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, 2016 was approved by the Board of Directors on March 2, 2017. 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, 2016 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. OVERVIEW

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

MEG owns a 100% working interest in over 900 square miles of oil sands leases. For information regarding MEG's estimated reserves, 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 two commercial SAGD projects; the Christina Lake Project and the Surmont Project. The Christina Lake Project has received regulatory approval for 210,000 barrels per day ("bbls/d") of production and MEG has applied for regulatory approval for 120,000 bbls/d of production at the Surmont Project. The ultimate production rate and life of each project will be dependent on a number of factors, including the size, performance and development schedule for each expansion or phase in those projects. In addition, the Corporation holds other leases known as the "May River Regional Project" and the "Growth Properties." On February 21, 2017, the Corporation filed regulatory applications with the Alberta Energy Regulator for the May River Regional Project. Management anticipates, consistent with the estimates contained in the GLJ Report, that the May River Regional Project can support an average of 164,000 bbls/d of bitumen production. The Growth Properties are in the resource definition and data gathering stage of development.

The Corporation's first two production phases at the Christina Lake Project, Phase 1 and Phase 2, commenced production in 2008 and 2009, respectively. In 2012, the Corporation announced the RISER initiative, which is a combination of proprietary reservoir technologies, including enhanced Modified Steam And Gas Push ("eMSAGP") and redeployment of steam and facilities modifications, including debottlenecking and expansions (collectively "RISER"). Phase 2B commenced production in 2013. Bitumen production at the Christina Lake Project for the year ended December 31, 2016 averaged 81,245 bbls/d. The application of eMSAGP and cogeneration have enabled MEG to lower its greenhouse gas intensity below the *in situ* industry average calculated based on reported data to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. MEG anticipates applying RISER, and specifically eMSAGP, to Phase 2B during 2017.

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.

The May River Regional Project has an anticipated design capacity of approximately 164,000 bbls/d over multiple phases. The May River Regional Project is situated on 285 square miles of lands in the southern Athabasca oil sands region of Alberta.

MEG holds a 50% interest in the Access Pipeline, a dual pipeline system that connects the Christina Lake Project to a large regional upgrading, refining, diluent supply and transportation hub in the Edmonton, Alberta area. MEG's 50% interest of the capacity in the 42-inch blend line is approximately 200,000 bbls/d of blended bitumen.

The Corporation continues to review options available to utilize its interest in the Access Pipeline to reduce the financial leverage of the Corporation. The potential monetization of MEG's 50% interest in the Access Pipeline continues to be a priority of the Corporation.

In addition to the Access Pipeline, MEG holds a 100% interest in the Stonefell Terminal, located near Edmonton, Alberta, with a storage and terminalling capacity of 900,000 barrels. The Stonefell Terminal is connected to local and export markets by pipeline, in addition to being pipeline connected 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.

Effective January 1, 2016, MEG increased its transportation capacity on the Flanagan South and Seaway pipeline systems to U.S. Gulf Coast refineries. This pipeline system went into operation in late 2014.

2. SUMMARY ANNUAL INFORMATION

($000s, except per share amounts)	2016	2015	2014
Revenue[(1)]	**1,866,284**	1,925,916	2,829,964
Net loss	**(428,726)**	(1,169,671)	(105,538)
Per share – basic	**(1.90)**	(5.21)	(0.47)
Per share – diluted	**(1.90)**	(5.21)	(0.47)
Total assets	**8,921,224**	9,400,269	9,930,108
Total non-current liabilities	**5,271,277**	5,474,106	4,700,771

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

During 2015, revenue decreased 32% from 2014, primarily as a result of the significant decline in U.S. crude oil benchmark pricing, partially offset by an increase in production volumes from the Christina Lake Project.

Net Loss

The decrease in the net loss in 2016 compared to the net loss in 2015 is primarily attributable to the change in value of the Canadian dollar relative to the U.S. dollar, which impacts the translation of the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. In 2016, the Corporation recognized an unrealized foreign exchange gain 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.

The net loss in 2015 increased from the net loss recorded in 2014 primarily due to higher unrealized foreign exchange losses attributable to a decrease in value of the Canadian dollar relative to the U.S. dollar, which impacts the translation of the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. In addition to higher unrealized foreign exchange losses in 2015, the net loss was impacted by lower bitumen realization, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, higher transportation costs associated with transporting volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, an increase in depletion and depreciation expense as a result of an increase in bitumen production volumes and an increase in interest expense due to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense. These factors were partially offset by an increase in bitumen sales volumes and lower royalties.

Total Assets

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 as well as an impairment charge of $80.1 million related to the Northern Gateway pipeline and a decrease in cash and cash equivalents. The depletion and depreciation expense in 2016 was in excess of capital investment incurred during 2016, as the Corporation has been focused on reducing capital spending until there is a sustained improvement in crude oil pricing. 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 activity.

Total assets as at December 31, 2015 decreased compared to December 31, 2014 primarily due to an increase in depletion and depreciation expense as a result of an increase in bitumen production volumes and a decrease in cash and cash equivalents. The depletion and depreciation expense in 2015 was in excess of capital investment incurred during 2015, as the Corporation has been focused on reducing capital spending until there is a sustained improvement in crude oil pricing. The cash and cash equivalents balance as at December 31, 2015 decreased compared to December 31, 2014 primarily due to the settlement of accounts payable related to 2014 capital investment activity.

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, 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.

Total non-current liabilities as at December 31, 2015 increased compared to December 31, 2014 primarily due to the Corporation recognizing an unrealized foreign exchange loss on the translation of the U.S. dollar denominated debt as a result of weakening of the Canadian dollar compared to the U.S. dollar by approximately 19% during the year ended December 31, 2015.

3. OPERATIONAL AND FINANCIAL HIGHLIGHTS

On January 27, 2017, the Corporation completed a comprehensive refinancing plan as outlined in the "Capital Resources" section of this MD&A.

The ongoing global imbalance between supply and demand for crude oil continued to significantly impact the Corporation's operating and financial results. The C$/bbl WTI average price for the year ended December 31, 2016 decreased 8% compared to the same period in 2015.

As a result of ongoing cost control initiatives in 2016, the Corporation has reduced non-energy operating costs per barrel by 14% compared to the year ended December 31, 2015 and has reduced general and administrative expense per barrel by 20% compared to the year ended December 31, 2015.

During 2016, the Corporation implemented a strategic commodity risk management program to partially manage its exposure on blend sales prices and condensate purchases with the intent to increase the predictability of the Corporation's future cash flow as governed by the Corporation's Risk Management Committee.

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)	**2016**	**2015**
Bitumen production - bbls/d	**81,245**	80,025
Bitumen realization - $/bbl	**27.79**	30.63
Net operating costs - $/bbl(1)	**7.99**	9.39
Non-energy operating costs - $/bbl	**5.62**	6.54
Cash operating netback - $/bbl(2)	**13.13**	15.72
Adjusted funds flow(3)	**(62)**	49
Per share, diluted(3)	**(0.27)**	0.22
Operating loss(3)	**(455)**	(374)
Per share, diluted(3)	**(2.01)**	(1.67)
Revenue(4)	**1,866**	1,926
Net loss(5)	**(429)**	(1,170)
Per share, basic	**(1.90)**	(5.21)
Per share, diluted	**(1.90)**	(5.21)
Total cash capital investment(6)	**137**	257
Cash and cash equivalents	**156**	408
Long-term debt(7)	**5,053**	5,190

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

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

(3) *Adjusted funds flow, Operating earnings (loss) and the related per share amounts do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. For the years ended December 31, 2016 and December 31, 2015, the non-GAAP measure of adjusted funds flow is reconciled to net cash provided by (used in) operating activities and the non-GAAP measure of operating loss is reconciled to net 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 (Loss) and Comprehensive Income (Loss).*

(5) *Includes a net unrealized foreign exchange gain of $148.2 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents for the year ended December 31, 2016. The net loss for the year ended December 31, 2015 includes a net unrealized foreign exchange loss of $785.3 million.*

(6) *Defined as total capital investment excluding dispositions, capitalized interest, capitalized cash-settled stock-based compensation and non-cash items.*

(7) *On December 8, 2016, Fitch Ratings ("Fitch") assigned the Corporation a first-time Long-Term Issuer Default Rating of B, and assigned a rating of BB to the Corporation's covenant-lite revolving credit facility and term loan and a rating of B to the Corporation's Senior Unsecured Notes. On January 12, 2017, Fitch assigned a BB rating to the Corporation's new second lien secured notes (see the "Capital Resources" section of this MD&A). Fitch's rating outlook is negative. On January 12, 2017, Standard & Poor's Ratings Services ("S&P") assigned a BB+ rating to the Corporation's new second lien secured notes. On January 12, 2017, Moody's Investors Service ("Moody's") upgraded the Corporation's Corporate Family Rating to B3 from Caa2, the Probability of Default Rating to B3-PD from Caa2-PD and the Corporation's Senior Unsecured Notes rating to Caa2 from Caa3. Moody's Speculative Grade Liquidity Rating was raised to SGL-1 from SGL-2. Moody's also assigned a rating of Ba3 to the Corporation's covenant-lite revolving credit facility and refinanced term loan and a rating of Caa1 to the new second lien secured notes. Moody's rating outlook was changed to stable from negative.*

4. RESULTS OF OPERATIONS

Bitumen Production and Steam to Oil Ratio

	2016	2015
Bitumen production – bbls/d	**81,245**	80,025
Steam to oil ratio (SOR)	**2.3**	2.5

Bitumen Production

Bitumen production for the year ended December 31, 2016 averaged 81,245 bbls/d compared to 80,025 bbls/d for the year ended December 31, 2015. The increase in production volumes for the year ended December 31, 2016 is primarily due to the efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project. The implementation of eMSAGP has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production.

Steam to Oil Ratio

The Corporation continues to focus on sustaining production and maintaining efficiency of current production through a lower SOR, which is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR averaged 2.3 for the year ended December 31, 2016 compared to an average SOR of 2.5 for the year ended December 31, 2015. The decrease in SOR for the year ended December 31, 2016 is due to the continued implementation of eMSAGP.

Operating Cash Flow

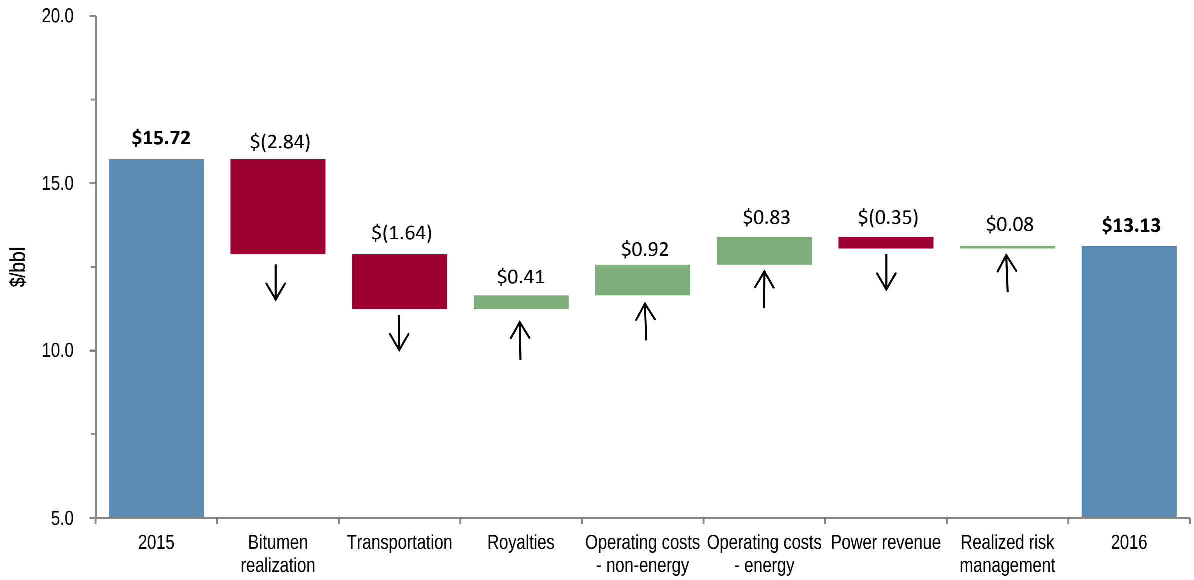
($000)	2016	2015
Petroleum revenue – proprietary(1)	**$ 1,626,025**	$ 1,799,154
Diluent expense	**(808,030)**	(893,995)
	817,995	905,159
Royalties	**(8,581)**	(20,765)
Transportation expense	**(209,864)**	(156,382)
Operating expenses	**(253,758)**	(306,725)
Power revenue	**18,868**	29,239
Transportation revenue	**19,791**	13,824
	384,451	464,350
Realized gain on risk management	**2,359**	-
Operating cash flow(2)	**$ 386,810**	$ 464,350

(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 $386.8 million for the year ended December 31, 2016 compared to $464.4 million for the year ended December 31, 2015. Operating cash flow decreased primarily due to lower blend sales revenue as a result of the year-over-year average decline in U.S. crude oil benchmark pricing, partially offset by a decrease in diluent expense. In addition, the Corporation realized a gain of $2.4 million on commodity risk management contracts in 2016. Blend sales revenue for the year ended December 31, 2016 was $1.6 billion compared to $1.8 billion for the year ended December 31, 2015. The decrease in blend sales revenue is primarily due to a 10% decrease in the average realized blend price. Diluent expense for the year ended December 31, 2016 was $808.0 million compared to $894.0 million for the year ended December 31, 2015, reflecting a decrease in condensate prices.

Cash Operating Netback



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

($/bbl)	**2016**	**2015**
Bitumen realization[1]	**$ 27.79**	$ 30.63
Transportation[2]	**(6.46)**	(4.82)
Royalties	**(0.29)**	(0.70)
	21.04	25.11
Operating costs – non-energy	**(5.62)**	(6.54)
Operating costs – energy	**(3.01)**	(3.84)
Power revenue	**0.64**	0.99
Net operating costs	**(7.99)**	(9.39)
	13.05	15.72
Realized gain on risk management	**0.08**	-
Cash operating netback	**$ 13.13**	$ 15.72

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

Cash operating netback for the year ended December 31, 2016 was $13.13 per barrel compared to $15.72 per barrel for the year ended December 31, 2015. The decrease in cash operating netback for the year ended December 31, 2016 was primarily due to a decrease in bitumen realization, as a result of the year-over-year average decline in U.S. crude oil benchmark pricing and an increase in transportation expense, partially offset by a decrease in net operating costs.

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 $27.79 per barrel for the year ended December 31, 2016 compared to $30.63 per barrel for the year ended December 31, 2015. The decrease in bitumen realization is primarily a result of the year-over-year average decline in U.S. crude oil benchmark pricing which resulted in lower blend sales revenue.

For the year ended December 31, 2016, the Corporation's cost of diluent was $61.06 per barrel of diluent compared to $67.72 per barrel of diluent for the year ended December 31, 2015. The decrease in the cost of diluent is primarily a result of the year-over-year average decline in 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. This improved cash operating netback requires additional transportation. Transportation costs averaged $6.46 per barrel for the year ended December 31, 2016 compared to $4.82 per barrel for the year ended December 31, 2015. Transportation expense increased primarily due to the cost of transporting higher blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan South and Seaway pipeline systems.

Royalties

The Corporation's royalty expense is based on price-sensitive royalty rates set by the Government of Alberta. The applicable royalty rates change dependent upon whether a project is pre-payout or post-payout, with payout being defined as the point in time when a project has generated enough 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.

Royalties averaged $0.29 per barrel during the year ended December 31, 2016 compared to $0.70 per barrel for the year ended December 31, 2015. The decrease in royalties is primarily attributable to lower royalty rates as a result of lower realized prices.

Net Operating Costs

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

Net operating costs for the year ended December 31, 2016 averaged $7.99 per barrel compared to $9.39 per barrel for the year ended December 31, 2015. The decrease in net operating costs is attributable to a per barrel decrease in energy and non-energy operating costs and power revenue.

Non-energy operating costs

Non-energy operating costs averaged $5.62 per barrel for the year ended December 31, 2016 compared to $6.54 per barrel for the year ended December 31, 2015. 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.

Energy operating costs

Energy operating costs averaged $3.01 per barrel for the year ended December 31, 2016 compared to $3.84 per barrel for the year ended December 31, 2015. The decrease in energy operating costs on a per barrel basis is primarily attributable to the decrease in natural gas prices. The Corporation's natural gas purchase price averaged $2.53 per mcf during the year ended December 31, 2016 compared to $3.11 per mcf for the same period in 2015.

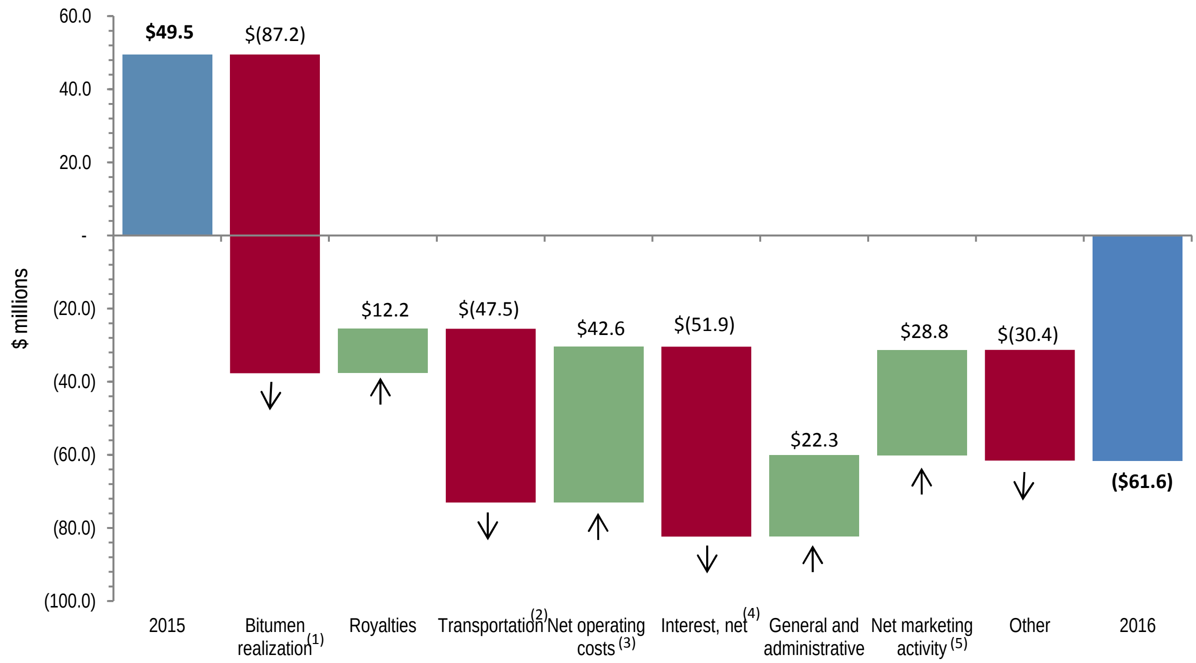
Power revenue

Power revenue averaged $0.64 per barrel for the year ended December 31, 2016 compared to $0.99 per barrel for the year ended December 31, 2015. The Corporation's average realized power sales price during the year ended December 31, 2016 was $18.74 per megawatt hour compared to $27.48 per megawatt hour for the same period in 2015. The decrease in the realized power sales price is primarily due to the overall surplus of power generation capacity in the province of Alberta.

Commodity Risk Management Gain

The realized gain on commodity risk management averaged $0.08 per barrel for the year ended December 31, 2016. Refer to the "RISK MANAGEMENT" section of this MD&A for further details.

Adjusted Funds Flow – 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 net interest expense in Note 21 of the Consolidated Financial Statements less amortization of debt issue costs as presented on the Consolidated Statement of Cash Flow.

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

Adjusted funds flow was $(61.6) million for the year ended December 31, 2016 compared to adjusted funds flow of $49.5 million for the year ended December 31, 2015. The decrease in adjusted funds flow was due to a decrease in bitumen realization and increases in net interest expense, transportation and other. These cash flow reductions were partially offset by decreases in net operating costs, net marketing activity, general and administrative expense and royalties. Adjusted funds flow decreased primarily due to lower bitumen realization. The decrease in bitumen realization is directly correlated to the year-over-year average decline in U.S. crude oil benchmark pricing. The increase in net interest expense is primarily due to the Corporation no longer capitalizing interest in 2016 as a result of the reduction in the Corporation's 2016 capital expenditures. During the fourth quarter of 2015 there was a termination of a marketing transportation contract that impacted net marketing activity. No expenses were incurred related to marketing and storage arrangements for the year ended December 31, 2016.

Operating Loss

Operating 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 $455.1 million for the year ended December 31, 2016 compared to an operating loss of $374.4 million for the year ended December 31, 2015. The increase in the operating loss for the year ended December 31, 2016 was primarily due to lower bitumen realization as a result of the year-over-year average decline in U.S. 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, 2016 totalled $1.87 billion compared to $1.93 billion for the year ended December 31, 2015. Revenue for the year ended December 31, 2016 decreased primarily due to a decrease in blend sales revenue as a result of the year-over-year average decline in U.S. crude oil benchmark pricing.

Net Loss

The Corporation recognized a net loss of $428.7 million for the year ended December 31, 2016 compared to a net loss of $1.2 billion for the year ended December 31, 2015. The net loss for the year ended December 31, 2016 was affected by lower bitumen realization, primarily as a result of the year-over-year average decline in U.S. crude oil benchmark pricing. The net loss for the year ended December 31, 2016 also included an $80.1 million impairment charge related to the Northern Gateway pipeline, an unrealized loss on commodity risk management of $30.3 million and other expenses primarily related to onerous contracts and severance totalling $64.1 million. These were partially offset by a net unrealized foreign exchange gain of $148.2 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. The net loss for the year ended December 31, 2015 included a net unrealized foreign exchange loss of $785.3 million on U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.

Total Cash Capital Investment

Total cash capital investment during the year ended December 31, 2016 totalled $137.2 million as compared to $257.2 million for the year ended December 31, 2015. Capital investment in 2016 was primarily directed towards sustaining capital activities as the Corporation had been focused on reducing capital spending until there is a sustained improvement in crude oil pricing.

5. OUTLOOK

Summary of 2016 Guidance	Guidance October 27, 2016	Annual Results
Capital investment - $ millions	$140	**$137**
Bitumen production - bbls/d	80,000 – 83,000	**81,245**
Non-energy operating costs - $/bbl	$5.75 – $6.50	**$5.62**

Cash capital investment incurred for 2016 was $137 million which was below the Corporation's most recent 2016 cash capital investment guidance of $140 million issued on October 27, 2016. Original capital guidance was issued December 4, 2015 for $328 million and reduced throughout 2016 as a result of continued focus on reducing capital spending until there was a sustained improvement in crude oil pricing.

Annual bitumen production averaged 81,245 bbls/d, consistent with the Corporation's 2016 bitumen production guidance.

As a result of continued operating cost management and efficiency gains in 2016, annual non-energy operating costs were $5.62/bbl, representing a 2% reduction from the low end of the most recent 2016 guidance issued on October 27, 2016. Original guidance issued on December 4, 2015 had non-energy operating costs targeted to be in the range of $6.75 to $7.75 per barrel.

Summary of 2017 Guidance	
Capital investment - $ millions	$590
Bitumen production - bbls/d	80,000 – 82,000
Bitumen exit production - bbls/d	86,000 – 89,000
Non-energy operating costs - $/bbl	$5.75 – $6.75

On January 11, 2017, the Corporation announced a 2017 capital budget of $590 million of which approximately 55% is directed towards initiation of the eMSAGP growth project at Christina Lake Phase 2B, 35% towards sustaining and turnaround costs and the remainder towards supporting marketing, corporate and other initiatives. The Corporation expects to fund the 2017 capital program with net proceeds from the $518 million equity issuance completed on January 27, 2017, internally generated cash flow and $156 million of cash on hand as at December 31, 2016.

The Corporation’s 2017 annual bitumen production volumes are targeted to be in the range of 80,000 to 82,000 bbls/d. Exit production for 2017 is targeted to be in the range of 86,000 to 89,000 bbls/d. Non-energy operating costs are targeted to be in the range of $5.75 to $6.75 per barrel.

6. BUSINESS ENVIRONMENT

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

	Year ended December 31		2016				2015			
	2016	**2015**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**44.97**	53.62	**51.13**	46.98	46.67	35.10	44.71	51.17	63.50	55.16
WTI (US$/bbl)	**43.33**	48.80	**49.29**	44.94	45.59	33.45	42.18	46.43	57.94	48.63
WTI (C$/bbl)	**57.44**	62.40	**65.75**	58.65	58.75	45.99	56.32	60.79	71.24	60.35
Differential – Brent:WTI (US$/bbl)	**1.64**	4.82	**1.84**	2.04	1.08	1.65	2.53	4.74	5.56	6.53
Differential – Brent:WTI (%)[1]	**3.6%**	9.0%	**3.6%**	4.3%	2.3%	4.7%	5.7%	9.3%	8.8%	11.8%
WCS (C$/bbl)	**39.09**	45.12	**46.65**	41.03	41.61	26.41	36.97	43.29	56.98	42.13
Differential – WTI:WCS (US$/bbl)	**13.84**	13.52	**14.32**	13.50	13.30	14.24	14.49	13.27	11.59	14.73
Differential – WTI:WCS (C$/bbl)	**18.35**	17.29	**19.10**	17.62	17.14	19.58	19.35	17.50	14.25	18.22
Differential – WTI:WCS (%)	**31.9%**	27.7%	**29.1%**	30.0%	29.2%	42.6%	34.4%	28.8%	20.0%	30.2%
Condensate prices										
Condensate at Edmonton (C$/bbl)	**56.21**	60.30	**64.49**	56.25	56.83	47.27	55.57	57.89	71.17	56.59
Condensate at Edmonton as % of WTI	**97.9%**	96.6%	**98.1%**	95.9%	96.7%	102.8%	98.7%	95.2%	99.9%	93.8%
Condensate at Mont Belvieu, Texas (US$/bbl)	**39.68**	45.23	**45.17**	41.17	40.37	32.03	40.76	41.27	52.89	46.01
Condensate at Mont Belvieu, Texas as % of WTI	**91.6%**	92.7%	**91.6%**	91.6%	88.6%	95.8%	96.6%	88.9%	91.3%	94.6%
Natural gas prices										
AECO (C$/mcf)	**2.25**	2.71	**3.31**	2.49	1.37	1.82	2.57	2.89	2.64	2.74
Electric power prices										
Alberta power pool (C$/MWh)	**18.19**	33.40	**21.97**	17.93	14.77	18.09	21.19	26.04	57.25	29.14
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.3256**	1.2788	**1.3339**	1.3051	1.2886	1.3748	1.3353	1.3093	1.2294	1.2411
C$ equivalent of 1 US$ - period end	**1.3427**	1.3840	**1.3427**	1.3117	1.3009	1.2971	1.3840	1.3394	1.2474	1.2683

Crude Oil Pricing

Brent crude is the primary world price benchmark for global light sweet crude oil. The Brent benchmark price averaged US$44.97 per barrel for the year ended December 31, 2016 compared to US$53.62 per barrel for the year ended December 31, 2015. Recent announcements arising out of a meeting between OPEC ("Organization of the Petroleum Exporting Countries") and non-OPEC counterparties, held in the latter part of the fourth quarter of 2016, resulted in a slight increase in late fourth quarter prices.

The price of WTI is the current benchmark for mid-continent North American crude oil prices, at Cushing Oklahoma, and its Canadian dollar equivalent is the basis for determining royalties on the Corporation's bitumen sales. The WTI price averaged US$43.33 per barrel for the year ended December 31, 2016 compared to US$48.80 per barrel for the year ended December 31, 2015. Recent announcements arising out of a meeting between OPEC and non-OPEC counterparties, held in the latter part of the fourth quarter of 2016, resulted in a slight increase in late fourth quarter prices.

The WCS benchmark reflects North American prices at Hardisty, Alberta. WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. WCS typically trades at a differential below the WTI benchmark price. The WTI:WCS differential averaged US$13.84 per barrel, or 31.9%, for the year ended December 31, 2016 compared to US$13.52 per barrel, or 27.7%, for the year ended December 31, 2015.

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 $56.21 per barrel, or 97.9% of WTI, for the year ended December 31, 2016 compared to $60.30 per barrel, or 96.6% of WTI, for the year ended December 31, 2015. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$39.68 per barrel, or 91.6% of WTI, for the year ended December 31, 2016 compared to US$45.23 per barrel, or 92.7% of WTI, for the year ended December 31, 2015.

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 $2.25 per mcf for the year ended December 31, 2016 compared to $2.71 per mcf for the year ended December 31, 2015.

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 $18.19 per megawatt hour for the year ended December 31, 2016 compared to $33.40 per megawatt hour for the same period in 2015. The decline in the Alberta power pool price is primarily due to an overall surplus of power generation capacity in the province.

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. 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, 2016, the Canadian dollar, at a rate of 1.3427, had increased in value by approximately 3% against the U.S. dollar compared to its value as at December 31, 2015, when the rate was 1.3840.

7. OTHER OPERATING RESULTS

Net Marketing Activity

($000)		2016		2015
Petroleum revenue – third party	**$**	**205,790**	$	104,464
Purchased product and storage:				
Purchased product		**(202,135)**		(101,928)
Marketing and storage arrangements		**-**		(27,687)
		(202,135)		(129,615)
Net marketing activity[1]	**$**	**3,655**	$	(25,151)

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

Net marketing activity includes the Corporation's activities toward enhancing its ability to transport proprietary crude oil products to a wider range of markets in Canada, the United States and on tidewater. Accordingly, the Corporation has entered into marketing arrangements for rail, pipelines, transportation commitments and product storage arrangements. The intent of these arrangements is to maximize the value of all barrels sold into the marketplace. In the event that the Corporation is not utilizing these arrangements for proprietary purposes, MEG 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.

During the fourth quarter of 2015, the Corporation recognized a contract cancellation expense of $18.8 million primarily due to the termination of a marketing transportation contract. No expenses were incurred related to marketing and storage arrangements for the year ended December 31, 2016.

Depletion and Depreciation

($000)		2016		2015
Depletion and depreciation expense	**$**	**499,811**	$	467,422
Depletion and depreciation expense per barrel of production	**$**	**16.81**	$	16.00

Depletion and depreciation expense for the year ended December 31, 2016 totalled $499.8 million compared to $467.4 million for the year ended December 31, 2015. Depletion and depreciation expense was $16.81 per barrel for the year ended December 31, 2016 compared to $16.00 per barrel for the year ended December 31, 2015. The increase in the depletion and depreciation expense per barrel was primarily due to an increase in the estimated future development costs associated with the Corporation's proved reserves and an increase in depreciable costs for the year ended December 31, 2016 compared to the year ended December 31, 2015.

Impairment

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. On June 18, 2014, Northern Gateway received certificates from the NEB permitting the construction of the oil pipeline subject to conditions. On June 30, 2016, the Federal Court of Appeal ("FCA") quashed these certificates on the basis that the Crown's Phase IV Aboriginal consultation process was inadequate. The FCA held that the hearing leading to the approved permits and the consultation conducted by Northern Gateway was properly done. On November 29, 2016, the Federal Government, rather than conducting further consultation with Aboriginal communities, announced that it would instruct the NEB to dismiss the application and on December 6, 2016, the NEB formalized this dismissal. As a result, the Corporation fully impaired its investment and has recognized an impairment charge of $80.1 million.

Commodity Risk Management Gain (Loss)

During the year ended December 31, 2016, the Corporation entered into commodity risk management contracts. The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes. All 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 commodity risk management contracts are the result of contract settlements during the year. 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 year.

	2016		
($000)	**Realized**	**Unrealized**	**Total**
Crude oil contracts[1]	**$ (9,888)**	**$ (59,404)**	**$ (69,292)**
Condensate contracts[2]	**12,247**	**29,091**	**41,338**
Commodity risk management gain (loss)	**$ 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 recognized an unrealized loss on commodity risk management contracts of $30.3 million and a realized gain on commodity risk management contracts of $2.4 million for the year ended December 31, 2016. Refer to the "RISK MANAGEMENT" section of this MD&A for further details.

During 2015, the Corporation did not enter into any commodity risk management contracts.

General and Administrative

($000)	**2016**	**2015**
General and administrative expense	**$ 96,241**	$ 118,518
General and administrative expense per barrel of production	**$ 3.24**	$ 4.06

General and administrative expense for the year ended December 31, 2016 was $96.2 million compared to $118.5 million for the year ended December 31, 2015. General and administrative expense was $3.24 per barrel for the year ended December 31, 2016 compared to $4.06 per barrel for the year ended December 31, 2015. General and administrative expense decreased primarily due to a reduction in staffing and the Corporation's continued focus on cost management in all areas of the business.

Stock-based Compensation

($000)	2016	2015
Cash-settled	**$ 16,354**	$ -
Equity-settled	**33,588**	50,105
Stock-based compensation expense	**$ 49,942**	$ 50,105

The fair value of compensation associated with the granting of stock options, restricted share units ("RSUs"), performance share units ("PSUs") and directors 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.

In June 2016, the Corporation granted RSUs and PSUs under a new cash-settled Restricted Share Unit Plan. 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 and PSUs are accounted for as liability instruments and are measured at fair value based on estimated vesting and 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, 2016 was $49.9 million compared to $50.1 million for the year ended December 31, 2015.

Research and Development

($000)	2016	2015
Research and development expense	**$ 5,499**	$ 7,497

Research and development expenditures related to the Corporation's research of crude quality improvement and related technologies have been expensed. Research and development expenditures were $5.5 million for the year ended December 31, 2016 compared to $7.5 million for the year ended December 31, 2015.

Foreign Exchange Loss (Gain), Net

($000)	2016	2015
Unrealized foreign exchange loss (gain) on:		
Long-term debt	**$ (157,272)**	$ 852,422
Other	**9,119**	(67,112)
Unrealized net loss (gain) on foreign exchange	**(148,153)**	785,310
Realized loss (gain) on foreign exchange	**(3,242)**	16,429
Foreign exchange loss (gain), net	**$ (151,395)**	$ 801,739
C$ equivalent of 1 US$		
Beginning of year	**1.3840**	1.1601
End of year	**1.3427**	1.3840

The Corporation recognized a net foreign exchange gain of $151.4 million for the year ended December 31, 2016 compared to a net foreign exchange loss of $801.7 million for the year ended December 31, 2015. The net foreign exchange gain is primarily due to 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. During the year ended December 31, 2015, the Canadian dollar weakened in value by approximately 19%.

Net Finance Expense

($000)	2016	2015
Total interest expense	**$ 328,335**	$ 313,411
Less capitalized interest	**-**	(56,449)
Net interest expense	**328,335**	256,962
Debt extinguishment expense	**28,845**	-
Accretion on provisions	**7,150**	5,663
Unrealized gain on derivative financial liabilities(1)	**(12,508)**	(13,289)
Realized loss on interest rate swaps	**4,548**	5,858
Net finance expense	**$ 356,370**	$ 255,194
Average effective interest rate(2)	**5.8%**	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 and senior unsecured notes outstanding, including the impact of interest rate swaps.*

Total interest expense, before capitalization, for the year ended December 31, 2016 was $328.3 million compared to $313.4 million for the year ended December 31, 2015. Total interest expense for the year ended December 31, 2016 was higher than the comparative 2015 period due to a weaker average Canadian dollar and its impact on U.S. dollar denominated interest expense.

The Corporation capitalizes interest associated with qualifying assets. As a result of the reduction in the Corporation's 2016 capital expenditures, the Corporation did not capitalize interest during the year ended December 31, 2016. During the year ended December 31, 2015, the Corporation capitalized $56.5 million of interest.

At December 31, 2016, the Corporation recognized $28.8 million of debt extinguishment expense associated with the planned redemption of the 6.5% Senior Unsecured Notes on March 15, 2017, under the comprehensive refinancing plan completed on January 27, 2017, as described in the "Capital Resources" section of this MD&A. The debt extinguishment expense is comprised of a redemption premium of $21.8 million and the associated remaining unamortized deferred debt issue costs of $7.0 million.

Unrealized gain on derivative liabilities includes unrealized gains related to the change in fair value of the interest rate floor associated with the Corporation's senior secured term loan and the change in fair value of the Corporation's interest rate swap contracts. The Corporation recognized an unrealized gain on derivative financial liabilities of $12.5 million for the year ended December 31, 2016 compared to an unrealized gain of $13.3 million for the year ended December 31, 2015.

The Corporation's interest rate swap contracts expired on September 30, 2016. The Corporation realized a loss on the interest rate swaps of $4.5 million for the year ended December 31, 2016 compared to a realized loss of $5.9 million for the year ended December 31, 2015.

Other Expenses

($000)	**2016**	**2015**
Onerous contracts	**$ 47,866**	$ 58,719
Severance and other	**16,242**	-
Contract cancellation expense	**-**	12,879
Other expenses	**$ 64,108**	$ 71,598

The Corporation recognized other expenses of $64.1 million for the year ended December 31, 2016 compared to $71.6 million for the year ended December 31, 2015.

For the year ended December 31, 2016, the Corporation recognized an onerous contracts expense of $47.9 million primarily due to a decrease in estimated future cash flow recoveries related to the onerous office lease provision. During the fourth quarter of 2015, the Corporation recognized $58.7 million relating to certain onerous Calgary office building lease contracts, determined as the difference between future lease obligations and estimated sublease recoveries.

During the year ended December 31, 2016, severance and other expenses of $16.2 million were incurred.

For the year ended December 31, 2015, the Corporation recognized contract cancellation expense of $12.9 million primarily relating to the termination of a marketing transportation contract, partially offset by a recovery of project cancellation costs recorded in the second quarter of 2015.

Income Tax Expense (Recovery)

($000)	2016	2015
Current income tax expense (recovery)	**$ 919**	$ (1,200)
Deferred income tax expense (recovery)	**(208,413)**	(90,733)
Income tax expense (recovery)	**$ (207,494)**	$ (91,933)

The Corporation recognized a current income tax expense of $0.9 million for the year ended December 31, 2016 relating to U.S. income tax associated with its operations in the United States. The Corporation's Canadian operations are not currently taxable. During the year ended December 31, 2015, the Corporation recognized a current income tax recovery of $1.2 million which was related to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures.

The Corporation recognized a deferred income tax recovery of $208.4 million for the year ended December 31, 2016 compared to a deferred income tax recovery of $90.7 million for the year ended December 31, 2015.

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 unrealized foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the year ended December 31, 2016, the non-taxable gain was $78.6 million compared to a non-taxable loss of $426.2 million for the year ended December 31, 2015.

- 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, 2016 was $33.6 million compared to $50.1 million for the year ended December 31, 2015.

- During the year ended December 31, 2016, a deferred tax recovery of $2.1 million was recognized relating to a tax deduction available for the fair market value of vested RSUs. During the year ended December 31, 2015, a deferred tax recovery of $5.5 million was recognized relating to a tax deduction available for the fair market value of vested RSUs.

As at December 31, 2016, the Corporation had approximately $8.0 billion of available tax pools and $219.6 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

As at December 31, 2016, the Corporation has recognized a deferred income tax asset of $120.9 million, as estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

As at December 31, 2016, the Corporation had not recognized the tax benefit related to $617.5 million of unrealized taxable capital foreign exchange losses.

8. SUMMARY OF QUARTERLY RESULTS

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

	2016				2015			
($ millions, except per share amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue[1]	**$565.8**	**$496.8**	**$513.4**	**$290.3**	$444.5	$459.8	$554.6	$467.0
Net earnings (loss)	**(304.8)**	**(108.6)**	**(146.2)**	**130.8**	(297.3)	(427.5)	63.4	(508.3)
Per share – basic	**(1.34)**	**(0.48)**	**(0.65)**	**0.58**	(1.32)	(1.90)	0.28	(2.27)
Per share – diluted	**(1.34)**	**(0.48)**	**(0.65)**	**0.58**	(1.32)	(1.90)	0.28	(2.27)

(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 for the eight most recent quarters has been impacted by the significant fluctuations in blend sales pricing and increases in production.

Net earnings (loss) during the periods noted was impacted by:

- increased blend sales volumes due to efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project during 2016, which has allowed additional wells to be placed into production;
- fluctuations in blend sales pricing due to significant changes in the price of WTI and the differential between WTI and the Corporation's AWB;
- changes in the value of the Canadian dollar relative to the U.S. dollar as blend sales prices are determined by reference to U.S. crude oil benchmark pricing;
- the cost of diluent due to 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;
- higher transportation expense due to the cost of transporting blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline;
- fluctuations in natural gas and power pricing;
- an increase in depletion and depreciation expense as a result of the increase in bitumen sales volumes, an increase in depreciable costs and higher estimated future development costs;
- an impairment charge related to the Corporation’s investment in the right to participate in the Northern Gateway pipeline;
- foreign exchange gains and losses attributable to fluctuations in the rate of exchange between the Canadian and U.S. dollar in translating the Corporation's U.S. dollar denominated debt (net of U.S. dollar denominated cash and cash equivalents);
- fluctuations in interest expense due to fluctuations in the average Canadian dollar and its impact on U.S. dollar denominated interest expense;
- gains and losses on commodity risk management contracts entered into in 2016; and
- other expenses primarily related to changes in onerous contracts and severance costs.

9. NET CAPITAL INVESTMENT

($000)	2016	2015
Total cash capital investment	**$ 137,245**	$ 257,178
Capitalized cash-settled stock-based compensation	**2,491**	-
Capitalized interest	**-**	56,449
	139,736	313,627
Dispositions	**-**	(41,827)
Net capital investment	**$ 139,736**	$ 271,800

Total cash capital investment for the year ended December 31, 2016 was $137.2 million, compared to $257.2 million for the year ended December 31, 2015. Total capital investment in 2016 was primarily directed towards sustaining capital activities, as the Corporation has been focused on reducing capital spending until there is a sustained improvement in crude oil pricing.

During 2016, the Corporation began capitalizing the cost related to a new cash-settled stock-based compensation plan for employees directly involved in capital investing activities. During the year ended December 31, 2016, the Corporation capitalized $2.5 million of cash-settled stock-based compensation.

The Corporation capitalizes interest associated with qualifying assets. As a result of the reduction in the Corporation's 2016 capital expenditures, the Corporation did not capitalize interest during the year ended December 31, 2016. During the year ended December 31, 2015, the Corporation capitalized $56.4 million of interest.

During the fourth quarter of 2015, the Corporation divested of a non-core undeveloped oil sands asset for proceeds of $110.0 million.

10. LIQUIDITY AND CAPITAL RESOURCES

($000)	December 31, 2016	December 31, 2015
Cash and cash equivalents	**$ 156,230**	$ 408,213
Senior secured term loan (December 31, 2016 – US$1.236 billion;December 31, 2015 – US$1.249 billion; due 2020)	**1,658,906**	1,727,924
US$2.5 billion revolver (due 2019)	**-**	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	**1,007,025**	1,038,000
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,074,160**	1,107,200
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,342,700**	1,384,000
Total debt[(1),(2)]	**$ 5,082,791**	$ 5,257,124

(1) *Total debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The Corporation uses this non-GAAP measure to analyze leverage and liquidity. Total debt plus the debt redemption premium less current portion of the senior secured term loan, unamortized financial derivative liability discount and unamortized deferred debt issue costs is equal to long-term debt as reported in the Corporation's consolidated financial statements as at December 31, 2016 and the Corporation's consolidated financial statements as at December 31, 2015.*

(2) *On December 8, 2016, Fitch Ratings ("Fitch") assigned the Corporation a first-time Long-Term Issuer Default Rating of B, and assigned a rating of BB to the Corporation's covenant-lite revolving credit facility and term loan and a rating of B to the*

Corporation's Senior Unsecured Notes. On January 12, 2017, Fitch assigned a BB rating to the Corporation's new second lien secured notes (see the "Capital Resources" section of this MD&A). Fitch's rating outlook is negative. On January 12, 2017, Standard & Poor's Ratings Services ("S&P") assigned a BB+ rating to the Corporation's new second lien secured notes. On January 12, 2017, Moody's Investors Service ("Moody's") upgraded the Corporation's Corporate Family Rating to B3 from Caa2, the Probability of Default Rating to B3-PD from Caa2-PD and the Corporation's Senior Unsecured Notes rating to Caa2 from Caa3. Moody's Speculative Grade Liquidity Rating was raised to SGL-1 from SGL-2. Moody's also assigned a rating of Ba3 to the Corporation's covenant-lite revolving credit facility and refinanced term loan and a rating of Caa1 to the new second lien secured notes. Moody's rating outlook was changed to stable from negative.

Capital Resources

The Corporation's cash and cash equivalents balance totalled $156.2 million as at December 31, 2016 compared to $408.2 million as at December 31, 2015. The Corporation's cash and cash equivalents balance decreased primarily due to the use of cash for interest and principal payments and payments relating to capital investing activity.

All of the Corporation's long-term debt is denominated in U.S. dollars. As a result of the increase in the value of the Canadian dollar relative to the U.S. dollar, long-term debt decreased to C$5.1 billion as at December 31, 2016 from C$5.2 billion as at December 31, 2015.

On December 1, 2016, the Corporation filed a Canadian base shelf prospectus for common shares, debt securities, subscription receipts, warrants and units (together referred to as "Securities") in the amount of $1.5 billion. The Canadian base shelf prospectus allows for the issuance of these Securities in Canadian dollars or other currencies from time to time in one or more offerings. As at December 31, 2016, no Securities were issued under the Canadian base shelf prospectus. The Canadian base shelf prospectus expires on January 1, 2019.

On January 27, 2017, the Corporation completed 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 existing 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. It has no financial covenants and is not subject to any borrowing base redetermination;
- The US$1.2 billion term loan has been refinanced to extend its maturity date from March 2020 to December 2023. The refinanced term loan will bear interest at an annual rate of LIBOR plus 3.5% with a LIBOR floor of 1%. The term loan was issued at a price equal to 99.75% of its face value;
- The existing 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% second lien secured notes, issued at par, maturing January 2025. The existing 2021 notes will be redeemed with the proceeds from the 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 subscription receipts at a price C$7.75 per subscription receipt on a bought deal basis from a syndicate of underwriters. As part of the closing, escrow release conditions for the subscription receipt offering have been satisfied and the subscription receipts have been converted into common shares.

In addition to the transactions noted above, on February 15, 2017, the Corporation extended the maturity date on the Corporation's current five-year guaranteed letter of credit facility, guaranteed by Export Development Canada, to November 2021 from November 2019. The guaranteed letter of credit facility has been reduced from US$500 million to US$440 million and as at December 31, 2016, US$318 million of letters of credit have been issued. Letters of credit under this facility do not consume capacity of the revolving credit facility.

All of MEG's long-term debt, 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 an investment grade debt rating. 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. During 2016, the Corporation implemented a strategic commodity risk management program through the use of derivative financial instruments with the intent to increase 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 commodity risk management contracts to partially manage its exposure on blend sales and condensate purchases. The Corporation had the following commodity risk management contracts relating to crude oil sales outstanding:

As at December 31, 2016	Volumes (bbls/d)	Term	Average Price (US$/bbl)
Fixed Price:			
WTI Fixed Price	3,500	Jan 1, 2017 – Jun 30, 2017	$52.54
WTI Fixed Price	13,100	Jul 1, 2017 – Dec 31, 2017	$55.19
WCS Fixed Differential	18,000	Jan 1, 2017 – Jun 30, 2017	$(14.94)
Collars:			
WTI Collars	49,250	Jan 1, 2017 – Mar 31, 2017	$45.69 – $54.76
WTI Collars	47,250	Apr 1, 2017 – Jun 30, 2017	$45.71 – $54.61
WTI Collars	28,000	Jul 1, 2017 – Dec 31, 2017	$47.68 – $58.53

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

As at December 31, 2016	Volumes (bbls/d)	Term	Average % of WTI
Mont Belvieu fixed % of WTI	15,150	Jan 1, 2017 – Dec 31, 2017	82.9%

The Corporation has entered into the following commodity risk management contracts relating to crude oil sales subsequent to December 31, 2016.

Subsequent to December 31, 2016	Volumes (bbls/d)	Term	Average Price (US$/bbl)
Fixed Price:			
WTI Fixed Price	6,000	Mar 1, 2017 – Jun 30, 2017	$54.82
WTI Fixed Price	9,000	Jul 1, 2017 – Dec 31, 2017	$55.09
WCS Fixed Differential	26,943	Feb 1, 2017 – Jun 30, 2017	$(15.06)
WCS Fixed Differential	28,000	Jul 1, 2017 – Dec 31, 2017	$(15.62)
Collars:			
WTI Collars	2,500	Jul 1, 2017 – Dec 31, 2017	$50.00 – $59.00

Interest Rate Risk Management

During 2015 and 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 $1.236 billion senior secured term loan. These interest rate swap contracts expired on September 30, 2016.

Cash Flow Summary

($000)	2016	2015
Net cash provided by (used in):		
Operating activities	**$ (94,074)**	$ 112,158
Investing activities	**(131,111)**	(416,996)
Financing activities	**(17,062)**	(17,020)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(9,736)**	73,974
Change in cash and cash equivalents	**$ (251,983)**	$ (247,884)

Cash Flow – Operating Activities

Net cash used in operating activities totalled $94.1 million for the year ended December 31, 2016 compared to net cash provided by operating activities of $112.2 million for the year ended December 31, 2015. The decrease in cash flow provided by operating activities is primarily due to lower bitumen realization, particularly in the first quarter of 2016, primarily as a result of the year-over-year average decline in U.S. crude oil benchmark pricing as well as the use of cash for quarterly interest payments.

Cash Flow – Investing Activities

Net cash used in investing activities was $131.1 million for the year ended December 31, 2016 compared to $417.0 million for the year ended December 31, 2015. The decrease in net cash used in investing activities is primarily due to a reduction of the Corporation's capital program in 2016.

Cash Flow – Financing Activities

Net cash used in financing activities was $17.1 million for the year ended December 31, 2016 compared to $17.0 million for the year ended December 31, 2015. Net cash used in financing activities is comprised of debt principal payments.

11. SHARES OUTSTANDING

As at December 31, 2016, the Corporation had the following share capital instruments outstanding or exercisable:

	Outstanding
Common shares	**226,467,107**
Convertible securities	
Stock options[1]	**9,281,186**
Equity-settled RSUs and PSUs	**1,655,606**

(1) 5,816,854 stock options were exercisable as at December 31, 2016.

As at February 21, 2017, the Corporation had 293,282,107 common shares, 8,950,363 stock options and 1,559,986 equity-settled restricted share units and equity-settled performance share units outstanding and 5,663,650 stock options exercisable.

The Corporation's common shares have increased as a result of the issuance of 66,815,000 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 AND COMMITMENTS

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

($000)	2017	2018	2019	2020	2021	Thereafter
Long-term debt(1)	$ 39,267	$ 17,455	$ 17,455	$1,606,541	$1,007,025	$ 2,416,860
Interest on long-term debt(1)	289,940	289,286	288,631	242,957	173,376	285,659
Decommissioning obligation(2)	3,097	6,252	7,795	7,956	2,957	797,029
Transportation and storage(3)	178,632	202,913	192,853	232,719	270,293	2,997,998
Office lease rentals(4)	33,640	32,198	32,228	33,144	33,542	231,543
Diluent purchases(5)	189,721	20,725	20,725	20,782	20,725	37,986
Other commitments(6)	35,323	8,440	11,657	12,354	11,552	74,077
Total	**$769,620**	**$ 577,269**	**$ 571,344**	**$ 2,156,453**	**$1,519,470**	**$ 6,841,152**

(1) This represents the scheduled principal repayments of the senior secured term loan and the senior unsecured notes, debt redemption premium and associated interest payments based on interest and foreign exchange rates in effect on December 31, 2016.
(2) This represents the undiscounted future obligations associated with the decommissioning of the Corporation's crude oil, transportation and storage assets.
(3) This represents transportation and storage commitments from 2017 to 2042, including various pipeline commitments which are awaiting regulatory approval.
(4) This represents the future lease commitments for the Calgary Corporate office.
(5) This represents the future commitments associated with the Corporation's diluent purchases.
(6) This represents the future commitments associated with the Corporation's capital program and other operating and maintenance commitments.

13. NON-GAAP MEASURES

Certain financial measures in this MD&A including: net marketing activity, funds flow, adjusted funds flow, operating loss and operating cash flow 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 related marketing 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 (Loss) and Comprehensive Income (Loss).

Funds Flow and Adjusted Funds Flow

Prior to the fourth quarter of 2016, the Corporation reported cash flow from (used in) operations as a non-GAAP measure. Beginning in the fourth quarter of 2016, the Corporation changed the label of this non-GAAP measure to "funds flow" and "adjusted funds flow". The Corporation believes that this labelling and presentation better distinguishes these measures from the IFRS measurement "net cash provided by (used in) operating activities".

Funds flow and adjusted funds flow, previously referred to as cash flow from (used in) operations, are non-GAAP measures utilized by the Corporation to analyze operating performance and liquidity. Funds flow 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 excludes the net change in non-cash operating working capital, net change in other liabilities, contract cancellation expense and decommissioning expenditures while the IFRS measurement "net cash provided by (used in) operating activities" includes these items. Funds flow and adjusted funds flow are not intended to represent net cash provided by (used in) operating activities calculated in accordance with IFRS. Funds flow and adjusted funds flow are reconciled to net cash provided by (used in) operating activities in the table below.

($000)	**2016**	**2015**
Net cash provided by (used in) operating activities	**$ (94,074)**	$ 112,158
Net change in non-cash operating working capital items	**25,061**	(77,991)
Funds flow	**(69,013)**	34,167
Adjustments:		
Net change in other liabilities	**6,116**	541
Contract cancellation expense	**-**	12,879
Decommissioning expenditures	**1,290**	1,873
Adjusted funds flow	**$ (61,607)**	$ 49,460

Operating Loss

Operating 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 loss is defined as net loss as reported, excluding unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial instruments, impairment charges, gains and losses on disposition of assets, unrealized gains and losses on risk management, debt extinguishment expense, contract cancellation expense, onerous contracts, insurance proceeds and the respective deferred tax impact on these adjustments. Operating loss is reconciled to "Net loss", the nearest IFRS measure, in the table below.

($000)	2016	2015
Net loss	**$ (428,726)**	$(1,169,671)
Adjustments:		
Unrealized net loss (gain) on foreign exchange[(1)]	**(148,153)**	785,310
Unrealized gain on derivative financial instruments[(2)]	**(12,508)**	(13,289)
Impairment charge	**80,072**	-
Gain on disposition of assets[(3)]	**-**	(68,192)
Unrealized loss on risk management[(4)]	**30,313**	-
Debt extinguishment expense[(5)]	**28,845**	-
Contract cancellation expense	**-**	12,879
Onerous contracts expense[(6)]	**47,866**	58,719
Insurance proceeds[(7)]	**(4,391)**	-
Deferred tax expense (recovery) relating to these adjustments	**(48,416)**	19,870
Operating loss	**$ (455,098)**	$ (374,374)

(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 instruments 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) *A gain related to the sale of a non-core undeveloped oil sands asset in the fourth quarter of 2015.*

(4) *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.*

(5) *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.*

(6) *During 2016, onerous contracts expenses were recognized primarily due to changes in estimated future cash flows related to the onerous office lease provision.*

(7) *Includes insurance proceeds related to the small fire that occurred during the first quarter of 2016, which caused damage to the Sulphur Recovery Unit at the Corporation's Christina Lake facility.*

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.

14. 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 share price at the date of grant 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.

15. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the year ended December 31, 2016 and December 31, 2015, other than compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($000)	2016	2015
Salaries and short-term employee benefits	**$ 9,117**	$ 8,710
Share-based compensation	**12,006**	13,323
Termination benefits	**1,617**	-
	$ 22,740	$ 22,033

16. OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2016 and December 31, 2015, 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, 2016 and December 31, 2015.

17. NEW ACCOUNTING STANDARDS

There were no new accounting standards adopted during the year ended December 31, 2016.

Accounting standards issued but not yet applied

The IASB has issued the following standards which are not yet effective:

On January 19, 2016, the IASB issued amendments to IAS 12, Income Taxes, relating to the recognition of deferred tax assets for unrealized losses. The amendments are effective for annual periods beginning on or after January 1, 2017, with early adoption permitted. Amendments to IAS 12 will be applied on a retrospective basis by the Corporation on January 1, 2017. The adoption of this amended standard is not expected to have a material impact on the Corporation's consolidated financial statements.

On January 29, 2016, the IASB issued amendments to IAS 7, Statement of Cash Flows, as part of its disclosure initiative. The amendments require an entity to disclose changes in liabilities arising from financing activities. The amendments are effective for annual periods beginning on or after January 1, 2017, with early adoption permitted. Amendments to IAS 7 will be applied by the Corporation on January 1, 2017. The adoption of this amended standard will have required disclosure impacts that enable users of financial statements to evaluate changes in liabilities arising from financing activities on the Corporation's consolidated financial statements.

On June 20, 2016, the IASB issued amendments to IFRS 2, relating to classification and measurement of particular share-based payment transactions. The amendments are effective for periods beginning on or after January 1, 2018. The Corporation is currently assessing the impact of the adoption of these amendments on the Corporation's consolidated financial statements.

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 and the Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements.

In May 2014, the IASB issued IFRS 15 Revenue From Contracts With Customers, which will replace IAS 11 Construction Contracts and IAS 18 Revenue and the related interpretations on revenue recognition. IFRS 15 provides a comprehensive revenue recognition and measurement framework that applies to all contracts with customers. The new standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. IFRS 15 will be adopted by the Corporation on January 1, 2018 and the Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements.

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

18. 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 the risks which have been categorized below as construction risks, operations risks and project development risks. Further information regarding the risk factors which may affect the Corporation is contained in the 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.

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, 2016 and a preparation date of February 2, 2017 ("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 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

The Corporation is 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. Recent amendments to the SGER have increased the maximum emission intensity reduction requirement for facility owners from 12% to 15% in 2016 and to 20% starting in 2017. Additionally, one of the options for complying with the SGER is for facility owners to purchase technology fund credits. In June 2016, the Government of Alberta increased the price for such credits from $15 per tonne to $20 per tonne for 2016 and to $30 per tonne beginning in 2017.

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 (the "Report") 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 will implement to address climate change: (1) the complete phase-out of coal-fired sources of electricity by 2030; (2) implementing an Alberta economy-wide price on greenhouse gas emissions of $30 per tonne; (3) 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 (4) 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*, 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. Many details regarding how the Plan will be implemented have not been released.

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. The 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, such as a cap-and-trade scheme. Alberta has already established a carbon pricing system that was referenced in the federal government announcement; therefore, in the short-term, the national price on carbon will likely have little additional impact.

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 conventional oil, natural gas and 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 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.

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.

19. 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, 2016 for the foregoing purposes.

20. 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, 2016.

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.

21. 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
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
OPEC	Organization of the Petroleum Exporting Countries
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam to 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

22. ADVISORY

Forward-Looking Information

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

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

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.

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

23. 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.

24. QUARTERLY SUMMARIES

	2016				2015			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL ($000 unless specified)								
Net earnings (loss)(1)	**(304,758)**	(108,632)	(146,165)	130,829	(297,275)	(427,503)	63,414	(508,307)
Per share, diluted	**(1.34)**	(0.48)	(0.65)	0.58	(1.32)	(1.90)	0.28	(2.27)
Operating loss	**(71,989)**	(87,929)	(97,894)	(197,286)	(140,234)	(86,769)	(22,950)	(124,421)
Per share, diluted	**(0.32)**	(0.39)	(0.43)	(0.88)	(0.62)	(0.39)	(0.10)	(0.56)
Adjusted funds flow	**39,967**	22,702	6,964	(131,240)	(44,130)	23,877	99,243	(29,534)
Per share, diluted	**0.18**	0.10	0.03	(0.58)	(0.20)	0.11	0.44	(0.13)
Cash capital investment(2)	**63,077**	19,203	19,990	34,975	54,473	32,139	90,465	80,101
Cash and cash equivalents	**156,230**	103,136	152,711	124,560	408,213	350,736	438,238	470,778
Working capital	**96,442**	163,038	128,586	183,649	363,038	366,725	374,766	386,130
Long-term debt	**5,053,239**	4,909,711	4,871,182	4,859,099	5,190,363	5,023,976	4,677,577	4,759,102
Shareholders' equity	**3,286,776**	3,577,557	3,679,372	3,812,566	3,677,867	3,956,689	4,358,078	4,279,873
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**49.29**	44.94	45.59	33.45	42.18	46.43	57.94	48.63
C$ equivalent of 1US$ - average	**1.3339**	1.3051	1.2886	1.3748	1.3353	1.3093	1.2294	1.2411
Differential – WTI:WCS ($/bbl)	**19.10**	17.62	17.14	19.58	19.35	17.50	14.25	18.22
Differential – WTI:WCS (%)	**29.1%**	30.0%	29.2%	42.6%	34.4%	28.8%	20.0%	30.2%
Natural gas – AECO ($/mcf)	**3.31**	2.49	1.37	1.82	2.57	2.89	2.64	2.74
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**81,780**	83,404	83,127	76,640	83,514	82,768	71,376	82,398
Bitumen sales – bbls/d	**81,746**	84,817	80,548	74,529	82,282	84,651	71,401	85,519
Steam to oil ratio (SOR)	**2.3**	2.2	2.3	2.4	2.5	2.5	2.3	2.6
Bitumen realization	**36.17**	30.98	30.93	11.43	23.17	31.03	44.54	25.82
Transportation – net	**(6.05)**	(6.46)	(6.66)	(6.68)	(5.35)	(4.64)	(4.57)	(4.70)
Royalties	**(0.51)**	(0.42)	(0.27)	0.07	(0.25)	(0.88)	(0.90)	(0.80)
Operating costs – non-energy	**(4.99)**	(5.32)	(5.81)	(6.45)	(5.66)	(5.98)	(7.01)	(7.57)
Operating costs – energy	**(4.12)**	(2.99)	(1.97)	(2.90)	(3.58)	(3.97)	(3.71)	(4.07)
Power revenue	**0.87**	0.55	0.35	0.82	0.72	0.85	1.29	1.15
Realized risk management gain (loss)	**0.36**	0.40	(0.48)	-	-	-	-	-
Cash operating netback	**21.73**	16.74	16.09	(3.71)	9.05	16.41	29.64	9.83
Power sales price (C$/MWh)	**21.94**	17.62	13.54	19.77	19.67	25.09	39.55	28.21
Power sales (MW/h)	**134**	110	86	129	125	119	97	145
Depletion and depreciation rate per bbl of production	**16.81**	16.81	16.84	16.78	16.55	15.99	15.84	15.58
COMMON SHARES								
Shares outstanding, end of period (000)	**226,467**	226,415	226,357	224,997	224,997	224,942	224,881	223,847
Volume traded (000)	**114,776**	112,720	157,056	182,199	76,631	73,099	40,929	57,657
Common share price ($)								
High	**9.79**	6.90	7.86	8.26	13.15	20.36	25.20	24.31
Low	**5.11**	4.72	5.21	3.46	7.33	7.87	17.56	14.84
Close (end of period)	**9.23**	5.93	6.84	6.55	8.02	8.24	20.40	20.46

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

(2) Defined as total capital investment excluding dispositions, capitalized interest, capitalized cash-settled stock-based compensation and non-cash items.

25. ANNUAL SUMMARIES

Unaudited	2016	2015	2014	2013	2012	2011
FINANCIAL ($000 unless specified)						
Net earnings (loss)(1)	**(428,726)**	(1,169,671)	(105,538)	(166,405)	52,569	63,837
Per share, diluted	**(1.90)**	(5.21)	(0.47)	(0.75)	0.26	0.32
Operating earnings (loss)	**(455,098)**	(374,374)	247,353	386	21,242	109,255
Per share, diluted	**(2.01)**	(1.67)	1.10	0.00	0.11	0.55
Adjusted funds flow	**(61,607)**	49,460	791,458	253,424	212,514	304,627
Per share, diluted	**(0.27)**	0.22	3.52	1.13	1.06	1.54
Cash capital investment(2)	**137,245**	257,178	1,237,539	2,111,824	1,567,906	914,292
Cash and cash equivalents	**156,230**	408,213	656,097	1,179,072	1,474,843	1,495,131
Working capital	**96,442**	363,038	525,534	1,045,606	1,655,915	1,475,245
Long-term debt	**5,053,239**	5,190,363	4,350,421	3,990,748	2,478,660	1,741,394
Shareholders' equity	**3,286,776**	3,677,867	4,768,235	4,788,430	4,870,534	3,984,104
BUSINESS ENVIRONMENT						
WTI (US$/bbl)	**43.33**	48.80	93.00	97.96	94.21	95.12
C$ equivalent of 1US$ - average	**1.3256**	1.2788	1.1047	1.0296	0.9994	0.9893
Differential – WTI:WCS ($/bbl)	**18.35**	17.29	21.63	25.89	21.01	16.95
Differential – WTI:WCS (%)	**31.9%**	27.7%	21.1%	25.7%	22.3%	18.0%
Natural gas – AECO ($/mcf)	**2.25**	2.71	4.50	3.16	2.38	3.66
OPERATIONAL ($/bbl unless specified)						
Bitumen production – bbls/d	**81,245**	80,025	71,186	35,317	28,773	26,605
Bitumen sales – bbls/d	**80,426**	80,965	67,243	33,715	28,845	26,587
Steam to oil ratio (SOR)	**2.3**	2.5	2.5	2.6	2.4	2.4
Bitumen realization	**27.79**	30.63	62.67	49.28	46.93	58.74
Transportation – net	**(6.46)**	(4.82)	(1.38)	(0.26)	(0.31)	(1.39)
Royalties	**(0.29)**	(0.70)	(4.36)	(3.14)	(2.46)	(3.24)
Operating costs – non-energy	**(5.62)**	(6.54)	(8.02)	(9.00)	(9.71)	(10.32)
Operating costs – energy	**(3.01)**	(3.84)	(6.30)	(4.62)	(3.46)	(5.14)
Power revenue	**0.64**	0.99	2.26	3.61	3.19	4.50
Realized risk management gain (loss)	**0.08**	-	-	-	-	-
Cash operating netback	**13.13**	15.72	44.87	35.87	34.18	43.15
Power sales price (C$/MWh)	**18.74**	27.48	48.83	76.23	59.22	74.33
Power sales (MW/h)	**115**	121	129	67	65	67
Depletion and depreciation rate per bbl of production	**16.81**	16.00	14.57	14.67	13.76	12.80
COMMON SHARES						
Shares outstanding, end of period (000)	**226,467**	224,997	223,847	222,507	220,190	193,472
Volume traded (000)	**566,751**	248,316	227,538	134,087	73,738	105,783
Common share price ($)						
High	**9.79**	25.20	41.29	36.69	47.11	52.90
Low	**3.46**	7.33	13.30	25.50	30.25	32.26
Close (end of period)	**9.23**	8.02	19.55	30.61	30.44	41.57

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

(2) Defined as total capital investment excluding dispositions, capitalized interest, capitalized cash-settled stock-based compensation and non-cash items.