Management's Discussion and Analysis

Q2 2017

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 July 26, 2017 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2016 and 2015. These financial statements, including the comparative figures, were prepared in accordance with International Financial Reporting Standards ("IFRS"). This MD&A contains forward looking information based on the Company's current expectations and projections. For information on the material factors and assumptions underlying such forward looking information, refer to the "Forward Looking Information" advisory on page 19 of this MD&A. See "Reserves and Resource information" on page 21 for important information regarding the Company's reserves and resource information included in this MD&A. For a listing of abbreviations, refer to "Abbreviations" on page 23 of this MD&A. Additional information relating to Athabasca is available on SEDAR at www.sedar.com, including the Company's most recent Annual Information Form dated March 9, 2017 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "ATH".

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ABOUT ATHABASCA

Athabasca is an intermediate oil weighted producer with exposure to several of the largest resource plays in Western Canada including the Montney, Duvernay and oil sands. The Company has a funded and flexible development outlook capable of delivering strong economic growth. In the current environment, the Company is focused on maintaining scale of operations within Light Oil and continued optimization of Thermal Oil to maximize profitability and long term recoveries. Athabasca retains optionality to accelerate operations across both divisions with pricing support. The Company is guided by a strategy that includes:

Light Oil: Defined and Material Growth

- A scalable operated Montney position at Placid ("Greater Placid")
- Funded Kaybob Duvernay ("Greater Kaybob") development through the joint venture with Murphy Oil Company Ltd. ("Murphy")
- Production growth to over 10,000 boe/d by year-end 2017 and potential to over 20,000 boe/d by 2020 with a 1-rig program in the Montney and current Duvernay development plans

Thermal Oil: Free Cash Flow with Leverage to Oil Prices

- A large low decline asset base accelerates free cash flow
- Free cash flow of approximately $350 million over a five year period at US$55/bbl WTI
- Future low risk expansion options

Financial Sustainability

- Maturing cash flow profile with strong sustainability metrics and a low overall corporate production decline of approximately 10% annually
- Diverse asset base provides flexibility in future capital allocation decisions
- Strong liquidity supported by $180 million of cash and equivalents, $189 million Duvernay carry balance, $15 million mark-to-market hedge gains and a $120 million credit facility at the end of Q2 2017

HIGHLIGHTS FOR THE QUARTER ENDED JUNE 30, 2017

Light Oil Division

- Achieved second quarter 2017 production of 7,246 boe/d (56% liquids), representing growth of 112% over the first quarter of 2017, and 26% as compared to the second quarter of 2016. Strong growth was driven by the tie-in of Placid Montney wells from the winter program.
- Realized netbacks of $24.85/boe, an increase of 80% over the prior year, and generated operating income of $16.4 million. Stronger netbacks and operating income were driven by higher production volumes, increased liquids content, lower operating costs and higher year-over-year commodity prices.
- At Greater Placid, successfully completed the winter program with 20 (gross) wells rig released and 11 (gross) wells completed and placed on production. Athabasca commissioned a new battery (the "Placid battery") and infrastructure project in Greater Placid in April with capacity for 10,000 bbl/d and 36 mmcf/d to support production growth in the area.
- At Greater Kaybob, completed two pads with two (gross) wells placed on production by quarter end. An additional 10 (gross) Duvernay wells are planned to be spud throughout the remainder of 2017.

Thermal Oil Division

- Achieved second quarter 2017 production of 29,328 bbl/d, representing growth of 26% over the first quarter of 2017, and 447% as compared to the second quarter of 2016. Growth was driven by the full integration of the Statoil Leismer acquisition as well as the continued ramp-up at Hangingstone.
- Generated operating income of $27.4 million, which exceeded capital expenditures for the quarter by $13.3 million, and realized netbacks of $10.39/bbl. Thermal Oil netbacks and operating income have increased substantially over the prior year with the addition of the Leismer asset to Athabasca's Thermal Oil portfolio.
- Increased commodity hedge positions to protect near-term cash flow with 20,000 bbl/d hedged for the balance of 2017 at approximately $50.73/bbl WCS.

Corporate

- Achieved second quarter production of 36,574 bbl/d, an increase of 229% over the prior year.
- Generated funds flow from operations of $27.6 million and net income of $24.2 million.
- Reduced G&A to $2.15/boe, a decrease of 61% from the prior year.
- Exited the quarter with $293 million of cash and cash equivalents (including $114 million of restricted cash - see page 13), a reconfirmed $120 million reserve based credit facility and a $189 million (undiscounted) capital carry balance.

FINANCIAL & OPERATIONAL HIGHLIGHTS

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

($ Thousands, except volume, boe and share amounts)[1]	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
CONSOLIDATED PRODUCTION				
Petroleum and natural gas volumes (boe/d)	36,574	11,101	31,683	12,224
LIGHT OIL DIVISION				
Petroleum and natural gas volumes (boe/d)	7,246	5,743	5,344	6,031
Light Oil Operating Income[1]	$ 16,391	$ 7,215	$ 23,253	$ 12,123
Light Oil Operating Netback[1] ($/boe)	$ 24.85	$ 13.80	$ 24.04	$ 11.03
Capital expenditures	$ 31,061	$ 5,518	$ 108,707	$ 36,176
Recovery of capital-carry through capital expenditures	$ (13,493)	$ (1,474)	$ (24,173)	$ (1,474)
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	29,328	5,358	26,339	6,193
Thermal Oil Operating Income (loss)[1]	$ 27,396	$ (11,915)	$ 39,735	$ (34,990)
Thermal Oil Operating Netback[1] ($/bbl)	$ 10.39	$ (29.33)	$ 8.40	$ (33.03)
Capital expenditures[2]	$ 14,127	$ 2,187	$ 24,994	$ 3,094
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 28,049	$ 5,759	$ (24,851)	$ (32,268)
per share (basic and diluted)	$ 0.06	$ 0.01	$ (0.05)	$ (0.08)
Funds Flow from Operations[1]	$ 27,567	$ (27,304)	$ 25,915	$ (67,420)
per share (basic and diluted)	$ 0.05	$ (0.07)	$ 0.05	$ (0.17)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ 24,233	$ (59,169)	$ (4,932)	$ (124,298)
per share (basic and diluted)	$ 0.05	$ (0.15)	$ (0.01)	$ (0.31)
SHARES OUTSTANDING				
Weighted average shares outstanding - basic	508,655,464	405,222,515	490,492,488	404,964,704
Weighted average shares outstanding - diluted	514,174,746	405,222,515	490,492,488	404,964,704
ACQUISITIONS AND FINANCINGS				
Leismer Corner Acquisition[3]	$ (3,687)	$ —	$ (625,764)	$ —
Net proceeds from sale of assets	$ 35	$ 392,175	$ 90,205	$ 392,338
Net proceeds from issuance of 2022 Notes	$ (437)	$ —	$ 542,117	$ —
Repayment of 2017 Notes and term loan	$ —	$ (284,722)	$ (550,000)	$ (285,441)

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP Financial Measures.
(2) Thermal Oil capital expenditures excludes the cost of the Leismer Corner Acquisition (see page 7).
(3) Consists of cash of $435.0 million, common shares of $166.0 million and contingent payment obligations of $24.7 million, for the six months ended June 30, 2017.

As at ($ Thousands)	June 30, 2017	December 31, 2016
LIQUIDITY AND INDEBTEDNESS		
Cash and cash equivalents	$ 179,611	$ 650,301
Restricted cash	$ 113,853	$ 107,012
Capital-carry receivable (current and long-term portion - undiscounted)	$ 189,296	$ 213,469
Face value of long-term debt (current and long-term portion)[4]	$ 584,212	$ 550,000

(4) Face value of the US dollar denominated 2022 Notes is US$450 million.

OUTLOOK

The following tables reflect Athabasca's 2017 capital budget and corporate production guidance:

2017 Capital Budget ($ millions)		Full year
Light Oil Division		
Greater Placid area (Montney)(1)	$	135
Greater Kaybob area (Duvernay)(2)		15
		150
Thermal Oil Division		
Leismer		40
Hangingstone		15
Other thermal		5
		60
Total capital expenditures(3)	$	210

(1) The Greater Placid area capital expenditures reflect Athabasca's 70% working interest.
(2) The Greater Kaybob area capital expenditures reflect Athabasca's 30% working interest, net of anticipated recovery from the capital-carry receivable.
(3) The 2017 capital budget of $210 million excludes capitalized staff costs of $5 million.

2017 Operational & Financial Guidance ($ millions, unless otherwise noted)		Full year
Corporate (net)		
Production (boe/d)(1)		33,500 - 36,500
Liquids weighting (%)		91%
Funds Flow from Operations(2)	$	55
Light Oil (net)		
Production (boe/d)		6,500 - 7,500
Light Oil Operating Income(2)	$	61
Capital expenditures	$	150
Thermal Oil		
Bitumen production (bbl/d)(1)		27,000 - 29,000
Thermal Oil Operating Income(2)	$	83
Capital expenditures	$	60
Commodity assumptions		
WTI (US$/bbl)	$	48.00
Western Canadian Select (C$/bbl)	$	47.25
AECO Gas (C$/mcf)	$	2.50
FX (US$/C$)		0.76

(1) Production guidance includes the Leismer Project's volumes reported from February to December 2017 (see page 7).
(2) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP Financial Measures.

Athabasca's 2017 corporate budget is unchanged at $210 million and includes running a single rig in the Greater Placid area during H2 2017. Annual corporate production is expected to average between 33,500 - 36,500 boe/d.

In the Light Oil Division, the capital budget has been increased by $15 million to $150 million ($135 million for Greater Placid and $15 million net for Greater Kaybob). The increased activity reflects spudding a 6-well Montney pad in Q3 2017 with completions and tie-in anticipated in early 2018. The increase in capital has been funded through an optimized Thermal Oil budget which is outlined below. Light Oil annual production guidance is unchanged at 6,500 - 7,500 boe/d and production is expected to reach 10,000 boe/d before year-end. Guidance incorporates a 19 day planned turnaround at Keyera's Simonette plant through August.

In the Thermal Oil Division, the capital budget has been reduced by an additional $15 million to $60 million. Inclusive of the prior reduction in Q1 2017, the Company has reduced its Thermal Oil budget by a total of $45 million from the original $105 million budget. Annual production guidance is between 27,000 - 29,000 bbl/d. The capital program consists of $40 million at Leismer, $15 million at Hangingstone and $5 million for maintaining Athabasca's long dated thermal leases.

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended June 30, 2017	2016	Change	Six months ended June 30, 2017	2016	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)	$ 48.29	$ 45.59	6%	$ 50.10	$ 39.52	27%
West Texas Intermediate (WTI) (C$/bbl)	$ 64.95	$ 58.81	10%	$ 66.81	$ 52.56	27%
Western Canadian Select (WCS) (C$/bbl)	$ 49.99	$ 41.62	20%	$ 49.68	$ 33.97	46%
Edmonton Par (C$/bbl)	$ 61.92	$ 54.78	13%	$ 62.95	$ 47.79	32%
Edmonton Condensate (C5+) (C$/bbl)	$ 65.15	$ 56.80	15%	$ 67.14	$ 52.03	29%
Differential:						
WTI vs. WCS (US$/bbl)	$ (11.13)	$ (13.30)	16%	$ (12.85)	$ (13.77)	7%
WTI vs. WCS (C$/bbl)	$ (14.96)	$ (17.19)	13%	$ (17.12)	$ (18.59)	8%
Differential as a % of WTI	(23)%	(29)%	21%	(26)%	(35)%	26%
Natural gas:						
NYMEX Henry Hub (US$/MMBtu)	$ 3.19	$ 1.95	64%	$ 3.25	$ 2.02	61%
AECO (C$/GJ)	$ 2.64	$ 1.32	100%	$ 2.60	$ 1.52	71%
Foreign exchange:						
USD : CAD	1.34	1.29	4%	1.33	1.33	0%

The price of WTI for crude oil sales at Cushing, Oklahoma is the primary benchmark for crude oil pricing in North America. The price Athabasca receives for its oil production in both its Light Oil and Thermal Oil Divisions is primarily driven by the price of WTI, the foreign exchange rate, transportation costs and quality differentials. For the three and six months ended June 30, 2017, the WTI price increased by 6% and 27%, respectively, compared to the same periods in the prior year.

The WCS price at Hardisty, Alberta is the primary benchmark for Athabasca's blended bitumen sales. The WCS price trades at a wider differential to the WTI price compared to lighter crude oil products. The increases in 2017 primarily reflect the increase in the WTI price and the narrower WCS to WTI differential.

The Edmonton Par price is the primary benchmark for crude oil sales in the Company's Light Oil Division. Higher prices in 2017 are consistent with the movement in the WTI price.

The Edmonton Condensate (C5+) price is the primary benchmark for condensate sales in the Company's Light Oil Division. In the Thermal Oil Division, the Edmonton Condensate (C5+) price is the primary benchmark for diluent purchases which Athabasca utilizes in the blending process at its Leismer and Hangingstone projects in order to deliver produced bitumen to the market. The increases in 2017 are consistent with the increases in the Edmonton Par price.

In the Thermal Oil Division, the AECO price is the primary benchmark for natural gas purchases consumed by Athabasca in order to generate steam in the SAGD recovery process. In the Light Oil Division, the NYMEX gas price is the primary benchmark for natural gas sales as Athabasca primarily delivers its sales product on the Fort Chicago pipeline. Prices in 2017 for these natural gas benchmarks increased over the same periods in 2016.

Athabasca's realized pricing reflects transportation costs and quality differentials relative to the benchmark prices discussed above.

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 area and Greater Kaybob area near the town of Fox Creek, Alberta.

On May 13, 2016, Athabasca entered into a strategic joint venture with Murphy to develop the Montney and Duvernay formations in the Greater Kaybob and Greater Placid areas (the "Murphy Transaction"). As part of the transaction, Athabasca sold an operated 70% interest in its Greater Kaybob area assets and a non-operated 30% interest in its Greater Placid area assets for gross proceeds of $486.5 million. Athabasca received $267.5 million in cash, including purchase price adjustments from the January 1, 2016 effective date, and also recognized additional consideration of $219.0 million (undiscounted) in the form of a capital-carry in the Greater Kaybob area, whereby Murphy will fund 75% of Athabasca's share of development capital up to a maximum five year period. The carry supports approximately $1 billion of Duvernay investment over the next four years of which Athabasca’s financial exposure is limited to $75 million to retain its 30% working interest.

In Greater Placid, Athabasca has an operated position in approximately 80,000 gross Montney acres, of which 48,000 gross acres (36,000 net) are high-graded Placid development. An inventory of over 200[1] 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 the Greater Kaybob area with exposure to both liquids-rich gas and volatile oil opportunities and an inventory of approximately 1,500[1] gross drilling locations. Athabasca's Light Oil Division assets are supported by jointly-owned regional infrastructure primarily consisting of four batteries, including the recently commissioned Placid battery, and a network of gas pipelines which connect the facilities to two regional third party gas processing plants.

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information regarding the Company's drilling locations.

Light Oil Operating Results

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
SALES VOLUMES				
Oil (bbl/d)	3,640	2,431	2,707	2,480
Natural gas (Mcf/d)	19,056	17,430	13,936	18,212
Natural gas liquids (bbl/d)	431	407	315	516
Total (boe/d)	7,246	5,743	5,344	6,031
Consisting of:				
Greater Placid area (boe/d)	5,813	2,960	3,925	1,827
% liquids	55%	51%	57%	51%
Greater Kaybob area (boe/d)	1,433	2,783	1,419	4,204
% liquids	61%	47%	56%	51%

	Three months ended June 30,		Six months ended June 30,	
($ Thousands, except volume and boe amounts)	2017	2016	2017	2016
Petroleum and natural gas sales	$ 24,195	$ 14,074	$ 36,194	$ 26,566
Midstream revenue	213	341	242	838
Royalties	(1,239)	(479)	(1,660)	(1,028)
Operating and transportation expenses	(6,778)	(6,721)	(11,523)	(14,253)
Light Oil Operating Income[1]	$ 16,391	$ 7,215	$ 23,253	$ 12,123
REALIZED PRICES				
Oil ($/bbl)	$ 57.48	$ 48.49	$ 58.32	$ 42.55
Natural gas ($/Mcf)	2.49	1.61	2.54	1.63
Natural gas liquids ($/bbl)	21.45	21.55	21.18	20.86
Realized price ($/boe)	36.69	26.93	37.42	24.20
Royalties ($/boe)	(1.88)	(0.92)	(1.72)	(0.94)
Operating and transportation expenses[1] ($/boe)	(9.96)	(12.21)	(11.66)	(12.23)
LIGHT OIL OPERATING NETBACK[2] ($/boe)	$ 24.85	$ 13.80	$ 24.04	$ 11.03

(1) Refer to “Advisories and Other Guidance” beginning on page 18 for additional information on Non-GAAP Financial Measures.
(2) For the three and six months ended June 30, 2017, operating and transportation expenses include midstream revenues of $0.32/boe and $0.25/boe, respectively (June 30, 2016 - $0.64/boe, $0.76/boe).

During the three months ended June 30, 2017, Athabasca's Light Oil production averaged 7,246 boe/d, an increase of 26% over the same period in the prior year mainly due to the tie-in of eight Montney and four Duvernay wells in the first half of 2017. During the six months ended June 30, 2017, Athabasca's Light Oil production averaged 5,344 boe/d, a reduction of 11% compared to the prior year. The lower production was primarily due to the sale of the Light Oil joint venture assets to Murphy on May 13, 2016, partially offset by production from 13 wells (seven Montney, six Duvernay) brought on stream during 2016, combined with the additional wells in 2017.

Athabasca's Light Oil Operating Netbacks were $24.85/boe and $24.04/boe during the three and six months ended 2017, up from 2016 primarily due to higher realized prices for oil and gas and lower per unit operating expenses.

Athabasca's realized price increased due to higher underlying benchmark prices for oil and natural gas and a higher liquids content in Athabasca's production. Royalties were higher in 2017 mainly due to the impact of higher commodity prices on price sensitive royalty rates. Operating and transportation expenses have trended lower in 2017 as a result of an increased production base combined with a continued focus on cost optimization and efficiency.

Light Oil Segment Income (Loss)

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	2017	2016	2017	2016
Light Oil Operating Income[(1)]	$ 16,391	$ 7,215	$ 23,253	$ 12,123
Depletion and depreciation	(10,181)	(9,934)	(14,791)	(20,762)
Loss on sale of assets	—	(5,546)	(101)	(5,585)
Exploration expense and other	(15)	(58)	(46)	—
LIGHT OIL SEGMENT INCOME (LOSS)	$ 6,195	$ (8,323)	$ 8,315	$ (14,224)

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP Financial Measures.

Depletion of oil and gas assets decreased by $6.0 million during the six months ended June 30, 2017, compared to the same period in the prior year, primarily due to lower production as a result of the Murphy Transaction as well as lower depletion rates resulting from reserve additions from drilling activities in the second half of 2016.

During the six months ended June 30, 2016, Athabasca recognized a loss of $5.6 million primarily related to closing adjustments and transaction costs associated with the Murphy Transaction.

Light Oil Capital Expenditures

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	2017	2016	2017	2016
Greater Placid area				
Drilling, completion and equipping	$ 4,039	$ 1,493	$ 50,469	$ 12,287
Facilities	4,586	1,259	22,717	10,686
Land acquisitions and other	4,401	2,417	4,660	6,458
	13,026	5,169	77,846	29,431
Greater Kaybob area				
Drilling, completion and equipping	17,803	(519)	30,188	1,553
Facilities	216	712	681	4,500
Land acquisitions and other	16	156	(8)	692
	18,035	349	30,861	6,745
TOTAL LIGHT OIL CAPITAL EXPENDITURES[(1)]	$ 31,061	$ 5,518	$ 108,707	$ 36,176
Less: Greater Kaybob capital carry	(13,493)	(1,474)	(24,173)	(1,474)
Net cash outflow from Light Oil capital expenditures	$ 17,568	$ 4,044	$ 84,534	$ 34,702

(1) For the three and six months ended June 30, 2017, capital expenditures included $1.5 million and $3.0 million in capitalized staff costs, respectively (June 30, 2016 - $1.7 million, $3.4 million).

During the second quarter of 2017, Athabasca finished its 20-well (gross) winter drilling program in the Greater Placid area. All 20 wells were rig-released ahead of spring break-up, with three of the five multi-well pads on stream. Athabasca anticipates that the remaining pads will be completed and brought on stream in the third quarter of 2017. Athabasca also commissioned the Placid battery to accommodate production growth in the area.

Including the recovery of the capital-carry, Athabasca's net cash outflow from capital expenditures in the Greater Kaybob area was $6.7 million during the six months ended June 30, 2017. In the second quarter of 2017, Athabasca completed a three-well Duvernay pad and brought on stream a two-well (gross) Duvernay pad. An additional 10 (gross) Duvernay wells are anticipated to be spud throughout the remainder of 2017.

THERMAL OIL DIVISION

Overview

Athabasca's Thermal Oil Division consists of two operating oil sands projects and a large resource base of 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 Statoil ASA (collectively "Statoil"). The acquired assets include the operating Leismer Thermal Oil Project (the "Leismer Project"), the delineated Corner exploration area and related strategic infrastructure (the "Leismer Corner Acquisition"). The 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 30 years. The acquired assets are high quality and resilient to lower commodity prices which has resulted in higher year-over-year netbacks and operating income within the Thermal Oil Division.

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

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 transaction included cash of $435.0 million, including provisional purchase price adjustments, and the issuance of 100 million common shares which were valued at $166.0 million based on Athabasca's January 31, 2017 closing share price of $1.66/share. Athabasca also agreed to a series of annual contingent payments which are only triggered at oil prices above US$65/bbl WTI for a four year term ending in 2020. Each annual payment is calculated on one-third of the Leismer Project bitumen production multiplied by an oil price factor (monthly average US$WTI/bbl less US$65/bbl, adjusted for inflation). The payments are capped at $75.0 million annually and $250.0 million over the term. Athabasca incurred $11.0 million in acquisition costs associated with the Leismer Corner Acquisition.

Athabasca also operates the Hangingstone Thermal Oil Project (the “Hangingstone Project"). The Hangingstone Project is currently ramping up towards design capacity of 12,000 bbl/d.

Athabasca's legacy 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.

Leismer Operating Results

	Three months ended June 30, 2017	Five months ended June 30, 2017	Six months ended June 30, 2017
VOLUMES			
Bitumen production (bbl/d)	20,463	21,273	17,629
Bitumen sales (bbl/d)	20,041	20,939	17,353
Blended bitumen sales (bbl/d)	28,506	30,142	24,980

($ Thousands, except volume and bbl amounts)	Three months ended June 30, 2017	Six months ended June 30, 2017
Blended bitumen sales	$ 123,545	$ 212,572
Cost of diluent	(65,368)	(115,102)
Total bitumen sales	58,177	97,470
Royalties	(1,237)	(2,186)
Operating expenses - non-energy	(15,450)	(28,684)
Operating expenses - energy	(7,728)	(12,605)
Transportation and marketing	(5,308)	(8,868)
Leismer Operating Income(1)(2)	$ 28,454	$ 45,127
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$ 47.63	$ 47.01
Bitumen sales ($/bbl)	$ 31.90	$ 31.03
Royalties ($/bbl)	(0.68)	(0.70)
Operating expenses - non-energy ($/bbl)	(8.47)	(9.13)
Operating expenses - energy ($/bbl)	(4.24)	(4.01)
Transportation and marketing ($/bbl)	(2.91)	(2.82)
LEISMER OPERATING NETBACK(1)(2) ($/bbl)	$ 15.60	$ 14.37

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP Financial Measures.
(2) The Leismer Project was acquired on January 31, 2017. The table above reflects Leismer Operating Income from February onwards for the six months ended June 30, 2017.

From the date of closing the acquisition to the end of June 2017 the Leismer Project has averaged production of 21,273 bbl/d and generated operating income of $45.1 million.

Athabasca realized a bitumen price of $31.90/bbl during the second quarter of 2017. The realized bitumen price represents the Company's realized price for blended bitumen sales, less the cost of diluent supply and transportation. Energy operating expenses, which primarily consist of electricity to power the facility and natural gas which is used to create steam for the SAGD recovery process, were $4.24/bbl during the second quarter of 2017 and non-energy operating costs, which include all other operational expenditures relating to production, were $8.47/bbl. Transportation and marketing expenses for the second quarter of 2017 were $2.91/bbl.

During the quarter ended June 30, 2017, the Leismer Operating Netback was $15.60/bbl, which represents an improvement of 23% over the first quarter of 2017. The increase was primarily a result of higher realized pricing and lower energy operating costs per bbl. In light of continued low commodity prices, the Company intends to closely manage reservoir performance and further optimize capital and operating expenses to maximize profitability.

Hangingstone Operating Results

	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
VOLUMES				
Bitumen production (bbl/d)	8,865	5,358	8,710	6,193
Bitumen sales (bbl/d)	8,929	4,463	8,777	5,820
Blended bitumen sales (bbl/d)	12,609	6,359	12,439	8,267

($ Thousands, except volume and bbl amounts)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Blended bitumen sales	$ 53,442	$ 19,500	$ 103,918	$ 40,602
Cost of diluent	(27,733)	(9,545)	(55,949)	(25,901)
Total bitumen sales	25,709	9,955	47,969	14,701
Royalties	(459)	(114)	(915)	(139)
Operating expenses - non-energy	(10,690)	(11,630)	(24,394)	(27,694)
Operating expenses - energy	(5,968)	(3,048)	(11,547)	(6,468)
Transportation and marketing	(10,385)	(7,078)	(19,531)	(15,390)
Hangingstone Operating Loss(1)	$ (1,793)	$ (11,915)	$ (8,418)	$ (34,990)
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 46.58	$ 33.70	$ 46.16	$ 26.99
Bitumen sales ($/bbl)	$ 31.64	$ 24.51	$ 30.20	$ 13.88
Royalties ($/bbl)	(0.56)	(0.28)	(0.58)	(0.13)
Operating expenses - non-energy ($/bbl)	(13.16)	(28.64)	(15.36)	(26.15)
Operating expenses - energy ($/bbl)	(7.34)	(7.50)	(7.27)	(6.11)
Transportation and marketing ($/bbl)	(12.78)	(17.43)	(12.29)	(14.53)
HANGINGSTONE OPERATING NETBACK(1) ($/bbl)	$ (2.20)	$ (29.34)	$ (5.30)	$ (33.04)

(1) Refer to “Advisories and Other Guidance” beginning on page 18 for additional information on Non-GAAP Financial Measures.

For the three and six months ended June 30, 2017, Athabasca averaged 8,865 bbl/d and 8,710 bbl/d of bitumen production, respectively, increases of 65% and 41% compared to the same periods in the prior year. The Hangingstone Project achieved first oil during the third quarter of 2015 and continues to ramp-up towards design capacity of 12,000 bbl/d.

In the second quarter of 2016, Hangingstone bitumen production was impacted by a 19 day shutdown as a result of the regional Fort McMurray wildfires. In the second quarter of 2017, Athabasca recognized $8.0 million of insurance proceeds in Other Income with respect to the settlement of an insurance claim filed to recover certain losses associated with the shutdown.

The Hangingstone Operating Netback was $(2.20)/bbl and $(5.30)/bbl for the three and six months ended June 30, 2017, compared to $(29.34)/bbl and $(33.04)/bbl during the same periods in 2016. The improvement in the Thermal Oil Operating Netback is primarily due to higher production volumes and a higher realized price for blended bitumen.

Compared to the same periods in the prior year, operating expenses per bbl decreased by 43% and 30% to $20.50/bbl and $22.63/bbl during the three and six months ended June 30, 2017, respectively. The decreases were primarily due to higher production which resulted in lower per-unit non-energy operating expenses which carry a high fixed component. Operating expenses and transportation costs per bbl are expected to continue to decrease as Hangingstone continues to ramp-up production.

Consolidated Thermal Oil Operating Results

	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
VOLUMES				
Bitumen production (bbl/d)	29,328	5,358	26,339	6,193
Bitumen sales (bbl/d)	28,970	4,463	26,130	5,820
Blended bitumen sales (bbl/d)	41,115	6,359	37,419	8,267

($ Thousands, except volume and bbl amounts)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Blended bitumen sales	$ 176,987	$ 19,500	$ 316,490	$ 40,602
Cost of diluent	(93,101)	(9,545)	(171,051)	(25,901)
Total bitumen sales	83,886	9,955	145,439	14,701
Realized gain on commodity risk management contracts	735	—	3,026	—
Royalties	(1,696)	(114)	(3,101)	(139)
Operating expenses - non-energy	(26,140)	(11,630)	(53,078)	(27,694)
Operating expenses - energy	(13,696)	(3,048)	(24,152)	(6,468)
Transportation and marketing	(15,693)	(7,078)	(28,399)	(15,390)
Thermal Oil Operating Income (Loss)(1)	$ 27,396	$ (11,915)	$ 39,735	$ (34,990)
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 47.30	$ 33.70	$ 46.73	$ 26.99
Bitumen sales ($/bbl)	$ 31.82	$ 24.51	$ 30.75	$ 13.88
Realized gain on commodity risk management contracts ($/bbl)	0.28	—	0.64	—
Royalties ($/bbl)	(0.64)	(0.28)	(0.66)	(0.13)
Operating expenses - non-energy ($/bbl)	(9.92)	(28.64)	(11.22)	(26.15)
Operating expenses - energy ($/bbl)	(5.20)	(7.50)	(5.11)	(6.11)
Transportation and marketing ($/bbl)	(5.95)	(17.43)	(6.00)	(14.53)
THERMAL OIL OPERATING NETBACK(1) ($/bbl)	$ 10.39	$ (29.34)	$ 8.40	$ (33.04)

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP Financial Measures.

Thermal Oil Segment Income (Loss)

($ Thousands)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Thermal Oil Operating Income (Loss)(1)	$ 27,396	$ (11,915)	$ 39,735	$ (34,990)
Unrealized gain on commodity risk management contracts	8,243	—	15,457	—
Depletion and depreciation	(17,952)	(5,302)	(32,624)	(11,997)
Acquisition expense	(3,400)	—	(11,047)	—
Gain (loss) on sale of assets	35	—	(271)	—
Exploration expenses and other	(75)	(76)	(212)	(221)
THERMAL OIL SEGMENT INCOME (LOSS)	$ 14,247	$ (17,293)	$ 11,038	$ (47,208)

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP Financial Measures.

The increases in depletion and depreciation expense in the three and six months ended June 30, 2017, compared to 2016, were primarily due to the Leismer Corner Acquisition.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Leismer Project[1]	$ 7,573	$ —	$ 12,905	$ —
Hangingstone Project	5,700	1,818	11,032	2,478
Other Thermal Oil exploration	854	369	1,057	616
TOTAL THERMAL OIL CAPITAL EXPENDITURES[2]	$ 14,127	$ 2,187	$ 24,994	$ 3,094

(1) Thermal Oil capital expenditures in the table above exclude the cost of the Leismer Corner Acquisition.
(2) For the three and six months ended June 30, 2017, capital expenditures included $2.2 million and $2.9 million in capitalized staff costs, respectively (June 30, 2016 - $0.4 million, $0.7 million).

Thermal Oil capital expenditures for the six months ended June 30, 2017 were primarily related to downhole pump conversions and replacements, an enhanced diluent recovery project and the tie-in of previously drilled infill wells at Leismer. In response to lower commodity prices, the Company has reduced its 2017 capital budget to $60 million from its initial 2017 budget of $105 million, with near-term activity focused on production optimization across the field.

Sale of Contingent Bitumen Royalty to Burgess

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

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

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

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

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

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

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

During the six months ended June 30, 2017, no amounts were payable in respect of the Royalty to Burgess.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

Balance sheet strength and flexibility continues to remain a key priority for Athabasca and the Company's objective in managing capital is to maintain sufficient available reserves to meet its liquidity requirements at any point in time. The Company expects to achieve this objective through disciplined capital spending, an active commodity risk management program and by maintaining sufficient funds for anticipated short-term spending in cash, cash equivalent and short-term investment accounts and through available credit facilities.

As at June 30, 2017, Athabasca had $293.5 million of cash and cash equivalents (including $113.9 million of restricted cash - see page 13). The Company also had available credit of $61.9 million under its New Credit Facility (see below) and additional funding available through the capital-carry receivable from Murphy of $189.3 million (undiscounted).

Going forward, it is anticipated that Athabasca's Light Oil and Thermal Oil capital and operating activities, based on current business plans, will be funded through cash flow from operations, the capital-carry receivable, existing cash and cash equivalents and available credit facilities. Any significant acceleration of Light Oil development activities, future expansion of the Company's Thermal Oil projects, or a prolonged period of commodity price weakness, may require the Company to secure 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 at the time and the current state of the equity and debt capital markets.

Indebtedness

As at ($ Thousands)	June 30, 2017	December 31, 2016
2022 Notes[(1)]	$ 584,212	$ —
2017 Notes	—	550,000
Debt issuance costs[(1)]	(45,497)	(21,664)
Amortization of debt issuance costs	2,484	17,873
TOTAL LONG-TERM DEBT	$ 541,199	$ 546,209

(1) As at June 30, 2017, the US dollar denominated 2022 Notes and associated debt issuance costs were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.2983.

Throughout 2016 and early 2017, Athabasca repositioned its capital structure through a series of refinancing transactions which included:

- the repayment of the Company's US$225 million senior secured first lien term loan (the "Term Loan") in the second quarter of 2016;
- the issuance of US$450.0 million (C$589.0 million) of senior secured second lien notes on February 24, 2017 (the "2022 Notes"), the proceeds of which were used to retire the Company's existing C$550.0 million of senior secured second lien notes which were due later in 2017 (the "2017 Notes"); and,
- the establishment of a new $120 million reserve-based credit facility (the "New Credit Facility").

This balance sheet refinancing provides a multi-year funding platform, a strong liquidity outlook and will allow the Company to advance its strategic objectives and maintain business flexibility.

2022 Notes

The 2022 Notes bear interest at a rate of 9.875% per annum, payable semi-annually, and have a term of five years maturing on February 24, 2022. At any time prior to February 24, 2019, Athabasca has the option to redeem the 2022 Notes at the make whole redemption price set forth in the 2022 Notes indenture. 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

New Credit Facility

The New Credit Facility, which was reaffirmed by the lenders on May 31, 2017, is a $120 million, 364 day committed facility available on a revolving basis until May 31, 2018, at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and any amount outstanding would be required to be repaid at the end of the non-revolving term, being May 31, 2019. The New Credit Facility is subject to a semi-annual borrowing base review of the Company's Light Oil and Thermal Oil properties with the next review occurring in the fourth quarter of 2017. The borrowing base of the New Credit Facility will be based on the lender's evaluation of the Company's petroleum and natural gas reserves at the time and their commodity price outlook.

Amounts borrowed under the New Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, LIBOR or bankers' acceptance rate, plus a margin of 4.5%. The Company also incurs a standby fee on the undrawn portion of the New Credit Facility of 1.125%. As at June 30, 2017, the Credit Facility had $58.1 million of letters of credit issued and outstanding.

Cash-Collateralized Letter of Credit Facility

Athabasca maintains a $110.0 million bilateral 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 used to satisfy certain financial assurance requirements under Athabasca's long-term transportation agreements. Under the terms of the Letter of Credit Facility, Athabasca is required to contribute cash to a cash-collateral account equivalent to 101% of the value of all letters of credit issued under the facility. As at June 30, 2017, Athabasca had $109.6 million in letters of credit issued under the Letter of Credit Facility, as well as $113.9 million in restricted cash that was primarily related to the Letter of Credit Facility.

Financing and Interest

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	2017	2016	2017	2016
Financing and interest expense on indebtedness	$ 15,595	$ 16,917	$ 30,285	$ 35,101
Amortization of debt issuance costs	2,597	8,583	7,696	10,438
Accretion of provisions	2,204	1,901	4,072	3,861
TOTAL FINANCING AND INTEREST	$ 20,396	$ 27,401	$ 42,053	$ 49,400

During the three and six months ended June 30, 2017, financing and interest expenses were primarily attributable to the Company's 2022 Notes and 2017 Notes, including $3.0 million related to the acceleration of remaining debt issuance costs associated with the 2017 Notes which were repaid in the first quarter of 2017. Athabasca also incurred fees related to its New Credit Facility and Letter of Credit Facility.

During the three and six months ended June 30, 2016, financing and interest expenses were primarily attributable to Athabasca's 2017 Notes and Term Loan, including $6.8 million related to the acceleration of remaining debt issuance costs associated with the Term Loan repayment and Credit Facility amendments in the second quarter of 2016. Athabasca also incurred standby fees and fees on issued letters of credit.

Foreign Exchange Gain (Loss), Net

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	2017	2016	2017	2016
Unrealized foreign exchange gain (loss)	$ 14,166	$ —	$ 4,252	$ —
Realized foreign exchange gain (loss)	(1,839)	697	(1,807)	19,882
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 12,327	$ 697	$ 2,445	$ 19,882

During the first quarter of 2017, Athabasca became exposed to foreign currency risk on the principal and interest components of its newly issued US dollar denominated 2022 Notes. For the six months ended June 30, 2017, the Company recognized a net foreign exchange gain of $2.4 million primarily due to an unrealized gain on the note principal as the average value of the Canadian dollar improved relative to the US dollar from the date the notes were issued to the end of the second quarter from 1.31:1 to 1.30:1. The unrealized gain in 2017 was partially offset by a realized loss primarily resulting from US denominated revenue settlements.

During the six months ended June 30, 2016, Athabasca was exposed to foreign currency risk on the principal and interest components of it US dollar denominated Term Loan and recognized a net foreign exchange gain of $19.9 million primarily due to a realized gain on the loan principal as the average value of the Canadian dollar increased relative to the US dollar from 1.38:1 to 1.29:1 from the beginning of the year until the date of the repayment of the Term Loan.

Risk Management Contracts

Following the Leismer Corner Acquisition, Athabasca commenced a commodity risk management program designed to support a base level of cash flow and capital spending.

As at June 30, 2017, Athabasca has the following risk management contracts in place:

Instrument (CAD)	Period	Volume		Average Price/ Unit
WCS fixed price swaps	February - December 2017	8,000 bbl/d	$	52.66
WTI fixed price swaps	February - December 2017	4,000 bbl/d	$	73.02
WTI/WCS differential fixed price swaps	February - December 2017	4,000 bbl/d	$	(20.25)
WTI/WCS differential fixed price swaps	April - December 2017	8,000 bbl/d	$	(19.68)
WTI costless collar	April - December 2017	1,000 bbl/d	$	65.00 - 79.00
WTI costless collar	June - December 2017	3,000 bbl/d	$	61.67 - 68.67
WTI fixed price swaps	June - December 2017	4,000 bbl/d	$	68.05

The following table summarizes the Company's net gain (loss) on risk management contracts during the three and six months ended June 30, 2017 and 2016:

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	2017	2016	2017	2016
COMMODITY CONTRACTS				
Unrealized gain on commodity risk management contracts	$ 8,243	$ —	$ 15,457	$ —
Realized gain on commodity risk management contracts	735	—	3,026	—
FOREIGN EXCHANGE CONTRACTS				
Realized loss on foreign exchange risk management contracts	—	(1,679)	—	(21,628)
GAIN (LOSS) ON RISK MANAGEMENT CONTRACTS (NET)	$ 8,978	$ (1,679)	$ 18,483	$ (21,628)

During the three and six months ended June 30, 2017, Athabasca recognized a net gain on risk management contracts primarily due to declines in WTI and WCS benchmark prices, partially offset by narrowing in the WTI/WCS differential, from the effective date of the contracts to the end of the second quarter of 2017.

During the six months ended June 30, 2016, Athabasca recognized a loss on risk management contracts of $21.6 million related to a foreign currency derivative put in place with respect to the Company's US dollar denominated Term Loan.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at June 30, 2017 for the following five years and thereafter:

($ Thousands)	2017	2018	2019	2020	2021	Thereafter	Total
Transportation	$ 49,099	$ 95,916	$ 65,903	$ 105,037	$ 102,946	$ 1,771,497	$ 2,190,398
Repayment of long-term debt(1)	—	—	—	—	—	584,212	584,212
Interest expense on long-term debt(1)	29,006	58,172	58,172	58,172	58,172	29,326	291,020
Office leases	1,226	2,452	2,452	2,452	2,452	9,356	20,390
Purchase commitments and other	8,374	2,976	—	—	—	—	11,350
TOTAL COMMITMENTS	$ 87,705	$ 159,516	$ 126,527	$ 165,661	$ 163,570	$ 2,394,391	$ 3,097,370

(1) The 2022 Notes and associated interest expense were translated into Canadian dollars at the June 30, 2017 exchange rate of US$1.00 = C$1.2983.

During the first quarter of 2017, Athabasca acquired firm service on the Trans Mountain Pipeline Expansion (the "TMX Pipeline") by entering into a long-term transportation service agreement with Trans Mountain Pipeline L.P. to deliver up to 20,000 bbl/d of the Company's blended bitumen from Edmonton, Alberta to Burnaby, B.C., starting in late 2019. The TMX Pipeline commitment has been included in the above table.

In conjunction with the Leismer Corner Acquisition, Statoil reassigned to Athabasca its existing commitment for the transportation of blended bitumen on the Enbridge Waupisoo pipeline. As at June 30, 2017, the remaining commitment was $58.9 million which expired at various times through 2021. Subsequent to the second quarter, Athabasca entered into a new long-term transportation agreement with Enbridge Pipelines (Athabasca) Inc. for the delivery of up to 33,000 bbl/d of blended bitumen which will replace the existing Waupisoo commitment. The new agreement has an effective date of July 1, 2017 and Athabasca's new minimum discounted commitment associated with the Waupisoo pipeline will be approximately $127.7 million based on Athabasca's credit-adjusted discount rate of 10% ($207 million undiscounted). The net increase in the commitment has not been reflected in the above table.

A second transportation commitment was reassigned by Statoil to Athabasca for the transportation of diluent to the Leismer Project's central processing facility. This commitment has been included in the above table.

Other Corporate Items

General and administrative ("G&A")

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	2017	2016	2017	2016
TOTAL GENERAL AND ADMINISTRATIVE	$ 7,066	$ 5,455	$ 13,494	$ 12,442
G&A per boe	$ 2.15	$ 5.46	$ 2.35	$ 5.62

During the three and six months ended June 30, 2017, Athabasca's general and administrative expenses increased compared to the same periods in the prior year, primarily reflecting higher employee costs related to the Leismer Corner Acquisition. However, for the same time periods, G&A per boe decreased 61% and 58% primarily due to higher production volumes in both the Thermal and Light Oil Divisions. The Company believes it has sufficient resources in place to support planned capital and operating activities over the next several years which is expected to result in further reductions to per unit general and administrative costs.

Stock-based compensation

During the six months ended June 30, 2017, stock-based compensation expense decreased from $4.7 million to $3.2 million compared to the same period in the prior year. The decrease was primarily due to a lower average balance of units outstanding under the 2010 RSU compensation plan which had carried higher fair values per award relative to the other plans.

Gain on Revaluation of Provisions and Other

During the six months ended June 30, 2017, Athabasca incurred a gain of $16.4 million relating to a decline in the fair value of the Company's contingent payment obligation to Statoil, mainly due to declines in the forecasted price for WTI, from the date of closing of the Leismer Corner Acquisition on January 31, 2017 to the end of the second quarter of 2017. The contingent payment obligation is remeasured at each reporting period with any gains or losses recognized in net income. No amounts are currently payable with respect to the continent payment obligation.

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

On January 31, 2017, Athabasca issued 100 million common shares to Statoil in respect of the Leismer Corner Acquisition. During the six months ended June 30, 2017, Athabasca also issued 2.5 million common shares in respect of the Company’s equity-settled share-based compensation plans.

Outstanding Share Data

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

As at July 20, 2017	
Common shares issued and outstanding	508,998,329
Convertible securities:	
Stock options	13,840,976
Restricted share units (2010 RSU Plan)	3,643,965
Restricted share units (2015 RSU Plan)	9,582,696
Performance share units	4,093,667
Deferred share units	1,669,323

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

SUMMARY OF QUARTERLY RESULTS

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

	2017		2016				2015	
($ Thousands, except share and per barrel amounts)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	48.29	51.91	49.29	44.94	45.59	33.45	42.18	46.43
WTI (C$/bbl)	64.95	68.52	65.56	58.87	58.81	45.83	56.52	60.82
Western Canadian Select (C$/bbl)	49.99	49.34	46.61	41.01	41.62	26.30	36.86	43.29
Edmonton Par (C$/bbl)	61.92	63.87	61.59	54.66	54.78	40.67	52.85	56.17
Edmonton Condensate (C5+) (C$/bbl)	65.15	68.73	63.38	55.31	56.80	46.32	54.52	56.94
NYMEX Henry Hub (US$/MMBtu)	3.19	3.32	2.98	2.81	1.95	2.09	2.27	2.80
AECO (C$/GJ)	2.64	2.55	2.93	2.20	1.32	1.74	2.33	2.75
Foreign exchange (CAD : USD)	1.34	1.32	1.33	1.31	1.29	1.37	1.34	1.31
LIGHT OIL DIVISION								
Sales volumes (boe/d)	7,246	3,421	3,337	3,018	5,743	6,319	5,873	5,145
Realized price ($/boe)	36.69	38.97	35.99	29.84	26.93	21.73	27.39	31.34
Revenues ($)[2]	23,169	11,607	10,607	8,091	13,936	12,440	17,624	14,043
Light Oil Operating Income ($)[1]	16,391	6,863	6,152	5,511	7,215	4,908	10,551	6,096
Light Oil Operating Netback ($/boe)[1]	24.85	22.28	20.04	19.85	13.80	8.53	19.50	12.88
Capital expenditures ($)	31,061	77,646	62,003	18,920	5,518	30,658	50,921	31,465
Recovery of the capital-carry receivable ($)	(13,493)	(10,680)	(52)	(4,286)	(1,474)	—	—	—
THERMAL OIL DIVISION								
Bitumen production (bbl/d)[3][4]	29,328	23,316	8,293	8,830	5,358	7,029	5,708	2,105
Sales volumes (bbl/d)[3][4]	28,970	23,257	8,015	9,744	4,463	7,176	4,096	1,792
Realized bitumen price ($/bbl)[5]	31.82	29.41	31.46	28.56	24.51	7.27	21.23	17.54
Revenues ($)[2]	175,291	138,098	44,058	45,124	19,386	21,076	15,033	6,145
Thermal Oil Operating Income (Loss) ($)[1][4][5]	27,396	12,341	(4,719)	(6,088)	(11,915)	(23,074)	(18,166)	(12,146)
Thermal Oil Operating Netback ($/bbl)[1][4][5]	10.39	5.89	(6.41)	(6.80)	(29.33)	(35.34)	(48.22)	(73.67)
Capital expenditures	14,127	10,868	4,088	3,754	2,187	916	2,257	9,366
OPERATING RESULTS								
Cash Flow from Operations ($)	28,049	(52,896)	(19,656)	(18,990)	5,759	(38,017)	(54,496)	(17,933)
Funds Flow from Operations ($)[1]	27,567	(1,649)	(16,867)	(15,778)	(27,304)	(39,982)	(30,141)	(24,223)
Net income (loss) ($)	24,233	(29,162)	(779,405)	(33,032)	(59,169)	(65,129)	(604,375)	(38,241)
Net income (loss) per share - basic ($)	0.05	(0.06)	(1.92)	(0.08)	(0.15)	(0.16)	(1.50)	(0.09)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	179,611	212,999	650,301	535,477	447,282	493,510	559,487	671,447
Short-term investments ($)	—	—	—	35,000	25,533	—	—	—
Restricted cash ($)	113,853	113,823	107,012	103,827	101,652	—	—	—
Capital-carry receivable (discounted) ($)[6]	173,714	183,745	191,174	188,448	188,742	—	—	—
Promissory notes ($)[6]	—	—	—	—	133,892	133,892	133,892	133,892
Assets held for sale ($)	—	—	—	—	—	466,159	—	—
Total assets ($)	2,488,995	2,524,187	2,257,887	3,017,285	3,028,938	3,394,367	3,462,442	4,160,344
Long-term debt ($)[6]	541,199	553,377	546,209	545,126	544,042	820,478	838,205	827,773
Shareholders' equity ($)	1,723,735	1,695,582	1,557,097	2,333,523	2,363,396	2,419,651	2,482,140	3,085,499

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP financial measures.
(2) Consists of petroleum and natural gas sales and midstream revenues, net of royalties. Excludes interest income and other.
(3) Q3 2015 includes capitalized volumes.
(4) Athabasca capitalized initial operating results of the Hangingstone Project until it was deemed ready for use in the manner intended by management on August 1, 2015. Operating results and sales volumes prior to August 1, 2015 have been capitalized and excluded from the calculation of the Thermal Oil Operating Loss and Netback.
(5) Figures include the impact of realized gains on commodity risk management contracts.
(6) Balances include the current and long-term portions as reported in the consolidated balance sheets.

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

ACCOUNTING POLICIES AND ESTIMATES

During the six months ended June 30, 2017, there were no changes to Athabasca's accounting policies or use of estimates in the preparation of the consolidated financial statements and the notes thereto that had a material impact to the consolidated financial statements. Refer to the December 31, 2016 audited consolidated financial statements of the Company for further guidance regarding Athabasca's accounting policies and use of estimates.

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

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

The following table reconciles cash flow from operating activities in the consolidated financial statements for the three and six months ended June 30, 2017 and 2016 to Funds Flow from Operations:

($ Thousands)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Cash flow from operating activities	$ 28,049	$ 5,759	$ (24,851)	$ (32,268)
Acquisition expenses	3,400	—	11,047	—
Receipt of proceeds from derivative unwind	—	(40,956)	—	(40,956)
Changes in non-cash working capital	(4,437)	5,071	34,645	1,299
Settlement of provisions	555	1,774	5,074	3,222
Other items	—	1,048	—	1,283
FUNDS FLOW FROM OPERATIONS	$ 27,567	$ (27,304)	$ 25,915	$ (67,420)

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

The Light Oil Operating Income and Light Oil Operating Netback measures in this MD&A are calculated by subtracting royalties and operating and transportation expenses from petroleum and natural gas sales and midstream revenues received. The Light Oil Operating Netback measure is presented on a per boe basis. The Light Oil Operating Income and the Light Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil assets. The table on page 6 reconciles Light Oil Operating Income to *Note 12 - Segmented Information* in the consolidated financial statements for the six months ended June 30, 2017.

The Operating Income 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 expenses from blended bitumen sales. The consolidated Thermal Oil Operating Income and Operating Netback measures also include realized gains on commodity risk management contracts. The Thermal Oil Operating Netback measure is presented on a per bbl basis. The Thermal Oil Operating Income 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 10 reconciles Thermal Oil Operating Income to *Note 12 - Segmented Information* in the consolidated financial statements for the six months ended June 30, 2017.

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 2017 exploration and development budget and Athabasca's capital expenditure programs;
- failure to realize anticipated benefits of acquisitions or divestments, including the Leismer Corner Acquisition;

- uncertainties inherent in estimating quantities of Proved Reserves, Probable Reserves and Contingent Resources;
- the timing of certain of Athabasca's operations and projects, including the commencement of its planned Thermal Oil Division development projects, the exploration and development of Athabasca's Light Oil assets and the levels and timing of anticipated production;
- the timing of the project activities related to the Hangingstone Project included the timing of the ramp-up of Hangingstone Project production to nameplate capacity;
- 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 petroleum, natural gas and oil sands 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;
- 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;
- 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;
- 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;
- the potential for future joint venture arrangements;
- insurance risks;
- hedging risks;
- variations in foreign exchange and interest rates;
- risks related to the New Credit Facility, the Letter of Credit Facility and the 2022 Notes;
- risks related to the Common Shares.

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;
- actions taken by the new American administration, including the potential renegotiation of the terms of the North American Free Trade Agreement, the withdrawal of the United States from the Trans-Pacific Partnership and the imposition of taxes on the importation of goods into the United States;
- aboriginal claims;
- risks associated with establishing and maintaining systems of internal controls;
- 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 five-year growth outlook and that such growth outlook is funded; the benefits expected to be realized by the Company from offering of 2022 Notes and the New 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 2017 corporate, Thermal Oil and Light Oil production levels and base decline rates; estimates of future depletion rates on the Hangingstone Project; the expectation that operating and transportation expenses will decrease at Hangingstone; the in-service date of the TMX Pipeline and the benefits Athabasca expects to realize by having capacity thereon; estimates of 2017 funds flow from operations, operating income and capital expenditures; the capability of the Company's five-year development outlook to deliver potential growth in per share production; the estimated impact of the Royalty on the economics of future expansion phases and development projects; future drilling and completion plans; the timing for achievement of name plate capacity at the Hangingstone Project the timing of facilities construction and in service dates and the capacity thereof; the timing of 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 2017 capital budget; the Company's anticipated sources of funding for 2017 and beyond; the Company's estimate future minimum capital commitments; the future allocation of capital; and other matters.

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

With respect to forward-looking information contained in this MD&A, assumptions have been made regarding, among other things: that Athabasca and its security holders will obtain the anticipated benefits from the 2022 Notes and the New Credit Facility; commodity prices, including for petroleum, natural gas and blended bitumen; the regulatory framework governing royalties, taxes and environmental matters in the jurisdiction in which the Company conducts and will conduct business and the effects that such regulatory framework will have on the Company, including on the Company's financial condition and results of operations; the Company's financial and operational flexibility; the Company's financial sustainability; Athabasca's cash flow break-even commodity price; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the applicability of technologies for the recovery and production of the Company's reserves and resources; future capital expenditures to be made by the Company; future sources of funding for the Company's capital programs; the Company's future debt levels; future production levels; the Company's ability to obtain financing and/or enter into joint venture arrangements, on acceptable terms; operating costs; compliance of counterparties with the terms of contractual arrangements; impact of increasing competition; collection risk of outstanding accounts receivable from third parties; geological and engineering estimates in respect of the Company's reserves and resources; recoverability of reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities and the quality of its assets.

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company's most recent AIF available on SEDAR at www.sedar.com, including, but not limited to: weakness in the oil and gas industry; fluctuations in market prices for crude oil, natural gas and bitumen blend; general economic, market and business conditions in Canada, the United States and globally; insurance risks; claims made in respect of Athabasca's operations, properties or assets; the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements; global financial uncertainty; failure to realize anticipated benefits of acquisitions or divestments; risks related to hydraulic fracturing; factors affecting potential profitability; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time; risks relating to changing royalty regimes; additional funding requirements and liquidity risk; variations in foreign exchange and interest rates; environmental risks and hazards and the cost of compliance with environmental regulations, including the licensee liability rating program, seismic activity regulations, greenhouse gas regulations and potential Canadian and U.S. climate change legislation; risks related to the Murphy Transaction, dependence on Murphy as the operator of the Greater Kaybob assets, dependence on Murphy as the Company's joint venture participant in the Company's Greater Kaybob and Greater Placid assets and dependence on Murphy's continued ability to pay the Greater Kaybob carry commitment, risks associated with events of force majeure; risks related to the New Credit Facility, the Letter of Credit Facility and the 2022 Notes; geopolitical risks; uncertainties inherent in estimating quantities of reserves and resources; contractual counterparty risks and operational dependence; risks related to future acquisition and joint venture activities; risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources, including the production of oil sands reserves and resources using SAGD, TAGD or other in-situ recovery technologies; failure to meet development schedules and potential cost overruns; aboriginal claims; reliance on, competition for, loss of, and failure to attract key personnel; financial assurance covenants and collateral requirements under the Company's pipeline transportation agreements; risks related to gathering and processing facilities and pipeline systems; availability of drilling and related equipment and limitations on access to Athabasca's assets; increases in operating costs could make Athabasca's projects uneconomic; the effect of diluent and natural gas supply constraints and increases in the costs thereof; costs of new technologies; alternatives to and changing demand for petroleum products; gas over bitumen issues affecting operational results; risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments; failure to accurately estimate abandonment and reclamation costs; the potential for management estimates and assumptions to be inaccurate; long-term reliance on third parties; reliance on third party infrastructure; seasonality; risks associated with establishing and maintaining systems of internal controls; competition for, among other things, capital, the acquisition of reserves and resources, export pipeline capacity and skilled personnel; expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits; breaches of confidentiality; inaccuracy of forward-looking information; expansion into new activities; risks related to the Common Shares.

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

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

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

Reserves and Resource Information

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

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

Oil and Gas Information

"Boe" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Drilling Locations

The 1,500 Duvernay drilling locations referenced on page 5 of this MD&A include: 31 proved undeveloped or non-producing locations and 42 probable undeveloped locations for a total of 73 undeveloped booked locations with the balance being unbooked locations. The 200 Montney drilling locations referenced on page 5 of this MD&A include: 34 proved undeveloped and 12 probable undeveloped locations, for a total of 46 undeveloped booked locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by GLJ as of December 31, 2016 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur over the next two decades based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, oil and natural gas prices, provincial fiscal and royalty policies, costs, actual drilling results and additional reservoir information that is obtained and other factors.

Definitions

"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, 2016, the Company is reporting Contingent Resources on a risked and unrisked basis located in its: Hangingstone asset area in the Development Pending project maturity sub-class; and, Hangingstone, Dover West Sands and Birch asset areas for Development On Hold and Development Unclarified project maturity sub-classes.

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

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

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

"**Risked**" 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
G&A	general and administrative
LIBOR	London interbank offered rate
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	millions of barrels
MMboe	millions of barrels of oil equivalent
MMBtu	million British thermal units
NYMEX	New York Mercantile Exchange
OPEC	Organization of the Petroleum Exporting Countries
SAGD	steam assisted gravity drainage
SOR	steam to oil ratio
TAGD	thermal assisted gravity drainage
US$	United States Dollars
WTI	West Texas Intermediate
WCS	Western Canadian Select