FOURTH QUARTER 2017

Report to Shareholders for the period ended December 31, 2017

MEG Energy Corp. reported fourth quarter and full-year 2017 operating and financial results on February 8, 2018. Highlights include:

- Record fourth quarter production volumes of 90,228 barrels per day (bpd) contributing to annual production of 80,774 bpd, within guidance for the year. Exit production volumes of 93,674 bpd, which are significantly above the company's exit guidance, reflect the continued ramp-up of MEG's eMSAGP growth initiative at Christina Lake Phase 2B;

- Fourth quarter non-energy operating costs of $4.53 per barrel contributing to record-low annual non-energy operating costs of $4.62 per barrel, which are well below the low end of the company's guidance;

- Record-low annual net operating costs of $6.84 per barrel;

- Total cash capital investment for 2017 of $503 million, 15% lower than MEG's original budget of $590 million and lower than the company's $510 million revised capital guidance; and

- Year-end cash and cash equivalents of $464 million, which along with expected funds flow will enable MEG to fully fund its 2018 capital program of $510 million.

MEG is positioned to complete the implementation of the eMSAGP growth initiative at Christina Lake Phase 2B in 2018, which is expected to enable production to continue to ramp up to reach 95,000 to 100,000 bpd by the end of the year.

"The transformation of MEG's business over the last two years has been remarkable. Our eMSAGP technology is enabling us to increase our production and decrease our costs, all at a very attractive capital efficiency," said Bill McCaffrey, President and Chief Executive Officer. "Through the application of eMSAGP on our Phase 2B assets, we expect to increase our production by 25% to 100,000 bpd while continuing to drive our non-energy operating costs down."

Record–Low Costs

MEG set records for the full year of 2017 in both per barrel net operating costs and non-energy operating costs, which totaled $6.84 per barrel and $4.62 per barrel respectively. Net operating costs per barrel for full year 2017 were 14% less than in 2016, while non-energy operating costs per barrel decreased 18% in 2017 compared to the previous year. The continued reduction in net operating costs and non-energy operating costs in 2017 were primarily due to efficiency gains and continued cost management.

MEG posted fourth quarter non-energy operating costs of $4.53 per barrel, a result of higher sales volumes. Non-energy operating costs for 2017 averaged $4.62 per barrel, below the low end of the $4.75-$5.00 per barrel revised guidance provided in MEG's third quarter 2017 disclosure, and a 55% reduction since 2011.

Net operating costs for the fourth quarter of 2017 averaged $5.86 per barrel compared to $8.24 per barrel for the same period in 2016. This 29% reduction is comprised of a per barrel decrease in both non- energy and energy operating costs, offset by a decrease in per barrel power revenue.

Strong Fourth Quarter Sales

Sales volumes in the fourth quarter of 2017 were approximately 4,300 bpd higher than fourth quarter production volumes, primarily as a result of volumes sold at the U.S. Gulf Coast that were in transit over the third quarter of 2017.

MEG benefitted from increases in its realized sales price during the fourth quarter. The WTI:WCS differential average narrowed to US$12.26 per barrel, or 22.1%, for the fourth quarter of 2017, compared to US$14.32 per barrel, or 29.1% for the same period in 2016 due to higher demand for Canadian heavy oil from U.S. Gulf Coast refineries. The WTI:WCS differential averaged US$11.98 per barrel, or 23.5%, for 2017 compared to US$13.84 per barrel, or 31.9%, for 2016.

Adjusted Funds Flow and Earnings

MEG realized adjusted funds flow from operations of $192 million for the fourth quarter of 2017 compared to adjusted funds flow from operations of $40 million in the same quarter of 2016. The increase was primarily due to an increase in bitumen realization and a reduction in net operating costs, partially offset by an increase in transportation. The increase in bitumen realization is a result of the quarter-over-quarter increase in average crude oil benchmark pricing and blend sales volumes.

The company recorded fourth quarter 2017 operating earnings of $44 million compared to an operating loss of $72 million for the same period in 2016. MEG recognized an operating loss of $114 million for 2017 compared to an operating loss of $455 million for 2016. The decrease in the operating loss for full year and fourth quarter 2017 was primarily due to higher bitumen realization as a result of the increase in average crude oil benchmark pricing and lower operating costs.

MEG's long-term debt is entirely denominated in U.S. dollars. Primarily 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 company's Consolidated Balance Sheet decreased to C$4.64 billion at December 31, 2017 from C$5.05 billion at December 31, 2016.

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

Highly-Economic Growth Progressing in 2018

"In 2018, our focus is on the successful completion of the Phase 2B eMSAGP program and our growth plans beyond 100,000 bpd," said McCaffrey. "We continue to be encouraged by the results we are getting from the eMVAPEX technology, and we also have further opportunities around the application of eMSAGP and brownfield expansions. Our low-cost continuous growth approach is providing the way for MEG into the future."

OPERATIONAL AND FINANCIAL HIGHLIGHTS

During the fourth quarter of 2017, the Corporation continued to benefit from increases in its realized sales price. The average US$WTI price increased 12% in the fourth quarter of 2017 compared to the same period in 2016. Also, the average WCS differential narrowed by US$2.06 per barrel, or 14%, due to higher demand for Canadian heavy oil from U.S. Gulf Coast refineries. These factors were the primary drivers in the approximately C$12 per barrel increase in bitumen realization in the fourth quarter 2017, as compared to the fourth quarter of 2016.

Capital investment for the fourth quarter of 2017 totaled $163.3 million, an increase of $100.3 million compared to the same period of 2016, primarily as a result of increased investment in the eMSAGP growth project at Christina Lake Phase 2B. Total capital investment for 2017 was $502.8 million, which approximated the Corporation's most recent guidance of $510 million.

At December 31, 2017, the Corporation had cash and cash equivalents of $463.5 million and US$1.4 billion of undrawn capacity under the revolving credit facility.

Bitumen production in the fourth quarter of 2017 averaged 90,228 bbls/d compared to 81,780 bbls/d for the same period in 2016. The increase in production volumes for the three months ended December 31, 2017 is primarily due to the efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake project. Still in the first year of a two-year development plan, the eMSAGP growth project is proceeding as planned. The implementation of eMSAGP has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production. Exit bitumen production volumes for 2017 were 93,674 bbls/d.

The Corporation's non-energy operating costs averaged $4.53 per barrel in the fourth quarter of 2017, compared to $4.99 per barrel in the same period of 2016. On an annual basis, non-energy operating costs averaged $4.62 per barrel, an 18% decrease compared to $5.62 per barrel in 2016. The decrease in costs are a result of efficiency gains and continued cost management.

The Corporation realized a net loss of $1.3 million for the three months ended December 31, 2017 and net earnings of $188.5 million for the year ended December 31, 2017. Net earnings are impacted by the foreign exchange rate as the Corporation's debt is denominated in U.S. dollars. The Canadian dollar weakened relative to the U.S. dollar in the fourth quarter, resulting in an unrealized foreign exchange loss of $7.0 million. The Canadian dollar strengthened overall in 2017, resulting in an unrealized foreign exchange gain of $338.1 million on a year-to-date basis.

On December 1, 2017, the Corporation announced a 2018 capital budget of $510 million. The Corporation expects to fund the 2018 capital program with internally generated cash flow and a portion of its $463.5 million of cash and cash equivalents as at December 31, 2017.

The Corporation's 2018 annual bitumen production volumes are targeted to be in the range of 85,000 – 88,000 bbls/d. Exit bitumen production for 2018 is targeted to be in the range of 95,000 – 100,000 bbls/day. Non-energy operating costs are targeted to be in the range of $4.75 – $5.25 per barrel. The operational guidance takes into account a major turnaround at the Corporation's Christina Lake Phase 2B facility in 2018, with an anticipated 5,000 to 6,000 bbls/d impact on production for the year.

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:

	Year ended December 31		2017				2016			
($ millions, except as indicated)	**2017**	**2016**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Bitumen production - bbls/d	**80,774**	81,245	**90,228**	83,008	72,448	77,245	81,780	83,404	83,127	76,640
Bitumen realization - $/bbl	**41.89**	27.79	**48.30**	39.89	39.66	37.93	36.17	30.98	30.93	11.43
Net operating costs - $/bbl(1)	**6.84**	7.99	**5.86**	6.00	7.42	8.43	8.24	7.76	7.43	8.53
Non-energy operating costs - $/bbl	**4.62**	5.62	**4.53**	4.57	4.23	5.20	4.99	5.32	5.81	6.45
Cash operating netback - $/bbl(2)	**27.00**	13.13	**33.83**	26.84	22.96	22.33	21.73	16.74	16.09	(3.71)
Adjusted funds flow from (used in) operations(3)	**374**	(62)	**192**	83	55	43	40	23	7	(131)
Per share, diluted(3)	**1.29**	(0.27)	**0.65**	0.28	0.19	0.16	0.18	0.10	0.03	(0.58)
Operating earnings (loss)(3)	**(114)**	(455)	**44**	(43)	(36)	(79)	(72)	(88)	(98)	(197)
Per share, diluted(3)	**(0.39)**	(2.01)	**0.15**	(0.14)	(0.12)	(0.29)	(0.32)	(0.39)	(0.43)	(0.88)
Revenue(4)	**2,435**	1,866	**755**	546	574	560	566	497	513	290
Net earnings (loss)	**188**	(429)	**(1)**	84	104	2	(305)	(109)	(146)	131
Per share, basic	**0.65**	(1.90)	**(0.00)**	0.29	0.36	0.01	(1.34)	(0.48)	(0.65)	0.58
Per share, diluted	**0.65**	(1.90)	**(0.00)**	0.28	0.35	0.01	(1.34)	(0.48)	(0.65)	0.58
Total cash capital investment	**503**	137	**163**	103	158	78	63	19	20	35
Cash and cash equivalents	**464**	156	**464**	398	512	549	156	103	153	125
Long-term debt	**4,637**	5,053	**4,637**	4,636	4,813	4,945	5,053	4,910	4,871	4,859

(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 months and years ended December 31, 2017 and December 31, 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.*

Bitumen Production and Steam-Oil Ratio

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Bitumen production – bbls/d	**90,228**	81,780	**80,774**	81,245
Steam-oil ratio (SOR)	**2.2**	2.3	**2.3**	2.3

Bitumen Production

Bitumen production at the Christina Lake Project averaged 90,228 bbls/d for the three months ended December 31, 2017 compared to 81,780 bbls/d for the three months ended December 31, 2016. The increase in production volumes for the three months ended December 31, 2017 is primarily due to the efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project. The implementation of eMSAGP has improved reservoir efficiency and allowed for the redeployment of steam, thereby enabling the Corporation to place additional wells into production.

Sales volumes in the fourth quarter of 2017 were approximately 4,300 bbls/d higher than fourth quarter production volumes, primarily as a result of volumes sold at the U.S. Gulf Coast that were in transit over the third quarter of 2017.

Bitumen production for the year ended December 31, 2017 averaged 80,774 bbls/d compared to 81,245 bbl/d for the year ended December 31, 2016. Average production for 2017 was affected by 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 2.2 and 2.3 during the three months and year ended December 31, 2017, respectively. The SOR averaged 2.3 for the three months and year ended December 31, 2016.

Operating Cash Flow

	Three months ended December 31		Year ended December 31	
($000)	2017	2016	2017	2016
Petroleum revenue – proprietary(1)	$ 710,817	$ 503,176	$ 2,168,602	$ 1,626,025
Diluent expense	(290,725)	(231,173)	(944,134)	(808,030)
	420,092	272,003	1,224,468	817,995
Royalties	(7,265)	(3,861)	(22,578)	(8,581)
Transportation expense	(64,495)	(50,102)	(214,280)	(209,864)
Operating expenses	(57,050)	(68,525)	(222,196)	(253,758)
Power revenue	6,105	6,508	22,209	18,868
Transportation revenue	3,601	4,605	12,801	19,791
	300,988	160,628	800,424	384,451
Realized gain (loss) on commodity risk management	(6,672)	2,718	(11,273)	2,359
Operating cash flow(2)	$ 294,316	$ 163,346	$ 789,151	$ 386,810

(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 Fourth Quarter Report.*

Operating cash flow was $294.3 million for the three months ended December 31, 2017 compared to $163.3 million for the three months ended December 31, 2016. The 80% increase in operating cash flow is primarily due to higher blend sales revenue partially offset by an increase in the Corporation's diluent expense. The increase in blend sales revenue is primarily due to a 23% increase in the average realized blend price, which is largely related to the quarter-over-quarter increase in average crude oil benchmark pricing. The increase in diluent expense is primarily due to an increase in condensate prices.

Operating cash flow was $789.2 million for the year ended December 31, 2017 compared to $386.8 million for the year ended December 31, 2016. The 104% 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 35% increase in the average realized blend price. Diluent expense for the year ended December 31, 2017 was $136.1 million higher than the year ended December 31, 2016, primarily due to an increase in condensate prices.

Cash Operating Netback

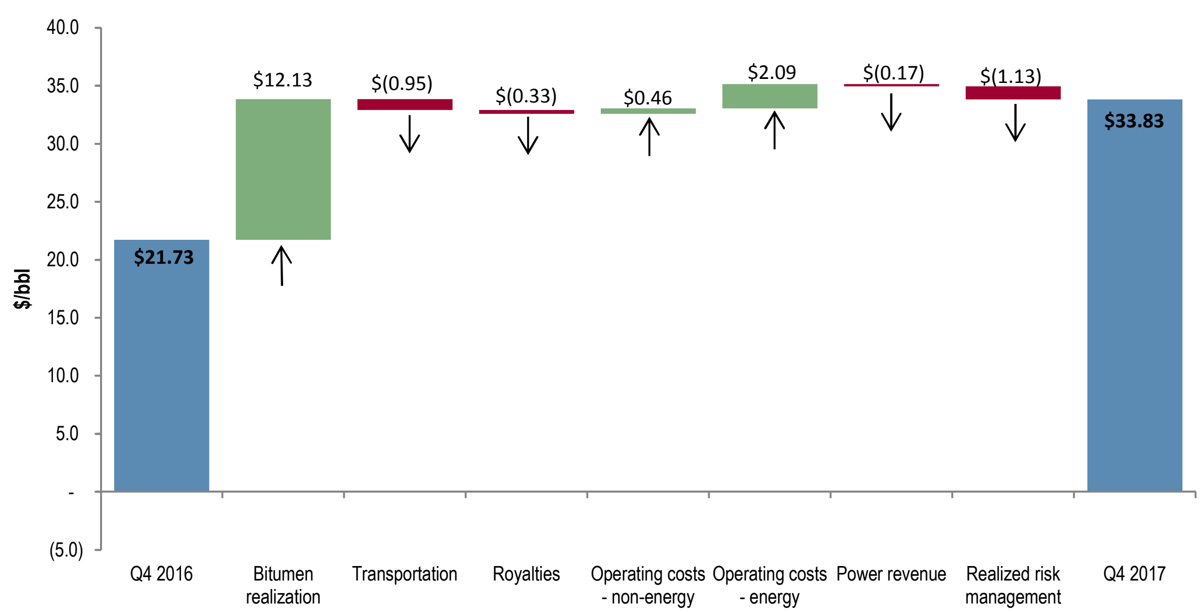
The following table summarizes the Corporation's per-unit calculation of operating cash flow, defined as cash operating netback for the periods indicated:

	Three months ended December 31		Year ended December 31	
($/bbl)	**2017**	**2016**	**2017**	**2016**
Bitumen realization[1]	**$ 48.30**	$ 36.17	**$ 41.89**	$ 27.79
Transportation[2]	**(7.00)**	(6.05)	**(6.89)**	(6.46)
Royalties	**(0.84)**	(0.51)	**(0.77)**	(0.29)
	40.46	29.61	**34.23**	21.04
Operating costs – non-energy	**(4.53)**	(4.99)	**(4.62)**	(5.62)
Operating costs – energy	**(2.03)**	(4.12)	**(2.98)**	(3.01)
Power revenue	**0.70**	0.87	**0.76**	0.64
Net operating costs	**(5.86)**	(8.24)	**(6.84)**	(7.99)
	34.60	21.37	**27.39**	13.05
Realized gain (loss) on commodity risk management	**(0.77)**	0.36	**(0.39)**	0.08
Cash operating netback	**$ 33.83**	$ 21.73	**$ 27.00**	$ 13.13

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

(2) *Defined as transportation expense less transportation revenue. Transportation 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.*

Cash Operating Netback - Three Months Ended December 31



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 $48.30 per barrel for the three months ended December 31, 2017 compared to $36.17 per barrel for the three months ended December 31, 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 December 31, 2017, the Corporation's cost of diluent was $77.09 per barrel of diluent compared to $69.15 per barrel of diluent for the three months ended December 31, 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, but generally obtain higher sales prices. As a result of a higher proportion of blend sales volumes shipped from Edmonton to the U.S. Gulf Coast via the Flanagan South and Seaway pipeline system during the three months ended December 31, 2017, transportation expense averaged $7.00 per barrel for the three months ended December 31, 2017 compared to $6.05 per barrel for the three months ended December 31, 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 December 31, 2017, compared to the three months ended December 31, 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, reduced by power revenue. Non-energy operating costs represent production-related operating activities. 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 December 31, 2017 averaged $5.86 per barrel compared to $8.24 per barrel for the three months ended December 31, 2016. The decrease in net operating costs is comprised of a per barrel decrease in both non-energy and energy operating costs, offset by a decrease in per barrel power revenue.

Non-energy operating costs

Non-energy operating costs averaged $4.53 per barrel for the three months ended December 31, 2017 compared to $4.99 per barrel for the three months ended December 31, 2016. The decrease in non-energy operating costs per barrel is primarily the result of higher sales volumes. Due to the fixed nature of a portion of non-energy operating costs, the per barrel costs will typically decrease as production increases.

Energy operating costs

Energy operating costs averaged $2.03 per barrel for the three months ended December 31, 2017 compared to $4.12 per barrel for the three months ended December 31, 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 $2.01 per mcf during the three months ended December 31, 2017 compared to $3.45 per mcf for the three months ended December 31, 2016.

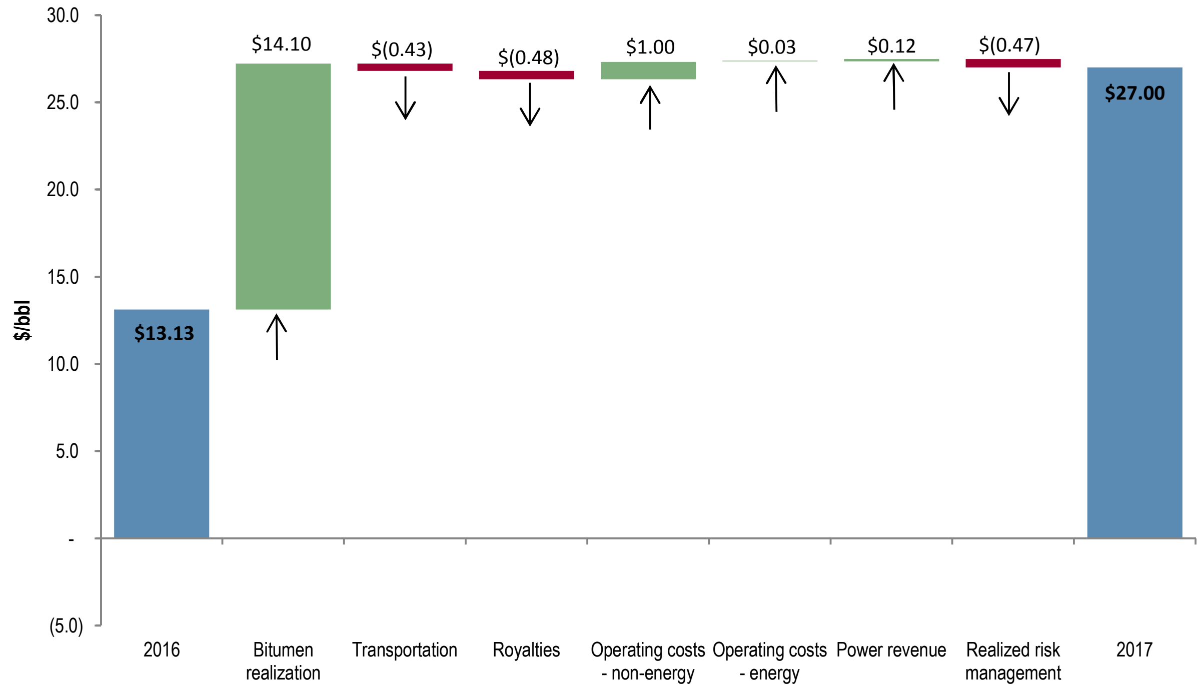
Power revenue

Power revenue averaged $0.70 per barrel for the three months ended December 31 2017 compared to $0.87 per barrel for the three months ended December 31, 2016. The Corporation's average realized power sales price during the three months ended December 31, 2017 was $21.37 per megawatt hour compared to $21.94 per megawatt hour for the three months ended December 31, 2016.

Realized Gain (Loss) on Commodity Risk Management

The realized loss on commodity risk management averaged $0.77 per barrel for the three months ended December 31, 2017 compared to a realized gain of $0.36 per barrel for the three months ended December 31, 2016. This is primarily due to settlement losses on commodity risk management contracts relating to crude oil sales, partially offset by settlement gains on contracts relating to condensate purchases. Refer to the "OTHER OPERATING RESULTS" and "RISK MANAGEMENT" sections of this Fourth Quarter Report for further details.

Cash Operating Netback – Year Ended December 31



Bitumen Realization

Bitumen realization averaged $41.89 per barrel for the year ended December 31, 2017 compared to $27.79 per barrel for the year ended December 31, 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 year ended December 31, 2017, the Corporation's cost of diluent was $72.32 per barrel of diluent compared to $61.06 per barrel of diluent for the year ended December 31, 2016. The increase in the cost of diluent is primarily a result of the increase in average condensate benchmark pricing.

Transportation

As a result of a higher proportion of blend sales volumes shipped from Edmonton to the U.S. Gulf Coast via the Flanagan South and Seaway pipeline system during the year ended December 31, 2017, transportation costs averaged $6.89 per barrel for the year ended December 31, 2017 compared to $6.46 per barrel for the year ended December 31, 2016.

Royalties

The increase in royalties for the year ended December 31, 2017, compared to the year ended December 31, 2016 is primarily the result of higher WTI crude oil prices.

Net Operating Costs

Net operating costs for the year ended December 31, 2017 averaged $6.84 per barrel compared to $7.99 per barrel for the year ended December 31, 2016. The decrease in net operating costs is primarily the result of a per barrel decrease in non-energy operating costs.

Non-energy operating costs

Non-energy operating costs averaged $4.62 per barrel for the year ended December 31, 2017 compared to $5.62 per barrel for the year ended December 31, 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 $0.15 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 $2.98 per barrel for the year ended December 31, 2017 which were substantially consistent with $3.01 per barrel for the year ended December, 2016. The Corporation's natural gas purchase price averaged $2.59 per mcf during the year ended December 31, 2017 compared to $2.53 per mcf for the same period in 2016.

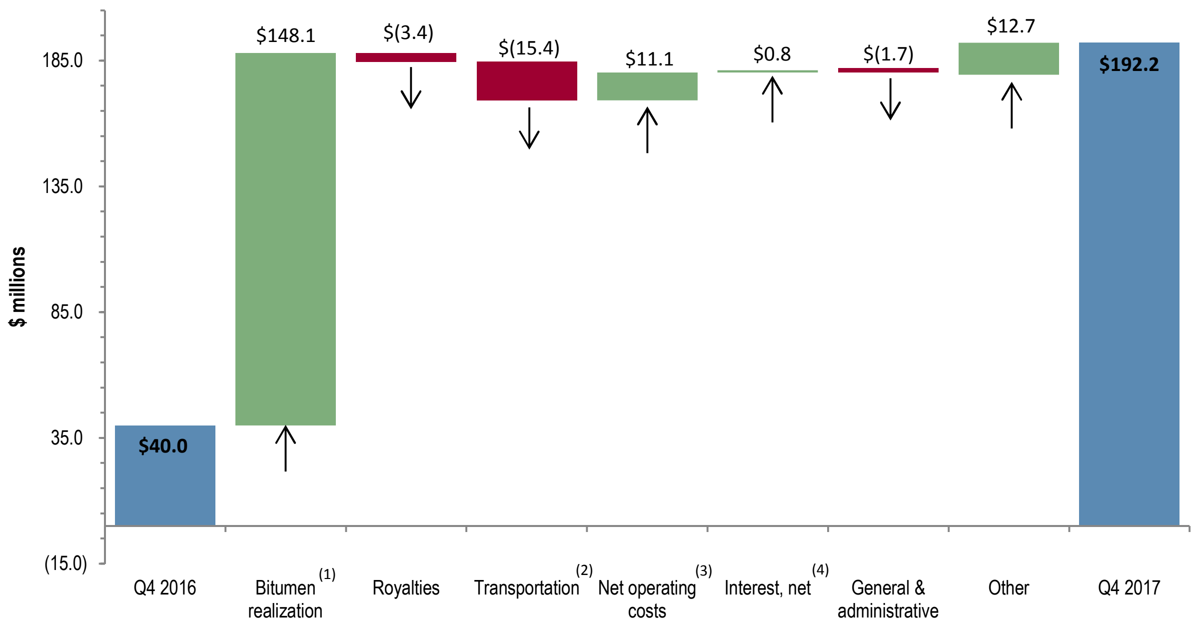
Power revenue

Power revenue averaged $0.76 per barrel for the year ended December 31, 2017 compared to $0.64 per barrel for the year ended December 31, 2016. The Corporation's average realized power sales price during the year ended December 31, 2017 was $21.49 per megawatt hour compared to $18.74 per megawatt hour for the same period in 2016.

Commodity Risk Management Gain (Loss)

The realized loss on commodity risk management averaged $0.39 per barrel for the year ended December 31, 2017 compared to a realized gain of $0.08 per barrel for the year ended December 31, 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 "OTHER OPERATING RESULTS" and "RISK MANAGEMENT" sections of this Fourth Quarter Report for further details.

Adjusted Funds Flow From (Used In) Operations – Three Months Ended December 31



(1) *Net of diluent expense.*

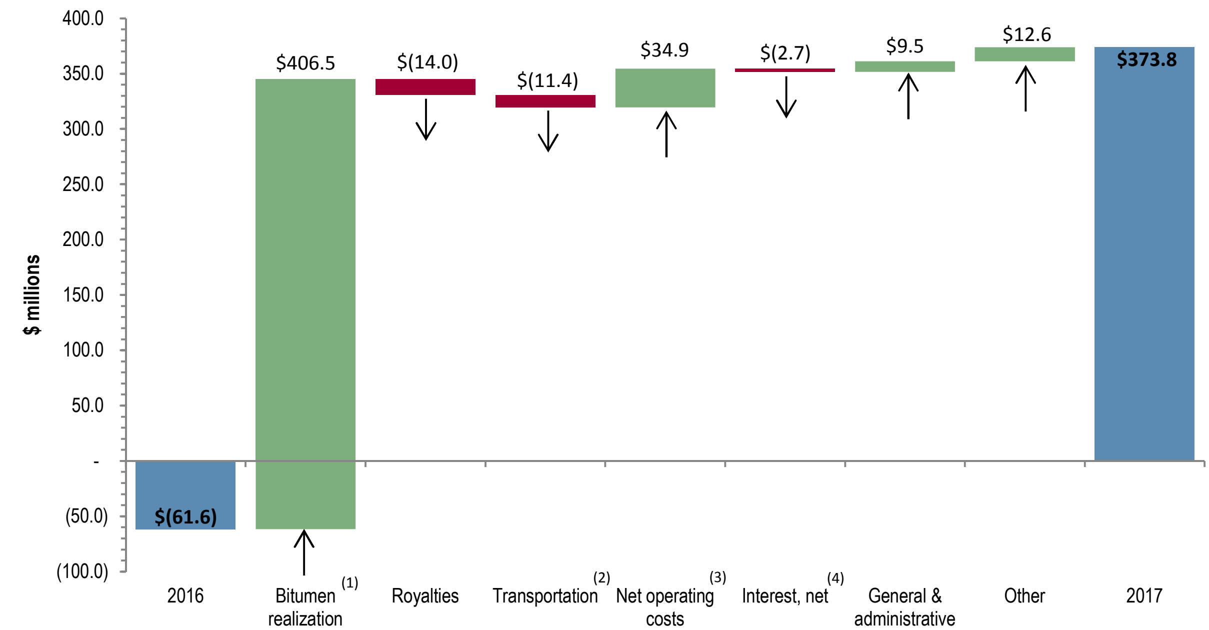
(2) *Defined as transportation expense less transportation revenue.*

(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 Fourth Quarter Report, which is used by the Corporation to analyze operating performance and liquidity. Adjusted funds flow from operations was $192.2 million for the three months ended December 31, 2017 compared to $40.0 million for the three months ended December 31, 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, partially offset by an increase in transportation. The increase in bitumen realization is primarily due to the quarter-over-quarter increase in average crude oil benchmark pricing and blend sales volumes. The decrease in net operating costs is a result of efficiency gains, a continued focus on cost management, and reduced natural gas prices. The increase in transportation expense is due to the increase in blend sales volumes shipped to the U.S. Gulf Coast.

Adjusted Funds Flow From (Used In) Operations – Year Ended December 31



(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 $373.8 million for the year ended December 31, 2017 compared to adjusted funds flow used in operations of $(61.6) million for the year ended December 31, 2016. The increase was primarily due to an increase in bitumen realization, as a result of 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 Fourth Quarter Report, which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. The Corporation recognized operating earnings of $44.1 million for the three months ended December 31, 2017 compared to an operating loss of $72.0 million for the three months ended December 31, 2016. The Corporation recognized an operating loss of $113.5 million for the year ended December 31, 2017 compared to an operating loss of $455.1 million for the year ended December 31, 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 December 31, 2017 totalled $754.8 million compared to $565.8 million for the three months ended December 31, 2016. Revenue for the year ended December 31, 2017 totaled $2.43 billion compared to $1.87 billion for the year ended December 31, 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 a net loss of $1.3 million for the three months ended December 31, 2017 compared to a net loss of $304.8 million for the three months ended December 31, 2016. The reduction in the net loss in the fourth quarter of 2017 was primarily a result of the increase in average crude oil benchmark pricing, as previously discussed under cash operating netback. In addition, the net loss for the three months ended December 31, 2017 included a net unrealized foreign exchange loss of $7.0 million and an unrealized loss on commodity risk management of $57.7 million. In comparison, the net loss in the fourth quarter of 2016 included a net unrealized foreign exchange loss of $119.6 million and an unrealized loss on commodity risk management of $42.0 million. In the fourth quarter of 2016, the Corporation also recognized an $80.1 million impairment charge related to the Northern Gateway pipeline.

Net earnings for the year ended December 31, 2017 were $188.5 million compared to a net loss of $428.7 million in the prior year. In addition to the impact of higher average crude oil benchmark pricing in 2017 as previously discussed under cash operating netback, the net unrealized foreign exchange gain increased by $190.0 million in 2017 compared to 2016. Also in 2016, the Corporation recognized an $80.1 million impairment charge related to the Northern Gateway pipeline.

Total Cash Capital Investment

Total cash capital investment during the three months ended December 31, 2017 totalled $163.3 million compared to $63.1 million for the three months ended December 31, 2016. Total cash capital investment during the year ended December 31, 2017 totaled $502.8 million as compared to $137.2 million for the year ended December 31, 2016. Capital investment in 2017 has been primarily directed towards the Corporation’s eMSAGP production growth initiative at Christina Lake Phase 2B and sustaining capital activities.

Capital Resources

The Corporation's cash and cash equivalents balance totalled $463.5 million as at December 31, 2017 compared to $156.2 million as at December 31, 2016. The increase is primarily due to net cash provided by operating activities of $317.9 million, net equity issuance proceeds of $496.3 million received pursuant to the comprehensive refinancing that closed on January 27, 2017, partially offset by net cash used in investing activities of $405.2 million.

All of the Corporation’s long-term debt is denominated in U.S. dollars. Primarily as a result of the increase in the value of the Canadian dollar relative to the U.S. dollar, long-term debt decreased to C$4.64 billion as at December 31, 2017 from C$5.05 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 Export Development Canada ("EDC"), 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 December 31, 2017, letters of credit of US$258 million were issued and outstanding under this 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 MEG's most recently filed Annual Information Form ("AIF").

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.

OUTLOOK

Summary of 2017 Guidance	Guidance October 26, 2017	Annual Results
Capital investment	$510 million	**$503 million**
Bitumen production – annual average (bbls/d)	80,000 – 82,000	**80,774**
Bitumen production – targeted exit volume (bbls/d)	86,000 – 89,000	**93,674**
Non-energy operating costs ($/bbl)	$4.75 – $5.00	**$4.62**

Capital investment for 2017 was $503 million, which approximated the Corporation's most recent 2017 capital investment guidance of $510 million issued on October 26, 2017.

Annual bitumen production averaged 80,774 bbls/d, consistent with the Corporation's most recent 2017 production guidance.

As a result of the continued implementation of eMSAGP, exit bitumen production volumes were 93,674 bbls/d, which exceeded the Corporation's most recent 2017 exit production guidance.

As a result of efficiency gains and a continued focus on cost management, annual non-energy operating costs averaged $4.62 per barrel, representing a 5% reduction from the mid-point of the most recent 2017 guidance.

Summary of 2018 Guidance	
Capital investment	**$510 million**
Bitumen production – annual average (bbls/d)	**85,000 – 88,000**
Bitumen production – targeted exit volume (bbls/d)	**95,000 – 100,000**
Non-energy operating costs ($/bbl)	**$4.75 – $5.25**

On December 1, 2017, the Corporation announced a 2018 capital budget of $510 million, of which approximately 24% will be directed towards the completion of the Phase 2B eMSAGP growth project at Christina Lake, 20% towards the expansion of the pilot program involving the Corporation's proprietary eMVAPEX technologies and 43% towards sustaining capital activities and Phase 2B turnaround costs. The remainder is dedicated toward supporting field infrastructure, corporate and other capital initiatives. The Corporation expects to fund the 2018 capital program with internally generated cash flow and a portion of its $463.5 million of cash and cash equivalents as at December 31, 2017.

The Corporation's 2018 annual bitumen production volumes are targeted to be in the range of 85,000 – 88,000 bbls/d. Exit bitumen production for 2018 is targeted to be in the range of 95,000 – 100,000 bbls/day. Non-energy operating costs are targeted to be in the range of $4.75 – $5.25 per barrel. The operational guidance takes into account a major turnaround at the Corporation's Christina Lake Phase 2B facility in 2018, with an anticipated 5,000 to 6,000 bbls/d impact on production for the year.

BUSINESS ENVIRONMENT

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

	Year ended December 31		2017				2016			
	2017	**2016**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**54.83**	44.97	**61.54**	52.18	50.93	54.66	51.13	46.98	46.67	35.10
WTI (US$/bbl)	**50.95**	43.33	**55.40**	48.21	48.29	51.91	49.29	44.94	45.59	33.45
WTI (C$/bbl)	**66.13**	57.44	**70.45**	60.38	64.94	68.68	65.75	58.65	58.75	45.99
WCS (C$/bbl)	**50.58**	39.09	**54.86**	47.93	49.98	49.39	46.65	41.03	41.61	26.41
Differential – WTI:WCS (US$/bbl)	**11.98**	13.84	**12.26**	9.94	11.13	14.58	14.32	13.50	13.30	14.24
Differential – WTI:WCS (%)	**23.5%**	31.9%	**22.1%**	20.6%	23.0%	28.1%	29.1%	30.0%	29.2%	42.6%
Condensate prices										
Condensate at Edmonton (C$/bbl)	**66.91**	56.21	**73.72**	59.59	65.16	69.17	64.49	56.25	56.83	47.27
Condensate at Edmonton as % of WTI	**101.2%**	97.9%	**104.6%**	98.7%	100.3%	100.7%	98.1%	95.9%	96.7%	102.8%
Condensate at Mont Belvieu, Texas (US$/bbl)	**48.14**	39.68	**55.35**	46.37	44.77	46.05	45.17	41.17	40.37	32.03
Condensate at Mont Belvieu, Texas as % of WTI	**94.5%**	91.6%	**99.9%**	96.2%	92.7%	88.7%	91.6%	91.6%	88.6%	95.8%
Natural gas prices										
AECO (C$/mcf)	**2.29**	2.25	**1.84**	1.58	2.81	2.91	3.31	2.49	1.37	1.82
Electric power prices										
Alberta power pool (C$/MWh)	**22.17**	18.19	**22.49**	24.55	19.26	22.38	21.97	17.93	14.77	18.09
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.2980**	1.3256	**1.2717**	1.2524	1.3449	1.3230	1.3339	1.3051	1.2886	1.3748
C$ equivalent of 1 US$ - period end	**1.2518**	1.3427	**1.2518**	1.2510	1.2977	1.3322	1.3427	1.3117	1.3009	1.2971

Crude Oil Prices

Brent crude is the primary world price benchmark for global light sweet crude oil. The Brent benchmark price averaged US$61.54 per barrel in the fourth quarter of 2017 compared to US$51.13 per barrel in the fourth quarter of 2016. The Brent benchmark price averaged US$54.83 per barrel for the year ended December 31, 2017 compared to US$44.97 per barrel for the year ended December 31, 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 the royalty rate on the Corporation's bitumen sales. The WTI price averaged US$55.40 per barrel in the fourth quarter of 2017 compared to US$49.29 in the fourth quarter of 2016. The WTI price averaged US$50.95 per barrel for the year ended December 31, 2017 compared to US$43.33 per barrel for the year ended December 31, 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 narrowed to US$12.26 per barrel, or 22.1%, for the fourth quarter of 2017, compared to US$14.32 per barrel, or 29.1% for the fourth quarter of 2016 due to higher demand for Canadian heavy oil from U.S. Gulf Coast refineries. The WTI:WCS differential averaged US$11.98 per barrel, or 23.5%, for the year ended December 31, 2017 compared to US$13.84 per barrel, or 31.9%, for the year ended December 31, 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 $73.72 per barrel, or 104.6% of WTI, for the fourth quarter of 2017 compared to $64.49 per barrel, or 98.1% of WTI, for the fourth quarter of 2016. Condensate prices, benchmarked at Edmonton, averaged $66.91 per barrel, or 101.2% of WTI, for the year ended December 31, 2017 compared to $56.21 per barrel, or 97.9% of WTI, for the year ended December 31, 2016.

Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$55.35 per barrel , or 99.9% of WTI, for the fourth quarter of 2017 compared to US$45.17 per barrel, or 91.6% of WTI, for the fourth quarter of 2016. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$48.14 per barrel, or 94.5% of WTI, for the year ended December 31, 2017 compared to US$39.68 per barrel, or 91.6% of WTI, for the year ended December 31, 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 $1.84 per mcf for the fourth quarter of 2017 compared to $3.31 per mcf for the fourth quarter of 2016.

The AECO natural gas price averaged $2.29 per mcf for the year ended December 31, 2017 compared to $2.25 per mcf for the year ended December 31, 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 $22.49 per megawatt hour for the fourth quarter of 2017 compared to $21.97 per megawatt hour for the fourth quarter of 2016. The Alberta power pool price averaged $22.17 per megawatt hour for the year ended December 31, 2017 compared to $18.19 per megawatt hour for the year ended December 31, 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 December 31, 2017, the Canadian dollar, at a rate of 1.2518, 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.

OTHER OPERATING RESULTS

Net Marketing Activity

	Three months ended December 31		Year ended December 31	
($000)	**2017**	**2016**	**2017**	**2016**
Petroleum revenue – third party	**$ 41,558**	$ 50,952	**$ 253,486**	$ 205,790
Purchased product and storage	**(40,759)**	(50,497)	**(250,681)**	(202,135)
Net marketing activity[1]	**$ 799**	$ 455	**$ 2,805**	$ 3,655

(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 December 31		Year ended December 31	
($000)	**2017**	**2016**	**2017**	**2016**
Depletion and depreciation expense	**$ 118,406**	$ 126,471	**$ 475,644**	$ 499,811
Depletion and depreciation expense per barrel of production	**$ 14.26**	$ 16.81	**$ 16.13**	$ 16.81

Depletion and depreciation expense decreased for both the three months and year-ended December 31, 2017 compared to 2016, primarily due to a significant reduction in estimated future development costs associated with the Corporation's proved reserves. Future development costs are derived from the Corporation's independent reserve report and are a key element of the rate determination. The decrease in future development costs is primarily related to the Corporation's future growth strategy, which anticipates reduced capital requirements to produce the reserves.

Impairment

There were no impairments recognized in 2017. 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 6, 2016 directive from the Government of Canada to the National Energy Board ("NEB") to dismiss the project application. As a result, the Corporation fully impaired its investment and recognized a fourth quarter 2016 impairment charge of $80.1 million.

Commodity Risk Management Gain (Loss)

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 December 31					
($000)	**2017**			**2016**		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Crude oil contracts[1]	**$ (23,378)**	**$ (44,177)**	**$ (67,555)**	$ (4,071)	$ (40,293)	$(44,364)
Condensate contracts[2]	**16,706**	**(13,512)**	**3,194**	6,789	(1,756)	5,033
Commodity risk management gain (loss)	**$ (6,672)**	**$ (57,689)**	**$ (64,361)**	$ 2,718	$ (42,049)	$(39,331)

The Corporation realized a net loss on commodity risk management contracts of $6.7 million for the three months ended December 31, 2017, due to settlement losses on contracts relating to crude oil sales, partially offset by settlement gains on contracts relating to condensate purchases. This compares to a gain of $2.7 million for the three months ended December 31, 2016.

The Corporation recognized an unrealized loss on commodity risk management contracts of $57.7 million for the three months ended December 31, 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. This was partially offset by unrealized gains on WCS fixed differential contracts, due to a widening of the WCS forward differentials. The $57.7 million unrealized loss for the three months ended December 31, 2017 compares to a $42.0 million unrealized loss for the comparative 2016 quarter. Refer to the “Risk Management” section of this Fourth Quarter Report for further details.

	Year ended December 31					
($000)	**2017**			**2016**		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Crude oil contracts[1]	**$ (53,364)**	**$ (9,245)**	**$ (62,609)**	$ (9,888)	$ (59,404)	$(69,292)
Condensate contracts[2]	**42,091**	**(29,091)**	**13,000**	12,247	29,091	41,338
Commodity risk management gain (loss)	**$ (11,273)**	**$ (38,336)**	**$ (49,609)**	$ 2,359	$ (30,313)	$(27,954)

(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 net loss on commodity risk management contracts of $11.3 million for the year ended December 31, 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 realized net gain of $2.4 million for the year ended December 31, 2016.

The Corporation recognized an unrealized loss on commodity risk management contracts of $38.3 million for the year ended December 31, 2017, reflecting unrealized losses on condensate purchase contracts and crude oil contracts. Crude oil benchmark forward prices increased over the period, resulting in unrealized losses on the Corporation's WTI fixed price contracts and collars. This was partially offset by unrealized gains on WCS fixed differential contracts, due to a widening of WCS forward differentials. The $38.3 million unrealized loss in 2017 compares to a $30.3 million unrealized loss in 2016. Refer to the "Risk Management" section of this Fourth Quarter Report for further details.

General and Administrative

	Three months ended December 31		Year ended December 31	
($000)	**2017**	**2016**	**2017**	**2016**
General and administrative expense	**$ 23,303**	$ 21,570	**$ 86,785**	$ 96,241
General and administrative expense per barrel of production	**$ 2.81**	$ 2.87	**$ 2.94**	$ 3.24

General and administrative expense per barrel of production has decreased for the quarter and year ended December 31, 2017 in relation to the comparative 2016 periods. Workforce reductions and the Corporation's continued focus on cost management have decreased expenses on an annual basis.

Stock-based Compensation

	Three months ended December 31		Year ended December 31	
($000)	**2017**	**2016**	**2017**	**2016**
Cash-settled expense	**$ (83)**	$ 10,859	**$ 3,476**	$ 16,354
Equity-settled expense	**5,288**	5,650	**19,052**	33,588
Stock-based compensation	**$ 5,205**	$ 16,509	**$ 22,528**	$ 49,942

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 December 31, 2017 was $5.2 million compared to $16.5 million for the three months ended December 31, 2016. This decrease was primarily the result of a decrease in the fair value of the cash-settled units due to the decrease in the Corporation's common share price during the three months ended December 31, 2017.

Stock-based compensation expense for the year ended December 31, 2017 was $22.5 million compared to $49.9 million for the year ended December 31, 2016. The decrease is primarily due to a decrease in the fair value of cash-settled units due to the decrease in the Corporation's common share price during 2017 in combination with a decrease in equity-settled share-based compensation expense. The Corporation commenced issuing RSUs and PSUs under a cash-settled plan in 2016.

Research and Development

	Three months ended December 31		Year ended December 31	
($000)	**2017**	**2016**	**2017**	**2016**
Research and development expense	**$ 2,403**	$ 1,139	**$ 5,808**	$ 5,499

Research and development expenditures related to the Corporation's research of crude quality improvement and related technologies have been expensed.

Foreign Exchange Gain (Loss), Net

	Three months ended December 31		Year ended December 31	
($000)	**2017**	**2016**	**2017**	**2016**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ (3,101)**	$ (117,451)	**$ 343,633**	$ 157,272
Other	**(3,871)**	(2,159)	**(5,489)**	(9,119)
Unrealized net gain (loss) on foreign exchange	**(6,972)**	(119,610)	**338,144**	148,153
Realized gain (loss) on foreign exchange	**1,112**	(611)	**4,403**	3,242
Foreign exchange gain (loss), net	**$ (5,860)**	$ (120,221)	**$ 342,547**	$ 151,395
C$ equivalent of 1 US$				
Beginning of period	**1.2510**	1.3117	**1.3427**	1.3840
End of period	**1.2518**	1.3427	**1.2518**	1.3427

The net foreign exchange gains and losses are primarily due to the translation of the U.S. dollar denominated debt as a result of the strengthening or weakening of the Canadian dollar compared to the U.S. dollar during each period.

The net foreign exchange loss of $5.9 million in the fourth quarter of 2017 was a result of a slight weakening of the Canadian dollar compared to the U.S. dollar. In comparison, during the fourth quarter of 2016, the Canadian dollar weakened more significantly, resulting in a net foreign exchange loss of $120.2 million.

For the years ended December 31, 2017 and 2016, the Canadian dollar strengthened by 7% and 3%, respectively. This resulted in a net foreign exchange gain of $342.5 million in 2017 compared to a net foreign exchange gain of $151.4 million in 2016.

Net Finance Expense

($000)	Three months ended December 31 2017	2016	Year ended December 31 2017	2016
Total interest expense	**$ 82,298**	$ 82,469	**$ 341,594**	$ 328,335
Debt extinguishment expense	**-**	28,845	**-**	28,845
Accretion on provisions	**2,085**	1,840	**7,760**	7,150
Unrealized loss (gain) on derivative financial liabilities[1]	**(8,833)**	(7,146)	**(16,179)**	(12,508)
Realized loss on interest rate swaps	**1,007**	-	**1,028**	4,548
Net finance expense	**$ 76,557**	$ 106,008	**$ 334,203**	$ 356,370
Average effective interest rate[2]	**6.1%**	5.7%	**6.1%**	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 December 31, 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 year ended December 31, 2017 was $341.6 million compared to $328.3 million for the year ended December 31, 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 during the first quarter of 2017. 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 "Capital Resources" section of this Fourth Quarter Report.

At December 31, 2016, the Corporation recognized $28.8 million of debt extinguishment expense associated with the planned redemption of the 6.5% Senior Unsecured Notes on March 15, 2017, under the comprehensive refinancing plan completed on January 27, 2017, as described in the "Capital Resources" section of this Fourth Quarter Report.

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 $8.8 million for the three months ended December 31, 2017 compared to an unrealized gain of $7.1 million for the three months ended December 31, 2016. The Corporation recognized an unrealized gain on derivative financial liabilities of $16.2 million for the year ended December 31, 2017 compared to an unrealized gain of $12.5 million for the year ended December 31, 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 commenced September 29, 2017 and expires on December 31, 2020. The Corporation realized a loss on the interest rate swaps of $1.0 million for the three months and year ended December 31, 2017.

In 2016, the Corporation realized a loss on interest rate swaps of $4.5 million. These swap contracts effectively 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 December 31		Year ended December 31	
($000)	**2017**	**2016**	**2017**	**2016**
Contract cancellation expense	**$ -**	$ -	**$ 18,765**	$ -
Onerous contracts	**5,149**	16,383	**10,830**	47,866
Severance and other	**250**	10,063	**5,231**	16,242
Other expenses	**$ 5,399**	$ 26,446	**$ 34,826**	$ 64,108

During the third quarter of 2017, the Corporation recognized contract cancellation expense of $18.8 million relating to the termination of a long-term transportation contract.

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.

Income Tax Expense (Recovery)

	Three months ended December 31		Year ended December 31	
($000)	**2017**	**2016**	**2017**	**2016**
Current income tax expense (recovery)	**$ 359**	$ 202	**$ (67)**	$ 919
Deferred income tax expense (recovery)	**2,455**	(67,620)	**(47,813)**	(208,413)
Income tax expense (recovery)	**$ 2,814**	$ (67,418)	**$ (47,880)**	$ (207,494)

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 December 31, 2017, the Corporation had approximately $8.4 billion of available Canadian tax pools.

For the year ended December 31, 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 $0.7 million related to its operations in the United States.

The Corporation recognized a deferred income tax expense of $2.5 million for the three months ended December 31, 2017 compared to a deferred income tax recovery of $67.6 million for the three months ended December 31, 2016. The Corporation recognized a deferred income tax recovery of $47.8 million for the year ended December 31, 2017 and a deferred income tax recovery of $208.4 million for the year ended December 31, 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 December 31, 2017, the non-taxable net loss was $1.5 million compared to a non-taxable loss of $58.7 million for the three months ended December 31, 2016. For the year ended December 31, 2017, the non-taxable net gain was $171.9 million compared to a non-taxable gain of $78.6 million for the year ended December 31, 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 December 31, 2017 was $5.3 million compared to $5.7 million for the three months ended December 31, 2016. Stock-based compensation expense for equity-settled plans for the year ended December 31, 2017 was $19.1 million compared to $33.6 million for the year ended December 31, 2016.

As at December 31, 2017, the Corporation has recognized a deferred income tax asset of $174.6 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 December 31, 2017, the Corporation had not recognized the tax benefit related to $445.7 million of realized and unrealized taxable foreign exchange losses.

NET CAPITAL INVESTMENT

	Three months ended December 31		Year ended December 31	
($000)	**2017**	**2016**	**2017**	**2016**
Total cash capital investment	**$ 163,337**	$ 63,077	**$ 502,754**	$ 137,245
Capitalized cash-settled stock-based compensation	**(49)**	1,772	**(308)**	2,491
	$ 163,288	$ 64,849	**$ 502,446**	$ 139,736

Total cash capital investment for the three months ended December 31, 2017 was $163.3 million, compared to $63.1 million for the three months ended December 31, 2016. Total cash capital investment for the year ended December 31, 2017 was $502.8 million as compared to $137.2 million for the year ended December 31, 2016. During 2017, the Corporation invested $223.0 million in the eMSAGP growth project at Christina Lake Phase 2B, $189.3 million in sustaining capital activities, and $90.5 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 months and year ended December 31, 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.

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 December 31, 2017	Volumes (bbls/d) [1]	Term	Average Price (US$/bbl) [1]
Fixed Price:			
WTI Fixed Price	30,675	Jan 1, 2018 – Jun 30, 2018	$52.89
WTI Fixed Price	22,500	Jul 1, 2018 – Dec 31, 2018	$52.72
WTI:WCS Fixed Differential	48,750	Jan 1, 2018 – Jun 30, 2018	$(14.43)
WTI:WCS Fixed Differential	32,000	Jul 1, 2018 – Dec 31, 2018	$(14.68)
Collars:			
WTI Collars	41,500	Jan 1, 2018 – Jun 30, 2018	$46.71 – $54.97
WTI Collars	32,500	Jul 1, 2018 – Dec 31, 2018	$46.64 – $54.52

The Corporation has entered into the following commodity risk management contracts relating to crude oil sales subsequent to December 31, 2017 up to the date of February 7, 2018:

Subsequent to December 31, 2017	Volumes (bbls/d) [1]	Term	Average Price (US$/bbl) [1]
Fixed Price:			
WTI Fixed Price	3,000	Apr 1, 2018 – Jun 30, 2018	$63.82
WTI Fixed Price	11,500	Jul 1, 2018 – Dec 31, 2018	$60.20

The Corporation has entered into the following financial commodity risk management contracts relating to condensate purchases subsequent to December 31, 2017 up to the date of February 7, 2018:

Subsequent to December 31, 2017	Volumes (bbls/d) [1]	Term	Average % of WTI[1]
Mont Belvieu fixed % of WTI	1,000	Apr 1, 2018 – Jun 30, 2018	92.3%
Mont Belvieu fixed % of WTI	500	Jul 1, 2018 – Sep 30, 2018	93.5%

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

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 effectively 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 first nine months of 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.

NON-GAAP MEASURES

Certain financial measures in this Fourth Quarter Report 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 December 31		Year ended December 31	
($000)	2017	2016	2017	2016
Net cash provided by (used in) operating activities	$ 200,538	$ 82,621	$ 317,935	$ (94,074)
Net change in non-cash operating working capital items	(4,405)	(43,636)	24,517	25,061
Funds flow from (used in) operations	196,133	38,985	342,452	(69,013)
Adjustments:				
Contract cancellation expense	-	-	18,765	-
Net change in other liabilities	(9,389)	(718)	(9,389)	-
Payments on onerous contracts	4,878	1,505	19,569	6,116
Decommissioning expenditures	556	195	2,403	1,290
Adjusted funds flow from (used in) operations	$ 192,178	$ 39,967	$ 373,800	$ (61,607)

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, impairment charge, contract cancellation expense, onerous contracts expense, debt extinguishment 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 December 31		Year ended December 31	
($000)	2017	2016	2017	2016
Net earnings (loss)	$ (1,295)	$ (304,758)	$ 188,460	$ (428,726)
Adjustments:				
Unrealized net loss (gain) on foreign exchange(1)	6,972	119,610	(338,144)	(148,153)
Unrealized loss (gain) on derivative financial liabilities(2)	(8,833)	(7,146)	(16,179)	(12,508)
Unrealized loss (gain) on commodity risk management(3)	57,689	42,049	38,336	30,313
Impairment charge(4)	-	80,072	-	80,072
Contract cancellation expense(5)	-	-	18,765	-
Onerous contracts expense(6)	5,149	16,383	10,830	47,866
Debt extinguishment expense(7)	-	28,845	-	28,845
Insurance proceeds	-	(4,391)	(183)	(4,391)
Deferred tax expense (recovery) relating to these adjustments	(15,627)	(42,653)	(15,409)	(48,416)
Operating earnings (loss)	$ 44,055	$ (71,989)	$ (113,524)	$ (455,098)

(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 fourth quarter of 2016, the Corporation recognized an impairment charge of $80.1 million relating to an investment in the right to participate in the Northern Gateway pipeline.*
(5) *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 transportation contract.*
(6) *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.*
(7) *At December 31, 2016, the Corporation recognized $28.8 million of debt extinguishment expense associated with the planned redemption of the 6.5% Senior Unsecured Notes on March 15, 2017, under the comprehensive refinancing plan completed on January 27, 2017.*

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.

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
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

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.

Non-GAAP Financial Measures

Certain financial measures in this Fourth Quarter Report 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) and operating cash flow. 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 Fourth Quarter Report.

QUARTERLY SUMMARIES

	2017				2016			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL ($000 unless specified)								
Net earnings (loss)	**(1,295)**	83,885	104,282	1,588	(304,758)	(108,632)	(146,165)	130,829
Per share, diluted	**(0.00)**	0.28	0.35	0.01	(1.34)	(0.48)	(0.65)	0.58
Operating earnings (loss)	**44,055**	(42,571)	(35,656)	(79,354)	(71,989)	(87,929)	(97,894)	(197,286)
Per share, diluted	**0.15**	(0.14)	(0.12)	(0.29)	(0.32)	(0.39)	(0.43)	(0.88)
Adjusted funds flow from (used in) operations	**192,178**	83,352	55,095	43,175	39,967	22,702	6,964	(131,240)
Per share, diluted	**0.65**	0.28	0.19	0.16	0.18	0.10	0.03	(0.58)
Cash capital investment	**163,337**	103,173	158,474	77,770	63,077	19,203	19,990	34,975
Cash and cash equivalents	**463,531**	397,598	512,424	548,981	156,230	103,136	152,711	124,560
Working capital	**313,025**	350,067	445,463	537,427	96,442	163,038	128,586	183,649
Long-term debt	**4,637,466**	4,635,740	4,813,092	4,944,741	5,053,239	4,909,711	4,871,182	4,859,099
Shareholders' equity	**3,986,597**	3,981,750	3,898,054	3,792,818	3,286,776	3,577,557	3,679,372	3,812,566
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**55.40**	48.21	48.29	51.91	49.29	44.94	45.59	33.45
C$ equivalent of 1US$ - average	**1.2717**	1.2524	1.3449	1.3230	1.3339	1.3051	1.2886	1.3748
Differential – WTI:WCS (C$/bbl)	**15.59**	12.45	14.97	19.29	19.10	17.62	17.14	19.58
Differential – WTI:WCS (%)	**22.1%**	20.6%	23.0%	28.1%	29.1%	30.0%	29.2%	42.6%
Natural gas – AECO ($/mcf)	**1.84**	1.58	2.81	2.91	3.31	2.49	1.37	1.82
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**90,228**	83,008	72,448	77,245	81,780	83,404	83,127	76,640
Bitumen sales – bbls/d	**94,541**	76,813	74,116	74,703	81,746	84,817	80,548	74,529
Steam-oil ratio (SOR)	**2.2**	2.3	2.3	2.4	2.3	2.2	2.3	2.4
Bitumen realization	**48.30**	39.89	39.66	37.93	36.17	30.98	30.93	11.43
Transportation – net	**(7.00)**	(7.08)	(6.91)	(6.54)	(6.05)	(6.46)	(6.66)	(6.68)
Royalties	**(0.84)**	(0.53)	(0.87)	(0.85)	(0.51)	(0.42)	(0.27)	0.07
Operating costs – non-energy	**(4.53)**	(4.57)	(4.23)	(5.20)	(4.99)	(5.32)	(5.81)	(6.45)
Operating costs – energy	**(2.03)**	(2.26)	(3.76)	(4.18)	(4.12)	(2.99)	(1.97)	(2.90)
Power revenue	**0.70**	0.83	0.57	0.95	0.87	0.55	0.35	0.82
Realized gain (loss) on commodity risk management	**(0.77)**	0.56	(1.50)	0.22	0.36	0.40	(0.48)	-
Cash operating netback	**33.83**	26.84	22.96	22.33	21.73	16.74	16.09	(3.71)
Power sales price (C$/MWh)	**21.37**	23.29	18.27	22.42	21.94	17.62	13.54	19.77
Power sales (MW/h)	**129**	115	97	131	134	110	86	129
Depletion and depreciation rate per bbl of production	**14.26**	16.86	16.93	16.81	16.81	16.81	16.84	16.78
COMMON SHARES								
Shares outstanding, end of period (000)	**294,104**	294,079	294,047	293,282	226,467	226,415	226,357	224,997
Volume traded (000)	**76,531**	70,216	98,795	123,445	114,776	112,720	157,056	182,199
Common share price ($)								
High	**6.82**	5.79	7.27	9.83	9.79	6.90	7.86	8.26
Low	**4.54**	3.28	3.63	5.84	5.11	4.72	5.21	3.46
Close (end of period)	**5.14**	5.49	3.81	6.74	9.23	5.93	6.84	6.55

Interim Consolidated Financial Statements

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

As at December 31	Note		2017		2016
Assets					
Current assets					
Cash and cash equivalents	19	**$**	**463,531**	$	156,230
Trade receivables and other			**289,104**		236,989
Inventories			**85,850**		66,394
			838,485		459,613
Non-current assets					
Property, plant and equipment	4		**7,634,399**		7,639,434
Exploration and evaluation assets	5		**548,828**		547,752
Other intangible assets	6		**13,037**		16,111
Other assets	7		**145,732**		137,370
Deferred income tax asset	18		**174,554**		120,944
Total assets		**$**	**9,355,035**	$	8,921,224
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities		**$**	**413,905**	$	292,340
Current portion of long-term debt	8		**15,460**		17,455
Current portion of provisions and other liabilities	9		**27,446**		23,063
Commodity risk management	21		**68,649**		30,313
			525,460		363,171
Non-current liabilities					
Long-term debt	8		**4,637,466**		5,053,239
Provisions and other liabilities	9		**205,512**		218,038
Total liabilities			**5,368,438**		5,634,448
Shareholders’ equity					
Share capital	10		**5,403,978**		4,878,607
Contributed surplus			**166,636**		168,253
Deficit			**(1,606,607)**		(1,795,067)
Accumulated other comprehensive income			**22,590**		34,983
Total shareholders’ equity			**3,986,597**		3,286,776
Total liabilities and shareholders’ equity		**$**	**9,355,035**	$	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 December 31		Year ended December 31	
	Note	**2017**	**2016**	**2017**	**2016**
Revenues					
Petroleum revenue, net of royalties	12	**$ 745,110**	$ 550,267	**$ 2,399,510**	$ 1,823,234
Other revenue	13	**9,706**	15,504	**35,193**	43,050
		754,816	565,771	**2,434,703**	1,866,284
Expenses					
Diluent and transportation	14	**355,220**	281,275	**1,158,414**	1,017,894
Operating expenses		**57,050**	68,525	**222,196**	253,758
Purchased product and storage		**40,759**	50,497	**250,681**	202,135
Depletion and depreciation	4,6	**118,406**	126,471	**475,644**	499,811
Impairment charge	6	**-**	80,072	**-**	80,072
Exploration expense	5	**-**	-	**-**	1,248
General and administrative		**23,303**	21,570	**86,785**	96,241
Stock-based compensation	11	**5,205**	16,509	**22,528**	49,942
Research and development		**2,403**	1,139	**5,808**	5,499
Net finance expense	16	**76,557**	106,008	**334,203**	356,370
Other expenses	17	**5,399**	26,446	**34,826**	64,108
Interest and other income		**(1,226)**	(117)	**(4,024)**	(1,133)
Commodity risk management loss (gain)	21	**64,361**	39,331	**49,609**	27,954
Foreign exchange loss (gain), net	15	**5,860**	120,221	**(342,547)**	(151,395)
Earnings (loss) before income taxes		**1,519**	(372,176)	**140,580**	(636,220)
Income tax expense (recovery)	18	**2,814**	(67,418)	**(47,880)**	(207,494)
Net earnings (loss)		**(1,295)**	(304,758)	**188,460**	(428,726)
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**126**	7,727	**(12,393)**	(590)
Comprehensive income (loss) for the period		**$ (1,169)**	$ (297,031)	**$ 176,067**	$ (429,316)
Net earnings (loss) per common share					
Basic	20	**$ (0.00)**	$ (1.34)	**$ 0.65**	$ (1.90)
Diluted	20	**$ (0.00)**	$ (1.34)	**$ 0.65**	$ (1.90)

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		**-**	**21,636**	**-**	**-**	**21,636**
RSUs and PSUs vested and released	10	**23,253**	**(23,253)**	**-**	**-**	**-**
Comprehensive income (loss)		**-**	**-**	**188,460**	**(12,393)**	**176,067**
Balance as at December 31, 2017		**$ 5,403,978**	**$ 166,636**	**$ (1,606,607)**	**$ 22,590**	**$ 3,986,597**
Balance as at December 31, 2015		$ 4,836,800	$ 171,835	$ (1,366,341)	$ 35,573	$ 3,677,867
Stock-based compensation		-	38,225	-	-	38,225
RSUs and PSUs vested and released		41,807	(41,807)	-	-	-
Comprehensive income (loss)		-	-	(428,726)	(590)	(429,316)
Balance as at December 31, 2016		$ 4,878,607	$ 168,253	$ (1,795,067)	$ 34,983	$ 3,286,776

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 December 31		Year ended December 31	
	Note	**2017**	**2016**	**2017**	**2016**
Cash provided by (used in):					
Operating activities					
Net earnings (loss)		**$ (1,295)**	$ (304,758)	**$ 188,460**	$ (428,726)
Adjustments for:					
Depletion and depreciation	4,6	**118,406**	126,471	**475,644**	499,811
Impairment charge	6	**-**	80,072	**-**	80,072
Exploration expense	5	**-**	-	**-**	1,248
Stock-based compensation	11	**5,288**	5,650	**19,052**	33,588
Unrealized loss (gain) on foreign exchange	15	**6,972**	119,610	**(338,144)**	(148,153)
Unrealized loss (gain) on derivative financial liabilities	16	**(8,833)**	(7,146)	**(16,179)**	(12,508)
Unrealized loss (gain) on risk management	21	**57,689**	42,049	**38,336**	30,313
Onerous contracts expense	17	**5,149**	16,383	**10,830**	47,866
Deferred income tax expense (recovery)	18	**2,455**	(67,620)	**(47,813)**	(208,413)
Amortization of debt discount and debt issue costs	7,8	**4,750**	3,090	**19,225**	12,192
Debt extinguishment expense	8,16	**-**	28,845	**-**	28,845
Other		**1,597**	(2,679)	**5,624**	2,258
Decommissioning expenditures	9	**(556)**	(195)	**(2,403)**	(1,290)
Payments on onerous contracts	9	**(4,878)**	(1,505)	**(19,569)**	(6,116)
Net change in other liabilities		**9,389**	718	**9,389**	-
Net change in non-cash working capital items	19	**4,405**	43,636	**(24,517)**	(25,061)
Net cash provided by (used in) operating activities		**200,538**	82,621	**317,935**	(94,074)
Investing activities					
Capital investments:					
Property, plant and equipment	4	**(162,955)**	(51,145)	**(505,713)**	(120,828)
Exploration and evaluation	5	**(317)**	(414)	**(1,569)**	(2,265)
Other intangible assets	6	**(405)**	(13,290)	**(534)**	(16,643)
Proceeds on dispositions	4	**389**	3,247	**5,370**	3,247
Deferred lease inducements and other	9	**(890)**	3,012	**20,983**	2,775
Net change in non-cash working capital items	19	**37,571**	34,906	**76,232**	2,603
Net cash used in investing activities		**(126,607)**	(23,684)	**(405,231)**	(131,111)
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	**(3,943)**	(4,364)	**(12,690)**	(17,062)
Refinancing costs	19	**-**	-	**(82,377)**	-
Net cash provided by (used in) financing activities		**(3,943)**	(4,364)	**401,245**	(17,062)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(4,055)**	(1,479)	**(6,648)**	(9,736)
Change in cash and cash equivalents		**65,933**	53,094	**307,301**	(251,983)
Cash and cash equivalents, beginning of period		**397,598**	103,136	**156,230**	408,213
Cash and cash equivalents, end of period		**$ 463,531**	$ 156,230	**$ 463,531**	$ 156,230

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 February 7, 2018.

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 and is in the process of planning and identifying leases that are within the scope of the standard. 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 has substantially completed its assessment and evaluation of the underlying terms of its revenue contracts with customers and has determined that adoption of the standard will not 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, and will be applied prospectively as required by the standard. 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, 2015	$ 7,768,244	$ 1,605,547	$ 51,076	$ 9,424,867
Additions	115,832	4,544	4,907	125,283
Dispositions	(3,641)	-	-	(3,641)
Change in decommissioning liabilities	(2,426)	27	-	(2,399)
Balance as at December 31, 2016	$ 7,878,009	$ 1,610,118	$ 55,983	$ 9,544,110
Additions	478,782	8,645	20,465	507,892
Dispositions	(24,102)	-	-	(24,102)
Change in decommissioning liabilities	(34,599)	(922)	-	(35,521)
Balance as at December 31, 2017	**$ 8,298,090**	**$ 1,617,841**	**$ 76,448**	**$ 9,992,379**
Accumulated depletion and depreciation				
Balance as at December 31, 2015	$ 1,310,669	$ 80,340	$ 22,098	$ 1,413,107
Depletion and depreciation	459,681	30,493	5,036	495,210
Dispositions	(3,641)	-	-	(3,641)
Balance as at December 31, 2016	$ 1,766,709	$ 110,833	$ 27,134	$ 1,904,676
Depletion and depreciation	436,271	29,801	5,964	472,036
Dispositions	(18,732)	-	-	(18,732)
Balance as at December 31, 2017	**$ 2,184,248**	**$ 140,634**	**$ 33,098**	**$ 2,357,980**
Carrying amounts				
Balance as at December 31, 2016	$ 6,111,300	$ 1,499,285	$ 28,849	$ 7,639,434
Balance as at December 31, 2017	**$ 6,113,842**	**$ 1,477,207**	**$ 43,350**	**$ 7,634,399**

As at December 31, 2017, no impairment has been recognized on property, plant and equipment.

5. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2015	$	546,421
Additions		2,265
Exploration expense		(1,248)
Change in decommissioning liabilities		314
Balance as at December 31, 2016	$	547,752
Additions		1,569
Change in decommissioning liabilities		(493)
Balance as at December 31, 2017	**$**	**548,828**

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 December 31, 2017, no impairment has been recognized on exploration and evaluation assets.

6. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2015	$	96,278
Additions		16,643
Balance as at December 31, 2016	$	112,921
Additions		534
Balance as at December 31, 2017	**$**	**113,455**

Accumulated depreciation		
Balance as at December 31, 2015	$	12,136
Impairment		80,072
Depreciation		4,602
Balance as at December 31, 2016	$	96,810
Depreciation		3,608
Balance as at December 31, 2017	**$**	**100,418**

Carrying amounts		
Balance as at December 31, 2016	$	16,111
Balance as at December 31, 2017	**$**	**13,037**

As at December 31, 2017, other intangible assets consist of $13.0 million invested in software that is not an integral component of the related computer hardware (December 31, 2016 – $16.1 million). No impairment has been recognized on other intangible assets for the year ended December 31, 2017.

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 and recognized a fourth quarter 2016 impairment charge of $80.1 million.

7. OTHER ASSETS

As at December 31		2017		2016
Long-term pipeline linefill[a]	$	**122,657**	$	129,733
Deferred financing costs[b]		**24,134**		12,001
Interest rate swap[c]		**8,067**		-
		154,858		141,734
Less current portion		**(9,126)**		(4,364)
	$	**145,732**	$	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 December 31, 2017, no impairment has been recognized on these assets.

(b) During the year ended December 31, 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 commenced 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 December 31		2017		2016
Senior secured term loan (December 31, 2017 – US$1.226 billion; due 2023; December 31, 2016 – US$1.236 billion)[a]	$	**1,534,378**	$	1,658,906
6.5% senior secured second lien notes (US$750.0 million; due 2025)[b]		**938,850**		-
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)		**1,001,440**		1,074,160
7.0% senior unsecured notes (US$1.0 billion; due 2024)		**1,251,800**		1,342,700
		4,726,468		5,082,791
Less unamortized financial derivative liability discount		**(18,048)**		(11,143)
Less unamortized deferred debt discount and debt issue costs[a][b]		**(55,494)**		(22,766)
Debt redemption premium[c]		**-**		21,812
		4,652,926		5,070,694
Less current portion of senior secured term loan		**(15,460)**		(17,455)
	$	**4,637,466**	$	5,053,239

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2518 (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 December 31, 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 December 31, 2017, letters of credit of US$258.4 million were issued and outstanding 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.

    As at December 31, 2017, the senior secured credit facilities are comprised of a US$1.226 billion term loan and a US$1.4 billion revolving credit facility. The senior secured credit facilities are secured by substantially all the assets of the Corporation.

(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 December 31		2017		2016
Decommissioning provision[a]	**$**	**102,530**	$	133,924
Onerous contracts provision[b]		**92,157**		100,159
Derivative financial liabilities[c]		**6,028**		3,714
Deferred lease inducements and other[d]		**32,243**		3,304
Provisions and other liabilities		**232,958**		241,101
Less current portion		**(27,446)**		(23,063)
Non-current portion	**$**	**205,512**	$	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 December 31		2017		2016
Balance, beginning of year	**$**	**133,924**	$	130,381
Changes in estimated future cash flows		**(351)**		(91)
Changes in discount rates		**(19,602)**		4,436
Changes in estimated settlement dates		**(35,963)**		(10,553)
Liabilities incurred		**19,902**		4,123
Liabilities settled		**(2,403)**		(1,290)
Accretion		**7,023**		6,918
Balance, end of year		**102,530**		133,924
Less current portion		**(6,386)**		(3,097)
Non-current portion	**$**	**96,144**	$	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 9.5% (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 December 31		2017		2016
Balance, beginning of year	**$**	**100,159**	$	58,178
Changes in estimated future cash flows		**13,337**		40,499
Changes in discount rates		**(2,507)**		(1,478)
Liabilities incurred		**-**		8,845
Liabilities settled		**(19,569)**		(6,116)
Accretion		**737**		231
Balance, end of year		**92,157**		100,159
Less current portion		**(19,047)**		(18,930)
Non-current portion	**$**	**73,110**	$	81,229

As at December 31, 2017, the Corporation has recognized a provision of $92.2 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 1.8% (December 31, 2016 – 1.3%). This estimate may vary as a result of changes in estimated recoveries.

(c) Derivative financial liabilities:

As at December 31		2017		2016
1% interest rate floor	**$**	**6,028**	$	3,714
Less current portion		**(90)**		(517)
Non-current portion	**$**	**5,938**	$	3,197

(d) Deferred lease inducements and other:

During the year ended December 31, 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. In addition, the Corporation recognized a $9.4 million long-term liability to be settled in installments over the next four years.

10. SHARE CAPITAL

Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

Changes in issued common shares are as follows:

Year ended December 31	2017			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	**821,836**		**23,253**	1,470,118		41,807
Balance, end of year	**294,103,943**	**$**	**5,403,978**	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:

Year ended December 31, 2017	
Outstanding, beginning of year	**6,013,010**
Granted	**1,454,659**
Vested and released	**(1,467,027)**
Forfeited	**(690,569)**
Outstanding, end of year	**5,310,073**

ii. Deferred share units outstanding:

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

As at December 31, 2017, the Corporation has recognized a liability of $14.3 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.

Year ended December 31, 2017	**Stock options**		**Weighted average exercise price**
Outstanding, beginning of year	**9,281,186**	**$**	**27.45**
Granted	**1,211,880**		**4.57**
Forfeited	**(927,256)**		**27.78**
Expired	**(669,807)**		**33.81**
Outstanding, end of year	**8,896,003**	**$**	**23.81**

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:

Year ended December 31, 2017	
Outstanding, beginning of year	**1,655,606**
Granted	**5,756,580**
Vested and released	**(822,821)**
Forfeited	**(282,137)**
Outstanding, end of year	**6,307,228**

(c) Stock-based compensation

	Three months ended December 31				**Year ended December 31**			
		2017		**2016**		**2017**		**2016**
Cash-settled expense (recovery) (i)	**$**	**(83)**	$	10,859	**$**	**3,476**	$	16,354
Equity-settled expense		**5,288**		5,650		**19,052**		33,588
Stock-based compensation	**$**	**5,205**	$	16,509	**$**	**22,528**	$	49,942

(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 December 31		Year ended December 31	
	2017	**2016**	**2017**	**2016**
Petroleum revenue:				
Proprietary	**$ 710,817**	$ 503,176	**$ 2,168,602**	$ 1,626,025
Third-party[(a)]	**41,558**	50,952	**253,486**	205,790
Petroleum revenue	**752,375**	554,128	**2,422,088**	1,831,815
Royalties	**(7,265)**	(3,861)	**(22,578)**	(8,581)
Petroleum revenue, net of royalties	**$ 745,110**	$ 550,267	**$ 2,399,510**	$ 1,823,234

(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 December 31		Year ended December 31	
	2017	**2016**	**2017**	**2016**
Power revenue	**$ 6,105**	$ 6,508	**$ 22,209**	$ 18,868
Transportation revenue	**3,601**	4,605	**12,801**	19,791
Insurance proceeds	**-**	4,391	**183**	4,391
Other revenue	**$ 9,706**	$ 15,504	**$ 35,193**	$ 43,050

14. DILUENT AND TRANSPORTATION

	Three months ended December 31		Year ended December 31	
	2017	**2016**	**2017**	**2016**
Diluent expense	**$ 290,725**	$ 231,173	**$ 944,134**	$ 808,030
Transportation expense	**64,495**	50,102	**214,280**	209,864
Diluent and transportation	**$ 355,220**	$ 281,275	**$ 1,158,414**	$ 1,017,894

15. FOREIGN EXCHANGE LOSS (GAIN), NET

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Unrealized foreign exchange loss (gain) on:				
Long-term debt	$ 3,101	$ 117,451	$ (343,633)	$ (157,272)
Other	3,871	2,159	5,489	9,119
Unrealized net loss (gain) on foreign exchange	6,972	119,610	(338,144)	(148,153)
Realized loss (gain) on foreign exchange	(1,112)	611	(4,403)	(3,242)
Foreign exchange loss (gain), net	$ 5,860	$ 120,221	$ (342,547)	$ (151,395)

C$ equivalent of 1 US$				
Beginning of period	1.2510	1.3117	1.3427	1.3840
End of period	1.2518	1.3427	1.2518	1.3427

16. NET FINANCE EXPENSE

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Total interest expense	$ 82,298	$ 82,469	$ 341,594	$ 328,335
Debt extinguishment expense[(a)]	-	28,845	-	28,845
Accretion on provisions	2,085	1,840	7,760	7,150
Unrealized loss (gain) on derivative financial liabilities	(8,833)	(7,146)	(16,179)	(12,508)
Realized loss (gain) on interest rate swaps	1,007	-	1,028	4,548
Net finance expense	$ 76,557	$ 106,008	$ 334,203	$ 356,370

(a) At December 31, 2016, the Corporation recognized $28.8 million of debt extinguishment expense associated with the planned redemption of the 6.5% Senior Unsecured Notes on March 15, 2017, under the comprehensive refinancing plan completed on January 27, 2017 (Note 8). The debt extinguishment expense is comprised of a redemption premium of $21.8 million and the associated remaining unamortized deferred debt issue costs of $7.0 million.

17. OTHER EXPENSES

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Contract cancellation expense	$ -	$ -	$ 18,765	$ -
Onerous contracts expense	5,149	16,383	10,830	47,866
Severance and other	250	10,063	5,231	16,242
Other expenses	$ 5,399	$ 26,446	$ 34,826	$ 64,108

During the third quarter of 2017, the Corporation recognized an $18.8 million contract cancellation expense relating to the termination of a long-term transportation contract.

18. INCOME TAX EXPENSE (RECOVERY)

	Three months ended December 31		Year ended December 31	
	2017	2016	**2017**	2016
Current income tax expense (recovery)	**$ 359**	$ 202	**$ (67)**	$ 919
Deferred income tax expense (recovery)	**2,455**	(67,620)	**(47,813)**	(208,413)
Income tax expense (recovery)	**$ 2,814**	$ (67,418)	**$ (47,880)**	$ (207,494)

The Corporation has recognized a deferred tax asset of $174.6 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 December 31		Year ended December 31	
	2017	2016	**2017**	2016
Cash provided by (used in):				
Trade receivables and other	**$ (62,449)**	$ (25,435)	**$ (52,074)**	$ (83,601)
Inventories	**10,052**	1,915	**(19,591)**	(13,524)
Accounts payable and accrued liabilities	**94,373**	102,062	**123,380**	74,667
	$ 41,976	$ 78,542	**$ 51,715**	$ (22,458)
Changes in non-cash working capital relating to:				
Operating	**$ 4,405**	$ 43,636	**$ (24,517)**	$ (25,061)
Investing	**37,571**	34,906	**76,232**	2,603
	$ 41,976	$ 78,542	**$ 51,715**	$ (22,458)
Cash and cash equivalents:(a)				
Cash	**$ 276,023**	$ 156,230	**$ 276,023**	$ 156,230
Cash equivalents	**187,508**	-	**187,508**	-
	$ 463,531	$ 156,230	**$ 463,531**	$ 156,230
Cash interest paid	**$ 19,197**	$ 15,766	**$ 294,743**	$ 286,983

(a) As at December 31, 2017, C$201.0 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (December 31, 2016 – C$102.8 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$1.2518 (December 31, 2016 – US$1 = C$1.3427).

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	(12,690)
Non-cash changes:	
Unrealized loss (gain) on foreign exchange	(343,633)
Change in fair value of financial derivative liability	(10,426)
Amortization of financial derivative liability discount	3,520
Amortization of deferred debt discount and debt issue costs	7,391
Balance as at December 31, 2017	**$ 4,652,926**

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

(a) During the year ended December 31, 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 December 31		Year ended December 31	
	2017	**2016**	**2017**	**2016**
Net earnings (loss)	**$ (1,295)**	$ (304,758)	**$ 188,460**	$ (428,726)
Weighted average common shares outstanding[a]	**294,227,246**	226,617,057	**289,142,338**	225,982,724
Dilutive effect of stock options, RSUs and PSUs[b]	**-**	-	**116,583**	-
Weighted average common shares outstanding – diluted	**294,227,246**	226,617,057	**289,258,921**	225,982,724
Net earnings (loss) per share, basic	**$ (0.00)**	$ (1.34)	**$ 0.65**	$ (1.90)
Net earnings (loss) per share, diluted	**$ (0.00)**	$ (1.34)	**$ 0.65**	$ (1.90)

(a) Weighted average common shares outstanding for the year ended December 31, 2017 includes 139,863 PSUs not yet released (year ended December 31, 2016 – 184,425 PSUs).

(b) For the three months ended December 31, 2017, 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 ended December 31, 2017, the dilutive effect of stock options, RSUs and PSUs would have been 2,701,547 weighted average common shares. For the three months and year ended December 31, 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 year ended

December 31, 2016, the dilutive effect of stock options, RSUs and PSUs would have been 46,293 and 122,500 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, the interest rate swap 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 December 31, 2017, commodity risk management contracts, the interest rate swap and derivative financial 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:

As at December 31, 2017	Carrying amount	Fair value measurements using Level 1	Level 2	Level 3
Recurring measurements:				
Financial assets				
Interest rate swap (Note 7)	**$ 8,067**	**$ -**	**$ 8,067**	**$ -**
Financial liabilities				
Long-term debt[i] (Note 8)	**$ 4,726,468**	**$ -**	**$ 4,415,238**	**$ -**
Derivative financial liabilities (Note 9)	**$ 6,028**	**$ -**	**$ 6,028**	**$ -**
Commodity risk management contracts	**$ 68,649**	**$ -**	**$ 68,649**	**$ -**

As at December 31, 2016	Carrying amount	Fair value measurements using 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 December 31, 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 December 31, 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 December 31, 2017:

As at December 31, 2017	**Volumes (bbls/d)[(i)]**	**Term**	**Average Price (US$/bbl)[(i)]**
Fixed Price:			
WTI[(ii)] Fixed Price	30,700	Jan 1, 2018 – Jun 30, 2018	$52.89
WTI Fixed Price	22,500	Jul 1, 2018 – Dec 31, 2018	$52.72
WTI:WCS[(iii)] Fixed Differential	48,700	Jan 1, 2018 – Jun 30, 2018	$(14.43)
WTI:WCS Fixed Differential	32,000	Jul 1, 2018 – Dec 31, 2018	$(14.68)
Collars:			
WTI Collars	41,500	Jan 1, 2018 – Jun 30, 2018	$46.71 – $54.97
WTI Collars	32,500	Jul 1, 2018 – Dec 31, 2018	$46.64 – $54.52

(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 December 31, 2017. As a result, these contracts are not reflected in the Corporation's Interim Consolidated Financial Statements:

Subsequent to December 31, 2017	**Volumes (bbls/d)[(i)]**	**Term**	**Average Price (US$/bbl)[(i)]**
Fixed Price:			
WTI Fixed Price	3,000	Apr 1, 2018 – Jun 30, 2018	$63.82
WTI Fixed Price	11,500	Jul 1, 2018 – Dec 31, 2018	$60.20

The Corporation has entered into the following financial commodity risk management contracts relating to condensate purchases subsequent to December 31, 2017. As a result, these contracts are not reflected in the Corporation's Interim Consolidated Financial Statements:

Subsequent to December 31, 2017	**Volumes (bbls/d)[(i)]**	**Term**	**Average % of WTI[(i)]**
Mont Belvieu fixed % of WTI	1,000	Apr 1, 2018 – Jun 30, 2018	92.3%
Mont Belvieu fixed % of WTI	500	Jul 1, 2018 – Sep 30, 2018	93.5%

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

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	**December 31, 2017**			**December 31, 2016**		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Gross amount	**$ -**	**$ (184,175)**	**$ (184,175)**	$ -	$ (165,740)	$ (165,740)
Amount offset	**-**	**115,526**	**115,526**	-	135,427	135,427
Net amount	**$ -**	**$ (68,649)**	**$ (68,649)**	$ -	$ (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 December 31:

As at December 31	**2017**	**2016**
Fair value of contracts, beginning of year	**$ (30,313)**	$ -
Fair value of contracts realized	**11,273**	(2,359)
Change in fair value of contracts	**(49,609)**	(27,954)
Fair value of contracts, end of year	**$ (68,649)**	$ (30,313)

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

	Three months ended December 31		Year ended December 31	
	2017	**2016**	**2017**	**2016**
Realized loss (gain) on commodity risk management	**$ 6,672**	$ (2,718)	**$ 11,273**	$ (2,359)
Unrealized loss (gain) on commodity risk management	**57,689**	42,049	**38,336**	30,313
Commodity risk management loss (gain)	**$ 64,361**	$ 39,331	**$ 49,609**	$ 27,954

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 December 31, 2017:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	$(145,090)	$ 140,206
Crude oil differential price (i)	± US$1.00 per bbl applied to WCS differential contracts	$ 18,414	$ (18,414)

(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 December 31, 2017, the Corporation has recognized an $8.1 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 December 31, 2017, the Corporation had non-current assets related to operations in the United States of $101.7 million (December 31, 2016 – $109.2 million). For the three months and year ended December 31, 2017, petroleum revenue related to operations in the United States was $365.2 million and $1.1 billion respectively (three months and year ended December 31, 2016 – $195.1 million and $664.2 million, respectively).

23. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation's commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at December 31, 2017:

	2018	2019	2020	2021	2022	Thereafter	Total
Transportation and storage(i)	$ 169,248	$ 182,850	$ 227,393	$ 283,457	$ 284,128	$ 2,248,252	$ 3,395,328
Office lease rentals(ii)	10,863	10,863	11,286	11,286	11,286	107,667	163,251
Diluent purchases	483,812	19,563	19,617	19,563	19,563	16,294	578,412
Other operating commitments	14,160	12,487	11,440	10,418	9,331	60,394	118,230
Capital commitments	14,843	-	-	-	-	-	14,843
Commitments	**$ 692,926**	**$ 225,763**	**$ 269,736**	**$ 324,724**	**$ 324,308**	**$ 2,432,607**	**$ 4,270,064**

(i) Includes transportation commitments of $1.2 billion that are awaiting regulatory approval and are not yet in service.

(ii) Excludes amounts for which an onerous contracts provision has been recognized on the consolidated balance sheet (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.

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation continues to view this three year old claim, and the recent amendments, as without merit and will defend against all such claims.

24. SUBSEQUENT EVENT

On February 7, 2018, the Corporation entered into an agreement with Wolf Midstream Inc. ("Wolf") for the sale of the Corporation's 50% interest in Access Pipeline and its 100% interest in the Stonefell Terminal for cash and other consideration of $1.61 billion.

As part of the transaction, the Corporation and Wolf have entered into a Transportation Services Agreement dedicating the Corporation's Christina Lake production and condensate transport to Access Pipeline for an initial term of 30 years. The transaction also includes a Stonefell Lease Agreement which is a 30-year arrangement that secures the Corporation's operational control and exclusive use of 100% of Stonefell Terminal's 900,000 barrel blend and condensate storage facility.

The Corporation will receive $1.52 billion in cash at closing, and a credit of $90 million toward future expansions of Access Pipeline whereby the Corporation will not pay incremental tolls to fund such expansions.

The transaction is expected to close in the first quarter of 2018, subject to regulatory approvals and customary closing conditions.