.39)
Transportation and marketing ($/bbl)	(3.42)	(2.65)	(3.11)	(2.79)
LEISMER OPERATING NETBACK[1][2] ($/bbl)	$ (24.40)	$ 20.60	$ 7.07	$ 16.99

(1) The Leismer Project was acquired on January 31, 2017. The table above reflects volumes and Operating Income from February 2017 onwards for the year ended December 31, 2017.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

In the fourth quarter of 2018, Leismer bitumen production averaged 17,315 bbl/d, a decrease of 18% compared to the fourth quarter of 2017. In response to unprecedented WCS differentials in the fourth quarter of 2018, which reached peak levels of US$55/bbl, Athabasca strategically curtailed production in November and December, which impacted fourth quarter production volumes by approximately 2,700 bbl/d. For the year ended December 31, 2018, bitumen production averaged 18,926 bbl/d, consistent with the prior year, despite the impact of the fourth quarter production curtailments and a planned turnaround, which was completed during the second quarter. In aggregate, the production curtailments and turnaround reduced 2018 production by approximately 1,700 bbl/d. This was offset by the start-up of four infill wells in the third quarter, production optimization activities and a full year of production from the Leismer Corner Acquisition which was completed on January 31, 2017.

The Leismer Operating Netback was $(24.40)/bbl during the fourth quarter of 2018 and $7.07/bbl for the year ended December 31, 2018, compared to $20.60/bbl and $16.99/bbl, in the comparable 2017 periods. The decrease in the fourth quarter was primarily due to the extreme WCS differential environment in the last two months of 2018, with differentials increasing 223% from US$12.20/bbl in the fourth quarter of 2017 to US$39.43/bbl in the fourth quarter of 2018. In addition, while the November and December production curtailments had a positive impact on Operating Income (Loss), lower production volumes resulted in higher per bbl operating and transportation costs. The per bbl costs are expected to revert to historical levels with the subsequent increase in production in early 2019. The decrease for the year ended December 31, 2018 was primarily due to lower realized bitumen pricing where the impact of stronger WTI prices was more than offset by the increase in the WCS differential and product basis spreads.

Total operating expenses were $12.19/bbl in the fourth quarter of 2018 and $10.89/bbl for the full year of 2018, an increase of 10% and a decrease of 11%, respectively, from the comparable 2017 periods. The increase on a per bbl basis in the fourth quarter of 2018 was primarily due to lower production due to the curtailment and an increase in power costs. The decrease in full year operating expenses was primarily due to lower non-energy operating expenses with continued efficiency gains and focus on cost management. For energy operating expenses, lower natural gas prices were partially offset by increased power costs.

Full year 2018 Leismer Operating Income was $49.1 million with an Operating Loss of $38.6 million in the fourth quarter.

Seasonality has an impact on the Thermal Oil business. In the first and fourth quarters of a given year, dilution costs will generally increase as more diluent is required to meet pipeline specifications.

Hangingstone Operating Results

	Three months ended December 31,		Year ended December 31,	
	2018	**2017**	**2018**	**2017**
VOLUMES				
Bitumen production (bbl/d)	8,060	9,566	8,997	8,938
Bitumen sales (bbl/d)	9,266	9,039	9,203	8,822
Blended bitumen sales (bbl/d)	13,489	12,827	13,396	12,402

	Three months ended December 31,		Year ended December 31,	
($ Thousands, unless otherwise noted)	**2018**	**2017**	**2018**	**2017**
Blended bitumen sales	$ 17,961	$ 60,353	$ 215,146	$ 213,878
Cost of diluent	(33,588)	(29,472)	(143,376)	(107,394)
Total bitumen sales	(15,627)	30,881	71,770	106,484
Royalties	(330)	(609)	(3,446)	(1,819)
Operating expenses - non-energy	(13,200)	(10,079)	(46,933)	(46,473)
Operating expenses - energy	(5,508)	(4,406)	(19,095)	(19,763)
Transportation and marketing	(11,270)	(9,064)	(40,724)	(37,808)
Hangingstone Operating Income (Loss)[1]	$ (45,935)	$ 6,723	$ (38,428)	$ 621
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 14.47	$ 51.14	$ 44.00	$ 47.25
Bitumen sales ($/bbl)	$ (18.33)	$ 37.13	$ 21.37	$ 33.07
Royalties ($/bbl)	(0.39)	(0.73)	(1.03)	(0.56)
Operating expenses - non-energy ($/bbl)	(15.48)	(12.12)	(13.97)	(14.43)
Operating expenses - energy ($/bbl)	(6.46)	(5.30)	(5.68)	(6.14)
Transportation and marketing ($/bbl)	(13.22)	(10.90)	(12.12)	(11.74)
HANGINGSTONE OPERATING NETBACK[1] ($/bbl)	$ (53.88)	$ 8.08	$ (11.43)	$ 0.20

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

In the fourth quarter of 2018, Hangingstone bitumen production averaged 8,060 bbl/d, a decrease of 16% compared to the fourth quarter of 2017. Consistent with the Leismer asset, production at Hangingstone was strategically curtailed in November and December in response to the extreme WCS differential environment, impacting fourth quarter 2018 production by approximately 1,300 bbl/d. During the year ended December 31, 2018, bitumen production averaged 8,997 bbl/d, an increase of 1% compared to the prior year. Production in 2018 was positively impacted by the continued steam chamber development, however this was offset by the production curtailment in the fourth quarter.

The Hangingstone Operating Netback was $(53.88)/bbl in the fourth quarter of 2018 compared to $8.08/bbl during the same period in 2017. The decrease in the fourth quarter was primarily due to the unprecedented WCS differential environment in the last two months of 2018, with differentials increasing 223% from US$12.20/bbl in the fourth quarter of 2017 to US$39.43/bbl in the fourth quarter of 2018. In addition, while the November and December production curtailments had a positive impact on Operating Income (Loss), lower production volumes resulted in higher per bbl operating and transportation costs. The per bbl costs are expected to revert to historical levels with the subsequent increase in production in early 2019. For the year ended December 31, 2018 the Operating Netback was $(11.43)/bbl compared to $0.20/bbl in 2017. The decrease for the year ended December 31, 2018 was primarily due to lower realized bitumen pricing as stronger WTI prices were more than offset by the increase in the WCS differential and product basis spreads.

Total operating expenses were $21.94/bbl in the fourth quarter of 2018 and $19.65/bbl for the full year of 2018, an increase of 26% and a decrease of 4%, respectively, from the comparable 2017 periods. The increase in the fourth quarter of 2018 was primarily due to lower production, an inventory draw in the quarter and an increase in power costs. The decrease in full year operating expenses was primarily due to lower non-energy operating expenses on a per bbl basis with continued efficiency gains and focus on cost management. For energy operating expenses, lower natural gas prices were partially offset by increased power costs.

The Hangingstone Operating Loss was $45.9 million in the fourth quarter of 2018 and $38.4 million for the full year.

Seasonality has an impact on the Thermal Oil business. In the first and fourth quarters of a given year, dilution costs will generally increase as more diluent is required to meet pipeline specifications.

Consolidated Thermal Oil Operating Results

	Three months ended December 31,		Year ended December 31,	
	2018	**2017**	**2018**	**2017**
VOLUMES				
Bitumen production (bbl/d)	25,375	30,557	27,923	27,886
Bitumen sales (bbl/d)	26,462	29,447	28,236	27,598
Blended bitumen sales (bbl/d)	37,602	41,864	40,058	38,965

($ Thousands, unless otherwise noted)	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
Blended bitumen sales	$ 59,451	$ 196,379	$ 640,620	$ 673,911
Cost of diluent	(88,021)	(99,611)	(413,525)	(343,742)
Total bitumen sales	(28,570)	96,768	227,095	330,169
Royalties	(1,297)	(2,055)	(12,392)	(6,142)
Operating expenses - non-energy	(26,467)	(25,311)	(100,303)	(107,084)
Operating expenses - energy	(11,527)	(9,970)	(41,391)	(43,008)
Transportation and marketing	(16,683)	(14,047)	(62,340)	(56,896)
Thermal Oil Operating Income (Loss)(1)	$ (84,544)	$ 45,385	$ 10,669	$ 117,039
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 17.19	$ 50.99	$ 43.81	$ 47.38
Bitumen sales ($/bbl)	$ (11.74)	$ 35.72	$ 22.03	$ 32.78
Royalties ($/bbl)	(0.53)	(0.76)	(1.20)	(0.61)
Operating expenses - non-energy ($/bbl)	(10.87)	(9.34)	(9.73)	(10.63)
Operating expenses - energy ($/bbl)	(4.73)	(3.68)	(4.02)	(4.27)
Transportation and marketing ($/bbl)	(6.85)	(5.19)	(6.05)	(5.65)
THERMAL OIL OPERATING NETBACK(1) ($/bbl)	$ (34.72)	$ 16.75	$ 1.03	$ 11.62

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Thermal Oil Segment Loss

($ Thousands)	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
Thermal Oil Operating Income (Loss)[1]	$ (84,544)	$ 45,385	$ 10,669	$ 117,039
Impairment loss	(356,674)	(189,535)	(356,674)	(189,535)
Depletion and depreciation	(17,762)	(22,754)	(86,278)	(73,182)
Acquisition expense	—	—	—	(11,047)
Loss on sale of assets	—	(15)	—	(286)
Exploration expenses and other	(142)	(5)	(894)	(234)
THERMAL OIL SEGMENT LOSS	$ (459,122)	$ (166,924)	$ (433,177)	$ (157,245)

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Athabasca recognized an impairment loss of $356.7 million in its fourth quarter consolidated financial statements relating to its Hangingstone and Dover West assets. The current Provincial and Federal regulatory environments have created uncertainty around the timing of new market egress solutions and future environmental compliance (carbon-tax) costs, both of which could impact the economics, capital allocation to and/or expected timing of future expansions or development related to these assets. In the fourth quarter of 2017, Athabasca recognized an impairment loss of $189.5 million related to its Hangingstone and Birch assets.

Depletion and depreciation expense decreased $5.0 million in the fourth quarter of 2018 compared to the same period in the prior year primarily due to the production curtailments at both Leismer and Hangingstone and a decrease in the depletion rate, partially offset by higher depreciation. The increase in depletion and depreciation expense of $13.1 million for the year ended December 31, 2018, compared to the prior year, was primarily due to a higher depletion rate in the first three quarters of 2018 and higher depreciation.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
Leismer Project[1]	$ 22,312	$ 9,544	$ 70,535	$ 35,920
Hangingstone Project	2,897	252	10,148	16,780
Other Thermal Oil exploration	494	1,572	3,013	4,044
TOTAL THERMAL OIL CAPITAL EXPENDITURES[2]	$ 25,703	$ 11,368	$ 83,696	$ 56,744

(1) 2017 Thermal Oil capital expenditures in the table above exclude the cost of the Leismer Corner Acquisition.
(2) For the three months and year ended December 31, 2018, capital expenditures include $1.5 million and $6.7 million of capitalized staff costs, respectively (December 31, 2017 - $1.6 million, $6.6 million).

Thermal Oil capital expenditures for the year ended December 31, 2018 were $83.7 million. At Leismer, activities included the second quarter turnaround, the tie-in of Leismer to the Norlite diluent pipeline, the tie-in of four pre-drilled Pad 5 infill wells which were placed on production in the third quarter, the installation of a fifth steam generator and commencement of drilling Pad 7 SAGD well pairs in the fourth quarter. Capital expenditures in 2018 also included downhole pump conversions and replacements and the installation of tubing-deployed flow control devices at both Leismer and Hangingstone.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

Balance sheet strength and flexibility continues to remain a key priority for Athabasca and the Company's objectives in managing capital are ensuring the Company has sufficient funding to develop its core operating properties and a resilient balance sheet with sufficient liquidity to manage periods of market volatility. The Company expects to achieve this objective by aligning capital expenditures with available funding, a commodity risk management program and by maintaining sufficient funds for anticipated short-term spending in cash, cash equivalent and short-term investment accounts as well as through available credit facilities.

As at December 31, 2018, Athabasca had $73.9 million of unrestricted cash and cash equivalents and additional funding available through the capital-carry receivable from Murphy of $81.7 million (undiscounted). The Company also had its full $120.0 million Credit Facility available and $6.5 million of available credit under its Unsecured Letter of Credit Facility. With completion of the Leismer Infrastructure Transaction on January 15, 2019, an additional $265.0 million was added to unrestricted cash and cash equivalents.

In 2019, it is anticipated that Athabasca's Light Oil and Thermal Oil capital and operating activities will be funded through cash flow from operating activities, the capital-carry receivable, existing cash and cash equivalents, proceeds from the Leismer Infrastructure Transaction and available credit facilities. Beyond 2019, depending on the Company's level of capital spend and the commodity price environment, the Company may require additional funding which could include debt, equity, joint ventures, asset sales 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 and the current availability of the equity and debt capital markets.

Indebtedness

As at ($ Thousands)	December 31, 2018	December 31, 2017
2022 Notes(1)	$ 614,070	$ 563,310
Debt issuance costs	(47,081)	(45,039)
Amortization of debt issuance costs	14,151	7,935
TOTAL LONG-TERM DEBT	$ 581,140	$ 526,206

(1) As at December 31, 2018, the US dollar denominated 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.3646.

Athabasca had the following notes and credit facilities in place as at December 31, 2018:

2022 Notes

On February 24, 2017 Athabasca issued US$450.0 million of Senior Secured Second Lien Notes (the "2022 Notes"). The 2022 Notes bear interest at a rate of 9.875% per annum, payable semi-annually, and mature on February 24, 2022. On or after February 24, 2019, Athabasca may redeem the 2022 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

Credit Facility

In the fourth quarter of 2018, Athabasca renewed its $120.0 million reserve-based credit facility (the "Credit Facility"). The Credit Facility is a 364 day committed facility available on a revolving basis until May 31, 2019, 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 amounts outstanding would be repayable at the end of the non-revolving term, being May 31, 2020. The Credit Facility is subject to a semi-annual borrowing base review, occurring approximately in May and November of each year. The borrowing base is based on the lender's evaluation of the Company's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal, which could result in an increase or a reduction to the Credit Facility.

As at December 31, 2018, amounts borrowed under the Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, LIBOR or bankers' acceptance rate, plus a margin of 2.00% to 3.00%. The Company incurs an issuance fee for letters of credit of 3.00% and a standby fee on the undrawn portion of the Credit Facility of 0.675%. As at December 31, 2018, the Company had no amounts drawn or letters of credit issued and outstanding under the Credit Facility.

Cash-Collateralized Letter of Credit Facility

Athabasca maintains a $110.0 million cash-collateralized letter of credit facility (the "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 primarily used to satisfy 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, 2018, Athabasca had $110.0 million in letters of credit issued and outstanding under the Letter of Credit Facility, as well as $111.1 million in restricted cash related to the Letter of Credit Facility.

Unsecured Letter of Credit Facility

In the fourth quarter of 2018, Athabasca entered into a $25.0 million unsecured letter of credit facility (the "Unsecured Letter of Credit Facility") with a Canadian bank which is supported by a performance security guarantee from Export Development Canada. The facility is available on a demand basis and letters of credit issued under this facility incur an issuance and performance guarantee fee of 2.20%. Letters of credit issued under the Unsecured Letter of Credit Facility support financial assurance requirements under Athabasca's long-term transportation agreements.

Financing and Interest

	Three months ended December 31,		Year ended December 31,	
($ Thousands)	2018	2017	2018	2017
Financing and interest expense on indebtedness	$ 15,129	$ 15,051	$ 60,242	$ 60,411
Amortization of debt issuance costs	2,278	2,489	8,627	12,639
Accretion of provisions	2,957	2,772	11,566	9,757
TOTAL FINANCING AND INTEREST	$ 20,364	$ 20,312	$ 80,435	$ 82,807

During the three months and years ended December 31, 2018 and 2017, financing and interest expenses were primarily attributable to the Company's 2022 Notes. Athabasca also incurred fees related to its Credit Facility, Letter of Credit Facility and Unsecured Letter of Credit Facility.

Foreign Exchange Gain (Loss), Net

	Three months ended December 31,		Year ended December 31,	
($ Thousands)	2018	2017	2018	2017
Unrealized foreign exchange gain (loss)	$ (32,523)	$ (298)	$ (48,729)	$ 23,653
Realized foreign exchange gain (loss)	(759)	(7)	(1,140)	471
FOREIGN EXCHANGE GAIN (LOSS), NET	$ (33,282)	$ (305)	$ (49,869)	$ 24,124

In 2017, Athabasca became exposed to foreign currency risk on the principal and interest components of its US dollar denominated 2022 Notes. The net foreign exchange gains (losses) recognized were primarily due to unrealized gains (losses) on the note principal as the value of the Canadian dollar fluctuates relative to the US dollar.

Risk Management Contracts

Under the Company's commodity risk management program, Athabasca may utilize financial and/or physical delivery contracts to fix the commodity price associated with a portion of its future production in order to manage its exposure to fluctuations in commodity prices. Physical delivery contracts are not considered financial instruments and therefore, no asset or liability is recognized on the consolidated balance sheet. Athabasca is also exposed to foreign exchange risk on the principal and interest components of its US dollar denominated 2022 Notes and has entered into US dollar forward swap contracts to reduce its exposure to foreign currency risk related to its near-term interest payments.

Financial commodity risk management contracts

As at December 31, 2018, Athabasca had the following financial commodity risk management contracts in place:

Instrument	Period	Volume	C$ Average Price/bbl	Implied US$ Average Price/bbl(1)
WTI/WCS fixed price differential swaps	January - March 2019	15,267 bbl/d	$ (27.98)	$ (20.50)
WTI/WCS fixed price differential swaps	April - June 2019	11,000 bbl/d	$ (28.79)	$ (21.10)
WTI/WCS fixed price differential swaps	July - September 2019	11,000 bbl/d	$ (28.91)	$ (21.19)
WTI/WCS fixed price differential swaps	October - December 2019	7,000 bbl/d	$ (30.06)	$ (22.03)

(1) The financial commodity risk management contracts were translated into US dollars at the December 31, 2018 exchange rate of US$1.00 = C$1.3646.

Additional financial commodity risk management activity related to 2019 has taken place subsequent to December 31, 2018, as noted in the table below:

Instrument	Period	Volume	C$ Average Price/bbl	Implied US$ Average Price/bbl[1]
WTI/WCS fixed price differential swaps	January - March 2019	1,033 bbl/d	$ (17.20)	$ (12.60)
WTI/WCS fixed price differential swaps	April - June 2019	7,000 bbl/d	$ (24.21)	$ (17.74)
WTI/WCS fixed price differential swaps	July - September 2019	4,000 bbl/d	$ (26.80)	$ (19.64)
WTI/WCS fixed price differential swaps	October - December 2019	6,000 bbl/d	$ (26.59)	$ (19.49)

(1) The financial commodity risk management contracts were translated into US dollars at the December 31, 2018 exchange rate of US$1.00 = C$1.3646.

The following table summarizes the Company's net loss on commodity risk management contracts for the three months and years ended December 31, 2018 and 2017:

	Three months ended December 31,		Year ended December 31,	
($ Thousands)	2018	2017	2018	2017
Unrealized loss on commodity risk management contracts	$ (15,623)	$ (5,836)	$ (8,155)	$ (3,548)
Realized gain (loss) on commodity risk management contracts	9,243	(7,079)	(23,695)	(388)
LOSS ON COMMODITY RISK MANAGEMENT CONTRACTS (NET)	$ (6,380)	$ (12,915)	$ (31,850)	$ (3,936)

The commodity risk management contracts are valued on the balance sheet by multiplying the contractual volumes by the differential between the anticipated market price (forecasted strip price) and the contractual fixed price at each future settlement date. The corresponding change in the asset or liability is recognized as an unrealized gain or loss in net income (loss). As the commodity derivatives are unwound (i.e. settled in cash), Athabasca recognizes a corresponding realized gain or loss in net income (loss).

Foreign exchange contracts

As at December 31, 2018, Athabasca had the following foreign exchange risk management contract in place to reduce its exposure to foreign currency risk on its February 2019 interest payment associated with the 2022 Notes.

Instrument	Period	Amount (US$)	Exchange rate (USD/CAD)
Forward swap contract	February 2019	$ 22,219	$ 1.2505

An additional foreign exchange risk management contract was entered into related to the August 2019 interest payment subsequent to December 31, 2018, as noted in the table below:

Instrument	Period	Amount (US$)	Exchange rate (USD/CAD)
Forward swap contract	August 2019	$ 22,219	$ 1.3250

The following table summarizes the net gain on foreign exchange risk management contracts for the three months and years ended December 31, 2018 and 2017:

	Three months ended December 31,		Year ended December 31,	
	2018	2017	2018	2017
Unrealized gain on foreign exchange risk management contracts	$ 1,669	$ —	$ 2,495	$ —
Realized gain on foreign exchange risk management contracts	—	—	1,071	—
GAIN ON FOREIGN EXCHANGE RISK MANAGEMENT CONTRACTS (NET)	$ 1,669	$ —	$ 3,566	$ —

The net gains on foreign exchange risk management contracts are due to fluctuations in the USD/CAD forward exchange rates and the settlement of the August 2018 contract.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at December 31, 2018 for the following five years and thereafter:

($ Thousands)	2019	2020	2021	2022	2023	Thereafter	Total
Transportation and processing[1]	$ 91,924	$ 92,995	$ 116,741	$ 151,180	$ 192,996	$ 3,102,349	$ 3,748,185
Repayment of long-term debt[1]	—	—	—	614,070	—	—	614,070
Interest expense on long-term debt[1]	60,639	60,639	60,639	30,404	—	—	212,321
Office leases	2,909	2,909	2,909	2,909	2,909	3,149	17,694
Purchase commitments and drilling rigs	3,120	—	—	—	—	—	3,120
TOTAL COMMITMENTS	$ 158,592	$ 156,543	$ 180,289	$ 798,563	$ 195,905	$ 3,105,498	$ 4,595,390

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the December 31, 2018 exchange rate of US$1.00 = C$1.3646.

The Company is, from time to time, involved in claims arising in the normal course of business. The Company is also currently undergoing income tax and partner related audits in the normal course of business. The final outcome of such claims and audits cannot be predicted with certainty, however, management believes that it has appropriately assessed any impact to the consolidated financial statements.

Credit Risk

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

As at December 31, 2018 and December 31, 2017, Athabasca's cash, cash equivalents and restricted cash were held with five counterparties. All counterparties were large reputable financial institutions. The Company believes that credit risk associated with these investments is low. Management believes collection risk on the outstanding accounts receivable as at December 31, 2018 is low given the high credit quality of the Company's material counterparties. No material amounts were past due at December 31, 2018. 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, 2018, Athabasca's risk management contracts were held with three counterparties, all of which were large reputable financial institutions. The Company believes that credit risk associated with risk management contracts is low.

Interest Rate Risk

The Company's exposure to interest rate fluctuations on interest earned on its floating rate cash balance of $185.0 million (December 31, 2017 - $276.7 million), from a 1.0% change in interest rates, would be approximately $1.8 million for a 12 month period (year ended December 31, 2017 - $2.8 million). The 2022 Notes are subject to a fixed interest rate of 9.875% per annum and are not exposed to changes in interest rates.

Other Corporate Items

General and Administrative ("G&A")

	Three months ended December 31,		Year ended December 31,	
($ Thousands, unless otherwise noted)	2018	2017	2018	2017
TOTAL GENERAL AND ADMINISTRATIVE	$ 6,975	$ 9,039	$ 29,962	$ 29,168
G&A per boe	$ 2.00	$ 2.34	$ 2.09	$ 2.26

During the three months ended December 31, 2018, Athabasca's G&A expenses decreased compared to the same period in the prior year primarily due to lower employee costs. During the year ended December 31, 2018, G&A expenses increased compared to the prior year primarily due to higher professional fees and lower capitalized costs offsetting lower employee costs. G&A per boe decreased 15% and 8% in the three months and year ended December 31, 2018, compared to the same periods in the prior year, primarily due to production growth year over year and a continued emphasis on cost optimization across the Company.

In the fourth quarter of 2018, Athabasca incurred staff restructuring charges of $3.6 million (December 31, 2017 - $nil) related to a 25% reduction in corporate head office staff which has been separately disclosed on the consolidated statement of loss.

Stock-based Compensation

During the year ended December 31, 2018, stock-based compensation expense increased to $8.6 million compared to $7.0 million in the prior year. The increase is primarily due to a higher deferred share units expense resulting from an increased number of outstanding units at December 31, 2018.

Gain (loss) on Revaluation of Provisions and Other

	Three months ended December 31,		Year ended December 31,	
($ Thousands)	**2018**	**2017**	**2018**	**2017**
Contingent payment obligation	$ 38,052	$ (15,763)	$ 21,816	$ (1,548)
Capital-carry receivable	252	5,607	5,428	14,309
Other	30	(196)	1,793	595
TOTAL GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER	$ 38,334	$ (10,352)	$ 29,037	$ 13,356

The gains and losses on revaluation of provisions and other are primarily a result of changes in the estimated value of the Company's contingent payment obligation to Equinor due to fluctuations in forecasted prices for WTI. The contingent payment obligation is remeasured at each reporting period using a call option pricing model with any gains or losses recognized in net income (loss). The call option model includes estimates regarding future WTI prices, foreign exchange rates, inflation rates and Leismer production volumes and is subject to measurement uncertainty. The difference in the actual cash outflows ultimately payable with respect to the obligation could be material.

The primary reason for the decrease in the capital-carry receivable amounts in 2018 relates to lower capital-carry accretion income due to the lower capital-carry receivable balances in 2018.

Income Taxes

As at December 31, 2018 and 2017, Athabasca was in a net unrecognized deferred tax asset position. The deductible temporary differences in excess of taxable temporary differences are approximately $2.0 billion (December 31, 2017 - $1.5 billion). Since Athabasca has not recognized the benefit of these deductible temporary differences, no deferred tax recovery was recognized during the years ended December 31, 2018 and 2017. As at December 31, 2018, the Company has approximately $3.2 billion in tax pools, including $2.0 billion in non-capital losses and exploration pools available for immediate deduction against future income.

From time to time, Athabasca undergoes income tax audits in the normal course of business. In May 2018, the Company received a notice of reassessment from the Canada Revenue Agency ("CRA”) with regards to its 2012 taxation year. While the final outcome of such reassessment cannot be predicted with certainty, Athabasca has received legal advice that confirms its position as filed and believes it is likely to be successful in appealing the reassessment. As such, the Company has not recognized any provision in its consolidated financial statements with respect to the reassessment and has posted a deposit with the CRA in order to file an objection against the reassessment.

Environmental and Regulatory Risks Impacting Athabasca

Athabasca operates in jurisdictions that have regulated greenhouse gas (“GHG”) emissions and other air pollutants. While some regulations are in effect, further changes and amendments are at various stages of review, discussion and implementation. There is uncertainty around how any future federal legislation will harmonize with provincial regulation, as well as the timing and effects of regulations. Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the crude oil and natural gas industry in Canada. Such regulations impose certain costs and risks on the industry, and there remains some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as Athabasca is unable to predict additional legislation or amendments that governments may enact in the future. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's assets, operations and cash flow.

Current export pipeline capacity constraints significantly impacted Canadian pricing differentials in 2018 which negatively impacted Athabasca's financial results. Uncertainty around timing of future pipeline infrastructure due to regulatory and legislative delays is a significant risk to Athabasca and could have a material impact on future financial results. Additional information is available in Athabasca’s AIF that is filed on the Company’s SEDAR profile at www.sedar.com.

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, 2018, Athabasca issued 5.8 million common shares in respect of the Company's equity-settled share-based compensation plans.

Outstanding Share Data

As at March 5, 2019	
Common shares issued and outstanding	516,012,397
Stock-based compensation plans:	
Stock options	8,786,933
Restricted share units (2010 RSU Plan)	1,105,208
Restricted share units (2015 RSU Plan)	12,546,644
Performance share units	4,774,600
Deferred share units	2,343,489

For additional information regarding these compensation plans, refer to the consolidated financial statements of the Company for the year ended December 31, 2018.

SUMMARY OF QUARTERLY RESULTS

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

	2018				2017			
($ Thousands, unless otherwise noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	58.81	69.50	67.90	62.87	55.40	48.21	48.29	51.91
WTI (C$/bbl)	77.70	90.84	87.67	79.53	70.47	60.35	64.95	68.52
Western Canadian Select (C$/bbl)	25.36	61.75	62.89	48.77	54.87	47.76	49.99	49.34
Edmonton Par (C$/bbl)	42.75	81.90	80.60	72.06	69.02	56.62	61.92	63.87
Edmonton Condensate (C5+) (C$/bbl)	59.73	87.01	88.87	79.74	73.74	59.01	65.15	68.73
AECO (C$/GJ)	1.48	1.13	1.12	1.97	1.60	1.38	2.64	2.55
NYMEX Henry Hub (US$/MMBtu)	3.64	2.91	2.80	3.00	2.93	3.00	3.19	3.32
Foreign exchange (USD : CAD)	1.32	1.31	1.29	1.27	1.27	1.25	1.34	1.32
CONSOLIDATED								
Petroleum and natural gas production (boe/d)	37,984	40,612	37,658	40,572	42,064	36,133	36,574	26,737
Realized price (net of cost of diluent) ($/boe)	2.47	43.42	39.73	24.23	36.95	34.13	33.68	31.42
Petroleum and natural gas sales ($)	96,885	253,404	251,369	207,979	238,835	187,722	204,098	153,378
Operating Income (Loss) ($)(1)	(53,180)	83,703	46,719	16,876	65,002	52,358	43,787	19,204
Operating Netback ($/boe)(1)	(14.80)	23.21	13.01	4.65	17.25	15.58	13.28	7.99
Capital expenditures ($)	65,399	74,509	54,159	82,261	52,418	73,833	45,674	90,124
Capital Expenditures Net of Capital-Carry ($)(1)	46,042	52,389	38,888	56,661	33,236	67,741	32,181	79,444
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)	12,609	10,135	11,872	10,495	11,507	7,875	7,246	3,421
Realized price ($/boe)	32.27	46.43	42.68	44.65	40.10	36.83	41.11	45.06
Petroleum and natural gas sales ($)	37,434	43,294	46,107	42,182	42,456	26,680	27,111	13,875
Operating Income ($)(1)	22,121	29,795	30,936	24,292	26,696	13,748	16,391	6,863
Operating Netback ($/boe)(1)	19.07	31.95	28.64	25.72	25.22	18.98	24.85	22.28
Capital expenditures ($)	39,569	60,739	25,557	66,630	40,988	53,406	31,061	77,646
Capital Expenditures Net of Capital-Carry ($)(1)	20,212	38,619	10,286	41,030	21,806	47,314	17,568	66,966
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	25,375	30,477	25,786	30,077	30,557	28,258	29,328	23,316
Bitumen sales volumes (bbl/d)	26,462	29,074	27,578	29,857	29,447	28,640	28,970	23,257
Realized bitumen price ($/bbl)	(11.74)	42.37	38.46	17.05	35.72	33.38	31.82	29.41
Blended bitumen sales ($)	59,451	210,110	205,262	165,797	196,379	161,042	176,987	139,503
Operating Income (Loss) ($)(1)	(84,544)	62,322	39,635	(6,744)	45,385	34,945	26,661	10,050
Operating Netback ($/bbl)(1)	(34.72)	23.30	15.79	(2.51)	16.75	13.27	10.11	4.80
Capital expenditures ($)	25,703	13,767	28,595	15,631	11,368	20,382	14,127	10,868
OPERATING RESULTS								
Cash flow from operating activities ($)	(2,253)	61,733	27,605	(3,241)	37,060	49,488	28,049	(52,896)
Adjusted Funds Flow ($)(1)	(75,296)	62,151	25,680	(6,360)	41,808	34,400	27,567	(1,649)
Net income (loss) ($)	(488,479)	31,419	(19,267)	(93,330)	(209,588)	5,113	24,233	(29,162)
Net income (loss) per share - basic ($)	(0.95)	0.06	(0.04)	(0.18)	(0.41)	0.01	0.05	(0.06)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	73,898	128,340	93,293	128,915	163,321	174,076	179,611	212,999
Restricted cash ($)	111,056	114,216	114,212	111,778	113,406	113,372	113,853	113,823
Capital-carry receivable (discounted) ($)(2)	79,116	98,221	119,018	132,745	156,036	169,611	173,714	183,745
Total assets ($)	1,825,638	2,320,838	2,297,112	2,318,471	2,323,572	2,498,740	2,488,995	2,524,187
Long-term debt ($)(2)	581,140	546,505	554,279	541,460	526,206	523,782	541,199	553,377
Shareholders' equity ($)	965,949	1,452,946	1,418,587	1,434,345	1,524,610	1,731,546	1,723,735	1,695,582

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.
(2) 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.

SELECTED ANNUAL INFORMATION

The following table provides a summary of selected annual information for the years ended 2018, 2017 and 2016:

($ Thousands, unless otherwise noted)[1]	December 31, 2018	December 31, 2017	December 31, 2016
Petroleum and natural gas production (boe/d)	39,203	35,421	11,981
Petroleum and natural gas sales	$ 809,637	$ 784,032	$ 185,350
Net loss and comprehensive loss	$ (569,657)	$ (209,407)	$ (936,734)
per share (basic and diluted)	$ (1.11)	$ (0.42)	$ (2.31)
Cash flow from operating activities	$ 83,844	$ 61,697	$ (70,968)
per share (basic)	$ 0.16	$ 0.12	$ (0.17)
Adjusted Funds Flow[1]	$ 6,175	$ 102,123	$ (101,502)
per share (basic)	$ 0.01	$ 0.20	$ (0.25)
Capital expenditures[2]	$ 276,328	$ 262,048	$ 128,079
Capital Expenditures Net of Capital-Carry[1][2]	$ 193,980	$ 212,601	$ 122,267
Total assets	$ 1,825,638	$ 2,323,572	$ 2,257,887
Face value of long-term debt (current and long-term portions)[3]	$ 614,070	$ 563,310	$ 550,000
Weighted average shares outstanding (basic and diluted)	514,151,731	500,136,092	405,621,706

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.
(2) 2017 capital expenditures excludes the cost of the Leismer Corner Acquisition (see page 10).
(3) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the December 31, 2018 exchange rate of US$1.00 = C$1.3646.

ACCOUNTING POLICIES AND ESTIMATES

During the year ended December 31, 2018, 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, except as noted below. A summary of the significant accounting polices used by Athabasca can be found in Note 3 of the December 31, 2018 consolidated financial statements. For the year ended December 31, 2018, Athabasca's significant estimates and judgments are as follows:

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 (loss).

Included in the carrying value of property, plant and equipment ("PP&E") are accumulated depletion, depreciation and impairment charges that are determined, in part, by utilizing estimates based on Athabasca's reserves, resources, relevant market transactions and land acreage values. The estimates of reserves and resources include estimates of the recoverable volumes of oil, gas, NGLs 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 ("E&E") 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.

For purposes of impairment testing PP&E and E&E are aggregated into cash-generating units ("CGUs") based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations. CGUs are not larger than an operating segment.

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 contingent payment obligation is based upon numerous assumptions including future WTI prices, inflation factors, foreign exchange rates and Leismer bitumen production. Actual 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, 2018 and as at December 31, 2017, Athabasca did not recognize deductible temporary differences in respect of income tax assets.

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of reserves and other assets acquired, forecast benchmark commodity prices and discount rates. Assumptions are also required to determine the fair value of decommissioning obligations associated with the properties. Changes in any of the assumptions or estimates used in determining the fair value of the acquired assets and liabilities could impact the amounts assigned to the assets and liabilities in the acquisition equation. Future net income (loss) can be affected as a result of changes in future depletion, depreciation or asset impairment.

The Company utilizes commodity risk management contracts to manage its commodity price risk on its petroleum and natural gas sales. The Company also utilizes foreign exchange risk management contracts to reduce its exposure to foreign exchange risk associated with its interest payments on its US dollar denominated 2022 Notes. The calculated fair value of the risk management contracts relies on external observable market data including quoted forward commodity prices and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts actually realized at settlement and as such are subject to measurement uncertainty.

Stock-based compensation includes volatility, expected 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 consolidated financial statements of future periods and have a significant impact on net income (loss).

Changes in accounting policies

IFRS 15 *Revenue from Contracts with Customers*
The IASB issued IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15") in May 2014. This IFRS replaces IAS 18 *Revenue*, IAS 11 *Construction Contracts* and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework which requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser.

Athabasca adopted IFRS 15 on January 1, 2018 using the cumulative effect method. As a result of the adoption of IFRS 15, no cumulative effect adjustment to retained deficit was required and there was no impact on net income (loss) or cash flow.

The additional disclosures required by IFRS 15 are detailed in the consolidated financial statements of the Company for the year ended December 31, 2018.

IFRS 9 *Financial Instruments*
In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ("IFRS 9") that replaces IAS 39 *Financial Instruments: recognition and measurement* ("IAS 39") and all previous versions of IFRS 9. IFRS 9 brings together all three aspects of the accounting for financial instruments: classification & measurement, impairment and hedge accounting. IFRS 9 introduces a single approach to determining whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income. Athabasca adopted IFRS 9 on January 1, 2018 with no adjustments required to the consolidated financial statements on adoption of IFRS 9.

Future Accounting Pronouncements

The following standard that has been issued, but is not yet effective up to the date of issuance of the Company's consolidated financial statements, is disclosed below. The Company adopted this standard on January 1, 2019.

IFRS 16 *Leases*
The IASB issued its new Lease Standard on January 13, 2016. This new IFRS requires that, for lessees, former operating leases will now be capitalized and recognized on the consolidated balance sheet. Lease assets and liabilities will be initially measured at the present value of the unavoidable lease payments and amortized over the lease term. Lessor accounting remains consistent with current IFRS standards. IFRS 16 is required to be adopted either retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect of IFRS 16 as an adjustment to the opening retained deficit and applies the standard prospectively. Athabasca currently plans to apply the modified retrospective approach at transition.

On initial adoption, Athabasca is applying the following expedients permitted under the standard:

- Leases with terms ending within 12 months will be recognized as short-term leases.
- Short-term leases and leases of low value assets that have been identified will not be recognized on the consolidated balance sheet. Payments for these leases will be disclosed in the notes to the consolidated financial statements.

Athabasca has evaluated its significant contracts and agreements and anticipates the only material impact of the standard will be related to its office lease. Upon adoption this will result in an estimated leased asset of $12.6 million, a lease liability of $18.7 million and a reallocation of future annual general and administrative expense of approximately $2.8 million to financing & interest and depletion & depreciation expense. Cash flows associated with lease repayments will be allocated between operating and financing activities based on their interest and principal repayment components. Athabasca will recognize a leased asset for its office lease that is not equal to its corresponding lease liability as a result of applying the modified retrospective approach at transition. Also, the previously recognized onerous office lease provision will be netted against the associated leased asset instead of reassessing the asset for impairment on January 1, 2019.

The quantified impacts of IFRS 16 disclosed herein are subject to change in future periods pending updates to individual contract terms, assumptions, and other facts and circumstances arising subsequent to the date of these consolidated financial statements. As new contracts and agreements are entered into and as interpretation of the standard continues, future leases may be identified and recognized on the consolidated balance sheet. Athabasca is also currently reviewing the new disclosure requirements for IFRS 16.

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

The "Adjusted Funds Flow", "Light Oil Operating Income", "Light Oil Operating Netback", "Light Oil Capital Expenditures Net of Capital-Carry", "Thermal Oil Operating Income (Loss)", "Thermal Oil Operating Netback", "Consolidated Operating Income (Loss)", "Consolidated Operating Netback" and "Consolidated Capital Expenditures Net of Capital-Carry" 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 three months and years ended December 31, 2018 and 2017 to Adjusted Funds Flow:

	Three months ended December 31,		Year ended December 31,	
($ Thousands)	**2018**	**2017**	**2018**	**2017**
Cash flow from operating activities	$ (2,253)	$ 37,060	$ 83,844	$ 61,697
Restructuring	3,604	—	3,604	—
Acquisition expenses	—	—	—	11,047
Changes in non-cash working capital	(81,506)	2,134	(103,787)	20,732
Settlement of provisions	4,859	2,614	9,937	8,647
Long-term deposits	—	—	12,577	—
ADJUSTED FUNDS FLOW	$ (75,296)	$ 41,808	$ 6,175	$ 102,123

Adjusted Funds Flow is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Adjusted Funds Flow 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. Adjusted Funds Flow per share is calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding.

The Light Oil Operating Income and Light Oil Operating Netback measures in this MD&A are calculated by subtracting royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Light Oil Operating Netback measure is presented on a per boe basis. The Light Oil Operating Income and the Light Oil Operating Netback 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 20 - Segmented Information* in the consolidated financial statements for the year ended December 31, 2018.

The Operating Income (Loss) and Operating Netback measures in this MD&A with respect to the Leismer Project and Hangingstone Project are calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation & marketing expenses from blended bitumen sales. The Thermal Oil Operating Netback measure is presented on a per barrel basis of bitumen sales. The Thermal Oil Operating Income (Loss) and the Thermal Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Thermal Oil assets. The table on page 14 reconciles Thermal Oil Operating Income (Loss) to *Note 20 - Segmented Information* in the consolidated financial statements for the year ended December 31, 2018.

The Consolidated Operating Income (Loss) and Consolidated Operating Netback measures in this MD&A are calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, royalties, the cost of diluent blending, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Consolidated Operating Netback measure is presented on a per boe basis. The Consolidated Operating Income (Loss) and the Consolidated Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil and Thermal Oil assets combined together including the impact of realized commodity risk management gains or losses. The table on page 6 reconciles Consolidated Operating Income (Loss) to *Note 20 - Segmented Information* in the consolidated financial statements for the year ended December 31, 2018.

The Consolidated Capital Expenditures Net of Capital-Carry and Light Oil Capital Expenditures Net of Capital-Carry measures in this MD&A are calculated in the tables on pages 7 and 9. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

Comparative Figures

Certain comparative figures have been restated to conform to the current period presentation.

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, 2018, 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, 2018, 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, 2018.

Risk Factors

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

Operational risks

- the performance of the Company's assets;
- Athabasca's exploration and development budget and Athabasca's capital expenditure programs;
- failure to realize anticipated benefits of acquisitions or divestments;
- 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;

- dependence upon Murphy as a working interest participant in its Light Oil assets and as operator of the Greater Kaybob assets;
- risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of bitumen, crude oil, natural gas and natural gas liquids reserves and resources;
- risks related to gathering and processing facilities and pipeline systems;
- reliance on third party infrastructure;
- risks associated with events of force majeure; and
- 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.

Planning risks
- the business strategy, objectives and business strengths of Athabasca;
- Athabasca's growth strategy and opportunities;
- Athabasca's plans to submit additional regulatory applications;
- 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; and
- the potential for management estimates and assumptions to be inaccurate.

Financial and market risks
- general economic, market and business conditions in Canada, the United States and globally;
- future market prices for crude oil, natural gas, condensate and bitumen blend;
- Canadian heavy and light oil export capacity constraints and the resulting impact on realized pricing;
- Athabasca's projections of commodity prices, costs and netbacks;
- the substantial capital requirements of Athabasca's projects and the Company's ability to raise capital;
- risk of reduced capital availability due to environmental and climate related reputational issues for industry;
- the potential for future joint venture arrangements;
- insurance risks;
- hedging risks;
- variations in foreign exchange and interest rates;
- risks related to the Credit Facility, the Letter of Credit Facility, the Unsecured Letter of Credit Facility and the 2022 Notes;
- risks related to the Common Shares; and
- Athabasca's information and computer systems and exposure to cyber-security breaches.

Legal and compliance risks
- the regulatory framework governing royalties, taxes, environmental matters and foreign investment in the jurisdictions in which Athabasca conducts and will conduct its business;
- risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments;
- actions taken by the American administration, including the renegotiation of the terms of the North American Free Trade Agreement and the imposition of taxes on the importation of goods into the United States;
- aboriginal claims;
- risks associated with establishing and maintaining systems of internal controls; and
- inaccuracy of forward-looking information.

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 future growth outlook and how that growth outlook is funded; the benefits expected to be realized by the Company from the 2022 Notes and the Credit Facility; the benefits expected to be realized by the Company from the Leismer Corner Acquisition; the timing by which the Corporation expects to achieve 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 corporate, Thermal Oil and Light Oil production levels and base decline rates; the in-service dates of the Trans Mountain pipeline expansion and TransCanada Keystone XL pipeline and the benefits Athabasca expects to realize by having capacity thereon; estimates of Adjusted Funds Flow, Operating Income and capital expenditures; the capability of the Company's future 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; production growth and future operating expenses; the timing of well spudding and completion operations and 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 capital budget; the Company's anticipated sources of funding for 2019 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 2022 Notes and the Credit Facility; commodity prices, including for petroleum, natural gas and blended bitumen; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions 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 globally; 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; prices, markets and marketing; adverse changes in general economic and market conditions; climate change; political uncertainty & terrorist attacks; regulatory; gathering and processing, facilities, pipeline systems and rail; statutes and regulations regarding the environment; anticipated benefits of acquisitions and dispositions; abandonment and reclamation costs; ability to finance; state of the capital markets; stage of development; royalty regimes; additional funding requirements; foreign exchange rates and interest rates; uncertainties inherent in estimating reserves and resources volumes; hedging; operational dependence; diluent supply; operating costs; hydraulic fracturing; future acquisition and joint venture activities; exploration, development and production risks; third party credit risk; conflicts of interest; aboriginal claims; reliance on key personnel and operators; financial assurances; inability to utilize the most advanced technologies; changing demand for oil and natural gas products; tax reassessments or changes to income tax laws; need to replace reserves; environmental and health and safety risks and hazards; management estimates and assumptions; liability management; seasonality and weather conditions; unexpected events; internal controls; insurance; litigation; natural gas overlying bitumen resources; competition; chain of title; breaches of confidentiality; new industry related activities or new geographical areas; cyber-security; risks related to our indebtedness; 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 report of McDaniel & Associates Consultants Ltd. ("McDaniel") evaluating Athabasca's Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2018 (which is respectively referred to herein as the "McDaniel 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

The McDaniel Report was 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, 2018. 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 McDaniel in the McDaniel Report, please refer to the Company's AIF that is available on SEDAR at www.sedar.com.

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 1,000 Duvernay drilling locations referenced on page 7 of this MD&A include: 50 proved undeveloped or non-producing locations and 35 probable undeveloped locations for a total of 85 booked locations with the balance being unbooked locations. The 200 Montney drilling locations referenced on page 7 of this MD&A include: 77 proved undeveloped locations and 12 probable undeveloped locations for a total of 89 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 McDaniel as of December 31, 2018 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, additional reservoir information that is obtained and other factors.

Definitions

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

"**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, 2018, the Company reported Contingent Resources on a risked and unrisked basis located in its Leismer and Corner asset areas in the Development Pending project maturity sub-class and for the Dover West Sands asset area in the Development on Hold project maturity sub-class.

"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**" or **"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**" or **"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
COGE	Canadian Oil and Gas Evaluation
GAAP	Generally Accepted Accounting Principles
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
US$	United States Dollars
WTI	West Texas Intermediate
WCS	Western Canadian Select