MEG ENERGY

THIRD QUARTER 2017

Report to Shareholders for the period ended September 30, 2017

MEG Energy Corp. reported third quarter 2017 operating and financial results on October 26, 2017. Highlights include:

- Quarterly production volumes of 83,008 barrels per day (bpd) with October production currently averaging approximately 85,000 bpd, reflecting the ramp-up of MEG's eMSAGP growth initiative at Christina Lake Phase 2B which is proceeding on schedule and under budget;
- Record-low quarterly net operating costs of $6.00 per barrel supported by non-energy operating costs of $4.57 per barrel;
- A 14% reduction in the company's capital budget guidance, from $590 million to $510 million, with the majority of the reduction driven by ongoing efficiency improvements, lower construction costs and improved facility design;
- Strong operational and financial results contributing to cash and cash equivalents of $398 million as of September 30, 2017; and
- A second sequential reduction in MEG's non-energy operating cost guidance to $4.75 - $5.00 per barrel, reflecting ongoing efficiency gains and a continued focus on cost management. The new guidance compares to the previous guidance of $5.00 - $5.50 per barrel and is 22% lower than the initial guidance of $5.75 - $6.75 per barrel at its mid-point.

MEG's third quarter 2017 production averaged 83,008 bpd, compared to 72,448 bpd for the previous quarter. Production for the third quarter reflected ramp-up from the company's second quarter turnaround and was partially affected by adverse weather conditions at the company's Christina Lake facility and the timing of tying in new wells that are part of the eMSAGP Phase 2B implementation. The company remains on track to meet its 2017 average production guidance of 80,000 to 82,000 bpd and exit the year with production between 86,000 and 89,000 bpd.

"MEG's ongoing technological developments are significantly changing the way we operate and grow," said Bill McCaffrey, President and Chief Executive Officer. "These technologies are enabling MEG to meaningfully reduce its steam-oil ratio, making it possible to reduce capital requirements for steam and water handling and decrease operating costs. It also allows for future expansions on a continuous basis as opposed to project by project, while offering significantly higher returns and reducing the company's greenhouse gas emissions intensity."

In those specific well patterns where eMSAGP has already been deployed, the company is currently seeing a steam-oil ratio of approximately 1.3, with the freed-up steam being diverted into new wells to further increase production.

"Our evolving technologies form the basis of the majority of MEG's future growth," said McCaffrey. "The targeted cost reductions associated with incremental production growth allow us to continue to lower our costs on a per barrel basis, and better position the company to carry out this highly-economic growth going forward."

For the third quarter of 2017, net operating costs were a record-low $6.00 per barrel, compared to $7.42 per barrel in the previous quarter, due to a per barrel decrease in energy operating costs and an increase in per barrel power revenue.

Non-energy operating costs were $4.57 per barrel in the third quarter. The continued decrease in non-energy operating costs compared to the company's guidance is primarily the result of efficiency gains and a continued focus on cost management, resulting in lower operations staffing and materials and services costs.

On a year-to-date basis, non-energy operating costs have decreased 20% compared to the first nine months of 2016. As a result of MEG's continued focus on cost control and efficiency improvements, annual non-energy operating costs for 2017 are now targeted to be in the range of $4.75 - $5.00 per barrel, below the original guidance of $5.75 - $6.75 per barrel and the adjusted $5.00 - $5.50 per barrel guidance provided in the company's second quarter 2017 disclosure.

In the third quarter, MEG continued to benefit from increases in its realized sales price. The average US$WTI price increased 7% in the third quarter of 2017 compared with the same period of 2016. However, the WCS differential narrowed by US$3.56 per barrel, or 26%, due to higher demand for Canadian heavy oil from U.S. Gulf Coast refineries. These factors increased the company's bitumen realization by approximately C$9 per barrel compared to the third quarter of 2016.

Blend sales in the third quarter of 2017 were approximately 6,000 bpd less than production, as these volumes were in transit over the quarter end, destined for the U.S. Gulf Coast. These sales volumes will be recognized in the fourth quarter of 2017.

MEG realized adjusted funds flow from operations of $83 million for the third quarter of 2017 compared to adjusted funds flow from operations of $55 million in the previous quarter. The increase in adjusted funds flow from operations was primarily due to an increase in bitumen realization and a reduction in net operating costs.

Capital Investment and Financial Liquidity

Total cash capital investment during the third quarter of 2017 was $103 million. Primarily as a result of ongoing efficiency improvements, lower construction costs, improved facility design and the optimization of MEG's investment profile, the company has reduced its 2017 capital investment program to $510 million, compared to the original budget of $590 million. Capital investment in 2017 is primarily directed towards the company's eMSAGP growth initiative at Christina Lake Phase 2B, which is proceeding on schedule and under budget.

"MEG's focus on innovation and cost containment is resulting in the company being able to achieve better results with lower investment dollars," said McCaffrey. "We are seeing significant reductions in our capital needs because of the efficiency improvements in our reservoir processes and fundamental changes to our pad and facility designs. As a result, we now anticipate spending $350 million on the implementation of eMSAGP on Phase 2B, which comes to $17,500 per flowing barrel, a 13% reduction from the original estimates of $400 million. This cost reduction contributes to the company's overall objective of generating higher returns from its capital investments."

MEG has entered into a series of hedges designed to protect its capital program against downward oil price movements and mitigate volatility in cash flow.

For the fourth quarter of 2017, MEG has entered into WTI hedges on approximately 50% of the company's forecast blend sales with 26% fixed at US$54.20/bbl and 24% hedged utilizing costless collars that provide it with downside price protection at US$47.90/bbl and upside participation to US$58.60/bbl. The company has also entered into financial hedges on approximately 45% of its WCS differential exposure at a price differential to WTI of US$15.00/bbl and 74% of its condensate exposure through a combination of financial and physical transactions at an average price of 99% of WTI.

MEG is also executing its hedge program for 2018. The company has now entered into WTI hedges on 42,000 bpd of blend sales with 12,500 bpd fixed at US$51.10/bbl and 29,500 bpd hedged utilizing costless collars that provide the company with downside price protection at US$45.45/bbl and upside participation to US$54.60/bbl. MEG has also entered into financial hedges on 29,375 bpd of its WCS differential exposure at a price differential to WTI of US$14.20/bbl and 12,675 bpd of its condensate exposure with physical transactions at an average price of 101% of WTI.

MEG's four-year covenant-lite US$1.4 billion credit facility remains undrawn.

Forward-Looking Information and Non-GAAP Financial Measures

This quarterly report contains forward-looking information and financial measures that are not defined by International Financial Reporting Standards ("IFRS") and should be read in conjunction with the "Forward-Looking Information" and "Non-GAAP Financial Measures" contained within the Advisory section of this quarter's Management's Discussion and Analysis.

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three and nine month periods ended September 30, 2017 was approved by the Corporation's Audit Committee on October 25, 2017. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three and nine month periods ended September 30, 2017, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2016, the 2016 annual MD&A and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in thousands of Canadian dollars, except where otherwise indicated.

MD&A – Table of Contents

1. OVERVIEW

MEG is an oil sands company focused on sustainable *in situ* oil sands development and production in the southern Athabasca oil sands region of Alberta, Canada. MEG is actively developing enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods. MEG is not engaged in oil sands mining.

MEG owns a 100% working interest in over 900 square miles of oil sands leases. For information regarding MEG's estimated reserves contained in the GLJ Petroleum Consultants Ltd. Report ("GLJ Report"), please refer to the Corporation's most recently filed Annual Information Form ("AIF"), which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

The Corporation has identified three commercial SAGD projects: the Christina Lake Project, the Surmont Project and the May River Regional Project. The Christina Lake Project has received regulatory approval for 210,000 barrels per day ("bbls/d") of bitumen production and MEG has applied for regulatory approval for 120,000 bbls/d of bitumen production at the Surmont Project. The ultimate production rate and life of each project will be dependent on a number of factors, including the size, performance and development schedule for each expansion or phase in those projects. In addition, the Corporation holds other leases known as the "May River Regional Project" and the "Growth Properties." On February 21, 2017, the Corporation filed regulatory applications with the Alberta Energy Regulator for the May River Regional Project. Management anticipates, consistent with the estimates contained in the GLJ Report, that the May River Regional Project can support an average of 164,000 bbls/d of bitumen production. The Growth Properties are in the resource definition and data gathering stage of development.

The Corporation's first two production phases at the Christina Lake Project, Phase 1 and Phase 2, commenced production in 2008 and 2009, respectively. In 2012, the Corporation announced the RISER initiative, which is a combination of proprietary reservoir technologies, including enhanced Modified Steam And Gas Push ("eMSAGP") and redeployment of steam and facilities modifications, including debottlenecking and brownfield expansions (collectively "RISER"). Phase 2B commenced production in 2013. Bitumen production at the Christina Lake Project for the year ended December 31, 2016 averaged 81,245 bbls/d. The application of eMSAGP and cogeneration have enabled MEG to lower its greenhouse gas intensity below the *in situ* industry average calculated based on reported data to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. In those specific well patterns where the implementation of eMSAGP has already been deployed, the Corporation is currently experiencing a steam-oil ratio of approximately 1.3. MEG is currently in the process of implementing the RISER initiative, and specifically eMSAGP, to Phase 2B.

The Surmont Project has an anticipated design capacity of approximately 120,000 bbls/d over multiple phases. The Surmont Project is located approximately 30 miles north of the Corporation's Christina Lake Project, and is situated along the same geological trend as the Christina Lake Project. The Corporation is actively pursuing regulatory approval.

MEG holds a 100% interest in the Stonefell Terminal, located near Edmonton, Alberta, with a storage and terminalling capacity of 900,000 barrels. The Stonefell Terminal provides the Corporation with the ability to sell and deliver Access Western Blend ("AWB" or "blend") opportunistically to a variety of markets, access multiple sources of diluent, and store both blend and diluent, including in periods of market and transportation disruptions or constraints. The Stonefell Terminal is directly connected by pipeline to a third party rail-loading terminal near Bruderheim, Alberta. This combination of facilities allows for the loading of bitumen blend for transport by rail.

MEG holds a 50% interest in the Access Pipeline, a dual pipeline system that connects the Christina Lake Project to a large regional upgrading, refining, diluent supply and transportation hub in the Edmonton, Alberta area.

The Corporation is taking a number of steps to address its financial leverage. In January 2017, MEG successfully completed a refinancing which pushed the first maturity of any of the Corporation's outstanding long-term debt obligations to 2023. The ongoing implementation of the eMSAGP growth project will increase future production while further reducing MEG's per barrel costs, and strengthen the Corporation's ability to deal with the current volatility in crude oil prices. In addition, the Corporation continues to consider, taking into account MEG's debt maturity profile and the ongoing price environment, other available options to reduce its overall amount of debt over time.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

During the third quarter of 2017, the Corporation continued to benefit from increases in its realized sales price. The average US$WTI price increased 7% in the third quarter of 2017 compared with the same period of 2016. However, the WCS differential narrowed by US$3.56 per barrel, or 26%, due to higher demand for Canadian heavy oil from U.S. Gulf Coast refineries. These factors increased the Corporation's bitumen realization by approximately C$9 per barrel compared to the third quarter of 2016.

Capital investment for the third quarter of 2017 totaled $103.2 million, an increase of $84.0 million compared to the same period of 2016, primarily directed at the eMSAGP growth project at Christina Lake Phase 2B. Still in the first year of a two-year development plan, the eMSAGP growth project is proceeding on schedule and budget. As expected, the Corporation's production volumes are beginning to increase as a result of this project. MEG exited the third quarter with production of approximately 85,000 barrels per day, with further increases expected in the fourth quarter as the Corporation continues to target an exit production rate of 86,000 to 89,000 barrels per day.

The Corporation's non-energy operating costs averaged $4.57 per barrel in the third quarter of 2017, compared to $5.32 per barrel in the same period of 2016. On a year-to-date basis, non-energy operating costs have decreased 20% compared to the first nine months of 2016. These decreases in costs are a result of efficiency gains and continued cost management.

The Corporation realized net earnings of $83.9 million in the third quarter of 2017 and $189.8 million on a year-to-date basis. Net earnings are impacted by the foreign exchange rate as the Corporation's debt is denominated in U.S. dollars. The Canadian dollar strengthened relative to the U.S. dollar so far in 2017, resulting in an unrealized foreign exchange gain of $180.4 million in the third quarter and $345.1 million on a year-to-date basis.

The following table summarizes selected operational and financial information of the Corporation for the periods noted. All dollar amounts are stated in Canadian dollars ($ or C$) unless otherwise noted:

	Nine months ended September 30		2017			2016				2015
($ millions, except as indicated)	**2017**	**2016**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Bitumen production - bbls/d	**77,588**	81,065	**83,008**	72,448	77,245	81,780	83,404	83,127	76,640	83,514
Bitumen realization - $/bbl	**39.17**	24.91	**39.89**	39.66	37.93	36.17	30.98	30.93	11.43	23.17
Net operating costs - $/bbl[(1)]	**7.26**	7.89	**6.00**	7.42	8.43	8.24	7.76	7.43	8.53	8.52
Non-energy operating costs - $/bbl	**4.66**	5.83	**4.57**	4.23	5.20	4.99	5.32	5.81	6.45	5.66
Cash operating netback - $/bbl[(2)]	**24.09**	10.18	**26.84**	22.96	22.33	21.73	16.74	16.09	(3.71)	9.05
Adjusted funds flow from (used in) operations[(3)]	**182**	(102)	**83**	55	43	40	23	7	(131)	(44)
Per share, diluted[(3)]	**0.63**	(0.45)	**0.28**	0.19	0.16	0.18	0.10	0.03	(0.58)	(0.20)
Operating earnings (loss)[(3)]	**(158)**	(383)	**(43)**	(36)	(79)	(72)	(88)	(98)	(197)	(140)
Per share, diluted[(3)]	**(0.55)**	(1.70)	**(0.14)**	(0.12)	(0.29)	(0.32)	(0.39)	(0.43)	(0.88)	(0.62)
Revenue[(4)]	**1,680**	1,301	**546**	574	560	566	497	513	290	445
Net earnings (loss)[(5)]	**190**	(124)	**84**	104	2	(305)	(109)	(146)	131	(297)
Per share, basic	**0.66**	(0.55)	**0.29**	0.36	0.01	(1.34)	(0.48)	(0.65)	0.58	(1.32)
Per share, diluted	**0.66**	(0.55)	**0.28**	0.35	0.01	(1.34)	(0.48)	(0.65)	0.58	(1.32)
Total cash capital investment	**339**	74	**103**	158	78	63	19	20	35	54
Cash and cash equivalents	**398**	103	**398**	512	549	156	103	153	125	408
Long-term debt	**4,636**	4,910	**4,636**	4,813	4,945	5,053	4,910	4,871	4,859	5,190

(1) Net operating costs include energy and non-energy operating costs, reduced by power revenue.

(2) Cash operating netback is calculated by deducting the related diluent expense, transportation, operating expenses, royalties and realized commodity risk management gains (losses) from proprietary blend revenues and power revenues, on a per barrel of bitumen sales volume basis.

(3) Adjusted funds flow from (used in) operations, Operating earnings (loss) and the related per share amounts do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. For the three and nine months ended September 30, 2017 and September 30, 2016, the non-GAAP measure of adjusted funds flow from (used in) operations is reconciled to net cash provided by (used in) operating activities and the non-GAAP measure of operating earnings (loss) is reconciled to net earnings (loss) in accordance with IFRS under the heading "NON-GAAP MEASURES" and discussed further in the "ADVISORY" section.

(4) The total of Petroleum revenue, net of royalties and Other revenue as presented on the Interim Consolidated Statement of Earnings and Comprehensive Income.

(5) Includes a net unrealized foreign exchange gain of $180.4 million and $345.1 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents for the three and nine months ended September 30, 2017, respectively. The net loss for the three and nine months ended, September 30, 2016 includes a net unrealized foreign exchange loss of $38.7 million and a net unrealized foreign exchange gain of $267.8 million, respectively.

3. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended September 30		Nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Bitumen production – bbls/d	**83,008**	83,404	**77,588**	81,065
Steam-oil ratio (SOR)	**2.3**	2.2	**2.3**	2.3

Bitumen Production

Bitumen production at the Christina Lake Project averaged 83,008 bbls/d for the three months ended September 30, 2017, which was substantially consistent with production of 83,404 bbls/d for the three months ended September 30, 2016. Production for the third quarter was partially affected by weather events at the Corporation’s Christina Lake facility combined with the introduction of new technology for well tie-ins as part of the eMSAGP growth project. The third quarter bitumen production exit rate was approximately 85,000 bbls/d, reflecting the initial impact of the Corporation’s eMSAGP implementation.

Sales volumes in the third quarter of 2017 were approximately 6,000 bbls/d less than third quarter production volumes, as these volumes were in transit over the quarter end, destined for the U.S. Gulf Coast. These sales volumes will be recognized in the fourth quarter of 2017.

Bitumen production for the nine months ended September 30, 2017 averaged 77,588 bbls/d compared to 81,065 bbl/d for the nine months ended September 30, 2016. Production for the nine months ended September 30, 2017 was primarily affected by preparatory work to accommodate ongoing drilling activities as well as a planned 37-day turnaround at the Christina Lake Project, which was successfully completed in early June. The 2017 turnaround had a greater impact on production volumes compared to only minor capital activities during the same period in 2016.

Steam-Oil Ratio

SOR is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The Corporation continues to focus on maintaining efficiency of production through a lower SOR. The SOR averaged 2.3 during the three months ended September 30, 2017 compared to 2.2 for the three months ended September 30, 2016. The increase in SOR relates to initial steam injections for the commissioning and start-up of 15 additional wells to be placed into production during the fourth quarter of 2017. The SOR averaged 2.3 for the nine months ended September 30, 2017 and 2016.

Operating Cash Flow

	Three months ended September 30		Nine months ended September 30	
($000)	**2017**	**2016**	**2017**	**2016**
Petroleum revenue – proprietary[1]	**$ 475,784**	$ 442,333	**$ 1,457,785**	$ 1,122,849
Diluent expense	**(193,897)**	(200,564)	**(653,409)**	(576,857)
	281,887	241,769	**804,376**	545,992
Royalties	**(3,745)**	(3,252)	**(15,313)**	(4,720)
Transportation expense	**(52,994)**	(55,252)	**(149,785)**	(159,762)
Operating expenses	**(48,222)**	(64,796)	**(165,146)**	(185,233)
Power revenue	**5,896**	4,277	**16,104**	12,360
Transportation revenue	**2,963**	4,863	**9,200**	15,186
	185,785	127,609	**499,436**	223,823
Realized gain (loss) on commodity risk management	**3,976**	3,128	**(4,601)**	(359)
Operating cash flow[2]	**$ 189,761**	$ 130,737	**$ 494,835**	$ 223,464

(1) *Proprietary petroleum revenue represents MEG's revenue ("blend sales revenue") from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.*

(2) *A non-GAAP measure as defined in the "NON-GAAP MEASURES" section of this MD&A.*

Operating cash flow was $189.8 million for the three months ended September 30, 2017 compared to $130.7 million for the three months ended September 30, 2016. The 45% increase is primarily due to higher blend sales revenue and lower operating expenses. The increase in blend sales revenue is primarily due to a 20% increase in the average realized blend price, which is directly correlated to the quarter-over-quarter increase in average crude oil benchmark pricing. The decrease in operating expenses is due to a continued focus on cost management and a decrease in natural gas prices.

Operating cash flow was $494.8 million for the nine months ended September 30, 2017 compared to $223.5 million for the nine months ended September 30, 2016. The 121% increase is primarily due to higher blend sales revenue as a result of the increase in average crude oil benchmark pricing, partially offset by an increase in diluent expense. The increase in blend sales revenue is primarily due to a 39% increase in the average realized blend price. Diluent expense for the nine months ended September 30, 2017 was $76.6 million higher than the nine months ended September 30, 2016, primarily due to an increase in condensate prices.

Cash Operating Netback

The following table summarizes the Corporation's cash operating netback for the periods indicated:

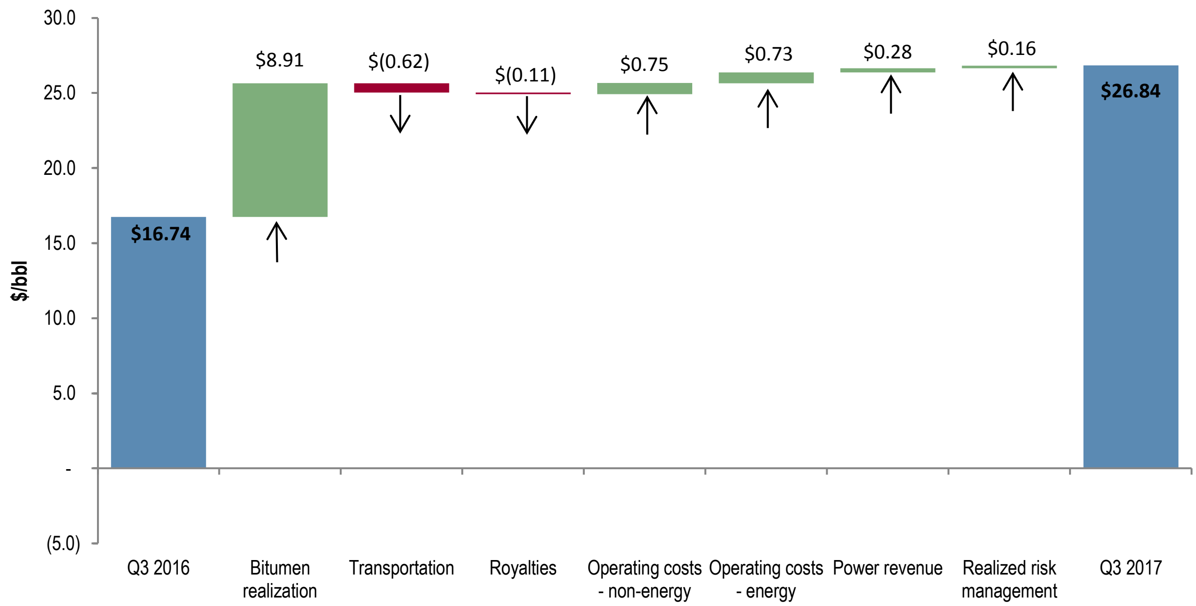
	Three months ended September 30		Nine months ended September 30	
($/bbl)	**2017**	**2016**	**2017**	**2016**
Bitumen realization[1]	**$ 39.89**	$ 30.98	**$ 39.17**	$ 24.91
Transportation[2]	**(7.08)**	(6.46)	**(6.85)**	(6.60)
Royalties	**(0.53)**	(0.42)	**(0.75)**	(0.22)
	32.28	24.10	**31.57**	18.09
Operating costs – non-energy	**(4.57)**	(5.32)	**(4.66)**	(5.83)
Operating costs – energy	**(2.26)**	(2.99)	**(3.38)**	(2.62)
Power revenue	**0.83**	0.55	**0.78**	0.56
Net operating costs	**(6.00)**	(7.76)	**(7.26)**	(7.89)
	26.28	16.34	**24.31**	10.20
Realized gain (loss) on commodity risk management	**0.56**	0.40	**(0.22)**	(0.02)
Cash operating netback	**$ 26.84**	$ 16.74	**$ 24.09**	$ 10.18

(1) *Blend sales revenue net of diluent expense.*

(2) *Defined as transportation expense less transportation revenue. Transportation expense includes rail, third-party pipelines and the Stonefell Terminal costs, as well as MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries on diluent transportation arrangements.*

The cash operating netback was $26.84 per barrel and $24.09 per barrel for the three and nine months ended September 30, 2017, respectively. Cash operating netback was $16.74 per barrel and $10.18 per barrel for the three and nine months ended September 30, 2016, respectively. The increase in the cash operating netback was primarily due to an increase in bitumen realization, as a result of the increase in average crude oil benchmark pricing.

Cash Operating Netback - Three Months Ended September 30



Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary petroleum revenue (“blend sales revenue”), net of diluent expense, expressed on a per barrel basis. Blend sales revenue represents MEG’s revenue from its heavy crude oil blend known as Access Western Blend ("AWB” or “blend”). AWB is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. The cost of blending is impacted by the amount of diluent required and the Corporation’s cost of purchasing and transporting diluent. A portion of diluent expense is effectively recovered in the sales price of the blended product. Diluent expense is also impacted by Canadian and U.S. benchmark pricing, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar.

Bitumen realization averaged $39.89 per barrel for the three months ended September 30, 2017 compared to $30.98 per barrel for the three months ended September 30, 2016. The increase in bitumen realization is primarily a result of the quarter-over-quarter increase in average crude oil benchmark pricing, which resulted in higher blend sales revenue.

For the three months ended September 30, 2017, the Corporation’s cost of diluent was $68.46 per barrel of diluent compared to $61.68 per barrel of diluent for the three months ended September 30, 2016. The increase in the cost of diluent is primarily a result of the quarter-over-quarter increase in average condensate benchmark pricing.

Transportation

The Corporation utilizes multiple facilities to transport and sell its blend to refiners throughout North America. In early 2016, the Corporation increased its transportation capacity on the Flanagan South and Seaway pipeline systems, thereby furthering the Corporation’s strategy of broadening market access to world prices with the intention of improving cash operating netback. Sales volumes destined for U.S. markets require additional transportation costs and generally obtain higher sales prices. Transportation expense averaged $7.08 per barrel for the three months ended September 30, 2017 compared to $6.46 per barrel for the three months ended September 30, 2016. Transportation expense increased on a per barrel basis as a result of fixed transportation costs spread over fewer sales volumes in the third quarter of 2017 as compared to the same period in 2016.

Royalties

The Corporation's royalty expense is based on price-sensitive royalty rates set by the Government of Alberta. The applicable royalty rates change depending on whether a project is pre-payout or post-payout, with payout being defined as the point in time when a project has generated enough cumulative net revenues to recover its cumulative costs. The royalty rate applicable to pre-payout oil sands operations starts at 1% of bitumen sales and increases for every dollar that the WTI crude oil price in Canadian dollars is priced above $55 per barrel, to a maximum of 9% when the WTI crude oil price is $120 per barrel or higher. All of the Corporation's projects are currently pre-payout.

The increase in royalties for the three months ended September 30, 2017, compared to the three months ended September 30, 2016 is primarily the result of higher realized WTI crude oil prices.

Net Operating Costs

Net operating costs are comprised of the sum of non-energy operating costs and energy operating costs, which are reduced by power revenue. Non-energy operating costs represent production-related operating activities excluding energy operating costs. Energy operating costs represent the cost of natural gas for the production of steam and power at the Corporation’s facilities. Power revenue is the sale of surplus power generated by the Corporation’s cogeneration facilities at the Christina Lake Project.

Net operating costs for the three months ended September 30, 2017 averaged $6.00 per barrel compared to $7.76 per barrel for the three months ended September 30, 2016. The decrease in net operating costs is comprised of a per barrel decrease in both non-energy and energy operating costs, and an increase in per barrel power revenue.

Non-energy operating costs

Non-energy operating costs averaged $4.57 per barrel for the three months ended September 30, 2017 compared to $5.32 per barrel for the three months ended September 30, 2016. The decrease in non-energy operating costs is primarily the result of efficiency gains and a continued focus on cost management resulting in lower operations staffing and associated camp and site services costs.

Energy operating costs

Energy operating costs averaged $2.26 per barrel for the three months ended September 30, 2017 compared to $2.99 per barrel for the three months ended September 30, 2016. The decrease in energy operating costs on a per barrel basis is primarily attributable to the decrease in natural gas prices. The Corporation’s natural gas purchase price averaged $1.94 per mcf during the three months ended September 30, 2017 compared to $2.69 per mcf for the three months ended September 30, 2016.

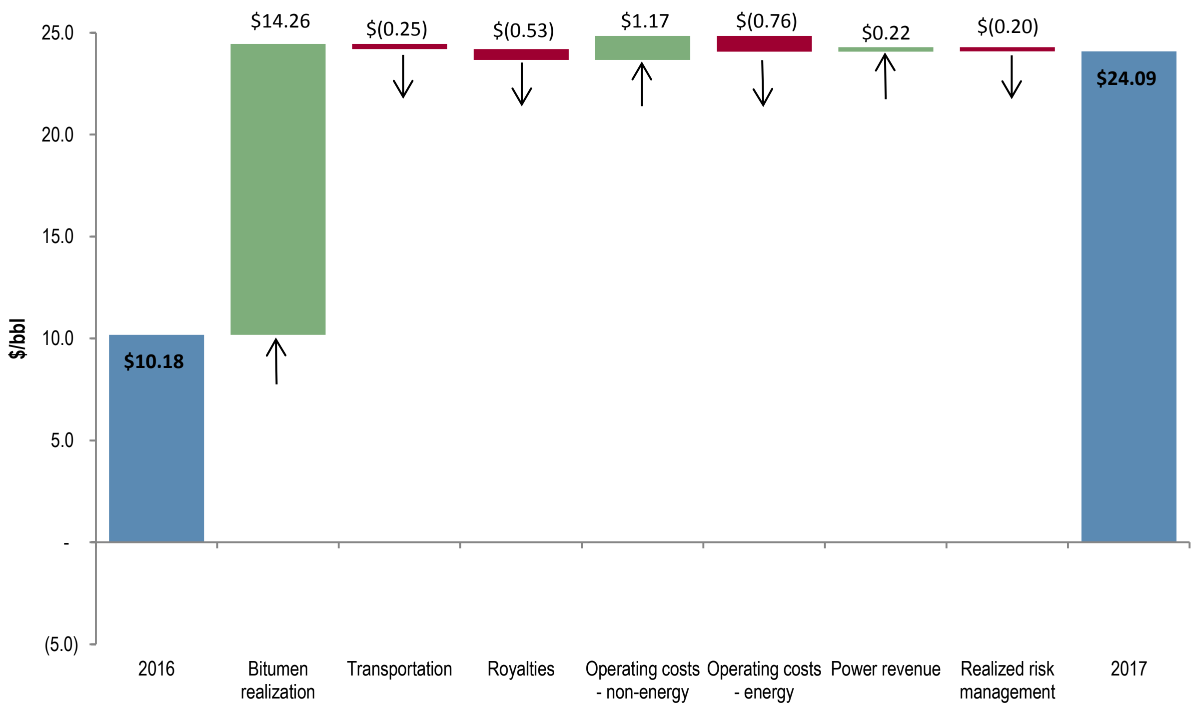
Power revenue

Power revenue averaged $0.83 per barrel for the three months ended September 30, 2017 compared to $0.55 per barrel for the three months ended September 30, 2016. The Corporation’s average realized power sales price during the three months ended September 30, 2017 was $23.29 per megawatt hour compared to $17.62 per megawatt hour for the three months ended September 30, 2016.

Realized Gain (Loss) on Commodity Risk Management

The realized gain on commodity risk management averaged $0.56 per barrel for the three months ended September 30, 2017 compared to a realized gain on commodity risk management of $0.40 per barrel for the three months ended September 30, 2016. This is primarily due to settlement gains on contracts relating to condensate purchases, partially offset by net settlement losses on contracts relating to crude oil sales. Refer to the "Risk Management" section of this MD&A for further details.

Cash Operating Netback – Nine Months Ended September 30



Bitumen Realization

Bitumen realization averaged $39.17 per barrel for the nine months ended September 30, 2017 compared to $24.91 per barrel for the nine months ended September 30, 2016. The increase in bitumen realization is primarily a result of the increase in average crude oil benchmark pricing, which resulted in higher blend sales revenue.

For the nine months ended September 30, 2017, the Corporation's cost of diluent was $70.39 per barrel of diluent compared to $58.32 per barrel of diluent for the nine months ended September 30, 2016. The increase in the cost of diluent is primarily a result of the increase in average condensate benchmark pricing.

Transportation

Transportation costs averaged $6.85 per barrel for the nine months ended September 30, 2017 compared to $6.60 per barrel for the nine months ended September 30, 2016. The increase is a result of fixed transportation costs spread over fewer sales volumes.

Royalties

The increase in royalties for the nine months ended September 30, 2017, compared to the nine months ended September 30, 2016 is primarily the result of higher realized WTI crude oil prices.

Net Operating Costs

Net operating costs for the nine months ended September 30, 2017 averaged $7.26 per barrel compared to $7.89 per barrel for the nine months ended September 30, 2016. The decrease in net operating costs is primarily attributable to a per barrel decrease in non-energy operating costs, offset by an increase in energy operating costs.

Non-energy operating costs

Non-energy operating costs averaged $4.66 per barrel for the nine months ended September 30, 2017 compared to $5.83 per barrel for the nine months ended September 30, 2016. The decrease in non-energy operating costs is primarily the result of efficiency gains and a continued focus on cost management resulting in lower operations staffing and materials and services costs, plus a $0.22 per barrel, or $4.5 million reduction of property taxes related to a one-time municipal reassessment of its Christina Lake facility in the second quarter of 2017.

Energy operating costs

Energy operating costs averaged $3.38 per barrel for the nine months ended September 30, 2017 compared to $2.62 per barrel for the nine months ended September 30, 2016. The increase in energy operating costs on a per barrel basis is primarily attributable to the increase in natural gas prices. The Corporation's natural gas purchase price averaged $2.79 per mcf during the nine months ended September 30, 2017 compared to $2.21 per mcf for the same period in 2016.

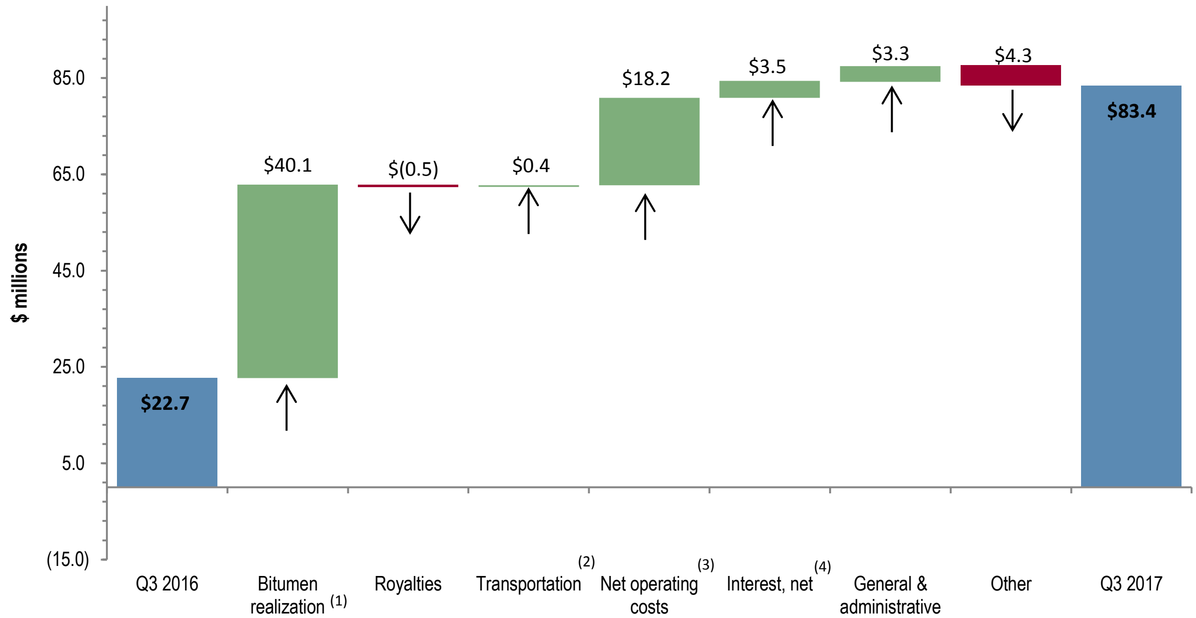
Power revenue

Power revenue averaged $0.78 per barrel for the nine months ended September 30, 2017 compared to $0.56 per barrel for the nine months ended September 30, 2016. The Corporation's average realized power sales price during the nine months ended September 30, 2017 was $21.54 per megawatt hour compared to $17.40 per megawatt hour for the same period in 2016.

Commodity Risk Management Gain (Loss)

The realized loss on commodity risk management averaged $0.22 per barrel for the nine months ended September 30, 2017 compared to $0.02 per barrel for the nine months ended September 30, 2016. This is primarily due to settlement losses on commodity risk management contracts relating to crude oil sales, partially offset by settlement gains on commodity risk management contracts relating to condensate purchases. Refer to the "RISK MANAGEMENT" section of this MD&A for further details.

Adjusted Funds Flow From (Used In) Operations – Three Months Ended September 30



(1) Net of diluent expense.

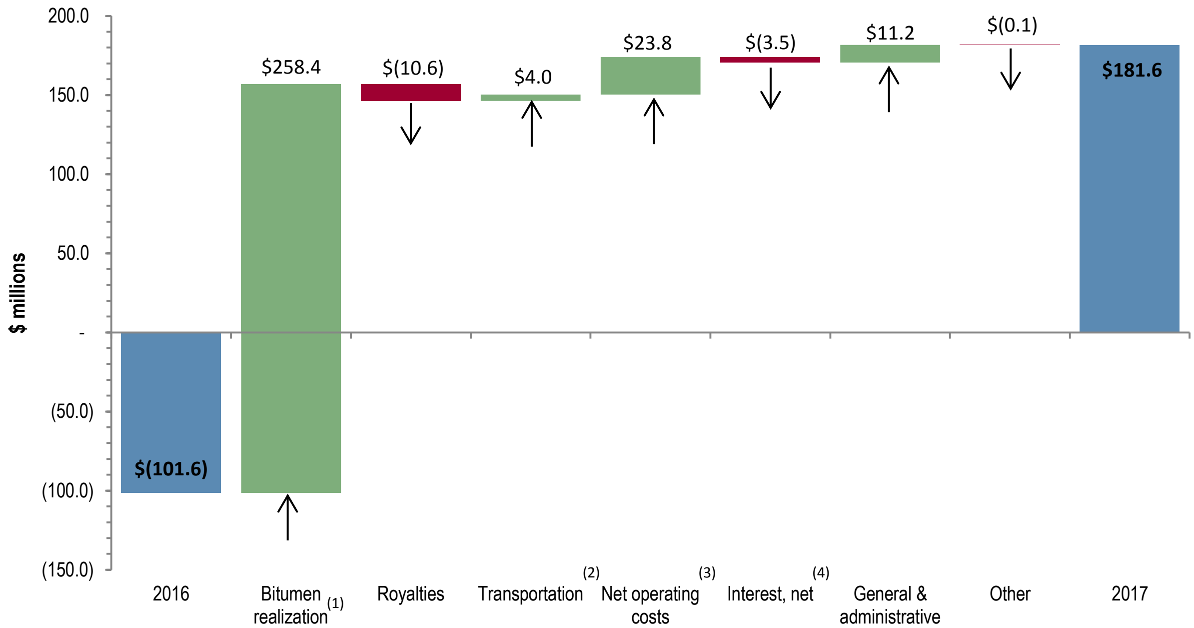
(2) Defined as transportation expense less transportation revenue.

(3) Includes non-energy and energy operating costs, reduced by power revenue.

(4) Defined as total interest expense plus realized gain/loss on interest rate swaps less amortization of debt discount and debt issue costs.

Adjusted funds flow from (used in) operations is a non-GAAP measure, as defined in the "NON-GAAP MEASURES" section of this MD&A, which is used by the Corporation to analyze operating performance and liquidity. Adjusted funds flow from operations was $83.4 million for the three months ended September 30, 2017 compared to $22.7 million for the three months ended September 30, 2016. The increase in adjusted funds flow from operations was primarily due to an increase in bitumen realization and a reduction in net operating costs. The increase in bitumen realization is directly correlated to the quarter-over-quarter increase in average crude oil benchmark pricing. The decrease in net operating costs is a result of efficiency gains, a continued focus on cost management, and reduced natural gas prices.

Adjusted Funds Flow From (Used In) Operations – Nine Months Ended September 30



(1) Net of diluent expense.
(2) Defined as transportation expense less transportation revenue.
(3) Includes non-energy and energy operating costs, reduced by power revenue.
(4) Defined as total interest expense plus realized gain/loss on interest rate swaps less amortization of debt discount and debt issue costs.

Adjusted funds flow from operations was $181.6 million for the nine months ended September 30, 2017 compared to adjusted funds flow used in operations of $(101.6) million for the nine months ended September 30, 2016. The increase was primarily due to an increase in bitumen realization, which is directly correlated to the increase in average crude oil benchmark pricing.

Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP measure, as defined in the “NON-GAAP MEASURES” section of this MD&A, which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. The Corporation recognized an operating loss of $42.6 million for the three months ended September 30, 2017 compared to an operating loss of $87.9 million for the three months ended September 30, 2016. The Corporation recognized an operating loss of $157.6 million for the nine months ended September 30, 2017 compared to an operating loss of $383.1 million for the nine months ended September 30, 2016. The decrease in the operating loss for each of the comparative periods was primarily due to higher bitumen realization as a result of the increase in average crude oil benchmark pricing.

Revenue

Revenue represents the total of petroleum revenue, net of royalties and other revenue. Revenue for the three months ended September 30, 2017 totalled $546.1 million compared to $496.8 million for the three months ended September 30, 2016. Revenue for the nine months ended September 30, 2017 totaled $1.7 billion compared to $1.3 billion for the nine months ended September 30, 2016. Revenue increased primarily due to an increase in blend sales revenue as a result of the increase in average crude oil benchmark pricing.

Net Earnings (Loss)

The Corporation recognized net earnings of $83.9 million for the three months ended September 30, 2017 compared to a net loss of $108.6 million for the three months ended September 30, 2016.

Net earnings for the three months ended September 30, 2017 included a net unrealized foreign exchange gain of $180.5 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents and an unrealized loss on commodity risk management of $57.5 million. The net loss for the three months ended September 30, 2016 included a net unrealized foreign exchange loss of $38.7 million on the Corporation's U.S. dollar denominated debt and U.S dollar denominated cash and cash equivalents which was largely offset by an unrealized gain on commodity risk management of $32.2 million.

The Corporation recognized net earnings of $189.8 million for the nine months ended September 30, 2017 compared to a net loss of $124.0 million for the nine months ended September 30, 2016.

Net earnings for the nine months ended September 30, 2017 included a net unrealized foreign exchange gain of $345.1 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents balance. The net loss for the nine months ended September 30, 2016 included a net unrealized foreign exchange gain of $267.8 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.

Total Cash Capital Investment

Total cash capital investment during the three months ended September 30, 2017 totalled $103.2 million compared to $19.2 million for the three months ended September 30, 2016. Total cash capital investment during the nine months ended September 30, 2017 totaled $339.4 million as compared to $74.2 million for the nine months ended September 30, 2016. Capital investment in 2017 has primarily been directed towards the Corporation's eMSAGP production growth initiative at Christina Lake Phase 2B and sustaining capital activities.

4. OUTLOOK

Summary of 2017 Guidance	Guidance January 11, 2017	Guidance July 26, 2017	Revised Guidance October 26, 2017
Capital investment	$590 million	$590 million	$510 million
Bitumen production – annual average (bbls/d)	80,000 – 82,000	80,000 – 82,000	80,000 – 82,000
Bitumen production – targeted exit volume (bbls/d)	86,000 – 89,000	86,000 – 89,000	86,000 – 89,000
Non-energy operating costs ($/bbl)	$5.75 – $6.75	$5.00 – $5.50	$4.75 – $5.00

The Corporation has reduced its capital guidance and now estimates capital investment in 2017 to be approximately $510 million, the remaining of which is expected to be primarily directed towards the eMSAGP growth initiative.

The Corporation's 2017 estimated annual bitumen production volumes remain unchanged and are targeted to average 80,000 – 82,000 bbls/d with targeted exit production of 86,000 – 89,000 bbls/d.

The Corporation's non-energy operating cost guidance has been reduced to $4.75 – $5.00 per barrel, reflecting ongoing efficiency gains and a continued focus on cost management. The new guidance compares to the previous guidance of $5.00 – $5.50 per barrel and is 22% lower than the initial guidance of $5.75 – $6.75 per barrel.

5. BUSINESS ENVIRONMENT

The following table shows industry commodity pricing information and foreign exchange rates on a quarterly basis to assist in understanding the impact of commodity prices and foreign exchange rates on the Corporation's financial results:

	Nine months ended September 30		2017			2016				2015
	2017	**2016**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**52.59**	42.91	**52.18**	50.93	54.66	51.13	46.98	46.67	35.10	44.71
WTI (US$/bbl)	**49.47**	41.34	**48.21**	48.29	51.91	49.29	44.94	45.59	33.45	42.18
WTI (C$/bbl)	**64.64**	54.69	**60.38**	64.94	68.68	65.75	58.65	58.75	45.99	56.32
WCS (C$/bbl)	**49.12**	36.59	**47.93**	49.98	49.39	46.65	41.03	41.61	26.41	36.97
Differential – WTI:WCS (US$/bbl)	**11.88**	13.68	**9.94**	11.13	14.58	14.32	13.50	13.30	14.24	14.49
Differential – WTI:WCS (%)	**24.0%**	33.1%	**20.6%**	23.0%	28.1%	29.1%	30.0%	29.2%	42.6%	34.4%
Condensate prices										
Condensate at Edmonton (C$/bbl)	**64.64**	53.45	**59.59**	65.16	69.17	64.49	56.25	56.83	47.27	55.57
Condensate at Edmonton as % of WTI	**100.0%**	97.7%	**98.7%**	100.3%	100.7%	98.1%	95.9%	96.7%	102.8%	98.7%
Condensate at Mont Belvieu, Texas (US$/bbl)	**45.73**	37.86	**46.37**	44.77	46.05	45.17	41.17	40.37	32.03	40.76
Condensate at Mont Belvieu, Texas as % of WTI	**92.4%**	91.6%	**96.2%**	92.7%	88.7%	91.6%	91.6%	88.6%	95.8%	96.6%
Natural gas prices										
AECO (C$/mcf)	**2.44**	1.89	**1.58**	2.81	2.91	3.31	2.49	1.37	1.82	2.57
Electric power prices										
Alberta power pool (C$/MWh)	**22.06**	16.93	**24.55**	19.26	22.38	21.97	17.93	14.77	18.09	21.19
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.3067**	1.3228	**1.2524**	1.3449	1.3230	1.3339	1.3051	1.2886	1.3748	1.3353
C$ equivalent of 1 US$ - period end	**1.2510**	1.3117	**1.2510**	1.2977	1.3322	1.3427	1.3117	1.3009	1.2971	1.3840

Crude Oil Prices

Brent crude is the primary world price benchmark for global light sweet crude oil. The Brent benchmark price averaged US$52.18 per barrel in the third quarter of 2017 compared to US$46.98 per barrel in the third quarter of 2016. The Brent benchmark price averaged US$52.59 per barrel for the nine months ended September 30, 2017 compared to US$42.91 per barrel for the nine months ended September 30, 2016. The price of WTI is the current benchmark for mid-continent North American crude oil prices, at Cushing Oklahoma, and its Canadian dollar equivalent is the basis for determining royalties on the Corporation's bitumen sales. The WTI price averaged US$48.21 per barrel in the third quarter of 2017 compared to US$44.94 in the third quarter of 2016. The WTI price averaged US$49.47 per barrel for the nine months ended September 30, 2017 compared to US$41.34 per barrel for the nine months ended September 30, 2016.

WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. The WCS benchmark reflects North American prices at Hardisty, Alberta. WCS typically trades at a differential below the WTI benchmark price. The WTI:WCS differential average decreased to US$9.94 per barrel, or 20.6%, for the third quarter of 2017, compared to US$13.50 per barrel, or 30.0% for the third quarter of 2016 due to higher demand for Canadian heavy oil from U.S. Gulf Coast refineries. The WTI:WCS differential averaged US$11.88 per barrel, or 24.0%, for the nine months ended September 30, 2017 compared to US$13.68 per barrel, or 33.1%, for the nine months ended September 30, 2016.

Condensate Prices

In order to facilitate pipeline transportation, MEG uses condensate sourced throughout North America as diluent for blending with the Corporation's bitumen. Condensate prices, benchmarked at Edmonton averaged $59.59 per barrel, or 98.7% of WTI, for the third quarter of 2017 compared to $56.25 per barrel, or 95.9% of WTI, for the third quarter of 2016. Condensate prices, benchmarked at Edmonton, averaged $64.64 per barrel, or 100.0% of WTI, for the nine months ended September 30, 2017 compared to $53.45 per barrel, or 97.7% of WTI, for the nine months ended September 30, 2016.

Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$46.37 per barrel , or 96.2% of WTI, for the third quarter of 2017 compared to US$41.17 per barrel, or 91.6% of WTI, for the third quarter of 2016. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$45.73 per barrel, or 92.4% of WTI, for the nine months ended September 30, 2017 compared to US$37.86 per barrel, or 91.6% of WTI, for the nine months ended September 30, 2016.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, as it is used as fuel to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facilities. The AECO natural gas price averaged $1.58 per mcf for the third quarter of 2017 compared to $2.49 per mcf for the third quarter of 2016.

The AECO natural gas price averaged $2.44 per mcf for the nine months ended September 30, 2017 compared to $1.89 per mcf for the nine months ended September 30, 2016.

Electric Power Prices

Electric power prices impact the price that the Corporation receives on the sale of surplus power from the Corporation's cogeneration facilities. The Alberta power pool price averaged $24.55 per megawatt hour for the third quarter of 2017 compared to $17.93 per megawatt hour for the third quarter of 2016. The Alberta power pool price averaged $22.06 per megawatt hour for the nine months ended September 30, 2017 compared to $16.93 per megawatt hour for the nine months ended September 30, 2016.

Foreign Exchange Rates

Changes in the value of the Canadian dollar relative to the U.S. dollar have an impact on the Corporation's blend sales revenue and diluent expense, as blend sales prices and diluent expense are determined by reference to U.S. benchmarks. Changes in the value of the Canadian dollar relative to the U.S. dollar also have an impact on principal and interest payments on the Corporation's U.S. dollar denominated debt. A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on blend sales revenue and a negative impact on diluent expense and principal and interest payments. Conversely, an increase in the value of the Canadian dollar has a negative impact on blend sales revenue and a positive impact on diluent expense and principal and interest payments.

The Corporation recognizes net unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents at each reporting date. As at September 30, 2017, the Canadian dollar, at a rate of 1.2510, had increased in value by approximately 7% against the U.S. dollar compared to its value as at December 31, 2016, when the rate was 1.3427. As at September 30, 2016, the Canadian dollar, at a rate of 1.3117, had increased in value by approximately 5% against the U.S. dollar compared to its value as at December 31, 2015, when the rate was 1.3840.

6. OTHER OPERATING RESULTS

Net Marketing Activity

	Three months ended September 30		Nine months ended September 30	
($000)	**2017**	**2016**	**2017**	**2016**
Petroleum revenue – third party	**$ 64,994**	$ 48,599	**$ 211,928**	$ 154,838
Purchased product and storage	**(64,738)**	(48,157)	**(209,922)**	(151,638)
Net marketing activity[1]	**$ 256**	$ 442	**$ 2,006**	$ 3,200

(1) *Net marketing activity is a non-GAAP measure as defined in the "NON-GAAP MEASURES" section.*

The Corporation has entered into marketing arrangements for rail and pipeline transportation commitments and product storage arrangements to enhance its ability to transport proprietary crude oil products to a wider range of markets in Canada, the United States and on tidewater. In the event that the Corporation is not utilizing these arrangements for proprietary purposes, the Corporation purchases and sells third-party crude oil and related products and enters into transactions to generate revenues to offset the costs of such marketing and storage arrangements.

Depletion and Depreciation

	Three months ended September 30		Nine months ended September 30	
($000)	**2017**	**2016**	**2017**	**2016**
Depletion and depreciation expense	**$ 128,754**	$ 128,995	**$ 357,238**	$ 373,340
Depletion and depreciation expense per barrel of production	**$ 16.86**	$ 16.81	**$ 16.87**	$ 16.81

Depletion and depreciation expense for the three months ended September 30, 2017 totalled $128.8 million compared to $129.0 million for the three months ended September 30, 2016. Depletion and depreciation expense for the nine months ended September 30, 2017 totalled $357.2 million compared to $373.3 million for the nine months ended September 30, 2016. The decrease in the depletion and depreciation expense was primarily due to the decrease in production, which was affected by a planned 37-day turnaround in the second quarter of 2017.

Commodity Risk Management (Loss) Gain

The Corporation has entered into financial commodity risk management contracts. The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes. All financial commodity risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss). Realized gains or losses on financial commodity risk management contracts are the result of contract settlements during the period. Unrealized gains or losses on financial commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.

	Three months ended September 30					
($000)	**2017**			**2016**		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Crude oil contracts[1]	**$ (7,182)**	**$ (55,300)**	**$(62,482)**	$ (512)	$ (820)	$ (1,332)
Condensate contracts[2]	**11,158**	**(2,170)**	**8,988**	3,640	33,027	36,667
Commodity risk management gain (loss)	**$ 3,976**	**$ (57,470)**	**$(53,494)**	$ 3,128	$ 32,207	$ 35,335

The Corporation realized a gain on commodity risk management contracts of $4.0 million for the three months ended September 30, 2017, due to settlement gains on condensate purchase contracts, partially offset by net settlement losses on contracts relating to crude oil sales. This compares to a gain of $3.1 million for the three months ended September 30, 2016.

The Corporation recognized an unrealized loss on commodity risk management contracts of $57.5 million for the three months ended September 30, 2017, primarily due to unrealized losses on crude oil contracts. Benchmark oil prices increased over the quarter, resulting in unrealized losses on WTI fixed price contracts and collars. The $57.5 million unrealized loss for the three months ended September 30, 2017 compares to a $32.2 million unrealized gain for the comparative 2016 quarter. Refer to the “Risk Management” section of this MD&A for further details.

	Nine months ended September 30					
($000)	**2017**			**2016**		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Crude oil contracts[1]	**$(29,984)**	**$ 34,931**	**$ 4,947**	$ (5,816)	$ (19,110)	$(24,926)
Condensate contracts[2]	**25,383**	**(15,578)**	**9,805**	5,457	30,846	36,303
Commodity risk management gain (loss)	**$ (4,601)**	**$ 19,353**	**$ 14,752**	$ (359)	$ 11,736	$ 11,377

(1) *Includes WTI fixed price, WTI collars and WCS fixed differential contracts.*

(2) *Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas as a percentage of WTI (US$/bbl).*

The Corporation realized a loss on commodity risk management contracts of $4.6 million for the nine months ended September 30, 2017, primarily due to net settlement losses on contracts relating to crude oil sales, partially offset by settlement gains on condensate purchase contracts. This compares to a loss of $0.4 million for the nine months ended September 30, 2016.

The Corporation recognized an unrealized gain on commodity risk management contracts of $19.4 million for the nine months ended September 30, 2017, reflecting unrealized gains on crude oil contracts partially offset by unrealized losses on condensate purchase contracts. Crude oil benchmark prices decreased over the period, resulting in unrealized gains on the Corporation’s WTI fixed price contracts and collars. This was partially offset by unrealized losses on WCS fixed differential contracts, due to a narrowing WCS differential. The $19.4 million unrealized gain in 2017 compares to an $11.7 million unrealized gain for the comparative 2016 period. Refer to the “Risk Management” section of this MD&A for further details.

General and Administrative

	Three months ended September 30		Nine months ended September 30	
($000)	**2017**	**2016**	**2017**	**2016**
General and administrative expense	**$ 19,321**	$ 22,587	**$ 63,482**	$ 74,671
General and administrative expense per barrel of production	**$ 2.53**	$ 2.94	**$ 3.00**	$ 3.36

General and administrative expense for the three months ended September 30, 2017 was $19.3 million compared to $22.6 million for the three months ended September 30, 2016. General and administrative expense was $2.53 per barrel for the three months ended September 30, 2017 compared to $2.94 per barrel for the three months ended September 30, 2016. General and administrative expense for the nine months ended September 30, 2017 was $63.5 million compared to $74.7 million for the nine months ended September 30, 2016. General and administrative expense was $3.00 per barrel for the nine months ended September 30, 2017 compared to $3.36 per barrel for the nine months ended September 30, 2016. General and administrative expense decreased primarily due to workforce reductions and the Corporation's continued focus on cost management.

Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
($000)	**2017**	**2016**	**2017**	**2016**
Cash-settled expense	**$ 7,054**	$ 4,045	**$ 3,559**	$ 5,495
Equity-settled expense	**5,491**	5,977	**13,764**	27,938
Stock-based compensation	**$ 12,545**	$ 10,022	**$ 17,323**	$ 33,433

The fair value of compensation associated with the granting of stock options, restricted share units ("RSUs"), performance share units ("PSUs") and deferred share units ("DSUs") to officers, directors, employees and consultants is recognized by the Corporation as stock-based compensation expense. Fair values for equity-settled plans are determined using the Black-Scholes option pricing model.

The Corporation also grants RSUs, PSUs and DSUs under cash-settled plans. RSUs generally vest over a three year period while PSUs generally vest on the third anniversary of the grant date, provided that the Corporation satisfies certain performance criteria identified by the Corporation's Board of Directors within a target range. Upon vesting of the RSUs and PSUs, the participants of the cash-settled RSU plan will receive a cash payment based on the fair value of the underlying share units at the vesting date. The cash-settled RSUs, PSUs and DSUs are accounted for as liability instruments and are measured at fair value based on the market value of the Corporation's common shares at each period end. Fluctuations in the fair value are recognized within stock-based compensation expense or capitalized to property, plant and equipment during the period in which they occur.

Stock-based compensation expense for the three months ended September 30, 2017 was $12.5 million compared to $10.0 million for the three months ended September 30, 2016. This increase was primarily the result of an increase in the fair value of the cash-settled units due to the increase in the Corporation's common share price during the three months ended September 30, 2017. Stock-based compensation expense for the nine months ended September 30, 2017 was $17.3 million compared to $33.4 million for the nine months ended September 30, 2016. The decrease is primarily due to a decrease in equity-settled share-based compensation costs as a result of fewer equity-settled compensation awards outstanding in 2017.

Research and Development

	Three months ended September 30		Nine months ended September 30	
($000)	**2017**	**2016**	**2017**	**2016**
Research and development expense	**$ 1,299**	$ 1,265	**$ 3,405**	$ 4,360

Research and development expenditures related to the Corporation's research of crude quality improvement and related technologies have been expensed. Research and development expenditures were $1.3 million for the three months ended September 30, 2017 and September 30, 2016. Research and development expenditures were $3.4 million for the nine months ended September 30, 2017 compared to $4.4 million for the nine months ended September 30, 2016.

Foreign Exchange Gain (Loss), Net

	Three months ended September 30		Nine months ended September 30	
($000)	**2017**	**2016**	**2017**	**2016**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ 176,586**	$ (40,954)	**$ 346,734**	$ 274,723
Other	**3,862**	2,225	**(1,618)**	(6,960)
Unrealized net gain (loss) on foreign exchange	**180,448**	(38,729)	**345,116**	267,763
Realized gain (loss) on foreign exchange	**(2,064)**	(1,005)	**3,291**	3,853
Foreign exchange gain (loss), net	**$ 178,384**	$ (39,734)	**$ 348,407**	$ 271,616
C$ equivalent of 1 US$				
Beginning of period	**1.2977**	1.3009	**1.3427**	1.3840
End of period	**1.2510**	1.3117	**1.2510**	1.3117

The Corporation recognized a net foreign exchange gain of $178.4 million for the three months ended September 30, 2017 compared to a net foreign exchange loss of $39.7 million for the three months ended September 30, 2016. The net foreign exchange gain in 2017 is primarily due to the translation of the U.S. dollar denominated debt as a result of the strengthening of the Canadian dollar compared to the U.S. dollar during the three months ended September 30, 2017.

The Corporation recognized a net foreign exchange gain of $348.4 million for the nine months ended September 30, 2017 compared to a net foreign exchange gain of $271.6 million for the nine months ended September 30, 2016. The net foreign exchange gains are primarily due to the translation of the U.S. dollar denominated debt as a result of the strengthening of the Canadian dollar compared to the U.S. dollar during each respective nine month period.

Net Finance Expense

	Three months ended September 30		Nine months ended September 30	
($000)	2017	2016	2017	2016
Total interest expense	$ 80,860	$ 81,194	$ 259,296	$ 245,866
Accretion on provisions	1,994	1,796	5,675	5,310
Unrealized loss (gain) on derivative financial liabilities(1)	(3,490)	(11,367)	(7,346)	(5,362)
Realized loss on interest rate swaps	21	1,507	21	4,548
Net finance expense	$ 79,385	$ 73,130	$ 257,646	$ 250,362
Average effective interest rate(2)	6.0%	5.8%	6.0%	5.8%

(1) *Derivative financial liabilities include the 1% interest rate floor and interest rate swaps.*

(2) *Defined as the weighted average interest rate applied to the U.S. dollar denominated senior secured term loan, Senior Secured Second Lien Notes, and Senior Unsecured Notes outstanding, including the impact of interest rate swaps.*

Total interest expense for the three months ended September 30, 2017 was slightly lower than the comparative 2016 period, primarily due to a stronger Canadian dollar and its impact on the Corporation's U.S. dollar denominated interest expense, partially offset by higher average effective interest rates. Total interest expense for the nine months ended September 30 , 2017 was $259.3 million compared to $245.9 million for the nine months ended September 30, 2016. This increase was due to higher effective interest rates and the incremental interest expense associated with carrying both the now repaid US$750 million aggregate principal amount of 6.5% Senior Unsecured Notes and the new 6.5% Senior Secured Second Lien Notes for a period of 49 days. Given the reduction in the early redemption premium threshold between closing and March 15, 2017, the economic cost of carrying interest on these notes for an incremental 49 days was less than the cost of redeeming the notes prior to March 15, 2017. The 6.5% Senior Unsecured Notes were repaid on March 15, 2017 with the proceeds from the Senior Secured Second Lien Notes. This issuance and repayment of notes was part of the Corporation's comprehensive refinancing plan which is further described in the "LIQUIDITY AND CAPITAL RESOURCES" section of this MD&A.

Unrealized gains and losses on derivative liabilities include changes in fair value of both the interest rate floor associated with the Corporation's senior secured term loan and the interest rate swap contracts. The Corporation recognized an unrealized gain on derivative financial liabilities of $3.5 million for the three months ended September 30, 2017 compared to an unrealized gain of $11.4 million for the three months ended September 30, 2016. The Corporation recognized an unrealized gain on derivative financial liabilities of $7.3 million for the nine months ended September 30, 2017 compared to an unrealized gain of $5.4 million for the nine months ended September 30, 2016.

In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of its US$1.2 billion senior secured term loan at approximately 5.3%. This interest rate swap contract is effective commencing September 29, 2017 and expires on December 31, 2020. The Corporation realized a loss on the interest rate swaps of $21 thousand for the three and nine months ended September 30, 2017.

In 2016, the Corporation realized a loss on interest rate swaps of $1.5 million and $4.5 million for the three and nine months ended September 30, 2016, respectively. These swap contracts fixed the interest rate on US$748.0 million of its US$1.2 billion senior secured term loan and expired on September 30, 2016.

Other Expenses

	Three months ended September 30		Nine months ended September 30	
($000)	2017	2016	2017	2016
Contract cancellation expense	$ 18,765	$ -	$ 18,765	$ -
Onerous contracts	(27)	18,057	5,681	31,483
Severance and other	1,513	-	4,981	6,179
Other expenses	$ 20,251	$ 18,057	$ 29,427	$ 37,662

The Corporation recognized other expenses of $20.3 million for the three months ended September 30, 2017 compared to $18.1 million for the three months ended September 30, 2016. The Corporation recognized other expenses of $29.4 million for the nine months ended September 30, 2017 compared to $37.7 million for the nine months ended September 30, 2016.

During the third quarter of 2017, the Corporation recognized contract cancellation expense of $18.8 million relating to the termination of a long-term marketing transportation contract that had not yet commenced.

Onerous contracts expense primarily includes changes in estimated future cash flow sublease recoveries related to the onerous office lease provision for the Corporation's office building lease contracts. The Corporation recognized a $27 thousand onerous contracts recovery in the third quarter of 2017 and an expense of $5.7 million for the nine months ended September 30, 2017. Onerous contracts expense of $18.1 million was recognized for the three months ended September 30, 2016 and an expense of $31.5 million was recognized for the nine months ended September 30, 2016.

Income Tax Expense (Recovery)

	Three months ended September 30		Nine months ended September 30	
($000)	2017	2016	2017	2016
Current income tax expense (recovery)	$ (257)	$ 103	$ (426)	$ 717
Deferred income tax expense (recovery)	(33,091)	(22,833)	(50,268)	(140,793)
Income tax expense (recovery)	$ (33,348)	$ (22,730)	$ (50,694)	$ (140,076)

The Corporation recognizes current income taxes associated with its operations in the United States. The Corporation's Canadian operations are not currently taxable. As at September 30, 2017, the Corporation had approximately $8.4 billion of available tax pools.

For the nine months ended September 30, 2017, the Corporation recognized a current income tax recovery of $0.8 million related to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures, and a current income tax expense of $0.4 million related to its operations in the United States.

The Corporation recognized a deferred income tax recovery of $33.1 million for the three months ended September 30, 2017 compared to a deferred income tax recovery of $22.8 million for the three months ended September 30, 2016. The Corporation recognized a deferred income tax recovery of $50.3 million for the nine months ended September 30, 2017 and a deferred income tax recovery of $140.8 million for the nine months ended September 30, 2016.

The Corporation's effective tax rate on earnings is impacted by permanent differences. The significant permanent differences are:

- The permanent difference due to the non-taxable portion of realized and unrealized foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the three months ended September 30, 2017, the non-taxable net gain was $88.3 million compared to a non-taxable loss of $20.5 million for the three months ended September 30, 2016. For the nine months ended September 30, 2017, the non-taxable gain was $173.4 million compared to a non-taxable gain of $137.4 million for the nine months ended September 30, 2016.

- Non-taxable stock-based compensation expense for equity-settled plans is a permanent difference. Stock-based compensation expense for equity-settled plans for the three months ended September 30, 2017 was $5.5 million compared to $6.0 million for the three months ended September 30, 2016. Stock-based compensation expense for equity-settled plans for the nine months ended September 30, 2017 was $13.8 million compared to $27.9 million for the three months ended September 30, 2016.

As at September 30, 2017, the Corporation has recognized a deferred income tax asset of $177.0 million on the Consolidated Balance Sheet, as estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

As at September 30, 2017, the Corporation had not recognized the tax benefit related to $444.2 million of realized and unrealized taxable capital foreign exchange losses.

7. NET CAPITAL INVESTMENT

	Three months ended September 30		Nine months ended September 30	
($000)	**2017**	**2016**	**2017**	**2016**
Total cash capital investment	**$ 103,173**	$ 19,203	**$ 339,417**	$ 74,168
Capitalized cash-settled stock-based compensation	**571**	416	**(259)**	719
	$ 103,744	$ 19,619	**$ 339,158**	$ 74,887

Total cash capital investment for the three months ended September 30, 2017 was $103.2 million, compared to $19.2 million for the three months ended September 30, 2016. Total cash capital investment for the nine months ended September 30, 2017 was $339.4 million as compared to $74.2 million for the nine months ended September 30, 2016. During the first nine months of 2017, the Corporation invested $150.2 million in the eMSAGP growth project at Christina Lake Phase 2B, $140.0 million in sustaining capital activities, and $49.2 million in marketing, corporate and other capital initiatives. Included in sustaining capital activities are turnaround costs of $37.1 million incurred in the second quarter of 2017, which are depreciated on a straight-line basis over the period to the next turnaround. Capital investment in the three and nine months ended September 30, 2016 was primarily directed towards sustaining capital activities.

In June 2016, the Corporation began capitalizing the cost related to a new cash-settled stock-based compensation plan for employees directly involved in capital investing activities.

8. LIQUIDITY AND CAPITAL RESOURCES

($000)	September 30, 2017	December 31, 2016
Cash and cash equivalents	**$ 397,598**	$ 156,230
Senior secured term loan (September 30, 2017 – US$1.229 billion; due 2023; December 31, 2016 – US$1.236 billion)	**1,537,260**	1,658,906
US$1.4 billion revolver (due 2021)	**-**	-
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**938,250**	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	**-**	1,007,025
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,000,800**	1,074,160
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,251,000**	1,342,700
Total debt(1)	**$ 4,727,310**	$ 5,082,791

(1) The non-GAAP measure of total debt is reconciled to long-term debt in accordance with IFRS under the heading "NON-GAAP MEASURES" and discussed further in the "ADVISORY" section.

Capital Resources

The Corporation's cash and cash equivalents balance totalled $397.6 million as at September 30, 2017 compared to $156.2 million as at December 31, 2016. The Corporation's cash and cash equivalents balance increased primarily due to net equity issuance proceeds of $496.3 million received pursuant to the comprehensive refinancing that closed on January 27, 2017.

All of the Corporation's long-term debt is denominated in U.S. dollars. As a result of the increase in the value of the Canadian dollar relative to the U.S. dollar, long-term debt as presented on the Consolidated Balance Sheet, decreased to C$4.6 billion as at September 30, 2017 from C$5.1 billion as at December 31, 2016.

On January 27, 2017, the Corporation closed a comprehensive refinancing plan by way of the Corporation's Canadian base shelf prospectus dated December 1, 2016. The plan was comprised of the following four transactions:

- An extension of the maturity date on substantially all of the commitments under the Corporation's undrawn covenant-lite revolving credit facility from November 2019 to November 2021. The commitment amount of the five-year facility has been reduced from US$2.5 billion to US$1.4 billion. The revolving credit facility has no financial maintenance covenants and is not subject to any borrowing base redetermination;
- The US$1.2 billion term loan has been refinanced and its maturity date has been extended from March 2020 to December 2023. The refinanced term loan bears interest at an annual rate of LIBOR plus 3.5% with a LIBOR floor of 1%;
- The US$750 million aggregate principal amount of 6.5% Senior Unsecured Notes, with a maturity date of March 2021, have been refinanced and replaced with new 6.5% Senior Secured Second Lien Notes, maturing January 2025. The existing 2021 notes were redeemed with the proceeds from the Senior Secured Second Lien Notes on March 15, 2017; and
- The Corporation raised C$518 million of equity, before underwriting fees and expenses, in the form of 66,815,000 common shares at a price of $7.75 per common share on a bought deal basis from a syndicate of underwriters.

In addition to the transactions noted above, on February 15, 2017, the Corporation extended the maturity date on its five-year letter of credit facility, guaranteed by EDC, from November 2019 to November 2021. The guaranteed letter of credit facility has been reduced from US$500 million to US$440 million. As at September 30, 2017, US$307 million of letters of credit had been issued. Letters of credit under this facility do not consume capacity of the revolving credit facility.

All of MEG's long-term debt, the revolving credit facility and the EDC facility are "covenant-lite" in structure, meaning they are free of any financial maintenance covenants and are not dependent on, nor calculated from, the Corporation's crude oil reserves. The first maturity of any of the Corporation's outstanding long-term debt obligations is in 2023.

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary. The Corporation's cash flow and the development of projects are dependent on factors discussed in the "RISK FACTORS" section of this MD&A.

The objectives of the Corporation's investment guidelines for surplus cash are to ensure preservation of capital and to maintain adequate liquidity to meet the Corporation's cash flow requirements. The Corporation only places surplus cash investments with counterparties that have a short term credit rating of R-1 (high) or equivalent. The Corporation has experienced no material loss or lack of access to its cash in operating accounts, invested cash or cash equivalents. However, the Corporation can provide no assurance that access to its invested cash and cash equivalents will not be impacted by adverse conditions in the financial markets. While the Corporation monitors the cash balances in its operating and investment accounts according to its investment practices and adjusts the cash balances as appropriate, these cash balances could be impacted if the underlying financial institutions or corporations fail or are subject to other adverse conditions in the financial markets.

Risk Management

Commodity Price Risk Management

Fluctuations in commodity prices and market conditions can impact the Corporation's financial performance, operating results, cash flows, expansion and growth opportunities, access to funding and the cost of borrowing. Under the Corporation's strategic commodity risk management program, derivative financial instruments are employed with the intent of increasing the predictability of the Corporation's future cash flow. MEG's commodity risk management program is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes.

To mitigate the Corporation's exposure to fluctuations in crude oil prices, the Corporation periodically enters into financial commodity risk management contracts to partially manage its exposure on blend sales and condensate purchases.

The Corporation had the following financial commodity risk management contracts relating to crude oil sales outstanding:

As at September 30, 2017	Volumes (bbls/d) [(1)]	Term	Average Price (US$/bbl) [(1)]
Fixed Price:			
WTI Fixed Price	33,100	Oct 1, 2017 – Dec 31, 2017	$54.19
WTI Fixed Price	15,000	Jan 1, 2018 – Jun 30, 2018	$51.24
WTI Fixed Price	10,000	Jul 1, 2018 – Dec 31, 2018	$50.88
WTI:WCS Fixed Differential	56,600	Oct 1, 2017 – Dec 31, 2017	$(15.02)
WTI:WCS Fixed Differential	31,000	Jan 1, 2018 – Jun 30, 2018	$(14.08)
WTI:WCS Fixed Differential	18,000	Jul 1, 2018 – Dec 31, 2018	$(14.26)
Collars:			
WTI Collars	30,500	Oct 1, 2017 – Dec 31, 2017	$47.87 – $58.57
WTI Collars	32,500	Jan 1, 2018 – Jun 30, 2018	$45.49 – $54.87
WTI Collars	24,500	Jul 1, 2018 – Dec 31, 2018	$45.04 – $54.33

The Corporation has entered into the following commodity risk management contracts relating to crude oil sales subsequent to September 30, 2017 up to the date of October 25, 2017:

Subsequent to September 30, 2017	Volumes (bbls/d) [(1)]	Term	Average Price (US$/bbl) [(1)]
Fixed Price:			
WTI:WCS Fixed Differential	6,200	Jan 1, 2018 – Jun 30, 2018	$(14.27)
WTI:WCS Fixed Differential	3,500	Jul 1, 2018 – Dec 31, 2018	$(14.51)
WTI Collars	1,000	Jan 1, 2018 – Dec 31, 2018	$50.10 – $53.82

(1) The volumes and prices in the above tables represent averages for various contracts with differing terms and prices. The average price for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.

The Corporation enters into commodity risk management contracts that effectively fix the average condensate prices at Mont Belvieu, Texas as a percentage of WTI. The Corporation had the following commodity risk management contracts relating to condensate purchases outstanding:

As at September 30, 2017	Volumes (bbls/d)	Term	Average % of WTI
Mont Belvieu fixed % of WTI	15,150	Oct 1, 2017 – Dec 31, 2017	82.9%

Interest Rate Risk Management

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. In the third quarter of 2017, the Corporation entered into an interest rate swap contract to fix the interest rate at approximately 5.3% on US$650.0 million of the US$1.2 billion senior secured term loan from September 29, 2017 to December 31, 2020. During the three and nine months ended September 30, 2016, the Corporation had interest rate swap contracts in place to effectively fix the interest rate at approximately 4.4% on US$748.0 million of the senior secured term loan. These interest rate swap contracts expired on September 30, 2016.

Cash Flow Summary

	Three months ended September 30		Nine months ended September 30	
($000)	**2017**	**2016**	**2017**	**2016**
Net cash provided by (used in):				
Operating activities	**$ 7,979**	$ (19,894)	**$ 117,397**	$ (175,978)
Investing activities	**(122,288)**	(27,552)	**(278,624)**	(108,144)
Financing activities	**(3,892)**	(4,263)	**405,188**	(12,698)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**3,375**	2,134	**(2,593)**	(8,257)
Change in cash and cash equivalents	**$ (114,826)**	$ (49,575)	**$ 241,368**	$ (305,077)

Cash Flow – Operating Activities

Net cash provided by operating activities totalled $8.0 million for the three months ended September 30, 2017, compared to net cash used in operating activities of $19.9 million for the three months ended September 30, 2016. This increase in cash flows is primarily due to higher bitumen realization, primarily as a result of the quarter-over-quarter increase in average U.S. crude oil benchmark pricing and the narrowing of the WTI:WCS differential.

Net cash provided by operating activities totalled $117.4 million for the nine months ended September 30, 2017 compared to net cash used in operating activities of $176.0 million for the nine months ended September 30, 2016. This increase in cash flows is primarily due to higher bitumen realization, primarily as a result of the increase in average crude oil benchmark pricing.

Cash Flow – Investing Activities

Net cash used in investing activities was $122.3 million for the three months ended September 30, 2017 compared to $27.6 million for the three months ended September 30, 2016. The increase in net cash used in investing activities is primarily due to increased capital spending activity directed toward the eMSAGP growth initiative at Christina Lake Phase 2B and sustaining costs.

Net cash used in investing activities was $278.6 million for the nine months ended September 30, 2017 compared to $108.1 million for the nine months ended September 30, 2016. The increase in net cash used in investing activities is primarily due to increased capital spending activity directed toward the eMSAGP growth initiative at Christina Lake Phase 2B and sustaining and turnaround costs.

Cash Flow – Financing Activities

Net cash used in financing activities was $3.9 million for the three months ended September 30, 2017 compared to $4.3 million for the three months ended September 30, 2016. Net cash used in financing activities includes quarterly debt repayments of US$3.1 million.

Net cash provided by financing activities was $405.2 million for the nine months ended September 30, 2017 compared to net cash used in financing activities of $12.7 million for the nine months ended September 30, 2016. Net cash provided by financing activities increased primarily due to $496.3 million of net equity issuance proceeds, partially offset by costs of $82.4 million paid as part of the comprehensive refinancing plan that closed on January 27, 2017.

9. SHARES OUTSTANDING

As at September 30, 2017, the Corporation had the following share capital instruments outstanding or exercisable:

(000)	Outstanding
Common shares	294,079
Convertible securities	
Stock options(1)	8,915
Equity-settled RSUs and PSUs	6,359

(1) 6.2 million stock options were exercisable as at September 30, 2017.

On January 27, 2017, the Corporation issued 66.8 million common shares at a price $7.75 per common share.

As at October 18, 2017, the Corporation had 294.1 million common shares, 8.9 million stock options and 6.3 million equity-settled restricted share units and equity-settled performance share units outstanding, and 6.2 million stock options exercisable.

10. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities, the Senior Secured Second Lien Notes, and the Senior Unsecured Notes may be retired earlier due to mandatory repayments or redemptions.

($000)	2017	2018	2019	2020	2021	Thereafter
Long-term debt(1)	$ 3,862	$ 15,450	$ 15,450	$ 15,450	$ 15,450	$ 4,661,648
Interest on long-term debt(1)	71,360	284,979	284,246	283,512	282,779	592,831
Decommissioning obligation(2)	287	6,252	7,059	5,916	2,957	806,058
Transportation and storage(3)	42,310	176,412	177,066	227,365	283,453	3,802,411
Office lease rentals(4)	7,765	31,773	31,803	32,719	33,119	229,884
Diluent purchases(5)	90,726	303,052	19,551	19,603	19,551	35,834
Other commitments(6)	12,937	14,381	10,283	11,892	11,138	73,287
Total	**$ 229,247**	**$ 832,299**	**$ 545,458**	**$ 596,457**	**$ 648,447**	**$10,201,953**

(1) This represents the scheduled principal repayments of the senior secured term loan, the Senior Secured Second Lien Notes, the Senior Unsecured Notes, and associated interest payments based on interest and foreign exchange rates in effect on September 30, 2017.

(2) This represents the undiscounted future obligations associated with the decommissioning of the Corporation's crude oil, transportation and storage assets.

(3) This represents transportation and storage commitments from 2017 to 2042, including various pipeline commitments which are awaiting regulatory approval.

(4) This represents the future gross lease commitments for the Corporation's corporate offices.

(5) This represents the future commitments associated with the Corporation's diluent purchases.

(6) This represents the future commitments associated with the Corporation's capital program and other operating and maintenance commitments.

11. NON-GAAP MEASURES

Certain financial measures in this MD&A including: net marketing activity, funds flow from (used in) operations, adjusted funds flow from (used in) operations, operating earnings (loss), operating cash flow and total debt are non-GAAP measures. These terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Net Marketing Activity

Net marketing activity is a non-GAAP measure which the Corporation uses to analyze the returns on the sale of third-party crude oil and related products through various marketing and storage arrangements. Net Marketing Activity represents the Corporation's third-party petroleum sales less the cost of purchased product and storage arrangements. Petroleum revenue – third party is disclosed in Note 12 in the Notes to the Interim Consolidated Financial Statements and purchased product and storage is presented as a line item on the Consolidated Statement of Earnings and Comprehensive Income.

Funds Flow From (Used in) Operations and Adjusted Funds Flow From (Used In) Operations

Funds flow from (used in) operations and adjusted funds flow from (used in) operations are non-GAAP measures utilized by the Corporation to analyze operating performance and liquidity. Funds flow from (used in) operations excludes the net change in non-cash operating working capital while the IFRS measurement "net cash provided by (used in) operating activities" includes these items. Adjusted funds flow from (used in) operations excludes the net change in non-cash operating working capital and charges not incurred in the normal course of operations, while the IFRS measurement "net cash provided by (used in) operating activities" includes these items. Funds flow from (used in) operations and adjusted funds flow from (used in) operations are not intended to represent net cash provided by (used in) operating activities calculated in accordance with IFRS. Funds flow from (used in) operations and adjusted funds flow from (used in) operations are reconciled to net cash provided by (used in) operating activities in the table below.

	Three months ended September 30		Nine months ended September 30	
($000)	**2017**	**2016**	**2017**	**2016**
Net cash provided by (used in) operating activities	**$ 7,979**	$ (19,894)	**$ 117,397**	$ (175,978)
Net change in non-cash operating working capital items	**51,133**	45,492	**28,922**	76,409
Funds flow from (used in) operations	**59,112**	25,598	**146,319**	(99,569)
Adjustments:				
Contract cancellation expense	**18,765**	-	**18,765**	-
Net change in other liabilities	**-**	(4,044)	**-**	(5,495)
Payments on onerous contracts	**5,089**	1,049	**14,691**	2,395
Decommissioning expenditures	**386**	99	**1,847**	1,095
Adjusted funds flow from (used in) operations	**$ 83,352**	$ 22,702	**$ 181,622**	$ (101,574)

Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP measure which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating earnings (loss) is defined as net earnings (loss) as reported, excluding unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial instruments, unrealized gains and losses on commodity risk management, contract cancellation expense, onerous contracts expense, insurance proceeds and the respective deferred tax impact on these adjustments. Operating earnings (loss) is reconciled to "Net earnings (loss)", the nearest IFRS measure, in the table below.

	Three months ended September 30		Nine months ended September 30	
($000)	**2017**	**2016**	**2017**	**2016**
Net earnings (loss)	**$ 83,885**	$ (108,632)	**$ 189,755**	$ (123,968)
Adjustments:				
Unrealized net loss (gain) on foreign exchange(1)	**(180,448)**	38,729	**(345,116)**	(267,763)
Unrealized loss (gain) on derivative financial liabilities(2)	**(3,490)**	(11,367)	**(7,346)**	(5,362)
Unrealized loss (gain) on commodity risk management(3)	**57,470**	(32,207)	**(19,353)**	(11,736)
Contract cancellation expense(4)	**18,765**	-	**18,765**	-
Onerous contracts expense(5)	**(27)**	18,057	**5,681**	31,483
Insurance proceeds	**(183)**	-	**(183)**	-
Deferred tax expense (recovery) relating to these adjustments	**(18,543)**	7,491	**218**	(5,763)
Operating earnings (loss)	**$ (42,571)**	$ (87,929)	**$ (157,579)**	$ (383,109)

(1) *Unrealized net foreign exchange gains and losses result from the translation of U.S. dollar denominated long-term debt and cash and cash equivalents using period-end exchange rates.*

(2) *Unrealized gains and losses on derivative financial liabilities result from the interest rate floor on the Corporation's long-term debt and interest rate swaps entered into to effectively fix a portion of its variable rate long-term debt.*

(3) *Unrealized gains or losses on commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.*

(4) *During the third quarter of 2017, the Corporation recognized a contract cancellation expense of $18.8 million relating to the termination of a long-term marketing transportation contract that had not yet commenced.*

(5) *Onerous contracts expense primarily includes changes in estimated future cash flow sublease recoveries related to the onerous office lease provision for the Corporation's office building lease contracts.*

Operating Cash Flow

Operating cash flow is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to fund future capital investments. The Corporation's operating cash flow is calculated by deducting the related diluent expense, transportation, field operating costs, royalties and realized commodity risk management gains or losses from proprietary blend sales revenue and power revenue. The per-unit calculation of operating cash flow, defined as cash operating netback, is calculated by deducting the related diluent expense, transportation, operating expenses, royalties and realized commodity risk management gains or losses from proprietary blend revenue and power revenue, on a per barrel of bitumen sales volume basis.

Total Debt

Total debt is a non-GAAP measure which is used by the Corporation to analyze leverage and liquidity. The Corporation's total debt is defined as long-term debt as reported, excluding the debt redemption premium, the current portion of the senior secured term loan, the unamortized financial derivative liability discount, and the unamortized deferred debt discount and debt issue costs. Total debt is reconciled to long-term debt in the table below.

($000)	September 30, 2017	December 31, 2016
Long-term debt	**$ 4,635,740**	$ 5,053,239
Adjustments:		
Debt redemption premium	**-**	(21,812)
Current portion of senior secured term loan	**15,450**	17,455
Unamortized financial derivative liability discount	**18,742**	11,143
Unamortized deferred debt discount and debt issue costs	**57,378**	22,766
Total debt	**$ 4,727,310**	$ 5,082,791

12. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting estimates are those estimates having a significant impact on the Corporation's financial position and operations and that require management to make judgments, assumptions and estimates in the application of IFRS. Judgments, assumptions and estimates are based on historical experience and other factors that management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgments, assumptions and estimates may be subject to change.

For a detailed discussion regarding the Corporation's critical accounting policies and estimates, please refer to the Corporation's 2016 annual MD&A.

13. NEW ACCOUNTING STANDARDS

The Corporation has adopted the following revised standards effective January 1, 2017:

IAS 7, Statement of Cash Flows, has been amended by the IASB as part of its disclosure initiative to require additional disclosure for changes in liabilities arising from financing activities. This includes changes arising from cash flows and non-cash changes. Additional disclosures for changes in liabilities arising from financing activities has been included in Note 19 to the Corporation's consolidated financial statements. As allowed by IAS 7, comparative information has not been presented.

IAS 12, Income Taxes, has been amended to clarify the recognition of deferred tax assets relating to unrealized losses. The adoption of this revision did not have an impact on the Corporation's consolidated financial statements.

Accounting standards issued but not yet applied

In January 2016, the IASB issued IFRS 16 Leases, which will replace IAS 17 Leases. Under IFRS 16, a single recognition and measurement model will apply for lessees, which will require recognition of lease assets and lease obligations on the balance sheet. The standard eliminates the classification of leases as either operating leases or finance leases for lessees, essentially treating all leases as finance leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases. The accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, but disclosure requirements are enhanced. The standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. IFRS 16 will be adopted by the Corporation on January 1, 2019. The Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements. The Corporation anticipates there will be a material impact on the consolidated financial statements and additional new disclosures.

In July 2014, the IASB issued IFRS 9 Financial Instruments, which is intended to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The accounting treatment of financial liabilities in IFRS 9 is essentially unchanged from IAS 39, except for financial liabilities designated at fair value through profit or loss, whereby an entity can recognize the portion of the change in fair value related to the change in the entity's own credit risk through other comprehensive income rather than net earnings. The standard also introduces a new expected credit loss impairment model for financial assets. In addition, IFRS 9 incorporates new hedge accounting requirements that more closely aligns with risk management activities. IFRS 9 is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. IFRS 9 will be adopted by the Corporation on January 1, 2018, and the Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements.

In May 2014, the IASB issued IFRS 15 Revenue From Contracts With Customers, which will replace IAS 11 Construction Contracts and IAS 18 Revenue and the related interpretations on revenue recognition. IFRS 15 provides a comprehensive revenue recognition and measurement framework that applies to all contracts with customers. The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Corporation will be adopting IFRS 15 retrospectively on January 1, 2018. The Corporation is currently assessing and evaluating the underlying terms of its revenue contracts with customers. Adoption of the standard is not expected to have a material impact on the Corporation's consolidated financial statements. The Corporation anticipates there will be additional enhanced disclosures.

In June 2016, the IASB issued amendments to IFRS 2 Share-based Payment, relating to classification and measurement of particular share-based payment transactions. The amendments are effective for periods beginning on or after January 1, 2018. The Corporation will adopt these amendments prospectively, as required by the standard, on January 1, 2018. The Corporation anticipates that the adoption of these amendments will not have a material impact on the Corporation's consolidated financial statements.

14. RISK FACTORS

The Corporation's primary focus is on the ongoing development and operation of its oil sands assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including construction risks, operations risks, project development risks and political-economic risks. Further information regarding the risk factors which may affect the Corporation is contained in the most recently filed Annual Information Form, which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

15. DISCLOSURE CONTROLS AND PROCEDURES

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

16. INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The CEO and CFO are required to cause the Corporation to disclose any change in the Corporation's internal controls over financial reporting that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting. No changes in internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

It should be noted that a control system, including the Corporation's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud. In reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost/benefit relationship of possible controls and procedures.

17. ABBREVIATIONS

The following provides a summary of common abbreviations used in this document:

Financial and Business Environment

AECO	Alberta natural gas price reference location
AIF	Annual Information Form
AWB	Access Western Blend
$ or C$	Canadian dollars
DSU	Deferred share units
EDC	Export Development Canada
eMSAGP	enhanced Modified Steam And Gas Push
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
MD&A	Management's Discussion and Analysis
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam-oil ratio
U.S.	United States
US$	United States dollars
WCS	Western Canadian Select
WTI	West Texas Intermediate

Measurement

bbl	barrel
bbls/d	barrels per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
MW	megawatts
MW/h	megawatts per hour

18. ADVISORY

Forward-Looking Information

This document may contain forward-looking information including but not limited to: expectations of future production, revenues, expenses, cash flow, operating costs, steam-oil ratios, pricing differentials, reliability, profitability and capital investments; estimates of reserves and resources; anticipated reductions in operating costs as a result of optimization and scalability of certain operations; and anticipated sources of funding for operations and capital investments. Such forward-looking information is based on management's expectations and assumptions regarding future growth, results of operations, production, future capital and other expenditures, plans for and results of drilling activity, environmental matters, and business prospects and opportunities.

By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: risks associated with the oil and gas industry, for example, results securing access to markets and transportation infrastructure; availability of capacity on the electricity transmission grid; uncertainty of reserve and resource estimates; uncertainty associated with estimates and projections relating to production, costs and revenues; health, safety and environmental risks; risks of legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws; assumptions regarding and the volatility of commodity prices, interest rates and foreign exchange rates, and, risks and uncertainties related to commodity price, interest rate and foreign exchange rate swap contracts and/or derivative financial instruments that MEG may enter into from time to time to manage its risk related to such prices and rates; risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with MEG's future phases and the expansion and/or operation of MEG's projects; risks and uncertainties related to the timing of completion, commissioning, and start-up, of MEG's future phases, expansions and projects; the operational risks and delays in the development, exploration, production, and the capacities and performance associated with MEG's projects; and uncertainties arising in connection with any future disposition of assets.

Although MEG believes that the assumptions used in such forward-looking information are reasonable, there can be no assurance that such assumptions will be correct. Accordingly, readers are cautioned that the actual results achieved may vary from the forward-looking information provided herein and that the variations may be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive.

Further information regarding the assumptions and risks inherent in the making of forward-looking statements can be found in MEG's most recently filed Annual Information Form ("AIF"), along with MEG's other public disclosure documents. Copies of the AIF and MEG's other public disclosure documents are available through the SEDAR website which is available at www.sedar.com.

The forward-looking information included in this document is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this document is made as of the date of this document and MEG assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

A full version of MEG's Third Quarter 2017 Report to Shareholders, including unaudited financial statements, is available at www.megenergy.com/investors and at www.sedar.com.

MEG Energy Corp. is focused on sustainable in situ oil sands development and production in the southern Athabasca oil sands region of Alberta, Canada. MEG is actively developing enhanced oil recovery projects that utilize SAGD extraction methods. MEG's common shares are listed on the Toronto Stock Exchange under the symbol "MEG."

Estimates of Reserves

For information regarding MEG's estimated reserves, please refer to MEG's AIF.

Non-GAAP Financial Measures

Certain financial measures in this MD&A do not have a standardized meaning as prescribed by IFRS including: net marketing activity, funds flow from (used in) operations, adjusted funds flow from (used in) operations, operating earnings (loss), operating cash flow and total debt. As such, these measures are considered non-GAAP financial measures. These terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. These measures are presented and described in order to provide shareholders and potential investors with additional measures in understanding MEG's ability to generate funds and to finance its operations as well as profitability measures specific to the oil sands industry. The definition and reconciliation of each non-GAAP measure is presented in the "NON-GAAP MEASURES" section of this MD&A.

19. ADDITIONAL INFORMATION

Additional information relating to the Corporation, including its AIF, is available on MEG's website at www.megenergy.com and is also available on SEDAR at www.sedar.com.

20. QUARTERLY SUMMARIES

	2017			2016				2015
Unaudited	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
FINANCIAL ($000 unless specified)								
Net earnings (loss)[1]	**83,885**	104,282	1,588	(304,758)	(108,632)	(146,165)	130,829	(297,275)
Per share, diluted	**0.28**	0.35	0.01	(1.34)	(0.48)	(0.65)	0.58	(1.32)
Operating earnings (loss)	**(42,571)**	(35,656)	(79,354)	(71,989)	(87,929)	(97,894)	(197,286)	(140,234)
Per share, diluted	**(0.14)**	(0.12)	(0.29)	(0.32)	(0.39)	(0.43)	(0.88)	(0.62)
Adjusted funds flow from (used in) operations	**83,352**	55,095	43,175	39,967	22,702	6,964	(131,240)	(44,130)
Per share, diluted	**0.28**	0.19	0.16	0.18	0.10	0.03	(0.58)	(0.20)
Cash capital investment	**103,173**	158,474	77,770	63,077	19,203	19,990	34,975	54,473
Cash and cash equivalents	**397,598**	512,424	548,981	156,230	103,136	152,711	124,560	408,213
Working capital	**350,067**	445,463	537,427	96,442	163,038	128,586	183,649	363,038
Long-term debt	**4,635,740**	4,813,092	4,944,741	5,053,239	4,909,711	4,871,182	4,859,099	5,190,363
Shareholders' equity	**3,981,750**	3,898,054	3,792,818	3,286,776	3,577,557	3,679,372	3,812,566	3,677,867
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**48.21**	48.29	51.91	49.29	44.94	45.59	33.45	42.18
C$ equivalent of 1US$ - average	**1.2524**	1.3449	1.3230	1.3339	1.3051	1.2886	1.3748	1.3353
Differential – WTI:WCS (C$/bbl)	**12.45**	14.97	19.29	19.10	17.62	17.14	19.58	19.35
Differential – WTI:WCS (%)	**20.6%**	23.0%	28.1%	29.1%	30.0%	29.2%	42.6%	34.4%
Natural gas – AECO ($/mcf)	**1.58**	2.81	2.91	3.31	2.49	1.37	1.82	2.57
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**83,008**	72,448	77,245	81,780	83,404	83,127	76,640	83,514
Bitumen sales – bbls/d	**76,813**	74,116	74,703	81,746	84,817	80,548	74,529	82,282
Steam-oil ratio (SOR)	**2.3**	2.3	2.4	2.3	2.2	2.3	2.4	2.5
Bitumen realization	**39.89**	39.66	37.93	36.17	30.98	30.93	11.43	23.17
Transportation – net	**(7.08)**	(6.91)	(6.54)	(6.05)	(6.46)	(6.66)	(6.68)	(5.35)
Royalties	**(0.53)**	(0.87)	(0.85)	(0.51)	(0.42)	(0.27)	0.07	(0.25)
Operating costs – non-energy	**(4.57)**	(4.23)	(5.20)	(4.99)	(5.32)	(5.81)	(6.45)	(5.66)
Operating costs – energy	**(2.26)**	(3.76)	(4.18)	(4.12)	(2.99)	(1.97)	(2.90)	(3.58)
Power revenue	**0.83**	0.57	0.95	0.87	0.55	0.35	0.82	0.72
Realized gain (loss) on commodity risk management	**0.56**	(1.50)	0.22	0.36	0.40	(0.48)	-	-
Cash operating netback	**26.84**	22.96	22.33	21.73	16.74	16.09	(3.71)	9.05
Power sales price (C$/MWh)	**23.29**	18.27	22.42	21.94	17.62	13.54	19.77	19.67
Power sales (MW/h)	**115**	97	131	134	110	86	129	125
Depletion and depreciation rate per bbl of production	**16.86**	16.93	16.81	16.81	16.81	16.84	16.78	16.55
COMMON SHARES								
Shares outstanding, end of period (000)	**294,079**	294,047	293,282	226,467	226,415	226,357	224,997	224,997
Volume traded (000)	**70,216**	98,795	123,445	114,776	112,720	157,056	182,199	76,631
Common share price ($)								
High	**5.79**	7.27	9.83	9.79	6.90	7.86	8.26	13.15
Low	**3.28**	3.63	5.84	5.11	4.72	5.21	3.46	7.33
Close (end of period)	**5.49**	3.81	6.74	9.23	5.93	6.84	6.55	8.02

(1) *Includes net unrealized foreign exchange gains and losses on translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.*

Interim Consolidated Financial Statements

Consolidated Balance Sheet
(Unaudited, expressed in thousands of Canadian dollars)

As at	Note	September 30, 2017	December 31, 2016
Assets			
Current assets			
Cash and cash equivalents	19	**$ 397,598**	$ 156,230
Trade receivables and other		**227,381**	236,989
Inventories		**96,559**	66,394
Commodity risk management	21	**15,353**	-
		736,891	459,613
Non-current assets			
Property, plant and equipment	4	**7,662,494**	7,639,434
Exploration and evaluation assets	5	**549,808**	547,752
Other intangible assets	6	**13,458**	16,111
Other assets	7	**143,791**	137,370
Deferred income tax asset	18	**177,013**	120,944
Total assets		**$ 9,283,455**	$ 8,921,224
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 322,157**	$ 292,340
Current portion of long-term debt	8	**15,450**	17,455
Current portion of provisions and other liabilities	9	**26,910**	23,063
Commodity risk management	21	**22,307**	30,313
		386,824	363,171
Non-current liabilities			
Long-term debt	8	**4,635,740**	5,053,239
Provisions and other liabilities	9	**275,135**	218,038
Commodity risk management	21	**4,006**	-
Total liabilities		**5,301,705**	5,634,448
Shareholders' equity			
Share capital	10	**5,403,580**	4,878,607
Contributed surplus		**161,018**	168,253
Deficit		**(1,605,312)**	(1,795,067)
Accumulated other comprehensive income		**22,464**	34,983
Total shareholders' equity		**3,981,750**	3,286,776
Total liabilities and shareholders' equity		**$ 9,283,455**	$ 8,921,224

Commitments and contingencies (Note 23)

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss)
(Unaudited, expressed in thousands of Canadian dollars, except per share amounts)

		Three months ended September 30		Nine months ended September 30	
	Note	**2017**	**2016**	**2017**	**2016**
Revenues					
Petroleum revenue, net of royalties	12	**$ 537,033**	$ 487,680	**$ 1,654,400**	$ 1,272,967
Other revenue	13	**9,042**	9,140	**25,487**	27,546
		546,075	496,820	**1,679,887**	1,300,513
Expenses					
Diluent and transportation	14	**246,891**	255,816	**803,194**	736,619
Operating expenses		**48,222**	64,796	**165,146**	185,233
Purchased product and storage		**64,738**	48,157	**209,922**	151,638
Depletion and depreciation	4,6	**128,754**	128,995	**357,238**	373,340
Exploration expense		**-**	1,248	**-**	1,248
General and administrative		**19,321**	22,587	**63,482**	74,671
Stock-based compensation	11	**12,545**	10,022	**17,323**	33,433
Research and development		**1,299**	1,265	**3,405**	4,360
Net finance expense	16	**79,385**	73,130	**257,646**	250,362
Other expenses	17	**20,251**	18,057	**29,427**	37,662
Interest and other income		**(978)**	(290)	**(2,798)**	(1,016)
Commodity risk management loss (gain)	21	**53,494**	(35,335)	**(14,752)**	(11,377)
Foreign exchange loss (gain), net	15	**(178,384)**	39,734	**(348,407)**	(271,616)
Earnings (loss) before income taxes		**50,537**	(131,362)	**139,061**	(264,044)
Income tax expense (recovery)	18	**(33,348)**	(22,730)	**(50,694)**	(140,076)
Net earnings (loss)		**83,885**	(108,632)	**189,755**	(123,968)
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**(6,352)**	397	**(12,519)**	(8,317)
Comprehensive income (loss) for the period		**$ 77,533**	$ (108,235)	**$ 177,236**	$ (132,285)
Net earnings (loss) per common share					
Basic	20	**$ 0.29**	$ (0.48)	**$ 0.66**	$ (0.55)
Diluted	20	**$ 0.28**	$ (0.48)	**$ 0.66**	$ (0.55)

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Changes in Shareholders' Equity
(Unaudited, expressed in thousands of Canadian dollars)

	Note	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2016		**$4,878,607**	**$ 168,253**	**$(1,795,067)**	**$ 34,983**	**$ 3,286,776**
Shares issued	10	**517,816**	**-**	**-**	**-**	**517,816**
Share issue costs, net of tax	10	**(15,698)**	**-**	**-**	**-**	**(15,698)**
Stock-based compensation		**-**	**15,620**	**-**	**-**	**15,620**
RSUs and PSUs vested and released	10	**22,855**	**(22,855)**	**-**	**-**	**-**
Comprehensive income (loss)		**-**	**-**	**189,755**	**(12,519)**	**177,236**
Balance as at September 30, 2017		**$5,403,580**	**$ 161,018**	**$(1,605,312)**	**$ 22,464**	**$ 3,981,750**
Balance as at December 31, 2015		$4,836,800	$ 171,835	$(1,366,341)	$ 35,573	$ 3,677,867
Stock-based compensation		-	31,975	-	-	31,975
RSUs and PSUs vested and released		40,620	(40,620)	-	-	-
Comprehensive income (loss)		-	-	(123,968)	(8,317)	(132,285)
Balance as at September 30, 2016		$4,877,420	$ 163,190	$(1,490,309)	$ 27,256	$ 3,577,557

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Cash Flow
(Unaudited, expressed in thousands of Canadian dollars)

		Three months ended September 30		Nine months ended September 30	
	Note	**2017**	**2016**	**2017**	**2016**
Cash provided by (used in):					
Operating activities					
Net earnings (loss)		**$ 83,885**	$ (108,632)	**$ 189,755**	$ (123,968)
Adjustments for:					
Depletion and depreciation	4,6	**128,754**	128,995	**357,238**	373,340
Exploration expense		**-**	1,248	**-**	1,248
Stock-based compensation	11	**5,491**	5,977	**13,764**	27,938
Unrealized loss (gain) on foreign exchange	15	**(180,448)**	38,729	**(345,116)**	(267,763)
Unrealized loss (gain) on derivative financial liabilities	16	**(3,490)**	(11,367)	**(7,346)**	(5,362)
Unrealized loss (gain) on risk management	21	**57,470**	(32,207)	**(19,353)**	(11,736)
Onerous contracts expense (recovery)	17	**(27)**	18,057	**5,681**	31,483
Deferred income tax expense (recovery)	18	**(33,091)**	(22,833)	**(50,268)**	(140,793)
Amortization of debt discount and debt issue costs	7,8	**4,721**	3,070	**14,475**	9,102
Other		**1,322**	1,665	**4,027**	4,937
Decommissioning expenditures	9	**(386)**	(99)	**(1,847)**	(1,095)
Payments on onerous contracts	9	**(5,089)**	(1,049)	**(14,691)**	(2,395)
Net change in other liabilities		**-**	4,044	**-**	5,495
Net change in non-cash working capital items	19	**(51,133)**	(45,492)	**(28,922)**	(76,409)
Net cash provided by (used in) operating activities		**7,979**	(19,894)	**117,397**	(175,978)
Investing activities					
Capital investments:					
Property, plant and equipment	4	**(108,050)**	(17,741)	**(342,758)**	(68,964)
Exploration and evaluation	5	**(560)**	(870)	**(1,252)**	(1,851)
Other intangible assets	6	**(115)**	(592)	**(129)**	(3,353)
Proceeds on dispositions	4	**4,981**	-	**4,981**	-
Deferred lease inducements and other	9	**4,940**	130	**21,873**	(956)
Net change in non-cash working capital items	19	**(23,484)**	(8,479)	**38,661**	(33,020)
Net cash used in investing activities		**(122,288)**	(27,552)	**(278,624)**	(108,144)
Financing activities					
Issue of shares, net of issue costs	10	**-**	-	**496,312**	-
Redemption of senior unsecured notes	19	**-**	-	**(1,008,825)**	-
Issue of senior secured second lien notes	19	**-**	-	**1,008,825**	-
Payments on term loan	19	**(3,892)**	(4,263)	**(8,747)**	(12,698)
Refinancing costs	19	**-**	-	**(82,377)**	-
Net cash provided by (used in) financing activities		**(3,892)**	(4,263)	**405,188**	(12,698)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**3,375**	2,134	**(2,593)**	(8,257)
Change in cash and cash equivalents		**(114,826)**	(49,575)	**241,368**	(305,077)
Cash and cash equivalents, beginning of period		**512,424**	152,711	**156,230**	408,213
Cash and cash equivalents, end of period		**$ 397,598**	$ 103,136	**$ 397,598**	$ 103,136

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange ("TSX") under the symbol "MEG". The Corporation owns a 100% interest in over 900 square miles of oil sands leases in the southern Athabasca oil sands region of northern Alberta and is primarily engaged in a steam assisted gravity drainage oil sands development at its 80 section Christina Lake Project. The Corporation also holds a 50% interest in the Access Pipeline, a dual pipeline to transport diluent north from the Edmonton area to the Athabasca oil sands area and a blend of bitumen and diluent south from the Christina Lake Project into the Edmonton area. In addition to the Access Pipeline, the Corporation owns the Stonefell Terminal, located near Edmonton, Alberta, which offers 900,000 barrels of terminalling and storage capacity. The Stonefell Terminal is connected to the Access Pipeline and is also connected by pipeline to a third-party rail-loading terminal. The corporate office is located at 600 – 3rd Avenue SW, Calgary, Alberta, Canada.

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements (“interim consolidated financial statements”) were prepared using the same accounting policies and methods as those used in the Corporation’s audited consolidated financial statements for the year ended December 31, 2016. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting (“IAS 34”). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board ("IASB"), have been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation’s accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 4 of the Corporation’s audited consolidated financial statements for the year ended December 31, 2016. These interim consolidated financial statements should be read in conjunction with the Corporation’s audited consolidated financial statements for the year ended December 31, 2016.

These interim consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation’s functional currency. The Corporation’s operations are aggregated into one operating segment for reporting, consistent with the internal reporting provided to the chief operating decision-maker of the Corporation.

These interim consolidated financial statements were approved by the Corporation’s Audit Committee on October 25, 2017.

3. CHANGE IN ACCOUNTING POLICIES

New accounting standards

The Corporation has adopted the following revised standards effective January 1, 2017:

IAS 7, Statement of Cash Flows, has been amended by the IASB as part of its disclosure initiative to require additional disclosure for changes in liabilities arising from financing activities. This includes changes arising from cash flows and non-cash changes. Additional disclosures for changes in liabilities arising from financing activities has been included in Note 19. As allowed by IAS 7, comparative information has not been presented.

IAS 12, Income Taxes, has been amended to clarify the recognition of deferred tax assets relating to unrealized losses. The adoption of this revision did not have an impact on the Corporation's consolidated financial statements.

Accounting standards issued but not yet applied

In January 2016, the IASB issued IFRS 16 Leases, which will replace IAS 17 Leases. Under IFRS 16, a single recognition and measurement model will apply for lessees, which will require recognition of lease assets and lease obligations on the balance sheet. The standard eliminates the classification of leases as either operating leases or finance leases for lessees, essentially treating all leases as finance leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases. The accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, but disclosure requirements are enhanced. The standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. IFRS 16 will be adopted by the Corporation on January 1, 2019. The Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements. The Corporation anticipates there will be a material impact on the consolidated financial statements and additional new disclosures.

In July 2014, the IASB issued IFRS 9 Financial Instruments, which is intended to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The accounting treatment of financial liabilities in IFRS 9 is essentially unchanged from IAS 39, except for financial liabilities designated at fair value through profit or loss, whereby an entity can recognize the portion of the change in fair value related to the change in the entity's own credit risk through other comprehensive income rather than net earnings. The standard also introduces a new expected credit loss impairment model for financial assets. In addition, IFRS 9 incorporates new hedge accounting requirements that more closely aligns with risk management activities. IFRS 9 is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. IFRS 9 will be adopted by the Corporation on January 1, 2018, and the Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements.

In May 2014, the IASB issued IFRS 15 Revenue From Contracts With Customers, which will replace IAS 11 Construction Contracts and IAS 18 Revenue and the related interpretations on revenue recognition. IFRS 15 provides a comprehensive revenue recognition and measurement framework that applies to all contracts with customers. The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Corporation will be adopting IFRS 15 retrospectively on January 1, 2018. The Corporation is currently assessing and evaluating the underlying terms of its revenue contracts with customers. Adoption of the standard is not expected to have a material impact on the Corporation's consolidated financial statements. The Corporation anticipates there will be additional enhanced disclosures.

In June 2016, the IASB issued amendments to IFRS 2 Share-based Payment, relating to classification and measurement of particular share-based payment transactions. The amendments are effective for periods beginning on or after January 1, 2018. The Corporation will adopt these amendments prospectively, as required by the standard, on January 1, 2018. The Corporation anticipates that the adoption of these amendments will not have a material impact on the Corporation's consolidated financial statements.

4. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Corporate assets	Total
Cost				
Balance as at December 31, 2016	$ 7,878,009	$ 1,610,118	$ 55,983	$ 9,544,110
Additions	319,046	4,551	20,610	344,207
Dispositions	(14,837)	-	-	(14,837)
Change in decommissioning liabilities	37,015	1,275	-	38,290
Balance as at September 30, 2017	**$ 8,219,233**	**$ 1,615,944**	**$ 76,593**	**$ 9,911,770**
Accumulated depletion and depreciation				
Balance as at December 31, 2016	$ 1,766,709	$ 110,833	$ 27,134	$ 1,904,676
Depletion and depreciation	327,794	22,340	4,322	354,456
Dispositions	(9,856)	-	-	(9,856)
Balance as at September 30, 2017	**$ 2,084,647**	**$ 133,173**	**$ 31,456**	**$ 2,249,276**
Carrying amounts				
Balance as at December 31, 2016	$ 6,111,300	$ 1,499,285	$ 28,849	$ 7,639,434
Balance as at September 30, 2017	**$ 6,134,586**	**$ 1,482,771**	**$ 45,137**	**$ 7,662,494**

As at September 30, 2017, $507.0 million of assets under construction were included within property, plant and equipment (December 31, 2016 – $547.9 million). Assets under construction are not subject to depletion and depreciation. As at September 30, 2017, no impairment has been recognized on property, plant and equipment.

5. EXPLORATION AND EVALUATION ASSETS

Cost	
Balance as at December 31, 2016	$ 547,752
Additions	1,252
Change in decommissioning liabilities	804
Balance as at September 30, 2017	**$ 549,808**

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. These assets are not subject to depletion, as they are in the exploration and evaluation stage, but are reviewed on a quarterly basis for any indication of impairment. As at September 30, 2017, no impairment has been recognized on exploration and evaluation assets.

6. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2016	$	112,921
Additions		129
Balance as at September 30, 2017	**$**	**113,050**

Accumulated depreciation		
Balance as at December 31, 2016	$	96,810
Depreciation		2,782
Balance as at September 30, 2017	**$**	**99,592**

Carrying amounts		
Balance as at December 31, 2016	$	16,111
Balance as at September 30, 2017	**$**	**13,458**

As at September 30, 2017, other intangible assets consist of $13.5 million invested in software that is not an integral component of the related computer hardware (December 31, 2016 – $16.1 million). As at September 30, 2017, no impairment has been recognized on these assets.

At December 31, 2016, the Corporation evaluated its investment in the right to participate in the Northern Gateway pipeline for impairment in relation to the December 2016 directive from the Government of Canada to the National Energy Board to dismiss the project application. As a result, the Corporation fully impaired its investment in the Northern Gateway pipeline in the fourth quarter of 2016 and recognized an impairment charge of $80.1 million.

7. OTHER ASSETS

As at		**September 30, 2017**		**December 31, 2016**
Long-term pipeline linefill[(a)]	**$**	**122,226**	$	129,733
Deferred financing costs[(b)]		**26,306**		12,001
Interest rate swap[(c)]		**3,912**		-
		152,444		141,734
Less current portion of deferred financing costs		**(8,653)**		(4,364)
	$	**143,791**	$	137,370

(a) The Corporation has entered into agreements to transport diluent and bitumen blend on third-party owned pipelines and is required to supply linefill for these pipelines. As the pipelines are owned by third parties, the linefill is not considered to be a component of the Corporation's property, plant and equipment. The linefill is classified as a long-term asset as these transportation contracts extend beyond the year 2024. As at September 30, 2017, no impairment has been recognized on these assets.

(b) During the nine months ended September 30, 2017, the Corporation recognized deferred financing costs on modifications to its revolving credit facility and guaranteed letter of credit facility of $17.5 million and $2.9 million, respectively. These costs are being amortized as a component of net finance expense over the respective terms of the credit facilities (Note 8).

(c) In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of its US$1.2 billion senior secured term loan at approximately 5.3% (Note 21(c)). This interest rate swap contract is effective commencing September 29, 2017 and expires on December 31, 2020. Derivative financial instruments are included on the balance sheet as either an asset or liability and are classified as current or non-current based on the contractual terms specific to the instrument. The interest rate swap is classified as a non-current derivative financial asset and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

8. LONG-TERM DEBT

As at	September 30, 2017	December 31, 2016
Senior secured term loan (September 30, 2017 – US$1.229 billion; due 2023; December 31, 2016 – US$1.236 billion)[(a)]	**$ 1,537,260**	$ 1,658,906
6.5% senior secured second lien notes (US$750.0 million; due 2025)[(b)]	**938,250**	-
6.5% senior unsecured notes (US$750.0 million; due 2021)[(c)]	**-**	1,007,025
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,000,800**	1,074,160
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,251,000**	1,342,700
	4,727,310	5,082,791
Less unamortized financial derivative liability discount	**(18,742)**	(11,143)
Less unamortized deferred debt discount and debt issue costs[(a)(b)]	**(57,378)**	(22,766)
Debt redemption premium[(c)]	**-**	21,812
	4,651,190	5,070,694
Less current portion of senior secured term loan	**(15,450)**	(17,455)
	$ 4,635,740	$ 5,053,239

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2510 (December 31, 2016 – US$1 = C$1.3427).

All of the Corporation’s long-term debt is “covenant-lite” in structure, meaning it is free of any financial maintenance covenants and is not dependent on, nor calculated from, the Corporation’s crude oil reserves.

(a) Effective January 27, 2017, the Corporation refinanced and extended the maturity date of its US$1.2 billion term loan from March 2020 to December 2023. The term loan bears interest at an annual rate based on either U.S. Prime or LIBOR, at the Corporation’s option, plus a credit spread of 2.5% or 3.5%, respectively. The term loan also has a U.S. Prime Rate floor of 2.0% and a LIBOR floor of 1.0%. The term loan is to be repaid in quarterly installment payments of US$3.1 million, with the balance due on December 31, 2023. The term loan was issued at a price equal to 99.75% of its face value. The Corporation has deferred the debt discount and the associated debt issue costs of $22.0 million and is amortizing these costs over the life of the loan utilizing the effective interest method.

Effective January 27, 2017, the Corporation extended the maturity date on substantially all of its commitments under the Corporation’s covenant-lite revolving credit facility from November 2019 to November 2021. The commitment amount of the five-year facility has been reduced from US$2.5 billion to US$1.4 billion. As at September 30, 2017, no amount has been drawn under the revolving credit facility.

On February 15, 2017, the Corporation extended the maturity date on the Corporation's five-year letter of credit facility, guaranteed by Export Development Canada, from November 2019 to November 2021. The guaranteed letter of credit facility has been reduced from US$500 million to US$440 million. Letters of credit under this facility do not consume capacity of the revolving credit facility. As at September 30, 2017, letters of credit of US$306.9 million had been issued under this facility.

The amendments to the term loan, revolving credit facility and guaranteed letter of credit facility were not considered to be new financial liabilities, as no substantial modifications arose between the existing and amended agreements. As a result, no profit or loss was recognized when the terms of the financial liabilities were amended.

(b) Effective January 27, 2017, the Corporation issued US$750 million in aggregate principal amount of 6.5% Senior Secured Second Lien Notes, with a maturity date of January 2025. Interest is paid semi-annually in January and July. No principal payments are required until 2025. The Corporation has deferred the associated debt issue costs of $18.1 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

(c) On March 15, 2017, the Corporation redeemed the previously outstanding US$750 million aggregate principal amount of 6.5% Senior Unsecured Notes due 2021, utilizing the proceeds received from the issuance of the US$750 million, 6.5% Senior Secured Second Lien Notes, which were held in escrow subject to the redemption. The 2.166% debt redemption premium of $21.8 million and associated remaining unamortized deferred debt issue costs of $7.0 million were recognized as debt extinguishment expense in the fourth quarter of 2016.

9. PROVISIONS AND OTHER LIABILITIES

As at	September 30, 2017	December 31, 2016
Decommissioning provision[(a)]	**$ 176,362**	$ 133,924
Onerous contracts provision[(b)]	**91,632**	100,159
Derivative financial liabilities[(c)]	**10,707**	3,714
Deferred lease inducements[(d)]	**23,344**	3,304
Provisions and other liabilities	**302,045**	241,101
Less current portion	**(26,910)**	(23,063)
Non-current portion	**$ 275,135**	$ 218,038

(a) Decommissioning provision:

The following table presents the decommissioning provision associated with the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets:

As at	September 30, 2017		December 31, 2016	
Balance, beginning of year	$	133,924	$	130,381
Changes in estimated future cash flows		(467)		(91)
Changes in discount rates and settlement dates		23,814		(6,117)
Liabilities incurred		15,747		4,123
Liabilities settled		(1,847)		(1,290)
Accretion		5,191		6,918
Balance, end of period		176,362		133,924
Less current portion		(6,184)		(3,097)
Non-current portion	$	170,178	$	130,827

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 6.9% (December 31, 2016 – 8.2%). The decommissioning provision is estimated to be settled in periods up to the year 2067 (December 31, 2016 – periods up to the year 2066).

(b) Onerous contracts provision:

As at	September 30, 2017		December 31, 2016	
Balance, beginning of year	$	100,159	$	58,178
Changes in estimated future cash flows		8,595		40,499
Changes in discount rates		(2,914)		(1,478)
Liabilities incurred		-		8,845
Liabilities settled		(14,691)		(6,116)
Accretion		483		231
Balance, end of period		91,632		100,159
Less current portion		(16,460)		(18,930)
Non-current portion	$	75,172	$	81,229

As at September 30, 2017, the Corporation has recognized a provision of $91.6 million related to onerous operating lease contracts (December 31, 2016 – $100.2 million). The provision represents the present value of the difference between the minimum future payments that the Corporation is obligated to make under the non-cancellable onerous operating lease contracts and estimated recoveries. These cash flows have been discounted using a risk-free discount rate of 1.9% (December 31, 2016 – 1.3%). This estimate may vary as a result of changes in estimated recoveries.

(c) Derivative financial liabilities:

As at	September 30, 2017		December 31, 2016	
1% interest rate floor	**$**	**8,397**	$	3,714
Interest rate swap (Note 21)		**2,310**		-
Derivative financial liabilities		**10,707**		3,714
Less current portion		**(2,332)**		(517)
Non-current portion	**$**	**8,375**	$	3,197

In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of its US$1.2 billion senior secured term loan at approximately 5.3% (Note 21(c)). This interest rate swap contract is effective commencing September 29, 2017 and expires on December 31, 2020. The interest rate floor and the current portion of the interest rate swap are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

(d) Deferred lease inducements:

During the nine months ended September 30, 2017, the Corporation recognized a $21.5 million tenant improvement allowance related to its corporate office lease. The allowance will be amortized and treated as a reduction to general and administrative expenses over the 15-year term of the lease.

10. SHARE CAPITAL

Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

Changes in issued common shares are as follows:

	Nine months ended September 30, 2017			Year ended December 31, 2016		
	Number of shares		**Amount**	**Number of shares**		**Amount**
Balance, beginning of year	**226,467,107**	**$**	**4,878,607**	224,996,989	$	4,836,800
Shares issued	**66,815,000**		**517,816**	-		-
Share issue costs net of tax	**-**		**(15,698)**	-		-
Issued upon vesting and release of RSUs and PSUs	**796,860**		**22,855**	1,470,118		41,807
Balance, end of period	**294,078,967**	**$**	**5,403,580**	226,467,107	$	4,878,607

On January 27, 2017, the Corporation issued 66,815,000 common shares at a price of $7.75 per share for gross proceeds of $517.8 million.

11. STOCK-BASED COMPENSATION

The Corporation has a number of stock-based compensation plans which include stock options, restricted share units ("RSUs"), performance share units ("PSUs") and deferred share units ("DSUs"). Further detail on each of these plans is outlined below.

(a) Cash-settled plans

i. Restricted share units and performance share units:

RSUs granted under the cash-settled Restricted Share Unit Plan generally vest over a three-year period. PSUs granted under the cash-settled Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that the Corporation satisfies certain performance criteria identified by the Corporation's Board of Directors within a target range.

Upon vesting of the RSUs and PSUs, the participants of the cash-settled RSU plan will receive a cash payment based on the fair value of the underlying share units at the vesting date. The cash-settled RSUs and PSUs are accounted for as liability instruments and are measured at fair value based on the market value of the Corporation's common shares at each period end. Fluctuations in the fair value are recognized within stock-based compensation expense or capitalized to property, plant and equipment during the period in which they occur.

RSUs and PSUs outstanding:

Nine months ended September 30, 2017	
Outstanding, beginning of year	**6,013,010**
Granted	**1,454,659**
Vested and released	**(1,459,000)**
Forfeited	**(643,401)**
Outstanding, end of period	**5,365,268**

ii. Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of DSUs to directors of the Corporation. As at September 30, 2017, there were 284,871 DSUs outstanding (December 31, 2016 – 163,954 DSUs outstanding).

As at September 30, 2017, the Corporation has recognized a liability of $14.5 million relating to the fair value of RSUs, PSUs and DSUs (December 31, 2016 – $19.2 million).

(b) Equity-settled plans

i. Stock options outstanding:

The Corporation's Stock Option Plan allows for the granting of stock options to directors, officers, employees and consultants of the Corporation. Stock options granted are generally fully exercisable after three years and expire seven years after the grant date.

Nine months ended September 30, 2017	Stock options		Weighted average exercise price
Outstanding, beginning of year	**9,281,186**	**$**	**27.45**
Granted	**1,211,880**		**4.57**
Forfeited	**(910,847)**		**27.80**
Expired	**(667,368)**		**33.79**
Outstanding, end of period	**8,914,851**	**$**	**23.82**

ii. Restricted share units and performance share units:

RSUs granted under the equity-settled Restricted Share Unit Plan generally vest annually over a three-year period. PSUs granted under the equity-settled Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that the Corporation satisfies certain performance criteria identified by the Corporation’s Board of Directors within a target range.

Upon vesting of the RSUs and PSUs, the holder receives the right to a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares. The Corporation does not intend to make cash payments under the equity-settled RSU plan.

RSUs and PSUs outstanding:

Nine months ended September 30, 2017	
Outstanding, beginning of year	**1,655,606**
Granted	**5,724,111**
Vested and released	**(796,860)**
Forfeited	**(223,486)**
Outstanding, end of period	**6,359,371**

(c) Stock-based compensation

	Three months ended September 30				Nine months ended September 30			
		2017		**2016**		**2017**		**2016**
Cash-settled expense [(i)]	**$**	**7,054**	$	4,045	**$**	**3,559**	$	5,495
Equity-settled expense		**5,491**		5,977		**13,764**		27,938
Stock-based compensation	**$**	**12,545**	$	10,022	**$**	**17,323**	$	33,433

(i) Cash-settled RSUs and PSUs are accounted for as liability instruments and are measured at fair value based on the market value of the Corporation’s common shares at each period end. Fluctuations in the fair value are recognized during the period in which they occur.

12. PETROLEUM REVENUE, NET OF ROYALTIES

	Three months ended September 30		Nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Petroleum revenue:				
Proprietary	**$ 475,784**	$ 442,333	**$ 1,457,785**	$ 1,122,849
Third-party[(a)]	**64,994**	48,599	**211,928**	154,838
Petroleum revenue	**540,778**	490,932	**1,669,713**	1,277,687
Royalties	**(3,745)**	(3,252)	**(15,313)**	(4,720)
Petroleum revenue, net of royalties	**$ 537,033**	$ 487,680	**$ 1,654,400**	$ 1,272,967

(a) The Corporation purchases crude oil products from third-parties for marketing-related activities. These purchases and associated storage charges are included in the consolidated statement of earnings (loss) and comprehensive income (loss) under the caption "Purchased product and storage".

13. OTHER REVENUE

	Three months ended September 30		Nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Power revenue	**$ 5,896**	$ 4,277	**$ 16,104**	$ 12,360
Transportation revenue	**2,963**	4,863	**9,200**	15,186
Insurance proceeds	**183**	-	**183**	-
Other revenue	**$ 9,042**	$ 9,140	**$ 25,487**	$ 27,546

14. DILUENT AND TRANSPORTATION

	Three months ended September 30		Nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Diluent expense	**$ 193,897**	$ 200,564	**$ 653,409**	$ 576,857
Transportation expense	**52,994**	55,252	**149,785**	159,762
Diluent and transportation	**$ 246,891**	$ 255,816	**$ 803,194**	$ 736,619

15. FOREIGN EXCHANGE LOSS (GAIN), NET

	Three months ended September 30		Nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Unrealized foreign exchange loss (gain) on:				
Long-term debt	**$ (176,586)**	$ 40,954	**$ (346,734)**	$ (274,723)
Other	**(3,862)**	(2,225)	**1,618**	6,960
Unrealized net loss (gain) on foreign exchange	**(180,448)**	38,729	**(345,116)**	(267,763)
Realized loss (gain) on foreign exchange	**2,064**	1,005	**(3,291)**	(3,853)
Foreign exchange loss (gain), net	**$ (178,384)**	$ 39,734	**$ (348,407)**	$ (271,616)

C$ equivalent of 1 US$				
Beginning of period	**1.2977**	1.3009	**1.3427**	1.3840
End of period	**1.2510**	1.3117	**1.2510**	1.3117

16. NET FINANCE EXPENSE

	Three months ended September 30		Nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Total interest expense	**$ 80,860**	$ 81,194	**$ 259,296**	$ 245,866
Accretion on provisions	**1,994**	1,796	**5,675**	5,310
Unrealized loss (gain) on derivative financial liabilities	**(3,490)**	(11,367)	**(7,346)**	(5,362)
Realized loss (gain) on interest rate swaps	**21**	1,507	**21**	4,548
Net finance expense	**$ 79,385**	$ 73,130	**$ 257,646**	$ 250,362

17. OTHER EXPENSES

	Three months ended September 30		Nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Contract cancellation expense	**$ 18,765**	$ -	**$ 18,765**	$ -
Onerous contracts expense (recovery)	**(27)**	18,057	**5,681**	31,483
Severance and other	**1,513**	-	**4,981**	6,179
Other expenses	**$ 20,251**	$ 18,057	**$ 29,427**	$ 37,662

During the third quarter of 2017, the Corporation recognized an $18.8 million contract cancellation expense relating to the termination of a long-term marketing transportation contract that had not yet commenced.

18. INCOME TAX EXPENSE (RECOVERY)

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Current income tax expense (recovery)	**$ (257)**	$ 103	**$ (426)**	$ 717
Deferred income tax expense (recovery)	**(33,091)**	(22,833)	**(50,268)**	(140,793)
Income tax expense (recovery)	**$ (33,348)**	$ (22,730)	**$ (50,694)**	$ (140,076)

The Corporation has recognized a deferred tax asset of $177.0 million (December 31, 2016 – $120.9 million). Future taxable income is expected to be sufficient to realize the deferred tax asset. The deferred tax asset is reviewed at each balance sheet date to assess whether it is probable that the related tax benefit will be realized.

19. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Cash provided by (used in):				
Trade receivables and other	**$ (22,371)**	$ (2,596)	**$ 10,375**	$ (61,886)
Inventories	**(30,249)**	4,778	**(29,643)**	(15,439)
Accounts payable and accrued liabilities	**(21,997)**	(56,153)	**29,007**	(32,104)
	$ (74,617)	$ (53,971)	**$ 9,739**	$ (109,429)
Changes in non-cash working capital relating to:				
Operating	**$ (51,133)**	$ (45,492)	**$ (28,922)**	$ (76,409)
Investing	**(23,484)**	(8,479)	**38,661**	(33,020)
	$ (74,617)	$ (53,971)	**$ 9,739**	$ (109,429)
Cash and cash equivalents:[(a)]				
Cash	**$ 247,044**	$ 93,114	**$ 247,044**	$ 93,114
Cash equivalents	**150,554**	10,022	**150,554**	10,022
	$ 397,598	$ 103,136	**$ 397,598**	$ 103,136
Cash interest paid	**$ 135,553**	$ 126,869	**$ 275,546**	$ 271,216

(a) As at September 30, 2017, C$50.0 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (September 30, 2016 – C$65.3 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2510 (September 30, 2016 – US$1 = C$1.3117).

The following table reconciles long-term debt to cash flows arising from financing activities:

	Long-term debt [i]
Balance as at December 31, 2016	$ 5,070,694
Cash changes:	
Debt refinancing costs[a]	(61,930)
Redemption of senior unsecured notes	(1,008,825)
Issue of senior secured second lien notes	1,008,825
Payments on term loan	(8,747)
Non-cash changes:	
Unrealized loss (gain) on foreign exchange	(346,734)
Change in fair value of financial derivative liability	(10,426)
Amortization of financial derivative liability discount	2,828
Amortization of deferred debt discount and debt issue costs	5,505
Balance as at September 30, 2017	**$ 4,651,190**

(i) Long-term debt, including the current portion of long-term debt.

(a) During the nine months ended September 30, 2017, debt refinancing costs of $82.4 million were paid, including $61.9 million for the refinancing and maturity extension of the Corporation's US$1.2 billion term loan and replacement of the Corporation's US$750 million Senior Unsecured Notes with US$750 million Senior Secured Second Lien Notes (Note 8). Refinancing costs related to amendments and extensions to the revolving credit facility and to the guaranteed letter of credit facility of $17.5 million and $2.9 million respectively, have been recognized as a component of Other Assets (Note 7).

20. NET EARNINGS (LOSS) PER COMMON SHARE

	Three months ended September 30		Nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Net earnings (loss)	**$ 83,885**	$ (108,632)	**$ 189,755**	$ (123,968)
Weighted average common shares outstanding[a]	**294,197,536**	226,560,337	**287,428,742**	225,769,736
Dilutive effect of stock options, RSUs and PSUs[b]	**1,270,561**	-	**127,689**	-
Weighted average common shares outstanding – diluted	**295,468,097**	226,560,337	**287,556,431**	225,769,736
Net earnings (loss) per share, basic	**$ 0.29**	$ (0.48)	**$ 0.66**	$ (0.55)
Net earnings (loss) per share, diluted	**$ 0.28**	$ (0.48)	**$ 0.66**	$ (0.55)

(a) Weighted average common shares outstanding for the nine months ended September 30, 2017 includes 139,863 PSUs not yet released (nine months ended September 30, 2016 – 184,425 PSUs).

(b) For the three months and nine months ended September 30, 2016, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss. If the Corporation had recognized net earnings during the three months and nine months ended September 30, 2016, the dilutive effect of stock options, RSUs and PSUs would have been 36,815 and 209,940 weighted average common shares, respectively.

21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments recognized on the consolidated balance sheet are comprised of cash and cash equivalents, trade receivables and other, commodity risk management contracts, derivative financial assets included within other assets, accounts payable and accrued liabilities, derivative financial liabilities included within provisions and other liabilities, long-term debt and debt redemption premium liability included within long-term debt. As at September 30, 2017, commodity risk management contracts and derivative financial assets and liabilities were classified as held-for-trading financial instruments; cash and cash equivalents and trade receivables and other were classified as loans and receivables; and accounts payable and accrued liabilities were classified as other financial liabilities. Long-term debt was carried at amortized cost.

The carrying value of cash and cash equivalents, trade receivables and other, and accounts payable and accrued liabilities included on the consolidated balance sheet approximate the fair value of the respective assets and liabilities due to the short-term nature of those instruments.

(a) Fair value measurement of long-term debt, derivative financial liabilities, derivative financial assets, commodity risk management contracts and debt redemption premium liability:

		Fair value measurements using		
As at September 30, 2017	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
Commodity risk management contracts	**$ 15,353**	**$ -**	**$ 15,353**	**$ -**
Derivative financial assets (Note 7)	**$ 3,912**	**$ -**	**$ 3,912**	**$ -**
Financial liabilities				
Long-term debt[(i)] (Note 8)	**$ 4,727,310**	**$ -**	**$ 4,380,134**	**$ -**
Derivative financial liabilities (Note 9)	**$ 10,707**	**$ -**	**$ 10,707**	**$ -**
Commodity risk management contracts	**$ 26,313**	**$ -**	**$ 26,313**	**$ -**

		Fair value measurements using		
As at December 31, 2016	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial liabilities				
Long-term debt[(i)] (Note 8)	$ 5,082,791	$ -	$ 4,768,344	$ -
Derivative financial liabilities (Note 9)	$ 3,714	$ -	$ 3,714	$ -
Commodity risk management contracts	$ 30,313	$ -	$ 30,313	$ -
Debt redemption premium (Note 8)	$ 21,812	$ -	$ 21,812	$ -

(i) Includes the current and long-term portions.

Level 1 fair value measurements are based on unadjusted quoted market prices.

As at September 30, 2017, the Corporation did not have any financial instruments measured at Level 1 fair value.

Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted prices or indices.

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker.

The fair value of commodity risk management contracts and derivative financial assets and liabilities are derived using third-party valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including forward prices for commodities, interest rate yield curves and foreign exchange rates. The observable inputs may be adjusted using certain methods, which include extrapolation to the end of the term of the contract.

Level 3 fair value measurements are based on unobservable information.

As at September 30, 2017, the Corporation did not have any financial instruments measured at Level 3 fair value. The Corporation recognizes transfers into and transfers out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer.

(b) Commodity price risk management:

The Corporation enters into derivative financial instruments to manage commodity price risk. The use of the financial commodity risk management contracts is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes. Financial commodity risk management contracts are measured at fair value, with gains and losses on re-measurement included in the consolidated statement of earnings and comprehensive income in the period in which they arise.

The Corporation has the following financial commodity risk management contracts relating to crude oil sales outstanding as at September 30, 2017:

As at September 30, 2017	**Volumes (bbls/d)**[(i)]	**Term**	**Average Price (US$/bbl)**[(i)]
Fixed Price:			
WTI[(ii)] Fixed Price	33,100	Oct 1, 2017 – Dec 31, 2017	$54.19
WTI Fixed Price	15,000	Jan 1, 2018 – Jun 30, 2018	$51.24
WTI Fixed Price	10,000	Jul 1, 2018 – Dec 31, 2018	$50.88
WTI:WCS[(iii)] Fixed Differential	56,600	Oct 1, 2017 – Dec 31, 2017	$(15.02)
WTI:WCS Fixed Differential	31,000	Jan 1, 2018 – Jun 30, 2018	$(14.08)
WTI:WCS Fixed Differential	18,000	Jul 1, 2018 – Dec 31, 2018	$(14.26)
Collars:			
WTI Collars	30,500	Oct 1, 2017 – Dec 31, 2017	$47.87 – $58.57
WTI Collars	32,500	Jan 1, 2018 – Jun 30, 2018	$45.49 – $54.87
WTI Collars	24,500	Jul 1, 2018 – Dec 31, 2018	$45.04 – $54.33

(i) The volumes and prices in the above tables represent averages for various contracts with differing terms and prices. The average price for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.

(ii) West Texas Intermediate ("WTI") crude oil

(iii) Western Canadian Select ("WCS") crude oil blend

The Corporation has entered into the following financial commodity risk management contracts relating to crude oil sales subsequent to September 30, 2017. As a result, these contracts are not reflected in the Corporation's Interim Consolidated Financial Statements:

Subsequent to September 30, 2017	Volumes (bbls/d)[(i)]	Term	Average Price (US$/bbl)[(i)]
Fixed Price:			
WTI:WCS Fixed Differential	6,200	Jan 1, 2018 – Jun 30, 2018	$(14.27)
WTI:WCS Fixed Differential	3,500	Jul 1, 2018 – Dec 31, 2018	$(14.51)
WTI Collars	1,000	Jan 1, 2018 – Dec 31, 2018	$50.10 – $53.82

(i) The volumes and prices in the above tables represent averages for various contracts with differing terms and prices. The average price for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.

The Corporation has the following financial commodity risk management contracts relating to condensate purchases outstanding:

As at September 30, 2017	Volumes (bbls/d)	Term	Average % of WTI
Mont Belvieu fixed % of WTI	15,150	Oct 1, 2017 – Dec 31, 2017	82.9%

The Corporation's financial commodity risk management contracts are subject to master agreements that create a legally enforceable right to offset, by counterparty, the related financial assets and financial liabilities on the Corporation's balance sheet in all circumstances.

The following table provides a summary of the Corporation's unrealized offsetting financial commodity risk management positions:

As at	September 30, 2017			December 31, 2016		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Gross amount	**$ 27,555**	**$ (68,254)**	**$(40,699)**	$ -	$ (165,740)	$ (165,740)
Amount offset	**(12,202)**	**41,941**	**29,739**	-	135,427	135,427
Net amount	**$ 15,353**	**$ (26,313)**	**$(10,960)**	$ -	$ (30,313)	$ (30,313)

The following table provides a reconciliation of changes in the fair value of the Corporation's financial commodity risk management assets and liabilities from January 1 to September 30:

As at	September 30, 2017	September 30, 2016
Fair value of contracts, beginning of year	**$ (30,313)**	$ -
Fair value of contracts realized during the period	**4,601**	359
Change in fair value of contracts during the period	**14,752**	11,377
Fair value of contracts, end of period	**$ (10,960)**	$ 11,736

The following table summarizes the financial commodity risk management gains and losses:

	Three months ended September 30		Nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Realized loss (gain) on commodity risk management	**$ (3,976)**	$ (3,128)	**$ 4,601**	$ 359
Unrealized loss (gain) on commodity risk management	**57,470**	(32,207)	**(19,353)**	(11,736)
Commodity risk management loss (gain)	**$ 53,494**	$ (35,335)	**$ (14,752)**	$ (11,377)

The following table summarizes the sensitivity of the earnings before income tax impact of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place as at September 30, 2017:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	$ (77,973)	$ 51,628
Crude oil differential price (i)	± US$1.00 per bbl applied to WCS differential contracts	$ 17,674	$ (17,674)
Condensate percentage	± 1% in condensate price as a percentage of US$ WTI price per bbl applied to condensate contracts	$ 752	$ (752)

(i) As the WCS differential is expressed as a discount to WTI, an increase in the differential results in a lower WCS price and a decrease in the differential results in a higher WCS price.

(c) Interest rate risk management:

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. The Corporation has entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of the US$1.2 billion senior secured term loan at approximately 5.3%. Interest rate swaps are classified as derivative financial assets and liabilities and measured at fair value, with gains and losses on re-measurement included as a component of net finance expense in the period in which they arise. As at September 30, 2017, the Corporation has recognized a $1.6 million net derivative financial asset related to this interest rate swap.

Amount	Effective date	Remaining term	Fixed rate	Floating rate
US$650 million	September 29, 2017	Oct 1, 2017 – Dec 31, 2020	5.319% (i)	3 month LIBOR (ii) + 3.5% credit spread

(i) Comprised of the fixed rate on the interest rate swap contract of 1.819% plus 3.5% credit spread
(ii) London Interbank Offered Rate

22. GEOGRAPHICAL DISCLOSURE

As at September 30, 2017, the Corporation had non-current assets related to operations in the United States of $101.5 million (December 31, 2016 – $109.2 million). For the three and nine months ended September 30, 2017, petroleum revenue related to operations in the United States was $248.6 million and $686.7 million respectively (three and nine months ended September 30, 2016 – $191.1 million and $469.1 million, respectively).

23. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at September 30, 2017:

	2017	2018	2019	2020	2021	Thereafter
Transportation and storage	$ 42,310	$ 176,412	$ 177,066	$ 227,365	$ 283,453	$ 3,802,411
Office lease rentals	7,765	31,773	31,803	32,719	33,119	229,884
Diluent purchases	90,726	303,052	19,551	19,603	19,551	35,834
Other operating commitments	5,115	14,381	10,283	11,892	11,138	73,287
Capital commitments	7,822	-	-	-	-	-
Commitments	**$ 153,738**	**$ 525,618**	**$ 238,703**	**$ 291,579**	**$ 347,261**	**$ 4,141,416**

The Corporation's commitments have been presented on a gross basis. A portion of these committed amounts have been recognized on the balance sheet within provisions and other liabilities (Note 9(b)).

(b) Contingencies

The Corporation is involved in various legal claims associated with the normal course of operations. The Corporation believes that any liabilities that may arise pertaining to such matters would not have a material impact on its financial position.