Management Discussion and Analysis
For the Three and Nine Months Ended September 30, 2015

Approved for Issuance by the Board of Directors on November 12, 2015

The following management's discussion and analysis ("MD&A") for Argent Energy Trust (the "Trust" or "Argent"), dated November 12, 2015, should be read in conjunction with unaudited interim consolidated financial statements for the period ended September 30, 2015, the audited annual consolidated financial statements for the year ended December 31, 2014, and the MD&A for the year ended December 31, 2014 that are available on www.sedar.com and on the Trust's website at www.argentenergytrust.com.

The Trust's unaudited interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), specifically International Accounting Standard ("IAS") 34, Interim Financial Reporting. Items included in the financial statements of each of the Trust's subsidiaries are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The unaudited interim consolidated financial statements are presented in Canadian dollars, which is the functional and presentation currency of the Trust. Figures within this MD&A are presented in Canadian dollars unless otherwise indicated.

Certain information contained in this MD&A constitutes "forward-looking statements". Investors should read the "Note about Forward Looking Statements" section at the end of this MD&A.

Non-IFRS Financial Measure

Statements throughout this MD&A make reference to the term "netbacks", which is a non-IFRS financial measure that does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers. Management believes that "netbacks" provides useful information to investors and management since this measure is commonly used by other oil and gas companies. "Netbacks" is equal to oil, natural gas and NGL sales revenue less royalties, transportation costs, production taxes and operating expenses. Other financial data has been prepared in accordance with IFRS.

Additional GAAP Measure

In this MD&A, the Trust refers to an additional GAAP measure that does not have any standardized meaning as prescribed by IFRS. "Funds flow from operations" is considered an additional GAAP measure and is equal to cash provided by operating activities, before changes for non-cash working capital, as stated in the Trust's unaudited interim consolidated financial statements. We believe funds flow from operations, which is not impacted by fluctuations in non-cash working capital balances, is more indicative of operational performance.

Overview of the Trust

The Trust is an unincorporated limited purpose open-ended trust established under the laws of the Province of Alberta. The Trust operates as a foreign asset trust with properties held in the U.S. therefore the Trust is not subject to the same taxation rules applicable to a Canadian Specified Investment Flow Through ("SIFT") trust.

The Trust's main objective is to provide a return to its unitholders through the acquisition and development of oil, and natural gas reserves and production with low risk exploration potential. The Trust owns, operates and manages oil and gas properties located primarily in South Texas, and Wyoming, U.S., with drilling opportunities in numerous horizons across its acreage.

The Trust was created on January 31, 2012 and owns all of the issued and outstanding shares of Argent Energy (Canada) Holdings Inc. ("Canada Holdco"), which in turn owns all of the issued and outstanding shares of Argent Energy (US) Holdings Inc. ("US Opco"). Canada Holdco was incorporated on May 4, 2012 to acquire and hold all of the issued and outstanding shares of US Opco. US Opco was incorporated on May 4, 2012 to acquire, develop and operate oil and gas assets in the United States.

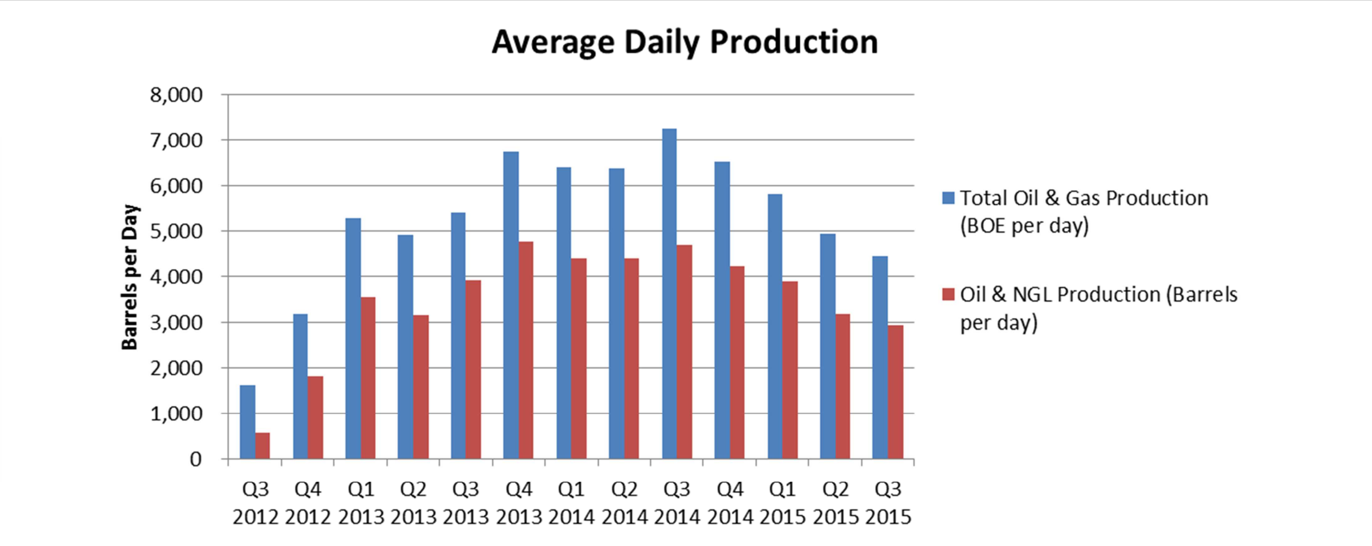
Throughout this MD&A, Argent Energy Trust and its subsidiaries are collectively referred to as the "Trust" or "Argent" for purposes of convenience. In addition, references to the results of operations refer to operations of the Trust's U.S. subsidiary, US Opco.

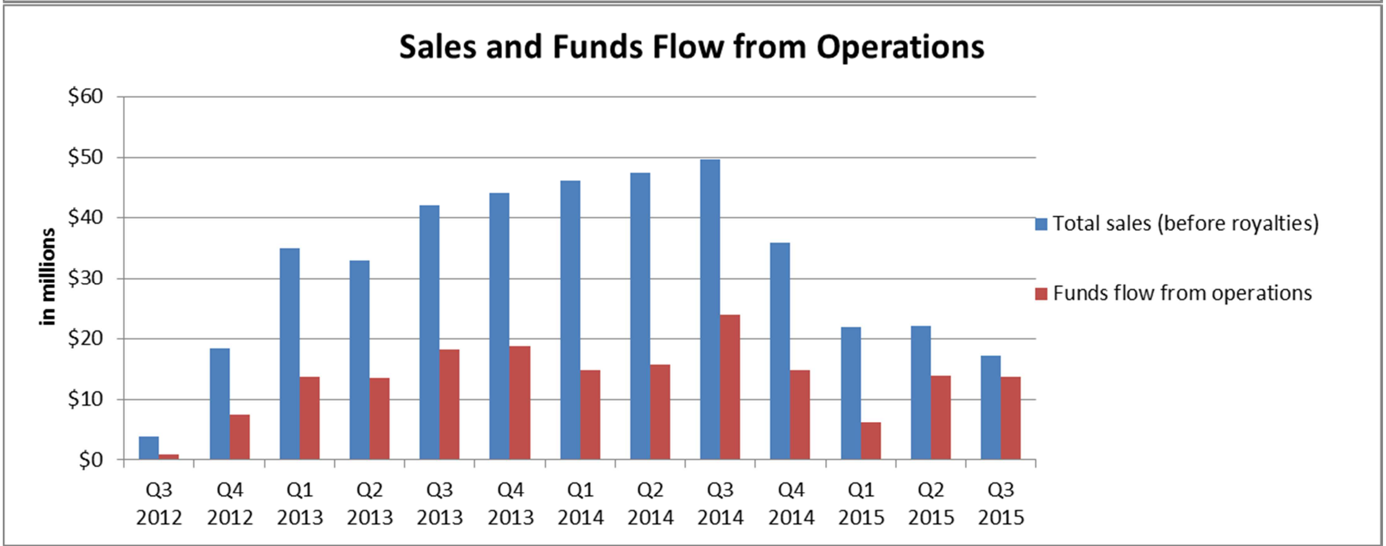
Highlights for the three months ended September 30, 2015

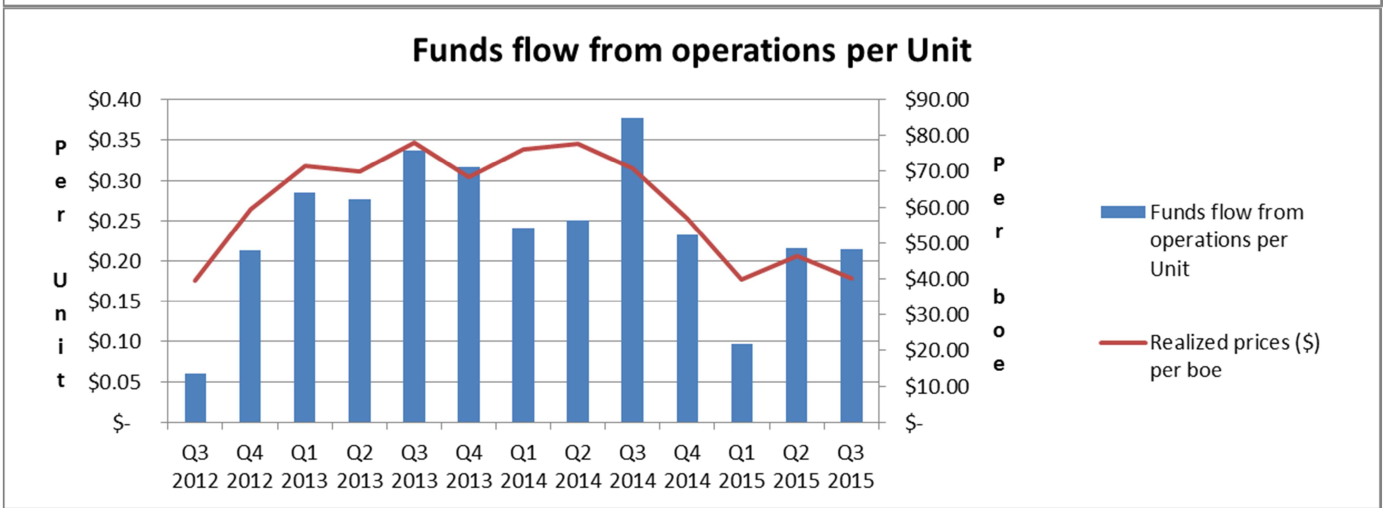
- After adjusting for the strategic divestitures in Q2 2015, production for Q3 2015 increased sequentially by 3% to 4,455 boe/d, from 4,311 boe/d in Q2 2015. The increase was due to new production from the capital drilling incurred in the first half of 2015 in the Wyoming properties, offset by natural declines.
- Q3 2015 production was 4,455 boe/d (66% oil and NGL), representing a reduction of 39% from Q3 2014 at 7,264 boe/d, primarily due to the strategic divestitures of the Manvel and Mid-Continent properties during Q2 2015 and the natural decline of Eagle Ford and South Escobas wells.
- Oil & gas revenue decreased to $17.1 million from $49.7 million in Q3 2014, mainly due to lower oil & gas prices in Q3 2015 and lower production. The average WTI oil price decreased by 43% from $106.57 per barrel in Q3 2014 to $60.84 per barrel in Q2 2015. The average Henry Hub natural gas price decreased by 16% from $4.32 per mmBTU in Q2 2014 to $3.61 per mmBTU in Q3 2015.
- Q3 2015 operating expense excluding workovers was reduced to an average of US$9.37 (CAD$12.27) per boe, from US$12.57 (CAD$13.68) per boe in Q3 2014, due to ongoing efforts to improve efficiencies and the divestiture of the Mid-Continent assets which historically had high operating costs relative to the remaining fields.
- Netbacks from sales volume for Q3 2015 were $5.0 million, or $12.28 per boe, as compared to $25.7 million, or $38.47 per boe for Q2 2014, with the decrease being primarily due to lower oil and gas prices. An additional $0.7 million in netback was received from overriding royalties in Q3 2015, as compared to $2.2 million in Q3 2014.
- Reduced general and administrative ("G&A") expenses in US$ by 19% as compared to Q3 2014.

- Q3 2015 funds flow from operations was $13.8 million, or $0.21 per Unit, compared to $24.0 million, or $0.38 per Unit in Q3 2014, a decrease of 42% due to lower oil & gas prices and lower oil & gas production partially offset by lower administrative costs and the hedge gains realized during the quarter. Q3 2015 funds flow from operations was flat relative to the $13.9 million, or $0.22 per Unit in Q2 2015.
- Q3 2015 loss decreased to $95.1 million, or $1.48 per Unit, from Q3 2014 loss of $141.9 million, or $2.24 per Unit. The reduction in Q3 2015 loss was primarily due to lower depreciation, depletion and amortization and impairment expenses, which more than offset the decrease in funds flow from operations.

Note: Netbacks and funds flow from operations are non-IFRS financial and additional GAAP measures respectively. See the Non-IFRS Financial and Additional GAAP Measure sections in the beginning of this MD&A.


Average Daily Production
Barrels per Day
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Q3 2012
Q4 2012
Q1 2013
Q2 2013
Q3 2013
Q4 2013
Q1 2014
Q2 2014
Q3 2014
Q4 2014
Q1 2015
Q2 2015
Q3 2015
Total Oil & Gas Production (BOE per day)
Oil & NGL Production (Barrels per day)


Sales and Funds Flow from Operations
in millions
$60
$50
$40
$30
$20
$10
$0
Q3 2012
Q4 2012
Q1 2013
Q2 2013
Q3 2013
Q4 2013
Q1 2014
Q2 2014
Q3 2014
Q4 2014
Q1 2015
Q2 2015
Q3 2015
Total sales (before royalties)
Funds flow from operations


Funds flow from operations per Unit
Per Unit
$0.40
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$-
Per boe
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
Q3 2012
Q4 2012
Q1 2013
Q2 2013
Q3 2013
Q4 2013
Q1 2014
Q2 2014
Q3 2014
Q4 2014
Q1 2015
Q2 2015
Q3 2015
Funds flow from operations per Unit
Realized prices ($) per boe

Outlook

Argent is focused on maintaining liquidity and working through the current challenging low commodity price environment. Capital expenditures, operating costs and administrative costs have all been reduced significantly, and Argent continues to review areas for additional savings while prudently managing operations. Argent continues to generate positive cash-flow from operations.

Argent is US$65 million drawn on its US$80 million credit facility, which is subject to a semi-annual borrowing base redetermination that is ongoing. Based on current commodity prices, it is expected that the facility could be reduced. Argent is in active discussions with the banking syndicate regarding its borrowing base, an extension of the credit facility and other terms. Argent continues to advance and explore all alternatives to provide the necessary liquidity and capital to the Trust based on the current commodity pricing environment. The redetermination is expected to be completed by November 30, 2015.

Capital expenditures for the year are substantially completed, with Argent having participated in the drilling of eight Parkman oil wells in Wyoming. The capital expenditure budget for 2016 will be finalized upon completion of the credit facility discussions. Assuming the continuation or replacement of the facility, the capital budget is expected to be approximately US$12 million for 2016, again focused on the Parkman formation prospects. Argent has approximately 11,500 net acres with significant Parkman potential including 18 more drilling locations currently identified. Drilling results from the wells Argent has participated in indicate results in line with expected type curves.

The 2015 annual production target is approximately 4,500 boe/d (approximately 67% oil and NGLs), with a Q4 2015 production rate of approximately 4,000 boe/d to 4,100 boe/d, which is down from the previous forecast range of 4,300 boe/d to 4,400 boe/d due to earlier commencement of production from the successful Parkman wells drilled, such that the higher initial production output was received in Q3 2015 rather than previously expected Q4. For 2016, depending on the ability to finance the US$12 million capital budget noted above, Argent has an annual production rate target of approximately 3,700 boe/d (approximately 70% oil and NGLs). This target represents limited capital to be incurred due to the current commodity price outlook.

Argent has entered into the following risk management contracts to protect its future cashflow in a low commodity price environment:

	Oil (US$ / bbl)	Natural Gas (US$ per mmBtu)
Q4 2015	2,000 barrels per day at average US$91.72	6,000 mmBTU per day at average US$4.12
Year 2016	1,000 barrels per day at average US$65.45	4,000 mmBTU per day at average US$4.06

Results of Operations

Production and Oil, NGL and Natural Gas Sales

(Amounts in Cdn$)	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Oil volumes (bbl/d)	2,715	4,426	3,095	4,195
NGL volumes (bbl/d)	213	277	231	309
Natural gas volumes (mcf/d)	9,163	15,365	10,444	13,049
Total sales volumes (boe/d)	4,455	7,264	5,067	6,679
% Oil & NGL	66%	65%	66%	67%
Total BOE	409,817	668,230	1,383,143	1,823,238
Benchmark Prices:				
WTI crude oil spot ($/bbl)	$60.84	$106.57	$64.18	$109.38
Henry Hub natural gas Spot ($/MMBtu)	$3.61	$4.32	$3.53	$5.01
Realized sales prices:				
Oil ($/bbl)	$54.21	$100.70	$57.68	$102.70
NGLs ($/bbl)	$11.32	$33.85	$13.49	$36.51
Natural gas ($/mcf)	$3.14	$3.91	$3.01	$4.38
Per Boe	$40.04	$70.93	$42.06	$74.75
($000s):				
Oil sales	$13,538	$41,003	$48,738	$117,615
NGL sales	222	862	850	3,077
Natural gas sales	2,649	5,530	8,581	15,596
	$16,409	$47,395	$58,169	$136,288
Production payment and overriding royalty	737	2,285	3,066	7,178
Oil and gas sales, before royalties and risk management gain(loss)	$17,146	$49,680	$61,235	$143,466

Total oil and gas sales (excluding overriding royalty revenue) in Q3 2015 were $16.4 million, as compared to $47.4 million in Q3 2014. Total oil and gas sales (excluding overriding royalty revenue) for the nine months ended September 30, 2015 were $58.2 million, as compared to $136.3 million for the same period in 2014. The decrease in oil and gas sales was due primarily to lower oil & gas prices realized accompanied by lower sales volumes.

Sales volumes in Q3 2015 averaged 4,455 boe/d (66% oil and NGLs), as compared to 7,264 boe/d in Q3 2014. Sales volumes for the nine months ended September 30, 2015 averaged 5,067 boe/d, as compared to 6,679 boe/d for the same period in 2014. The decrease in sales volume was primarily due to the strategic divestitures of the Manvel and Mid-Continent assets in Q2 2015 and lower production volumes associated with the natural declines in the Eagle Ford oil wells and South Texas gas wells drilled in 2014. The decrease in sales volume was partially offset by increased production from the Trust's non-operated Wyoming assets, as a result of successful drilling in the Parkman and Turner formations in the first half of 2015.

Revenue from the Production Payment and overriding royalties was $0.7 million in Q3 2015 as compared to $2.3 million in Q3 2014. For the nine months ended September 30, 2015, revenue from the Production Payment and overriding royalties decreased to $3.1 million from $7.2 million for the same period in 2014. The decrease was due primarily to lower oil & gas prices and declining production operated by third parties.

The Production Payment is equivalent to approximately 3.4% net revenue interest in currently producing Eagle Ford oil production developed by a third party on certain leases in the Wilson and Gonzales Counties in Texas, and represents the equivalent of revenue from approximately 82 boe/d and 128 boe/d of additional production during the three months and nine months ended September 30, 2015, respectively.

	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
WTI crude oil spot ($/bbl)	$60.84	$106.57	$64.18	$109.38
Realized oil price ($/bbl)	$54.21	$100.70	$57.68	$102.70
Oil differential discount	($6.63)	($5.87)	($6.50)	($6.68)

The average realized oil price (excluding the effects of risk management contracts) was $54.21 per barrel in Q3 2015 as compared to $100.70 per barrel in Q3 2014. The average realized oil price for the nine months ended September 30, 2015 was $57.68 per barrel as compared to $102.70 per barrel for the same period in 2014. The majority of the decrease in oil prices realized for the Q3 2015 was driven by the significant decline in the average WTI price which began falling in early September 2014 and was partially offset in Canadian dollars term by the increase in value of the US dollar compared to the Canadian dollar. Due to the strategic divestitures in Q2 2015, the realized oil differential to WTI increased in Q3 2015 as compared to Q3 2014 as the oil production mix was more heavily weighted towards the Trust's Wyoming assets which have higher discounts to WTI.

Royalty and Production Taxes

($000s):	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Royalties	$3,292	$9,016	$11,348	$25,933
Production taxes:				
- on Oil, NGL and Natural Gas sales	627	1,846	1,963	5,225
- on Overriding royalty revenue	28	95	124	309
Total Royalties and production taxes	$3,947	$10,957	$13,435	$31,467

Royalties and production taxes for Q3 2015 totaled $3.9 million or 23% of oil and gas sales, as compared to $11.0 million or 22% of oil and gas sales in Q3 2014. Royalties and production taxes for the nine months ended September 30, 2015 totaled $13.4 million or 22% of oil and gas sales, as compared to $31.5 million or 22% of oil and gas sales for the same period in 2014.

Royalties and production taxes as a percentage of total oil and gas sales remained relatively consistent. Royalties are paid to mineral lease owners on acreages that have production, while production tax expenses are severance taxes paid to the State governments on mineral production based on the value and/or quantity of production. Depending on the commodity and state where the Trust operates, severance tax rates range from 4% to 8% of oil and gas sales.

Operating Expenses

($000s):	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating expenses:				
- on Oil, NGL and Natural Gas sales	$5,028	$9,143	$22,488	$28,253
- on Overriding Royalty revenue	-	(18)	(3)	11
Operating expenses (excluding workovers)	$5,028	$9,125	$22,485	$28,264
- Workovers	2,421	1,680	5,809	6,342
Total Operating Expenses	$7,449	$10,805	$28,294	$34,606

Note: Operating expenses exclude ad valorem taxes that are based on factors independent to the production volume.

$ per boe	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating expense excluding workovers (in US$)	$9.37	$12.57	$12.99	$14.16
Effect from US$/CAD$ exchange rate	2.89	1.11	3.27	1.34
Operating expense excluding workovers in CAD$	$12.27	$13.68	$16.26	$15.50
Change over the same period in prior year (in US$)	-25%		-8%	

Operating expenses excluding workovers relating to Oil, NGL and Natural Gas sales for Q3 2015 were approximately $5.0 million (US$3.8 million), or $12.27 per boe (US$9.37 per boe), as compared to $9.1 million (US$8.4 million), or $13.68 per boe (US$12.57 per boe) in Q3 2014. Operating expenses excluding workovers relating to Oil, NGL and Natural Gas sales for the nine months ended September 30, 2015 were approximately $22.5 million (US$18.0 million), or $16.26 per boe (US$12.99 per boe), as compared to $28.3 million (US$25.8 million), or $15.50 per boe (US$14.16 per boe) for the same period in 2014.

On a US$ per boe basis, Q3 2015 operating expenses excluding workovers decreased 25% as compared to Q3 2014. For the nine months ended September 30, 2015, operating expenses excluding workovers (US$ per boe) decreased 8% as compared to the same period in 2014. These decreases were due to concentrated and ongoing efforts to reduce costs and the divestiture of the Mid-Continent assets which historically had high operating costs relative to the remaining fields.

$ per boe	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Workover expenses in US$	$4.52	$2.31	$3.32	$3.18
Effect from US$/CAD$ exchange rate	1.39	0.20	0.88	0.30
Workover expenses in CAD$	$5.91	$2.51	$4.20	$3.48

Workover expenses in Q3 2015 were approximately $2.4 million (US$1.9 million), or $5.91 per boe (US$4.52 per boe), as compared to $1.7 million (US$1.5 million), or $2.51 per boe (US$2.31 per boe), in Q3 2014. Workover expenses for the nine months ended September 30, 2015 were approximately $5.8 million (US$4.6 million), or $4.20 per boe (US$3.32 per boe), as compared to $6.3 million (US$5.8 million), or $3.48 per boe (US$3.18 per boe), for 2014.

In Q3 2015, the Trust incurred higher workover costs as compared to Q3 2014 due to a small backlog of well work from previous quarters, an extended workover inclusive of fishing operations to remove a stuck object from the wellbore in Wyoming, recurring workovers, the repair of an Austin Chalk well eliminating the root problem and two unsuccessful attempts made in South Texas to test and return long term non-producing wells to production.

For the nine months ended September 30, 2015, workover expenses were lower as compared to the same period in 2014 as the Trust continues to target cost efficient projects in response to the low commodity price environment. The Trust expects workover expenses will be reduced going forward.

Netbacks

($000s):	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Net oil and gas revenue	$13,199	$38,723	$47,800	$111,999
Less:				
- Operating expenses	7,449	10,805	28,294	34,606
Total Netbacks	$5,750	$27,918	$19,506	$77,393

Netbacks ($/boe)	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Oil, NGL and Natural Gas sales (i)	$40.04	$70.93	$42.06	$74.75
Less:				
Royalties and Production taxes	9.58	16.27	9.64	17.10
Operating expenses	12.27	13.68	16.26	15.50
Operating expenses - workovers	5.91	2.51	4.20	3.48
Netbacks from sales volume ($/boe) (ii)	$12.28	$38.47	$11.96	$38.67
Netbacks *(000s):*				
- from sales volumes	$5,041	$25,710	$16,561	$70,535
- from Overriding royalty	709	2,208	2,945	6,858
Total Netbacks	$5,750	$27,918	$19,506	$77,393

(i) Excludes hedging gain or loss and items related to overriding royalty revenue as no production or boes are associated with this revenue.

(ii) Netbacks is a non-IFRS financial measure. See the Non-IFRS Financial Measure section in the beginning of this MD&A

Netbacks from sales volume for Q3 2015 were approximately $5.8 million, or $12.28 per boe, as compared to $27.9 million or $38.47 per boe for Q3 2014. Netbacks from sales volume for the nine months ended September 30, 2015 were approximately $19.5 million, or $11.96 per boe, as compared to $77.4 million or $38.67 per boe for the same period in 2014.

The decrease in netbacks from sales volumes was driven primarily by the drop in realized sales prices and decrease in sales volumes in 2015 as compared to that of 2014.

General and administrative expenses

The following tables show the three and nine month period ended September 30, 2015 and 2014 G&A expenses in both CAD$ and US$ terms:

('000, except per boe figures)	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
G&A Expenses	$3,394	$3,504	$13,326	$13,330
% Change	-3%		0%	
Average US$/CAD$ Exchange Rates	1.3087	1.0889	1.2598	1.0942
G&A Expenses (in US$)	$2,593	$3,218	$10,578	$12,182
% Change	-19%		-13%	

General and administrative ("G&A") expenses for Q3 2015 were $3.4 million, as compared to $3.5 million in Q3 2014. The majority of our G&A expenses are denominated in US$. G&A expenses (in US$) were reduced by 19% in Q3 2015, as compared to Q3 2014. For the nine months ended September 30, 2015, G&A expenses were reduced by 13% (in US$), as compared to the nine months ended September 30, 2014.

In the first half of 2015, the Trust reduced its technical and administrative staff by approximately 30%, with resulting annualized salary cost savings (excluding severance payments) expected to be approximately US$2 million.

As compared to Q2 2015, the Trust reduced its G&A expenses (in US$) by 17% in Q3 2015, as noted in the table below. On a per boe basis, Q3 2015 was reduced by 9% over Q2 2015, demonstrating the effect of staff reductions and the Trust's continued efforts to control G&A expenses.

('000, except per boe figures)	Q3 2015	Q2 2015
G&A Expenses	$3,394	$3,823
% Change	-11%	
G&A Expenses per boe	$8.28	$8.46
% Change	-2%	
Average US$/CAD$ Exchange Rates	1.3087	1.2294
G&A Expenses (in US$)	$2,593	$3,110
% Change	-17%	
G&A Expenses per boe (in US$)	$6.33	$6.92
% Change	-9%	

Foreign Exchange Gain

The foreign exchange gains or losses are primarily a non-cash period end accounting adjustment resulting from translating the Trust's US dollar denominated inter-company loan issued to its subsidiary into Canadian dollars, the presentation currency of the Trust. Under IFRS, this US$185 million inter-company loan is eliminated on consolidation and is not part of the net investment in the subsidiary and any related period end foreign exchange translation adjustment is recorded in income or loss.

During Q3 2015, the Trust recorded a foreign exchange gain of $17.4 million, as compared to a foreign exchange gain of $12.1 million in Q3 2014. The foreign exchange gain was due to the decline in value of the CAD$, relative to the US$, during both three month periods.

For the nine month period ended September 30, 2015, the Trust recorded a foreign exchange gain of $36.7 million, as compared to a foreign exchange gain of $12.9 million during the same period in 2014. The foreign exchange gain was due to the decrease in value of the CAD$, relative to the US$, over these nine-month periods.

($000s):	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Unrealized foreign exchange gain	$17,365	$11,595	$36,008	$11,209
Realized foreign exchange gain	50	463	684	1,702
Foreign exchange gain	$17,415	$12,058	$36,692	$12,911

Depreciation, depletion, amortization and impairment

Depreciation, depletion and amortization ("DD&A") expenses were $12.2 million in Q3 2015, as compared to $33.3 million in Q3 2014. For the nine months ended September 30, 2015, DD&A expenses were $38.1 million, as compared to $75.2 million in the same period of 2014.

The decrease in DD&A expenses were due partly to lower depletion rates for the current quarter and due partly to lower oil & gas production, as a result of the strategic divestitures of the Manvel and Mid-Continent properties during Q2 2015. The impairment charges recorded in Q4 2014 and Q1 2015 have resulted in a lower depletion rate and lower depletion expenses on oil & gas properties recognized on a unit-of-production basis over their reserves.

For the three and nine months period ended September 30, 2015, the Trust recognized an impairment loss as follows:

($000s):	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
South Texas Gas	$ -	$16,576	$ -	$16,576
Texas Conventional Oil	45,774	-	51,740	-
Texas Unconventional Oil	32,028	100,240	32,028	100,240
Oklahoma	-	-	10,258	-
Kansas / Colorado	2,269	2,576	11,642	2,576
Wyoming	32,028	-	32,028	-
Total Cash Generating Units ("CGUs")	112,099	119,392	137,696	119,392
Exploration & Evaluation Properties	-	36,661	-	36,661
Total Impairment	$112,099	$156,053	$137,696	$156,053

The impairment recorded in the Q3 2015 of $112.1 million was a result of utilizing a lower future oil price deck in the fair value calculations due to the decline in oil price.

The impairment losses recognized were the difference between the carrying amount of each CGU and their fair value less costs of disposal. The fair value less costs of disposal was calculated using a discounted cash flow model based on the proved plus probable reserves using forecast oil prices and an after-tax discount rate of 10.0% for all CGUs.

For the nine months ended September 30, 2015, the Trust recorded an impairment loss of $137.7 million, which included an impairment recorded in Q1 2015 of $25.6 million. The Q1 2015 impairment represented adjustments made to the recoverable amount of these assets due to the Trust entering into a purchase and sale agreement for the Manvel Field assets within its Texas Conventional CGU, and a purchase and sale agreement for the Trust's Mid-Continent assets which consisted of the Oklahoma CGU and Kansas assets within its Kansas/Colorado CGU. The recoverable amount for each CGU was determined with reference to the sale value.

Risk management gain (loss)

As part of the Trust's strategy to mitigate the impact of fluctuating commodity prices on its funds flow from operations, the Trust has entered into derivatives contracts to manage commodity price risk. Risk management gain and loss include the realized gain and loss from settlements of derivatives contracts, and period-end unrealized mark-to-market adjustments of the Trust's derivative contracts.

During Q3 2015, the Trust recorded $14.2 million as a risk management gain on its derivative contracts, as compared to $14.2 million in Q3 2014. For the nine months ended September 30, 2015, the Trust recorded $15.8 million as a risk management gain, as compared to a $1.0 million loss in the same period in 2014.

The gains during the three and the nine months ended September 30, 2015 was due to decrease in oil & gas prices during the periods.

($000s):	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Unrealized risk management gain (loss)	$2,891	$15,053	($13,415)	$4,469
Realized risk management gain (loss)	11,342	(836)	29,197	(5,491)
Risk management gain (loss)	$14,233	$14,217	$15,782	($1,022)

Loss on change in fair value of convertible debentures

($000s):	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Change in fair value due to change in:				
- credit risk	$1,833	$17,102	$7,883	$36,445
- market risk	(661)	2,257	(3,420)	(131)
Net gain	$1,172	$19,359	$4,463	$36,314

During 2013, the Trust issued a total of $149.3 million in convertible debentures, of which $0.5 million was subsequently converted into equity. The Trust has designated these convertible debentures as fair value through profit or loss ("FVTPL") in accordance with IFRS 9, Financial Instruments. As such, the convertible debentures are recorded at their fair value, and are marked to market at each financial reporting date. Changes in the fair value due to changes in market risks are recorded through income and loss, and changes in fair value due to changes in the Trust's internal credit risk is recognized through other comprehensive income.

During Q3 2015, the Trust recorded a net gain of $1.2 million to comprehensive income on the change in fair value of convertible debentures, as compared to a net gain of $19.4 million during Q3 2014. The net gain in Q3 2015 was due to the decrease in the market price of its convertible debentures on the Toronto Stock Exchange during the period.

For the nine month periods ended September 30, 2015, the Trust recorded a net gain of $4.5 million to comprehensive income, as compared to a net gain of $36.3 million during the same period in 2014. The net gain during the nine month period ended September 30, 2014 was larger due to the significant decline in the fair value of the convertible debentures during that period.

Funds Flow and Loss

Q3 2015 funds flow from operations was $13.8 million, or $0.21 per Unit, as compared to $24.0 million, or $0.38 per Unit in Q3 2014. For the nine month period ended September 30, 2015, funds flow from operations was $33.9 million, or $0.53 per Unit, as compared to $54.6 million, or $0.87 per Unit during the same period in 2014.

The decrease in funds flow from operations from same periods in 2014 was mainly due to the effect of lower oil & gas prices and lower oil & gas production, which more than offset the decrease in operating expenses and general and administrative expenses.

The Q3 2015 loss was $95.1 million, or $1.48 per Unit, as compared to Q3 2014 loss of $141.9 million, or $2.24 per Unit. The reduction in comparable loss was due to lower depreciation, depletion, amortization and impairment expenses.

For the nine month periods ended September 30, 2015, the loss was $134.0 million, or $2.09 per Unit, as compared to $169.5 million, or $2.71 per Unit during the same period in 2014. The decrease in loss was mainly due to lower depreciation, depletion, amortization and impairment expenses.

Note: Funds flow from operations is an Additional GAAP measure. See the Additional GAAP Measure sections in the beginning of this MD&A.

Summary of Quarterly Results

($000 unless stated)	Q3 2015	Q2 2015	Q1 2015	Q4 2014	Q3 2014	Q2 2014	Q1 2014
Oil and gas sales, before royalties	$17,146	$22,108	$21,981	$35,938	$49,680	$47,538	$46,248
Production							
- Oil (bbl/d)	2,715	2,954	3,627	3,948	4,426	4,071	4,085
- NGL (bbl/d)	213	225	255	286	277	324	326
- Natural Gas (mcf/d)	9,163	10,577	11,619	13,763	15,365	11,867	11,876
Oil & gas production (boe/d)	4,455	4,942	5,819	6,528	7,264	6,373	6,390
% Oil and NGLs	66%	64%	67%	65%	65%	69%	69%
Total Netbacks (1)	$5,750	$8,660	$5,096	$14,975	$27,918	$24,383	$25,092
Netbacks from sales volume only	$5,040	$7,401	$4,118	$13,350	$25,710	$21,962	$22,865
- per boe	$12.28	$16.45	$7.84	$22.23	$38.47	$38.03	$39.52
Funds flow from operations (1)	$13,808	$13,893	$6,189	$14,750	$23,958	$15,791	$14,866
- per boe	$33.69	$30.90	$11.82	$24.56	$35.85	$27.23	$25.85
- per Trust Unit, basic	$0.21	$0.22	$0.10	$0.23	$0.38	$0.25	$0.24
Income (Loss)	($95,102)	($17,315)	($21,551)	($132,044)	($141,884)	($25,334)	($2,294)
- per Trust Unit, basic	(1.48)	(0.27)	(0.34)	($2.08)	($2.24)	($0.40)	($0.04)
- per Trust Unit, fully diluted	(1.48)	(0.27)	(0.34)	($2.08)	($2.24)	($0.40)	($0.04)
Total Assets	$262,210	$354,087	$438,844	$444,464	$574,959	$734,230	$751,715
Non-current Liabilities	$149,778	$147,649	$201,379	$192,407	$253,508	$278,202	$253,399
Distribution per Trust Unit	$0.00	$0.01	$0.03	$0.06	$0.06	$0.06	$0.26
Capital Expenditures (2)	$8,390	$6,206	$2,421	$3,349	$7,157	$29,702	$28,128
Unitholders' Equity	$81,420	$176,825	$202,021	$210,579	$279,615	$394,023	$427,781

Note (1): Netbacks and funds flow from operations are non-IFRS financial and additional GAAP measures respectively. See the Non-IFRS Financial and Additional GAAP Measure sections in the beginning of this MD&A.

Note (2): Capital expenditures exclude corporate acquisitions

Note (3): Netback, funds flow from operation and income (loss) figures for 2013 were restated, per the retrospective application of IFRIC 21 that was effective January 1, 2014 and to be comparable with current presentation.

Production volumes in Q3 2015 averaged 4,455 boe/d as compared to 4,942 boe/d in Q2 2015. The reduction was primarily due to the strategic divestitures of the Manvel and Mid-Continent assets in Q2 2015 and lower production volumes associated with natural decline rates.

After adjusting for the strategic divestitures in Q2 2015, production for Q3 2015 increased sequentially by 3% to 4,455 boe/d, from 4,311 boe/d in Q2 2015. The increase was due to new production from the capital drilling incurred in the first half of 2015 in the Wyoming properties, offset by natural declines.

Commodity prices realized decreased to $40.04 per boe in Q3 2015, from $46.26 per boe in Q2 2015. Oil and gas sales before royalties in Q3 2015 was $17.1 million as compared to $22.1 million in Q2 2015. Oil and gas sales before royalties in Q3 2015 decreased as compared to Q2 2015 due to lower realized prices in conjunction with a decline in production volumes.

Netbacks from sales volume in Q3 2015 decreased to $5.0 million from $7.4 million in Q2 2015. On a per boe basis, netbacks from sales volume in Q3 2015 was $12.28 per boe as compared to $16.45 per boe in Q2 2015. This was due primarily to lower realized prices partially offset by lower operating costs.

Funds flow from operations of $13.8 million ($0.21 per Unit) in Q3 2015 was flat relative to that in Q2 2015 of $13.9 million ($0.22 per Unit). The decrease in oil and gas sales in Q3 2015 was offset by risk management gains realized during the quarter.

The loss for Q3 2015 increased to $95.1 million from $17.3 million for Q2 2015. The higher loss in Q3 2015 was due to non-cash impairment charges of $112.1 million during the quarter, as a result of lower oil & gas prices, partially offset by lower depletion expenses.

Tax Horizon

The tax horizon as determined from a full cycle corporate model developed by the Trust and incorporating all applicable U.S. deductions, indicates that no material U.S. taxes are expected to be payable in respect of income attributable to the Trust's U.S. assets until at least 2022. The Trust expects to maintain this position through capital investments primarily in the U.S.

No taxes are expected to be payable by the Trust in Canada as the Trust intends to distribute all of its taxable income each year to Unitholders and will not be a SIFT trust provided that the Trust does not hold any "non-portfolio property", as defined in the Income Tax Act (Canada).

Liquidity and Capital Resources

As at September 30, 2015, the Trust had net working capital of 2.6 million, which included an unrealized risk management contracts asset of $20.0 million.

Bank Credit Facility

As at September 30, 2015, the Trust had US$65.0 million (CDN$86.7 million) outstanding under its US$80 million (CDN $106.8 million) credit facility. The credit facility was renewed on June 30 and the Trust is required to obtain permission from the lender to draw on the credit facility in excess of US$75 million (CDN$100.1 million).

The credit facility is subject to a semi-annual borrowing base redetermination that is ongoing. Based on current commodity prices, it is expected that the facility could be reduced. Argent is in active discussions with the banking syndicate regarding its borrowing base, an extension of the credit facility and other terms. Argent continues to advance and explore all alternatives to provide the necessary liquidity and capital to the Trust based on the current commodity pricing environment. The redetermination is expected to be completed by November 30, 2015.

There can be no assurances that an extension to the facility or alternatives can be sourced on terms acceptable to the Trust. If the facility is not extended then any undrawn credit above the redetermined borrowing base shall cease to be available to the Trust and the total available facility shall be reduced to an amount equal to the borrowing base. Argent intends to make further announcements with respect to the status of these discussions as and when material developments occur.

Capital Budget

The Trust had reduced its capital expenditure budget for 2015 to US$12 million, all of which has already been incurred as at September 30, 2015. The 2015 capital expenditure represents already spent development capital on eight gross (1.25 net) Parkman formation wells in Wyoming and maintenance and workover capital for the balance of the year.

The following table summarizes the capital expenditures on oil & gas properties during the three and nine month periods ended September 30, 2014 and 2015:

($000s):	Q3 2015	Q3 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Drilling & Completion	$6,502	$4,239	$13,254	$52,032
Minor asset and working interests acquired	-	108	-	311
Site Preparation for Drilling	-	55	-	1,554
Facilities, capital equipment & other	1,666	2,626	3,539	9,557
Additions to oil and gas properties	$8,168	$7,028	$16,793	$63,454

During 2015, the Trust continued to reduce its capital budget with the aim to reduce debt. In Q3 2015 and nine months ended September 30, 2015, it incurred capital expenditures of approximately $8.2 million (US$6.2 million) and $16.8 million (US$13.3 million), respectively, in the development of its oil & gas properties, focusing on the non-operated Parkman and Turner drilling program in Wyoming and capital workovers. The Trust participated in 10 (1.3 net) wells, 2 Tuner and 8 Parkman, with working interest percentages of between 3% and 25% and workovers on 27 wells.

Capital expenditures for the remainder of 2015 are expected to be minimal.

Distributions

As required by National Policy 41-201, "Income Trusts and Other Indirect Offerings", the following table outlines the differences between net cash provided by operating activities and cash distributions as well as the differences between net income and cash distributions.

($000)	Three Month Ended September 30, 2015 [3]	Nine Month Ended September 30, 2015	Year Ended December 31, 2014	Year Ended December 31, 2013
Net cash provided by operating activities [2]	$ 11,804	$ 15,745	$ 59,382	$ 59,765
Loss for the period	$ (95,102)	$ (133,968)	$ (301,556)	$ (87,228)
Actual cash distributions paid or payable (recovery) [1]	$ -	$ 1,641	$ 11,685	$ 21,367
Excess of net cash provided by operating activities over cash distributions paid	$ 11,804	$ 14,104	$ 47,697	$ 38,398
Shortfall of Loss over cash distributions paid	N/A	$ (135,609)	$ (313,241)	$ (108,595)

(1) Cash distributions paid or payable exclude distributions reinvested in units pursuant to the Trust's unitholder distribution reinvestment plan.

(2) Interest on term credit facility and convertible debentures, totaling $3.1 million and $10.0 million for three and nine month period ended September 30, 2015 respectively was deducted from net cash provided by operating activities. For fiscal years ended December 31, 2014 and 2013, the interest incurred during the periods of $13.1 million and $5.5 million respectively has been deducted from net cash provided by operating activities.

(3) The Trust had suspended cash distributions since April 2015 and no cash distribution was paid during Q3 2015.

For all periods in the above table, net cash provided by operating activities exceeded actual cash distribution.

Except for Q3 2015 in which there was no distributions paid, for all periods in the above table, distributions exceeded loss for the period due to non-cash items which are deducted or added in determining loss for the period. Examples of non-cash items include depreciation, depletion and amortization, impairment, and exploration and evaluation expenses, all of which have no impact on cash available to pay distributions.

This amount of shortfall of actual cash distributions over loss had been eliminated by Q3 2015, as the Trust had suspended its cash distribution beginning April 2015.

Outstanding Unit Data

At the date of this MD&A, the Trust had approximately 64.4 million units outstanding. The outstanding Restricted Trust Units ("RTUs") and Phantom Unit Rights ("PURs"), including reinvested distribution, were approximately 306,000 and 2,575,000 respectively.

Risk Management

Overview:

The Trust's operations are affected by a number of underlying risks, both internal and external to the Trust. These risks are similar to those affecting conventional oil and natural gas exploration and production companies. The Trust's financial position, results of operations, and cash distributions are directly impacted by these factors.

A full listing of the operational and business risks is set out in the Trust's 2014 Annual Information Form filed on SEDAR at www.sedar.com.

The Trust's activities expose it to a variety of financial risks that arise as a result of its operating, investing, and financing activities such as:

- Credit risk;
- Liquidity risk;
- Market risk; and
- Foreign exchange risk.

This note presents information about the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Further quantitative disclosures are included throughout the consolidated financial statements.

The Board of Directors oversees Management's establishment and execution of the Trust's risk management framework. Management has implemented and monitors compliance with risk management policies. The Trust's risk management policies are established to identify and analyze the risks faced by the Trust, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Trust's activities.

a) Credit Risk:

Credit risk is the potential for financial loss to the Trust if a counterparty in a transaction fails to meet its obligations. The Trust's cash and restricted cash, trade and other receivables and risk management are exposed to credit risk. The Trust monitors its credit risk management policies continuously to evaluate their effectiveness and feels that the credit worthiness of its counterparties is satisfactory at this time.

The Trust's operations are conducted in the United States. Exposure to credit risk is primarily influenced by the individual characteristics of each customer, and is primarily limited to the Trust's product marketer and joint venture partners.

As at September 30, 2015, the Trust's most significant customer is an international oil & gas company which is the operator of the Trust's Wyoming property. It accounts for approximately 14% of trade receivables at September 30, 2015. This customer accounts for approximately 15% of the Trust's Q3 2015 oil and gas sales.

Another significant customer US oil and natural gas marketer, accounting for approximately 11% of trade receivables at September 30, 2015. This customer accounts for approximately 23% of the Trust's Q3 2015 oil and gas sales.

Receivables from the Trust's product marketers are normally collected in the month following production. The Trust's policy to mitigate credit risk associated with these balances is to establish marketing relationships with reputable purchasers with good credit, and over time, by spreading this risk over as many marketers as is reasonable. The Trust historically has not experienced collection issues with its marketers. The Trust does not typically obtain collateral from its operator and marketers.

Joint venture receivables are with customers in the oil and gas industry and are subject to normal industry credit risks. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. In certain circumstances, the Trust may request an operating advance or cash call a partner in advance of capital expenditures being incurred.

The Trust does not anticipate any default as it transacts with creditworthy customers and Management does not expect any material losses from non-performance by these customers. As such, no material provision for doubtful accounts has been recorded at September 30, 2015.

b) Liquidity Risk:

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. The Trust's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Trust's reputation.

Typically the Trust ensures that it has sufficient cash or available credit on the Trust's credit facility to meet expected operational expenses for a period of 120 days, including the servicing of financial obligations; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted. To achieve this objective, the Trust prepares annual operational and capital expenditure budgets which are regularly monitored and updated as considered necessary. The Trust also attempts to match its payment cycle with collection of its oil revenue each month. The Trust also utilizes authorizations for expenditures ("AFEs") on both operated and non-operated projects to manage capital expenditures.

Argent is US$65 million drawn on its US$80 million credit facility, which is subject to a semi-annual borrowing base redetermination that is ongoing. Based on current commodity prices, it is expected that the facility could be reduced. Argent is in active discussions with the banking syndicate regarding its borrowing base, an extension of the credit facility and other terms. Argent continues to advance and explore all alternatives to provide the necessary liquidity and capital to the Trust based on the current commodity pricing environment. The redetermination is expected to be completed by November 30, 2015.

Any significant change in the borrowing base by the lenders can impact the liquidity position of the Trust.

This indicates the existence of a material uncertainty related to events or conditions that may cast significant doubt about the Trust's ability to continue as a going concern and accordingly, the appropriateness of the use of accounting principles applicable to a going concern.

The Trust's ability to continue as a going concern is dependent upon its ability to maintain access to credit facilities, find alternative financing for any borrowing base shortfall, if required, and effectively manage risks associated with depressed oil prices and generate positive cash flows from operations.

The following are the contractual maturities of financial liabilities including estimated interest payments at September 30, 2015:

($000)

As at September 30, 2015	Carrying amount	Contractual cash flows	Less than one year	One - two years	Two - five years	More than five years
Financial liabilities:						
Trade payables	$ 30,503	$ 30,503	$ 30,503	$ -	$ -	$ -
Convertible debenture interest	-	34,493	9,270	9,270	11,318	-
Credit facility interest (l)	289	5,563	2,986	2,577	-	-
Trade and other payables	$ 30,792	$ 70,559	$ 42,759	$ 11,847	$ 11,318	$ -
Convertible debentures - principal	44,625	148,750	-	-	148,750	-
Credit Facility - principal	86,067	86,743	-	86,743	-	-
	$ 161,484	**$ 306,052**	**$ 42,759**	**$ 98,590**	**$ 160,068**	**$ -**
Decommission liability	19,259	29,553	855	1,556	1,463	25,678
Total:	**$ 180,743**	**$ 335,605**	**$ 43,614**	**$ 100,146**	**$ 161,531**	**$ 25,678**

c) Market Risk:

Market risk is the potential for loss to the Trust from changes in the values of its financial instruments due to changes in commodity prices, interest rates or foreign exchange rates.

The Trust may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Commodity Price Risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar, but also world economic events that dictate the levels of supply and demand.

The Trust may enter into certain financial derivative instruments periodically to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Trust does not apply hedge accounting for these contracts. The Trust’s production is usually sold using “spot” or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Trust, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts.

As part of the Trust’s strategy to mitigate the impact of fluctuating commodity prices on its funds flow from operations, the Trust had entered in to the following financial contracts at September 30, 2015:

	Commodity	Volume	Measure	Beginning	Term	Fixed US$
Fixed contract swaps						
WTI (i)	Oil	800	bbl/d	Oct-15	Dec-15	91.11/bbl
LLS (i)	Oil	1,200	bbl/d	Oct-15	Dec-15	92.12/bbl
WTI (i)	Oil	1,000	bbl/d	Jan-16	Dec-16	65.45/bbl
NYMEX (ii)	Natural gas	6,000	MMBtu/d	Oct-15	Dec-15	4.12/MMBTU
NYMEX (ii)	Natural gas	4,000	MMBtu/d	Jan-16	Dec-16	4.06/MMBTU

	Commodity	Volume	Measure	Beginning	Term	Fixed US$
Sold (wrote) call options (iii)						
WTI Call	Oil	600	bbl/d	Jan-16	Dec-16	91.40/bbl
WTI Call	Oil	200	bbl/d	Jan-16	Dec-16	90.25/bbl
WTI Call	Oil	200	bbl/d	Jan-17	Dec-17	67.00/bbl

(i) Represents fixed price financial swap transactions with a set forward sale oil reference prices that are based on West Texas Intermediary ("WTI"), Brent or Louisiana Light Sweet ("LLS") oil.

(ii) Represents fixed price financial swap transactions based on the NYMEX natural gas forward sale reference price.

(iii) Represents the selling of call options, giving the counter party the right (but not obligation) on December 31 of the year preceding the contract term to enter into fixed price financial swap transactions with a set forward sales reference price.

The total fair value of the Trust's unrealized risk management positions at September 30, 2015, was a net asset of $22.2 million and has been calculated using both quoted prices in active markets and observable market-corroborated data.

A $1 per bbl increase in the market price of oil would have resulted in a decrease of income (loss) of approximately $0.8 million due to a change in unrealized risk management loss (gain) as a result of a change in the fair value of the Trust's risk management position at September 30, 2015. At September 30, 2015, a $0.25 per mcf increase in the market price of gas would have resulted in decrease of income (loss) of approximately $0.6 million, respectively, due to a change in the unrealized risk management loss (gain).

Securities Price Risk

The Trust's convertible debentures are subject to securities price risk as they are traded on a public exchange.

As at September 30, 2015, had the securities price of the convertible debentures increased or decreased by 1%, net income would have decreased or increased by approximately $0.5 million due to a change in the fair value of the convertible debentures.

Foreign Exchange Risk

Foreign exchange risk is the risk that future cash flows will fluctuate as a result of changes in market foreign exchange rates. The Trust's operating cash flows are generated in US dollars and distributions are declared in Canadian dollars. As a consequence, there is an element of foreign exchange risk to the Trust. The Trust's treasury management function is responsible for managing funding requirements and investments, which include banking and cash flow management. Prices for oil are determined in global markets and generally denominated in US dollars. The exchange rate effect cannot be quantified but generally an increase in the value of the Cdn$ as compared to the US$ will reduce the prices received by the Trust for its petroleum and natural gas sales but will also reduce the operating expenses associated with those sales.

A $0.01 increase (decrease) in the value of CDN$ versus US$ on September 30, 2015 would have decreased (increased) income (loss) by approximately $1.9 million due to the unrealized foreign exchange loss (gain) from the Trust's inter-company loan to its US subsidiary of approximately US$185 million. Under IFRS, this inter-company loan is not part of the net investment in the subsidiary and any period end foreign exchange translation adjustment is required to be recorded in income or loss. This analysis assumes that all other variables, in particular interest rates, remain constant.

Critical accounting estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Such estimates and assumptions are based on historical experience and various other factors that are believed to be reasonable in the circumstances and constitute Management's best judgment at the date of the financial statements. In the future, actual experience may deviate from these estimates and assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

The significant areas of estimation uncertainty in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are summarized as follows:

<u>Estimation of oil and gas reserves</u>

Oil and gas reserves are the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of oil and gas reserves are inherently imprecise, require the application of judgment and are subject to future revision. Accordingly, financial and accounting measures (such as the impairment calculation, depletion charges, and decommissioning provisions) that are based on reserves are also subject to change.

<u>Capitalized exploration and evaluation expenditures</u>

In making decisions about whether to continue to capitalize exploration and evaluation expenditures, it is necessary to make judgments about the commercial reserves and the level of activities that constitute on-going evaluation determination. If there is a change in any judgment in a subsequent period, then the related capitalized exploration and evaluation expenditure would be expensed in that period, resulting in a charge to income.

<u>Impairment indicators</u>

Cash-generating units ("CGUs") are reviewed for impairment at each reporting date or more frequently if changes in circumstances indicate that the carrying value may be impaired. The values associated with CGUs involve significant estimates and assumptions, including those with respect to future cash inflows and outflows, reserve estimates, discount rates, and asset lives.

<u>Classification of Trust units as equity</u>

Trust units issued by the Trust give the holder the right to put the units back to the issuer in exchange for cash. IAS32 "Financial Instruments: Presentation" establishes the general principle that an instrument which gives the holder the right to put the instrument back to the issuer for cash should be classified as a financial liability, unless such instrument has all of the features and meets the conditions of the IAS 32 "puttable instrument exemption". If these "puttable instrument exemption" criteria are met, the instrument is classified as equity. The Trust has examined the terms and conditions of its Trust Indenture and classifies its outstanding Trust units as equity because the Trust units meet the "puttable instrument exemption" criteria as there is no contractual obligation to distribute cash.

The significant areas of critical judgment in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are summarized as follows:

Measurement of unit based compensation

The cost of services received in exchange for awards of equity instruments recognized is estimated using fair value methods as determined by management which require the use of assumptions.

Acquisition and business combinations

The Trust has made significant estimates and assumptions in determining the fair value of assets and liabilities acquired through business combination. These estimates require judgment to assess the fair value of assets and liabilities acquired.

Accounting standards and interpretations

The accounting policies followed in unaudited interim consolidated financial statements are consistent with those of the previous financial year, except for income tax expense for an interim period which is based on an estimated average annual effective income tax rate. There were no new or amended standards issued during the three and nine months ended September 30, 2015 that are applicable to the Trust in future periods.

Disclosure Controls and Procedures

The President and Chief Financial Officer oversees this evaluation process and has concluded that the design and operation of these disclosure controls and procedures are not effective due to the material weaknesses identified in internal controls over financial reporting as noted below.

Internal Controls Over Financial Reporting

During Q2 and Q3 2015, the Trust reduced the number of its administrative and finance staffs as part of its restructuring.

The Trust’s certifying officers have assessed the design effectiveness of internal controls over financial reporting and concluded that the Company’s ICFR were ineffective at September 30, 2015.

Management is aware that there is a lack of segregation of duties due to the small number of employees dealing with period end close review, administrative and financial matters. However, management believes that at this time the potential benefits of adding employees to clearly segregate duties do not justify the costs associated with such increase. Management believes that it has designed compensating internal controls to mitigate these limitations, including audit committee and senior management review of financial statements and MD&A and dual signatories on all cheques.

These material weaknesses in internal controls over financial reporting result in a reasonable possibility that a material misstatement will not be prevented or detected on a timely basis. Management and the Board of Directors work to mitigate the risk of material misstatement; however, Management and the Board do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement.

It should be noted, that the Trust’s control system, no matter how well designed, can provide only reasonable, but not absolute assurance of detecting, preventing and deterring errors or fraud.

Note about forward-looking statements

Certain of the statements made and information contained in this MD&A are forward-looking statements and forward looking information (collectively referred to as "forward-looking statements") within the meaning of Canadian securities laws. All statements other than statements of historic fact are forward-looking statements. The Trust cautions investors that important factors could cause the Trust's actual results to differ materially from those projected, or set out, in any forward-looking statements included in this MD&A.

In particular, and without limitation, this MD&A contains forward looking statements pertaining to the following:

- Argent's capital budget and drilling and tie in plans;
- the Trust's expectation regarding its average working interest production for 2015 and 2016;
- the Trust's expectation to reduce operating expenses on a per boe basis;
- production uplifts from workovers undertaken; commodity prices and exchange rates;
- the future level of general and administrative expenses; and
- management's objective to maintain a bank debt to funds flow from operations ratio below 1.5 times.

With respect to forward-looking statements contained in this MD&A, assumptions have been made regarding, among other things:

- future oil and natural gas commodity prices;
- future currency exchange and interest rates;
- the regulatory framework governing taxes in the US and Canada and the Trust's status as a "mutual fund trust" and not a "SIFT trust;"
- estimates of anticipated production from its oil & gas assets, which estimates are based on the proposed drilling program with a success rate that, in turn, is based upon historical drilling success and an evaluation of the particular wells to be drilled;
- future recoverability of reserves for its oil & gas assets;
- future capital expenditures and the ability of the Trust to obtain financing on acceptable terms for its capital projects and future acquisitions;
- the Trust's capital budget, which is subject to change in light of ongoing results, prevailing economic circumstances, commodity prices and industry conditions and regulations;
- the amount realized from asset divestitures; not including capital required to pursue future acquisitions in the forecasted capital expenditures;
- the ability and the intent of the Trust to continue making distributions; and
- the borrowing base of the Trust's credit facility, which is subject to redetermination by its lenders.
- the Trust's ability to access alternative capital to fund any borrowing base shortfall or the bank credit facility.

The Trust's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and included in the Trust's Annual Information Form:

• volatility of commodity prices;

• commodity supply and demand;

• fluctuations in currency and interest rates;

• inherent risks and changes in costs associated in the drilling and development of petroleum properties;

• unexpected operational delays and challenges

• access to drilling equipment on a timely basis and at reasonable prices;

• ultimate recoverability of reserves;

• timing, results and costs of drilling activities and resulting production;

• availability of financing and capital; and

• new regulations and legislation that apply to the Trust and the operations of its subsidiaries.

Additional risks and uncertainties affecting the Trust are contained in the Trust's Annual Information Form under the heading "Risk Factors".

As a result of these risks, actual performance and financial results in 2015 may differ materially from any projections of future performance or results expressed or implied by these forward looking statements. New factors emerge from time to time, and it is not possible for management to predict all of these factors or to assess, in advance, the impact of each such factor on the Trust's business, or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward looking statement. Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward looking statements will not occur. Although Management believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date the forward-looking statements were made, there can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will in fact be realized. Actual results will differ, and the difference may be material and adverse to the Trust and its Unitholders. The Trust does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise.

Note regarding barrel of oil equivalency

This MD&A contains disclosure expressed as "boe" or "boe/d". All oil and natural gas equivalency volumes have been derived using the conversion ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of oil. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of 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 well head. In addition, given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of six to one, utilizing a boe conversion ratio of 6 Mcf: 1 bbl would be misleading as an indication of value.