Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the year ended December 31, 2017 was approved by the Board of Directors on March 8, 2018. This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2017 and its most recently filed Annual Information Form ("AIF"). This MD&A and the audited consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in thousands of Canadian dollars, except where otherwise indicated.

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1. BUSINESS DESCRIPTION

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

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

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

The Corporation's first two production phases at the Christina Lake Project, Phase 1 and Phase 2, commenced production in 2008 and 2009, respectively. In 2012, the Corporation announced the RISER initiative, which is a combination of proprietary reservoir technologies, including enhanced Modified Steam And Gas Push ("eMSAGP") and redeployment of steam and facilities modifications, including debottlenecking and brownfield expansions (collectively "RISER"). Phase 2B commenced production in 2013. Bitumen production at the Christina Lake Project for the year ended December 31, 2017 averaged 80,774 bbls/d. The application of eMSAGP and cogeneration have enabled MEG to lower its greenhouse gas intensity below the *in situ* industry average calculated based on reported data to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. In those specific well patterns where the implementation of eMSAGP has already been deployed, the Corporation is currently experiencing a steam-oil ratio of approximately 1.3. MEG is currently continuing the process of implementing the RISER initiative, and specifically eMSAGP, to Phase 2B of the Christina Lake Project.

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

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

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

The Corporation is taking a number of steps to address its financial leverage. In January 2017, MEG successfully completed a refinancing which pushed the first maturity of any of the Corporation's outstanding long-term debt obligations to 2023. The ongoing implementation of the eMSAGP growth project will increase future production while further reducing MEG's per barrel costs, and strengthen the Corporation's ability to deal with the current volatility in crude oil prices.

On February 8, 2018 the Corporation announced that it had entered into an agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of MEG's senior secured term loan and to fund MEG's 13,000 bbls/d Phase 2B brownfield expansion. Closing of the transaction is anticipated to occur in the first quarter of 2018. As part of the transaction, MEG entered into a Transportation Services Agreement ("TSA") dedicating MEG'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 MEG's operational control and exclusive use of 100% of the Stonefell Terminal's 900,000-barrel blend and condensate storage facility.

In addition, the Corporation continues to consider, taking into account MEG's debt maturity profile and the ongoing price environment, other available options to reduce its overall amount of debt over time.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

During 2017, the Corporation continued to benefit from increases in its realized sales price. The average US$WTI price increased 18% in 2017 compared to 2016. Also, the average WCS differential narrowed by US$1.86 per barrel, or 13%, due to higher demand for Canadian heavy oil from U.S. Gulf Coast refineries. These factors were the primary drivers in the approximately C$14 per barrel increase in bitumen realization in 2017, as compared to 2016.

Capital investment in 2017 totaled $502.8 million, an increase of $365.5 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 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.

The Corporation continues to benefit from 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 $4.62 per barrel for 2017, an 18% decrease compared to $5.62 per barrel in 2016. The decrease in costs is a result of efficiency gains and continued cost management.

The Corporation realized net earnings of $166.0 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 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. On February 8, 2018, following the announcement of the agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal, the Corporation announced that it intends to increase its 2018 capital budget from $510 million to $700 million to fund approximately 70% of the Phase 2B brownfield expansion in 2018. The Corporation expects to fund the 2018 capital program with internally generated cash flow, a portion of its $463.5 million of cash and cash equivalents as at December 31, 2017 and a portion of the proceeds from the asset sales.

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 years noted. All dollar amounts are stated in Canadian dollars ($ or C$) unless otherwise noted:

($ millions, except as indicated)	**2017**	**2016**
Bitumen production - bbls/d	**80,774**	81,245
Bitumen realization - $/bbl	**41.89**	27.79
Net operating costs - $/bbl(1)	**6.84**	7.99
Non-energy operating costs - $/bbl	**4.62**	5.62
Cash operating netback - $/bbl(2)	**27.00**	13.13
Adjusted funds flow from (used in) operations(3)	**374**	(62)
Per share, diluted(3)	**1.29**	(0.27)
Operating earnings (loss)(3)	**(114)**	(455)
Per share, diluted(3)	**(0.39)**	(2.01)
Revenue(4)	**2,435**	1,866
Net earnings (loss)	**166**	(429)
Per share, basic	**0.57**	(1.90)
Per share, diluted	**0.57**	(1.90)
Total cash capital investment	**503**	137
Cash and cash equivalents	**464**	156
Long-term debt	**4,668**	5,053

(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. 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 Consolidated Statement of Earnings and Comprehensive Income.

3. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	2017	2016
Bitumen production – bbls/d	**80,774**	81,245
Steam-oil ratio (SOR)	**2.3**	2.3

Bitumen Production

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 cy indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The Corporation continues to focus on maintaining efficiency of production through a lower SOR. The SOR averaged 2.3 for the years ended December 31, 2017 and 2016.

Operating Cash Flow

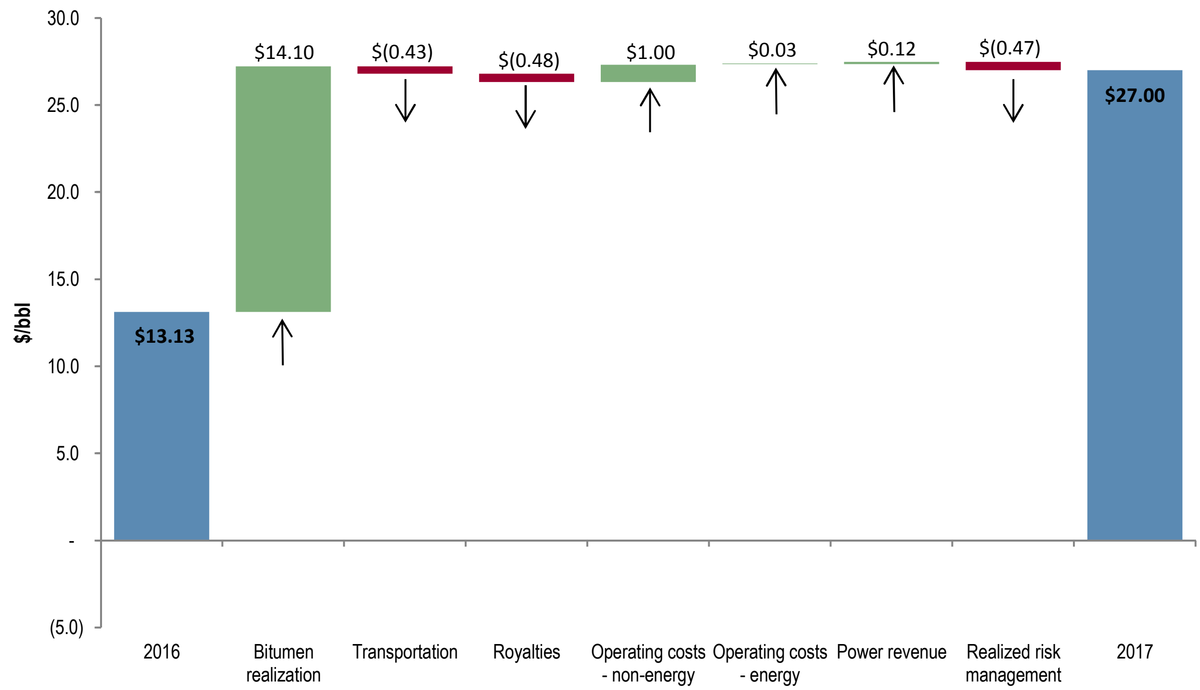
($000)	2017	2016
Petroleum revenue – proprietary(1)	**$ 2,168,602**	$ 1,626,025
Diluent expense	**(944,134)**	(808,030)
	1,224,468	817,995
Royalties	**(22,578)**	(8,581)
Transportation expense	**(214,280)**	(209,864)
Operating expenses	**(222,196)**	(253,758)
Power revenue	**22,209**	18,868
Transportation revenue	**12,801**	19,791
	800,424	384,451
Realized gain (loss) on commodity risk management	**(11,273)**	2,359
Operating cash flow(2)	**$ 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 MD&A.*

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 years indicated:

($/bbl)	2017	2016
Bitumen realization[1]	**$ 41.89**	$ 27.79
Transportation[2]	**(6.89)**	(6.46)
Royalties	**(0.77)**	(0.29)
	34.23	21.04
Operating costs – non-energy	**(4.62)**	(5.62)
Operating costs – energy	**(2.98)**	(3.01)
Power revenue	**0.76**	0.64
Net operating costs	**(6.84)**	(7.99)
	27.39	13.05
Realized gain (loss) on commodity risk management	**(0.39)**	0.08
Cash operating netback	**$ 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.*

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 $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

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 systems 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 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 year ended December 31, 2017, compared to the year 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 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.

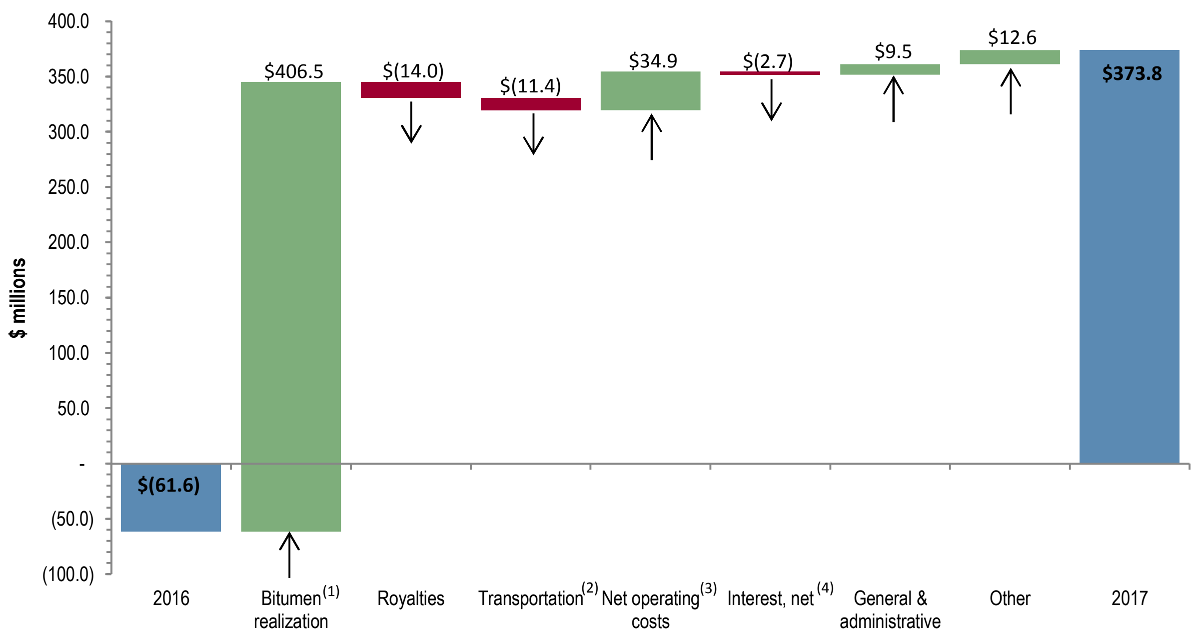
Energy operating costs

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.

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 (used in) operations is a non-GAAP measure, as defined in the "NON-GAAP MEASURES" section of this MD&A, which is used by the Corporation to analyze operating performance and liquidity. Adjusted funds flow from operations was $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 MD&A, which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. The Corporation recognized an operating loss of $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 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 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 net earnings of $166.0 million for the year ended December 31, 2017 compared to a net loss of $428.7 million for the year ended December 31, 2016. 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 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.

4. 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	$700 million
Bitumen production – annual average (bbls/d)	85,000 – 88,000
Bitumen production – targeted exit volume (bbls/d)	95,000 – 100,000
Non-energy operating costs ($/bbl)	$4.75 – $5.25

On December 1, 2017, the Corporation announced a 2018 capital budget of $510 million. On February 8, 2018, following the announcement of the agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal, the Corporation announced it intends to increase its 2018 capital budget from $510 million to $700 million to fund approximately 70% of the Phase 2B brownfield expansion in 2018. The Corporation expects to fund the 2018 capital program with internally generated cash flow, a portion of its $463.5 million of cash and cash equivalents as at December 31, 2017 and a portion of the proceeds from the asset sales.

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.

5. 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 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$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 averaged US$11.98 per barrel, or 23.5% of WTI, for the year ended December 31, 2017 compared to US$13.84 per barrel, or 31.9% of WTI, 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 $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$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 $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 $22.17 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.

6. OTHER OPERATING RESULTS

Net Marketing Activity

($000)	**2017**	**2016**
Petroleum revenue – third party	**$ 253,486**	$ 205,790
Purchased product and storage	**(250,681)**	(202,135)
Net marketing activity[1]	**$ 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

($000)	2017	2016
Depletion and depreciation expense	**$ 475,644**	$ 499,811
Depletion and depreciation expense per barrel of production	**$ 16.13**	$ 16.81

Depletion and depreciation expense decreased, 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 year. 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 year.

($000)	2017			2016		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Crude oil contracts(1)	**$(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 MD&A for further details.

General and Administrative

($000)	2017	2016
General and administrative expense	$ 86,785	$ 96,241
General and administrative expense per barrel of production	$ 2.94	$ 3.24

General and administrative expense decreased primarily due to workforce reductions and the Corporation's continued focus on cost management.

Stock-based Compensation

($000)	2017	2016
Cash-settled expense	$ 3,476	$ 16,354
Equity-settled expense	19,052	33,588
Stock-based compensation	$ 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 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

	Year ended December 31	
($000)	2017	2016
Research and development expense	$ 5,808	$ 5,499

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

Foreign Exchange Gain (Loss), Net

($000)	2017	2016
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ 343,633**	$ 157,272
Other	**(5,489)**	(9,119)
Unrealized net gain (loss) on foreign exchange	**338,144**	148,153
Realized gain (loss) on foreign exchange	**4,403**	3,242
Foreign exchange gain (loss), net	**$ 342,547**	$ 151,395

C$ equivalent of 1 US$		
Beginning of year	**1.3427**	1.3840
End of year	**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.

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

($000)	2017	2016
Total interest expense	**$ 341,594**	$ 328,335
Total interest income	**(3,924)**	(1,047)
Net Interest expense	**337,670**	327,288
Debt extinguishment expense	**30,801**	28,845
Accretion on provisions	**7,760**	7,150
Unrealized loss (gain) on derivative financial liabilities[1]	**(16,179)**	(12,508)
Realized loss on interest rate swaps	**1,028**	4,548
Net finance expense	**$ 361,080**	$ 355,323

Average effective interest rate[2]	**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 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 "LIQUIDITY AND CAPITAL RESOURCES" section of this MD&A.

On February 8, 2018, the Corporation announced that it had entered into an agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal, as described in the "SUBSEQUENT EVENTS" section of this MD&A. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of the Corporation's senior secured term loan. The expected repayment of debt reduces the estimated amortization period of the unamortized debt discount and debt issue costs, and the unamortized financial derivative liability discount. The change in estimate is an adjusting subsequent event under IAS 10, *Events after the Reporting Period*, and a debt extinguishment expense of $30.8 million was recorded at December 31, 2017. The debt extinguishment expense is comprised of the unamortized proportion of the senior secured term loan debt discount and debt issue costs of $17.0 million and the unamortized proportion of the senior secured term loan financial derivative liability discount of $13.8 million.

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 "LIQUIDITY AND CAPITAL RESOURCES" section of this MD&A.

Unrealized gains and losses on derivative liabilities include changes in fair value of both the interest rate floor associated with the Corporation's senior secured term loan and the interest rate swap contracts. The Corporation recognized an unrealized gain on derivative financial liabilities of $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 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

($000)	**2017**	**2016**
Contract cancellation expense	**$ 18,765**	$ -
Onerous contracts	**10,830**	47,866
Severance and other	**5,131**	16,156
Other expenses	**$ 34,726**	$ 64,022

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 sublease recoveries related to the onerous contracts provision for the Corporation's office building leases.

Income Tax Expense (Recovery)

($000)	2017	2016
Current income tax expense (recovery)	**$ (67)**	$ 919
Deferred income tax expense (recovery)	**(56,130)**	(208,413)
Income tax expense (recovery)	**$ (56,197)**	$ (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.

The Corporation recognized a current income tax recovery of $0.1 million and an expense of $0.9 million in the years ended December 31, 2017 and 2016, respectively. The 2017 recovery is comprised of $0.8 million related to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures, partially offset by an expense of $0.7 million related to the United States income tax associated with its operations in the United States. The 2016 expense was related to the United States income tax associated with its operations in the United States.

The Corporation recognized a deferred income tax recovery of $56.1 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 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 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 $182.9 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.

7. NET CAPITAL INVESTMENT

($000)	2017	2016
eMSAGP growth	**$ 222,982**	$ 2,678
Sustaining	**189,288**	64,230
Marketing, corporate and other	**90,484**	70,337
Total cash capital investment	**502,754**	137,245
Capitalized cash-settled stock-based compensation	**(308)**	2,491
	$ 502,446	$ 139,736

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 first year of its two-year development plan for the eMSAGP growth project at Christina Lake Phase 2B. Also in 2017, the Corporation invested $189.3 million in sustaining capital activities, including turnaround costs of $37.1 million incurred in the second quarter. In 2016, the Corporation was focused on reducing capital spending and capital investments were primarily directed towards sustaining capital activities.

8. SUMMARY OF QUARTERLY RESULTS

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

	2017				2016			
($ millions, except per share amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue[1]	**$754.8**	**$546.1**	**$574.0**	**$559.8**	$565.8	$496.8	$513.4	$290.3
Net earnings (loss)	**(23.8)**	**83.9**	**104.3**	**1.6**	(304.8)	(108.6)	(146.2)	130.8
Per share – basic	**(0.08)**	**0.29**	**0.36**	**0.01**	(1.34)	(0.48)	(0.65)	0.58
Per share – diluted	**(0.08)**	**0.28**	**0.35**	**0.01**	(1.34)	(0.48)	(0.65)	0.58

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

During the eight most recent quarters the following items have had a significant impact on the Corporation's quarterly results:

- fluctuations in blend sales pricing due to significant changes in the price of WTI and the differential between WTI and the Corporation's AWB;
- the cost of diluent due to Canadian and U.S. benchmark pricing and the timing of diluent inventory purchases;
- changes in the value of the Canadian dollar relative to the U.S. dollar and its impact on blend sales prices, the cost of diluent, interest expense, and foreign exchange gains and losses associated with the Corporation's U.S. dollar denominated debt;
- increased bitumen production volumes due to efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project, which has allowed additional wells to be placed into production;
- fluctuations in natural gas and power pricing;
- gains and losses on commodity risk management contracts;
- other expenses primarily related to contract cancellation expense, onerous contracts and severance costs;
- a fourth quarter 2016 impairment charge related to the Corporation's investment in the right to participate in the Northern Gateway pipeline; and
- changes in depletion and depreciation expense as a result of changes in production rates and future development costs.

9. SUMMARY ANNUAL INFORMATION

($000s, except per share amounts)	2017	2016	2015
Revenue(1)	**2,434,703**	1,866,284	1,925,916
Net earnings (loss)	**165,976**	(428,726)	(1,169,671)
Per share – basic	**0.57**	(1.90)	(5.21)
Per share – diluted	**0.57**	(1.90)	(5.21)
Total assets	**9,363,352**	8,921,224	9,400,269
Total non-current liabilities	**4,873,779**	5,271,277	5,474,106

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

Revenue

During 2017, revenue increased 30% from 2016, primarily as a result of the year-over-year average increase in crude oil benchmark pricing.

During 2016, revenue decreased 3% from 2015, primarily as a result of the year-over-year average decline in crude oil benchmark pricing.

Net Earnings (Loss)

The increase in net earnings in 2017 compared to the net loss in 2016 is primarily attributable to higher bitumen realization as a result of the increase in average crude oil benchmark pricing in 2017. In addition, the net unrealized foreign exchange gain increased in 2017 compared to 2016. The change in value of the Canadian dollar relative to the U.S. dollar impacts the translation of the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.

The decrease in the net loss in 2016 compared to the net loss in 2015 is primarily attributable to the Corporation recognizing an unrealized foreign exchange gain in 2016 compared to an unrealized foreign exchange loss in 2015. The net loss for the year ended December 31, 2016 was impacted by lower bitumen realization, primarily as a result of the year-over-year average decline in U.S. crude oil benchmark pricing, an impairment charge related to the Northern Gateway pipeline, an unrealized loss on commodity risk management and other expenses primarily related to onerous contracts and severance.

Total Assets

Total assets as at December 31, 2017 increased compared to December 31, 2016 primarily due to an increase in cash as a result of the equity issuance pursuant to the comprehensive refinancing that closed on January 27, 2017.

Total assets as at December 31, 2016 decreased compared to December 31, 2015 primarily due to an increase in depletion and depreciation expense as a result of an increase in the estimated future development costs associated with the Corporation's proved reserves, and a decrease in cash and cash equivalents. The cash and cash equivalents balance as at December 31, 2016 decreased compared to December 31, 2015 primarily due to the use of cash for interest and principal payments and payments relating to capital investing activities.

For a detailed discussion of the Corporation's investing activities, see "LIQUIDITY AND CAPITAL RESOURCES – Cash Flow – Investing Activities".

Total Non-Current Liabilities

Total non-current liabilities as at December 31, 2017 decreased compared to December 31, 2016 primarily due to the Corporation recognizing an unrealized foreign exchange gain on the translation of the U.S. dollar denominated debt as a result of strengthening of the Canadian dollar compared to the U.S. dollar by approximately 7% during the year.

Total non-current liabilities as at December 31, 2016 decreased compared to December 31, 2015 primarily due to the Corporation recognizing an unrealized foreign exchange gain on the translation of the U.S. dollar denominated debt as a result of strengthening of the Canadian dollar compared to the U.S. dollar by approximately 3% during the year ended December 31, 2016. In addition, the Corporation recognized a deferred income tax asset as at December 31, 2016 compared to a deferred income tax liability as at December 31, 2015.

10. LIQUIDITY AND CAPITAL RESOURCES

($000)	**December 31, 2017**	**December 31, 2016**
Cash and cash equivalents	**$ 463,531**	$ 156,230
Senior secured term loan (December 31, 2017 – US$1.226 billion; due 2023; December 31, 2016 – US$1.236 billion)	**1,534,378**	1,658,906
US$1.4 billion revolving credit facility (due 2021)	**-**	-
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**938,850**	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	**-**	1,007,025
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,001,440**	1,074,160
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,251,800**	1,342,700
Total debt[(1)]	**$ 4,726,468**	$ 5,082,791

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

Capital Resources

The Corporation's cash and cash equivalents balance totalled $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. The senior secured term loan, revolving credit facility, letter of credit facility and second lien notes are secured by substantially all the assets of the Corporation. 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$4.67 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.

On February 8, 2018 the Corporation announced that it had entered into an agreement for the sale of the Corporation’s 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of MEG's senior secured term loan.

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

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

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

Risk Management

Commodity Price Risk Management

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

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

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

As at December 31, 2017	Volumes (bbls/d)(1)	Term	Average Price (US$/bbl)(1)
Fixed Price:			
WTI 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 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

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 March 8, 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 March 8, 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.

Cash Flow Summary

($000)	2017	2016
Net cash provided by (used in):		
Operating activities	**$ 317,935**	$ (94,074)
Investing activities	**(405,231)**	(131,111)
Financing activities	**401,245**	(17,062)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(6,648)**	(9,736)
Change in cash and cash equivalents	**$ 307,301**	$ (251,983)

Cash Flow – Operating Activities

Net cash provided by operating activities totalled $317.9 million for the year ended December 31, 2017 compared to net cash used in operating activities of $94.1 million for the year ended December 31, 2016. This increase in cash flows is primarily due to higher bitumen realization, primarily as a result of the increase in average crude oil benchmark pricing.

Cash Flow – Investing Activities

Net cash used in investing activities was $405.2 million for the year ended December 31, 2017 compared to $131.1 million for the year ended December 31, 2016. The increase in 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.

Cash Flow – Financing Activities

Net cash provided by financing activities was $401.2 million for the year ended December 31, 2017 compared to net cash used in financing activities of $17.1 million for the year ended December 31, 2016. Net cash provided by financing activities increased primarily due to net equity issuance proceeds as part of the comprehensive refinancing plan that closed on January 27, 2017. Net cash used in financing activities also includes debt principal payments of $12.7 million.

11. SHARES OUTSTANDING

As at December 31, 2017, the Corporation had the following share capital instruments outstanding or exercisable:

(000)	Outstanding
Common shares	**294,104**
Convertible securities	
Stock options[1]	**8,896**
Equity-settled RSUs and PSUs	**6,307**

(1) 6.2 million stock options were exercisable as at December 31, 2017.

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

As at March 7, 2018, the Corporation had 294.1 million common shares, 8.8 million stock options and 6.3 million equity-settled restricted share units and equity-settled performance share units outstanding, and 6.1 million stock options exercisable.

The Corporation's common shares have increased as a result of the issuance of 66.8 million common shares pursuant to the $518 million equity issuance which closed on January 27, 2017 as outlined in the "Capital Resources" section of this MD&A.

12. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

(a) Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations as at December 31, 2017 and excludes any impact related to transactions that occurred subsequent to December 31, 2017 as described in the "SUBSEQUENT EVENTS" section. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities, the Senior Secured Second Lien Notes, and the Senior Unsecured Notes may be retired earlier due to mandatory repayments or redemptions.

($000)	2018	2019	2020	2021	2022	Thereafter	Total
Long-term debt[1]	$ 15,460	$ 15,460	$ 15,460	$ 15,460	$ 15,460	$ 4,649,168	$ 4,726,468
Interest on long-term debt[1]	292,046	291,243	290,439	289,634	288,830	317,522	1,769,714
Decommissioning obligation[2]	6,386	9,811	7,435	8,614	8,614	818,268	859,128
Transportation and storage[3]	169,248	182,850	227,393	283,457	284,128	2,248,252	3,395,328
Office lease rentals	10,863	10,863	11,286	11,286	11,286	107,667	163,251
Diluent purchases[4]	483,812	19,563	19,617	19,563	19,563	16,294	578,412
Other commitments[5]	47,834	22,862	21,304	20,017	18,106	105,093	235,216
Total	**$ 1,025,649**	**$ 552,652**	**$ 592,934**	**$ 648,031**	**$ 645,987**	**$ 8,262,264**	**$11,727,517**

(1) This represents the scheduled principal repayments of the senior secured term loan, the Senior Secured Second Lien Notes, the Senior Unsecured Notes, and associated interest payments based on interest and foreign exchange rates in effect on December 31, 2017.

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

(3) This represents transportation and storage commitments from 2018 to 2039, including various pipeline commitments which are awaiting regulatory approval and are not yet in service.
(4) This represents the future commitments associated with the Corporation's diluent purchases.
(5) This represents the future commitments associated with the Corporation's capital program, other operating and maintenance commitments, and estimated net payments related to onerous lease contracts.

(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.

13. SUBSEQUENT EVENTS

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 ("the transaction"). The transaction was announced on February 8, 2018.

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 sale of the Stonefell Terminal and the Stonefell Lease Agreement will be accounted for as a sale and leaseback transaction that results in a finance lease.

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. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of MEG's senior secured term loan.

As a result of the transaction announced on February 8, 2018, the Corporation determined that the expected repayment of debt results in a change in estimated life of certain amounts associated with the senior secured term loan. A debt extinguishment expense of $30.8 million was recorded at December 31, 2017, as an adjusting subsequent event under IAS 10, *Events after the Reporting Period*.

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

Subsequent to entering into the agreement, the Corporation entered into forward currency contracts to manage the foreign exchange risk on the Canadian dollar denominated proceeds from the sale of assets designated for U.S. dollar denominated long-term debt repayment.

14. NON-GAAP MEASURES

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

Net Marketing Activity

Net marketing activity is a non-GAAP measure which the Corporation uses to analyze the returns on the sale of third-party crude oil and related products through various marketing and storage arrangements. Net marketing activity represents the Corporation's third-party petroleum sales less the cost of purchased product and storage arrangements. Petroleum revenue – third party is disclosed in Note 17 in the Notes to the 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, contract cancellation expense, net change in other liabilities, payments on onerous contracts and decommissioning expenditures, 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.

($000)	**2017**	**2016**
Net cash provided by (used in) operating activities	**$ 317,935**	$ (94,074)
Net change in non-cash operating working capital items	**24,517**	25,061
Funds flow from (used in) operations	**342,452**	(69,013)
Adjustments:		
Contract cancellation expense	**18,765**	-
Net change in other liabilities	**(9,389)**	-
Payments on onerous contracts	**19,569**	6,116
Decommissioning expenditures	**2,403**	1,290
Adjusted funds flow from (used in) operations	**$ 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.

($000)	**2017**	**2016**
Net earnings (loss)	**$ 165,976**	$ (428,726)
Adjustments:		
Unrealized net loss (gain) on foreign exchange(1)	**(338,144)**	(148,153)
Unrealized loss (gain) on derivative financial liabilities(2)	**(16,179)**	(12,508)
Unrealized loss (gain) on commodity risk management(3)	**38,336**	30,313
Impairment charge(4)	**-**	80,072
Contract cancellation expense(5)	**18,765**	-
Onerous contracts expense(6)	**10,830**	47,866
Debt extinguishment expense(7)	**30,801**	28,845
Insurance proceeds	**(183)**	(4,391)
Deferred tax expense (recovery) relating to these adjustments	**(23,726)**	(48,416)
Operating earnings (loss)	**$ (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, 2017 the Corporation recognized debt extinguishment expense of $30.8 million associated with the planned repayment of approximately C$1.225 billion of the senior secured term loan. 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.

Total Debt

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

($000)	December 31, 2017	December 31, 2016
Long-term debt	**$ 4,668,267**	$ 5,053,239
Adjustments:		
Debt redemption premium	**-**	(21,812)
Current portion of senior secured term loan	**15,460**	17,455
Unamortized financial derivative liability discount	**4,242**	11,143
Unamortized deferred debt discount and debt issue costs	**38,499**	22,766
Total debt	**$ 4,726,468**	$ 5,082,791

15. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Property, Plant and Equipment

Items of property, plant and equipment, including oil sands property and equipment, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Capitalized costs associated with the Corporation's field production assets, including estimated future development costs, are depleted using the unit-of-production method based on estimated proved reserves. The Corporation's oil sands facilities are depreciated on a unit-of-production method based on the facilities' productive capacity over their estimated remaining useful lives. The costs associated with the Corporation's interest in transportation and storage assets are depreciated on a straight-line basis over the estimated remaining useful lives of the assets. The determination of future development costs, proved reserves, productive capacity and remaining useful lives are subject to significant judgments and estimates.

Exploration and Evaluation Assets

Pre-exploration costs incurred before the Corporation obtains the legal right to explore an area are expensed. Exploration and evaluation costs associated with the Corporation's oil sands activities are capitalized. These costs are accumulated in cost centres pending determination of technical feasibility and commercial viability at which point the costs are transferred to property, plant and equipment. If it is determined that an exploration and evaluation asset is not technically feasible or commercially viable and the Corporation decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to expense. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. The determination of proved or probable reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Impairments

The carrying amounts of the Corporation's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated. An impairment test is completed each year for intangible assets that are not yet available for use. Exploration and evaluation assets are assessed for impairment when they are reclassified to property, plant and equipment or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, property, plant and equipment assets are grouped into cash-generating units ("CGUs"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal. Exploration and evaluation assets are assessed for impairment within the aggregation of all CGUs in that segment.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In determining fair value less costs of disposal, recent market transactions are taken into account if available. In the absence of such transaction, an appropriate valuation model is used.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized within net earnings during the period in which they arise. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the CGU on a pro-rata basis.

Impairment losses recognized in prior years are assessed at each reporting date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimate used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

Bitumen Reserves

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the cost and timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Corporation expects that over time its reserves estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation and for determining potential asset impairment. The Corporation’s reserves estimates are evaluated annually by independent qualified reserve evaluators.

Joint Operations

Judgment is required to determine whether an interest the Corporation holds in a joint arrangement should be classified as a joint operation or joint venture. The determination includes an assessment as to whether the Corporation has the rights to the assets and obligations for the liabilities of the arrangement or the rights to the net assets. The Corporation holds an undivided interest in Access Pipeline. As a result, the Corporation presents its proportionate share of the assets, liabilities, revenues and expenses of Access Pipeline on a line-by-line basis in the consolidated financial statements.

Decommissioning Provision

The Corporation recognizes an asset and a liability for any existing decommissioning obligations associated with the dismantling, decommissioning and restoration of property, plant and equipment and exploration and evaluation assets. The provision is determined by estimating the fair value of the decommissioning obligation at the end of the period. This fair value is determined by estimating expected timing and cash flows that will be required for future dismantlement and site restoration, and then calculating the present value of these future payments using a credit-adjusted risk-free rate specific to the liability. Any change in timing or amount of the cash flows subsequent to initial recognition results in a change in the asset and liability, which then impacts the depletion and depreciation on the asset and accretion charged on the liability. Estimating the timing and amount of third party cash flows to settle these obligations is inherently difficult and is based on third party estimates and management's experience.

Onerous Contracts

The Corporation recognizes a provision for onerous contracts when the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be derived from the contract. The determination of when to record a provision for an onerous contract is a complex process that involves management judgment about outcomes of future events, and estimates concerning the nature, extent and timing of expected future cash flows and discount rates related to the contract. The provision is determined by estimating the present value of the minimum future contractual payments that the Corporation is obligated to make under the non-cancellable onerous contracts reduced by estimated recoveries.

Deferred Income Taxes

The Corporation follows the liability method of accounting for income taxes. Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date. The periods in which timing differences reverse are impacted by future earnings and capital expenditures. Rates are also affected by changes to tax legislation. Income taxes are recognized in net earnings except to the extent that they relate to items recognized directly in shareholders' equity, in which case the income taxes are recognized in shareholders' equity. The Corporation also makes interpretations and judgments on the application of tax laws for which the eventual tax determination may be uncertain. To the extent that interpretations change, there may be a significant impact on the consolidated financial statements.

Stock-based Compensation

The fair values of equity-settled and cash-settled share-based compensation plans are estimated using the Black-Scholes options pricing model. These estimates are based on the Corporation's share price and on several assumptions, including the risk-free interest rate, the future forfeiture rate, the expected volatility of the Corporation's share price and the future attainment of performance criteria. Accordingly, these estimates are subject to measurement uncertainty.

Derivative Financial Instruments

The Corporation may utilize derivative financial instruments to manage commodity price, foreign currency and interest rate exposures. These financial instruments are not used for trading or speculative purposes. The fair values of derivative financial instruments are estimated at the end of each reporting period based on expectations of future cash flows associated with the derivative instrument. Estimates of future cash flows are based on forecast commodity prices, interest rates and foreign exchange rates expected to be in effect over the remaining life of the contract. Any subsequent changes in these rates will impact the amounts ultimately recognized in relation to the derivative instruments.

16. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the year ended December 31, 2017 and December 31, 2016, other than compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($000)		2017		2016
Salaries and short-term employee benefits	**$**	**7,385**	$	9,117
Share-based compensation		**9,578**		12,006
Termination benefits		**64**		1,617
	$	**17,027**	$	22,740

17. OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2017 and December 31, 2016, the Corporation did not have any off-balance sheet arrangements. The Corporation has certain operating or rental lease agreements, as disclosed in the Contractual Obligations and Commitments section of this MD&A, which are entered into in the normal course of operations. Payments of these leases are included as an expense as incurred over the lease term. No asset or liability value had been assigned to these leases as at December 31, 2017 and December 31, 2016.

18. NEW ACCOUNTING STANDARDS

The Corporation has adopted the following revised standards during the year ended December 31, 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 have been included in Note 25 to the Corporation's consolidated financial statements. As allowed by IAS 7, comparative information has not been presented.

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

Accounting standards issued but not yet applied

IFRS 16 *Leases*

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.

IFRS 9 *Financial Instruments*

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. The adoption of these changes will not have a material impact on the Corporation's consolidated financial statements.

A new amendment to IFRS 9 requires debt modifications to be discounted at the original effective interest rate of the debt rather than a revised effective interest rate as was required under IAS 39. The Corporation is currently assessing and evaluating the impact of the new amendment. IFRS 9 will be adopted by the Corporation on January 1, 2018, as required by the standard, on a modified retrospective basis.

IFRS 15 *Revenue From Contracts With Customers*

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.

IFRS 2 *Share-based Payment*

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.

19. RISK FACTORS

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

Risks Arising From Construction Activities

Cost and Schedule Risk

Additional phases of development of the Christina Lake Project and the development of the Corporation's other projects may suffer from delays, cancellation, interruptions or increased costs due to many factors, some of which may be beyond the Corporation's control, including:

- engineering, construction and/or procurement performance falling below expected levels of output or efficiency;
- denial or delays in receipt of regulatory approvals, additional requirements imposed by changes in Provincial and Federal laws or non-compliance with conditions imposed by regulatory approvals;
- labour disputes or disruptions, declines in labour productivity or the unavailability of skilled labour;
- increases in the cost of labour and materials; and
- changes in project scope or errors in design.

If any of the above events occur, they could have a material adverse effect on the Corporation's ability to continue to develop the Christina Lake Project, the Corporation's facilities or the Corporation's other future projects and facilities, which would materially adversely affect its business, financial condition and results of operations.

Risks Arising From Operations

Operating Risk

The operation of the Corporation's oil sands properties and projects are and will continue to be subject to the customary hazards associated with recovering, transporting and processing hydrocarbons, such as fires, severe weather, natural disasters (including wildfires), explosions, gaseous leaks, migration of harmful substances, blowouts and spills. A casualty occurrence might result in the loss of equipment or life, as well as injury, property damage or the interruption of the Corporation's operations. The Corporation's insurance may not be sufficient to cover all potential casualties, damages, losses or disruptions. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Operating Results

The Corporation's operating results are affected by many factors. The principal factors, amongst others, which could affect MEG's operating results include:

- a substantial decline in oil, bitumen or electricity prices, due to a lack of infrastructure or otherwise;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher steam-to-oil ratios;
- a lack of access to, or an increase in, the cost of diluent;
- an increase in the cost of natural gas;
- the reliability and maintenance of the Access Pipeline, Stonefell Terminal and MEG's other facilities;
- the need to repair existing horizontal wells, or the need to drill additional horizontal wells;
- the ability and cost to transport bitumen, diluent and bitumen diluent blends, and the cost to dispose of certain by-products;
- increased royalty payments resulting from changes in the regulatory regime;
- a lack of sufficient pipeline or electrical transmission capacity, and the effect that an apportionment may have on MEG’s access to such capacity;
- the cost of labour, materials, services and chemicals used in MEG's operations; and
- the cost of compliance with existing and new regulations.

Labour Risk

The Corporation depends on its management team and other key personnel to run its business and manage the operation of its projects. The loss of any of these individuals could adversely affect the Corporation's operations. Due to the specialized nature of the Corporation's business, the Corporation believes that its future success will also depend upon its ability to continue to attract, retain and motivate highly skilled management, technical, operations and marketing personnel.

Project Development Risks

Reliance on Third Parties

The Christina Lake Project and the Corporation's future projects will depend on the successful operation and the adequate capacities of certain infrastructure owned and operated by third parties or joint ventures with third parties, including:

- pipelines for the transport of natural gas, diluent and blended bitumen;
- power transmission grids supplying and exporting electricity; and
- other third-party transportation infrastructure such as roads, rail, terminals and airstrips.

The failure or lack of any or all of the infrastructure described above will negatively impact the operation of the Christina Lake Project and MEG's future projects, which in turn, may have a material adverse effect on MEG's business, results of operations and financial condition.

Reserves and Resources

There are numerous uncertainties inherent in estimating quantities of in-place bitumen reserves and resources, including many factors beyond the Corporation's control. In general, estimates of economically recoverable bitumen reserves and resources and the future net cash flow therefrom are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the effects of regulation by governmental agencies, and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, the classification of such reserves and resources based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

MEG retained GLJ Petroleum Consultants Ltd. as the Corporation’s independent qualified reserve evaluator to evaluate and prepare a report on the Corporation’s reserves with an effective date of December 31, 2017 and a preparation date of February 9, 2018 (“GLJ Report”). Although third parties have prepared the GLJ Report and other reviews, reports and projections relating to the viability and expected performance of the Christina Lake Project, the Surmont Project, the May River Regional Project and the Growth Properties, the GLJ Report, the reviews, reports and projections and the assumptions on which they are based may not, over time, prove to be accurate. Actual production and cash flow derived from the Corporation's oil sands leases may vary from the GLJ Report and other reviews, reports and projections.

Financing Risk

Significant amounts of capital will be required to develop future phases of the Christina Lake Project, the Surmont Project, the May River Regional Project and the Growth Properties. At present, cash flow from the Corporation's operations is largely dependent on the performance of a single project and a major source of funds available to the Corporation is the issuance of additional equity or debt. Capital requirements are subject to capital market risks, including the availability and cost of capital. There can be no assurance that sufficient capital will be available or be available on acceptable terms or on a timely basis, to fund the Corporation's capital obligations in respect of the development of its projects or any other capital obligations it may have. The Corporation may not generate sufficient cash flow from operations and may not have additional equity or debt available to it in amounts sufficient to enable it to make payments with respect to its indebtedness or to fund its other liquidity needs. In these circumstances, the Corporation may need to refinance all or a portion of its indebtedness on or before maturity. The Corporation may not be able to refinance any of its indebtedness on commercially reasonable terms or at all.

Commodity Price Risk

The Corporation's business, financial condition, results of operations and cash flow are dependent upon the prevailing prices of its bitumen blend, condensate, power and natural gas. Prices of these commodities have historically been extremely volatile and fluctuate significantly in response to regional, national and global supply and demand, and other factors beyond the Corporation's control.

Declines in prices received for the Corporation's bitumen blend could materially adversely affect the Corporation's business, financial position, results of operations and cash flow. In addition, any prolonged period of low bitumen blend prices or high natural gas or condensate prices could result in a decision by the Corporation to suspend or reduce production. Any suspension or reduction of production would result in a corresponding decrease in the Corporation's revenues and could materially impact the Corporation's ability to meet its debt service obligations. If over-the-counter derivative structures are employed to mitigate commodity price risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Interest Rate Risk

The Corporation has obtained certain credit facilities to finance a portion of the capital costs of the Christina Lake Project and to fund the Corporation's other development and acquisition activities. Variations in interest rates could result in significant changes to debt service requirements and would affect the financial results of the Corporation. If over-the-counter derivative structures are employed to mitigate interest rate risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Foreign Currency Risk

The Corporation's credit facilities and high yield notes are denominated in U.S. dollars and prices of the Corporation's bitumen blend are generally based on U.S. dollar market prices. Fluctuations in U.S. and Canadian dollar exchange rates may cause a negative impact on revenue, costs and debt service obligations and may have a material adverse impact on the Corporation. If over-the-counter derivative structures are employed to mitigate foreign currency risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Regulatory and Environmental Risk

The oil and gas industry in Canada, including the oil sands industry, operates under Canadian federal, provincial and municipal legislation and regulations. Future development of the Christina Lake Project, the Surmont Project, the May River Regional Project and the Growth Properties is dependent on the Corporation maintaining its current oil sands leases and licences and receiving required regulatory approvals and permits on a timely basis. The Government of Alberta has initiated a process to control cumulative environment effects of industrial development through the Lower Athabasca Regional Plan ("LARP"). While the LARP has not had a significant effect on the Corporation, there can be no assurance that changes to the LARP or future laws or regulations will not adversely impact the Corporation's ability to develop or operate its projects.

The Corporation is committed to meeting its responsibilities to protect the environment and fully comply with all environmental laws and regulations. Alberta regulates emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("GHG"), and Canada's federal government has proposed significant extensions to its GHG regulatory requirements. The direct and indirect costs of the various regulations, existing, proposed and future, may adversely affect MEG's business, operations and financial results. The emission reduction compliance obligations required under existing and future federal and provincial industrial air pollutant and GHG emission reduction targets and requirements, together with emission reduction requirements in future regulatory approvals, may not be technically or economically feasible to implement for MEG's bitumen recovery and cogeneration activities. Any failure to meet MEG's emission reduction compliance obligations may materially adversely affect MEG's business and result in fines, penalties and the suspension of operations.

Alberta Climate Leadership Plan

For the 2017 compliance year, the Corporation was subject to the Specified Gas Emitters Regulation (the "SGER"), which imposes greenhouse gas emissions intensity limits and reduction requirements for owners of facilities that emit 100,000 tonnes or more per year of greenhouse gas. In December 2017, the Alberta government released the Carbon Competitiveness Incentive Regulation (the “CCIR”), which came into force on January 1, 2018. The CCIR replaces the SGER for compliance years 2018 and thereafter. Various elements of the SGER are included in the CCIR, as the CCIR remains an emissions intensity-based regime requiring large emitters to reduce their emissions intensity below a prescribed level, or otherwise achieve this through a true-up obligation whereby credits can be applied against such required level, together with or as an alternative to physical abatement, with penalties for failure to achieve compliance. However, the CCIR has fundamental differences with SGER as the facility specific baselines in the SGER have now largely been replaced in the CCIR with product specific benchmarks.

There are four compliance options for facilities that are subject to the CCIR: (i) improve emissions intensity at the facility; (ii) purchase or use banked emission performance credits (“EPCs”); (iii) purchase emission offsets in the open market, which are generated from Alberta based projects; and/or (iv) purchase fund credits by contributing to the Climate Change and Emissions Management Fund ("Fund") run by the Alberta government. Currently the contribution costs to the Fund are set at $30 per tonne although this is subject to change by Ministerial order. Under the CCIR there are no limits on purchasing fund credits to meet a facility’s true up obligation; however, the CCIR includes limits on the use of EPCs and emission offsets for compliance purposes, and adds expiry periods for EPCs and emission offsets according to the vintage year.

In November 2015, the Government of Alberta announced its climate leadership plan (the "Plan") and released to the public the climate leadership report to the Minister of Environment and Parks that it commissioned from the Climate Change Advisory Panel and on which the Plan is largely based. The Plan highlights four key strategies that the Government of Alberta is implementing to address climate change: (i) the complete phase-out of coal-fired sources of electricity by 2030; (ii) an Alberta economy-wide price on greenhouse gas emissions of $30 per tonne; (iii) capping oil sands emissions to a province-wide total of 100 megatonnes per year (compared to current emissions of approximately 70 megatonnes per year), with certain exceptions for cogeneration power sources and new upgrading capacity; and (iv) reducing methane emissions from oil and gas activities by 45% by 2025. Certain details regarding how the Plan will be implemented, for example, the carbon levy under the *Climate Leadership Act* and the CCIR have been released. The *Oil Sands Emissions Limit Act* has been enacted but it does not obligate oil sands producers until a regulatory system is designed and implemented under the regulations. Certain details regarding how the Plan will be implemented have not been released.

The Climate Leadership Act came into force on January 1, 2017 and establishes an Alberta carbon pricing regime in the form of a carbon levy on various types of fuel. Under the Climate Leadership Act, facilities subject to the SGER and the CCIR are exempt from the carbon levy.

No assurance can be given that environmental laws and regulations, including the implementation of the Plan, will not result in a curtailment of the Corporation's production or a material increase in the Corporation's costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's results of operations, financial condition and prospects. The Corporation believes that it is reasonably likely that the trend towards stricter standards in environmental legislation will continue and anticipates that capital and operating costs may increase as a result of more stringent environmental laws. A legislated cap on oil sands greenhouse gas emissions could significantly reduce the value of the Corporation's assets.

The Paris Agreement

Canada and 195 other countries that are members of the United Nations Framework Convention on Climate Change met in Paris, France in December 2015, and signed the Paris Agreement on climate change. The stated objective of the Paris Agreement is to hold "the increase in global average temperature to well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius." Signatory countries agreed to meet every five years to review their individual progress on greenhouse gas emissions reductions and to consider amendments to individual country targets, which are not legally binding. Canada is required to report and monitor its greenhouse gas emissions, though details of how such reporting and monitoring will take place have yet to be determined. Additionally, the Paris Agreement contemplates that, by 2020, the parties will develop a new market-based mechanism related to carbon trading. It is expected that this mechanism will largely be based on the best practices and lessons learned from the Kyoto Protocol. The Government of Canada has stated that it will develop and announce a Canada-wide approach to implementing the Paris Agreement.

In October 2016, the Government of Canada announced that it would implement a national price on carbon (the “Pan-Canadian Carbon Plan”) in response to the Paris Agreement. Under the Pan-Canadian Carbon Plan, the federal government is proposing a carbon pricing program that includes, at a minimum, a floor price on carbon emissions of $10 per tonne in 2018, rising by $10 per tonne each year to $50 per tonne in 2022. The Pan-Canadian Carbon Plan will allow provinces to implement either a carbon tax or use a broad market based mechanism. The Pan-Canadian Carbon Plan includes a federal backstop in the event jurisdictions do not meet the floor carbon price. On January 15, 2018 the Government of Canada released draft legislative proposals for the federal backstop. The proposed Greenhouse Gas Pollution Pricing Act, which is similar in structure to Alberta’s approach to carbon pricing, includes a levy on fossil fuels and an output-based pricing system for industrial facilities. The federal government’s proposed legislation would apply, in whole or in part, in provinces that voluntarily adopt the federal standard or that do not have a carbon pricing system in place that meets the federal standard by January 1, 2019. The federal government has requested that a province opting to establish or maintain a provincial carbon pricing system must outline its system by September 1, 2018, after which the federal government will confirm whether the provincial carbon pricing system meets the federal standard. The federal government will implement the proposed federal legislation in whole or in part on January 1, 2019 in any province that does not have a carbon pricing system that meets the federal standard. It is uncertain at this time if Alberta will be subject to the proposed Greenhouse Gas Pollution Pricing Act; however, it is expected Alberta will attempt to make the case that Alberta’s approach to carbon pricing is equivalent to the federal standard and as a result the proposed federal legislation may not apply in Alberta.

Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil sands producers. The Corporation is unable to predict the impact of emissions reduction legislation on the Corporation and it is possible that such legislation may have a material adverse effect on the Corporation's financial condition, results of operations and prospects.

Royalty Risk

The Corporation's revenue and expenses will be directly affected by the royalty regime applicable to its oil sands development. The Government of Alberta implemented a new oil and gas royalty regime effective January 1, 2009 through which the royalties for bitumen are linked to price and production levels. The royalty regime applies to both new and existing oil sands projects.

Under the royalty regime, the Government of Alberta increased its royalty share from oil sands development by introducing price-sensitive formulas applied both before and after specified allowed costs have been recovered.

The Government of Alberta has publicly indicated that it intends for the revised royalty regime to be further reviewed and revised from time to time. There can be no assurances that the Government of Alberta or the Government of Canada will not adopt new royalty regimes which may render the Corporation's projects uneconomic or otherwise adversely affect its business, financial condition or results of operations.

On January 29, 2016, the Alberta government finalized results of a royalty review which commenced in September 2015 and announced that the current structure and royalty rates for oil sands will generally remain unchanged.

There can be no assurances that the government of Alberta will not adopt new royalty regimes which may render the Corporation's projects uneconomic or adversely affect its results of operations, financial condition or prospects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments or the Corporation's operations uneconomic and could make it more difficult to service and repay the Corporation's debt. Any material increase in royalties could also materially reduce the value of the Corporation's assets.

Lease Expiries Risk

Certain of MEG's oil sands leases may expire and MEG may be required to surrender lands to the Province of Alberta. The initial term for MEG's oil sands leases, some of which began in or subsequent to 1996, is 15 years. At the conclusion of this initial term, each oil sands lease may be continued if it meets certain criteria related to the extent to which MEG has evaluated the oil sands resource covered by the lease. Continued leases currently have indefinite terms and application for continuation may be made during the last year of the term of the lease or at any time during the lease with the consent of the Minister.

In view of the potentially changing tenure environment, MEG is actively evaluating all of its oil sands leases to determine the best continuation approach. In 2017, none of MEG’s oil sand leases expired and MEG received indefinite continuations on 7 leases at Christina Lake and the May River Regional Project with 2017 expiry dates. MEG's oil sands leases scheduled to expire in 2018 and located at Christina Lake and the May River Regional Project have obtained indefinite continuations or have received pre-determinations for indefinite continuation. MEG has received pre-determinations for indefinite continuation on two Surmont oil sand leases expiring in 2019. MEG will apply for pre-determinations or continuations for the remaining oil sands leases at Surmont when appropriate.

Certain oil sands leases located in MEG’s Growth Properties (those outside of the Christina Lake, Surmont and May River Regional Projects) are scheduled to expire in 2018 and beyond. As further described in the AIF, MEG is actively working on a lease continuation strategy for these lands in the context of the caribou extensions and the evolving lease tenure regulations.

The Corporation cannot predict the outcome of the lease tenure review and the resulting impact on MEG's oil sands leases. In order to assist lessees in adapting to the changing tenure environment, Alberta Energy has relaxed the minimum level of evaluation while such lease tenure review is ongoing and also provided extensions to lease terms. In addition, Alberta Energy has recently offered the ability for lessees to apply for further lease extensions to March 31, 2019 for leases that fall within designated caribou ranges.

Third Party Risks

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the Regional Municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the Christina Lake Project, MEG's other projects and most of the other oil sands operations in Alberta are located. Such claims and other similar claims that may be initiated, if successful, could have a significant adverse effect on MEG and the Christina Lake Project and MEG's other projects.

Possible Failure to Complete Sale of Access Pipeline and Stonefell Terminal

The sale of the Access Pipeline and Stonefell Terminal is subject to the normal commercial risks that the transaction will not close on the terms specified or at all. The completion of the sale is subject to satisfaction or waiver of a number of conditions, certain of which have not been satisfied or waived as of the date of this MD&A. Accordingly, there can be no assurance that the Corporation will complete the sale of the Access Pipeline and Stonefell Terminal in the timeframe or on the basis described herein, or at all. A failure to complete the sale of the Access Pipeline and Stonefell Terminal or a substantial delay in obtaining necessary approvals could have a material adverse effect on the Corporation’s ability to complete the sale and on the Corporation’s business, financial condition or results of operations.

20. DISCLOSURE CONTROLS AND PROCEDURES

The Corporation’s Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”) have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation’s CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. The CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the Corporation and have concluded that the Corporation's disclosure controls and procedures are effective at December 31, 2017 for the foregoing purposes.

21. INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation’s financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The CEO’s and CFO’s evaluation concluded that internal controls over financial reporting were effective as of December 31, 2017.

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

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

22. ABBREVIATIONS

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

Financial and Business Environment

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

Measurement

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

23. 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, competitive advantage, 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.

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

Estimates of Reserves

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

Non-GAAP Financial Measures

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

24. ADDITIONAL INFORMATION

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

25. QUARTERLY SUMMARIES

	2017				2016			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL ($000 unless specified)								
Net earnings (loss)	**(23,779)**	83,885	104,282	1,588	(304,758)	(108,632)	(146,165)	130,829
Per share, diluted	**(0.08)**	0.28	0.35	0.01	(1.34)	(0.48)	(0.65)	0.58
Operating earnings (loss)	**44,055**	(42,571)	(35,656)	(79,354)	(71,989)	(87,929)	(97,894)	(197,286)
Per share, diluted	**0.15**	(0.14)	(0.12)	(0.29)	(0.32)	(0.39)	(0.43)	(0.88)
Adjusted funds flow from (used in) operations	**192,178**	83,352	55,095	43,175	39,967	22,702	6,964	(131,240)
Per share, diluted	**0.65**	0.28	0.19	0.16	0.18	0.10	0.03	(0.58)
Cash capital investment	**163,337**	103,173	158,474	77,770	63,077	19,203	19,990	34,975
Cash and cash equivalents	**463,531**	397,598	512,424	548,981	156,230	103,136	152,711	124,560
Working capital	**313,025**	350,067	445,463	537,427	96,442	163,038	128,586	183,649
Long-term debt	**4,668,267**	4,635,740	4,813,092	4,944,741	5,053,239	4,909,711	4,871,182	4,859,099
Shareholders' equity	**3,964,113**	3,981,750	3,898,054	3,792,818	3,286,776	3,577,557	3,679,372	3,812,566
BUSINESS ENVIRONMENT								
WTI (US$/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

26. ANNUAL SUMMARIES

Unaudited	2017	2016	2015	2014	2013	2012
FINANCIAL						
($000 unless specified)						
Net earnings (loss)	**165,976**	(428,726)	(1,169,671)	(105,538)	(166,405)	52,569
Per share, diluted	**0.57**	(1.90)	(5.21)	(0.47)	(0.75)	0.26
Operating earnings (loss)	**(113,524)**	(455,098)	(374,374)	247,353	386	21,242
Per share, diluted	**(0.39)**	(2.01)	(1.67)	1.10	0.00	0.11
Adjusted funds flow from (used in) operations	**373,800**	(61,607)	49,460	791,458	253,424	212,514
Per share, diluted	**1.29**	(0.27)	0.22	3.52	1.13	1.06
Cash capital investment	**502,754**	137,245	257,178	1,237,539	2,111,824	1,567,906
Cash and cash equivalents	**463,531**	156,230	408,213	656,097	1,179,072	1,474,843
Working capital	**313,025**	96,442	363,038	525,534	1,045,606	1,655,915
Long-term debt	**4,668,267**	5,053,239	5,190,363	4,350,421	3,990,748	2,478,660
Shareholders' equity	**3,964,113**	3,286,776	3,677,867	4,768,235	4,788,430	4,870,534
BUSINESS ENVIRONMENT						
WTI (US$/bbl)	**50.95**	43.33	48.80	93.00	97.96	94.21
C$ equivalent of 1US$ - average	**1.2980**	1.3256	1.2788	1.1047	1.0296	0.9994
Differential – WTI:WCS ($/bbl)	**15.55**	18.35	17.29	21.63	25.89	21.01
Differential – WTI:WCS (%)	**23.5%**	31.9%	27.7%	21.1%	25.7%	22.3%
Natural gas – AECO ($/mcf)	**2.29**	2.25	2.71	4.50	3.16	2.38
OPERATIONAL						
($/bbl unless specified)						
Bitumen production – bbls/d	**80,774**	81,245	80,025	71,186	35,317	28,773
Bitumen sales – bbls/d	**80,089**	80,426	80,965	67,243	33,715	28,845
Steam-oil ratio (SOR)	**2.3**	2.3	2.5	2.5	2.6	2.4
Bitumen realization	**41.89**	27.79	30.63	62.67	49.28	46.93
Transportation – net	**(6.89)**	(6.46)	(4.82)	(1.38)	(0.26)	(0.31)
Royalties	**(0.77)**	(0.29)	(0.70)	(4.36)	(3.14)	(2.46)
Operating costs – non-energy	**(4.62)**	(5.62)	(6.54)	(8.02)	(9.00)	(9.71)
Operating costs – energy	**(2.98)**	(3.01)	(3.84)	(6.30)	(4.62)	(3.46)
Power revenue	**0.76**	0.64	0.99	2.26	3.61	3.19
Realized gain (loss) on commodity risk management	**(0.39)**	0.08	-	-	-	-
Cash operating netback	**27.00**	13.13	15.72	44.87	35.87	34.18
Power sales price (C$/MWh)	**21.49**	18.74	27.48	48.83	76.23	59.22
Power sales (MW/h)	**118**	115	121	129	67	65
Depletion and depreciation rate per bbl of production	**16.13**	16.81	16.00	14.57	14.67	13.76
COMMON SHARES						
Shares outstanding, end of period (000)	**294,104**	226,467	224,997	223,847	222,507	220,190
Volume traded (000)	**368,987**	566,751	248,316	227,538	134,087	73,738
Common share price ($)						
High	**9.83**	9.79	25.20	41.29	36.69	47.11
Low	**3.28**	3.46	7.33	13.30	25.50	30.25
Close (end of period)	**5.14**	9.23	8.02	19.55	30.61	30.44