FIRST QUARTER 2016

Report to Shareholders for the period ended March 31, 2016.

MEG Energy Corp. reported first quarter 2016 operating and financial results on April 28, 2016. Highlights include:

- Quarterly production of 76,640 barrels per day (bpd), which includes the impact of planned turnaround work;
- Net operating costs of $8.53 per barrel, a decrease of 19% from the first quarter of 2015 and in line with record-low costs of $8.52 per barrel in the fourth quarter of 2015;
- Cash flow used in operations of $0.58 per share, primarily resulting from lower bitumen price realizations;
- A reduction in planned annual capital spending from $328 million to $170 million, while still maintaining annual guidance of 80,000 to 83,000 bpd at $6.75 to $7.75 per barrel non-energy operating costs;
- Continuing strong financial liquidity, exiting the quarter with $125 million of cash and cash equivalents and an undrawn US$2.5 billion credit facility.

“Operating results for the first quarter were right on plan.” said Bill McCaffrey, President and Chief Executive Officer. “Strong, steady and reliable production, combined with low operating costs and capital flexibility are the foundation this company is built on.”

MEG recorded production of 76,640 bpd in the first quarter of 2016. This included the impact of a turnaround at the company’s Christina Lake facilities that was brought forward from the second quarter of 2016 to take advantage of the lower oil price environment. Volumes in the first quarter of 2016 were only slightly lower than the first quarter 2015, which was not impacted by a turnaround.

MEG continues to target average production of 80,000 to 83,000 barrels per day in 2016 at an average non-energy operating cost of $6.75 to $7.75 per barrel.

Net operating costs in the first quarter of 2016 averaged $8.53 per barrel compared to $10.49 per barrel in the first quarter of 2015. The significant decrease in net operating costs reflects the implementation of efficiency measures through MEG’s RISER initiative and a continuing focus on cost management for services at the company’s operating facilities. Net operating costs also benefited from a decrease in the cost of natural gas used to power the company’s SAGD facilities.

“The low commodity price environment continued to impact cash flow generated from the strong operating performance,” says McCaffrey. “Low operating and capital costs, strong liquidity and well-structured debt have all helped MEG to navigate through this current low price environment.”

MEG reported cash flow used in operations of $131 million for the first quarter of 2016, compared to cash flow used in operations of $30 million for the same period in 2015. Cash flow used in operations increased primarily due to lower bitumen realization and reduced sales volumes associated with the turnaround, partially offset by lower net operating costs and lower royalties. The decrease in bitumen realization is directly correlated to the significant decline of U.S. crude oil benchmark pricing.

MEG recognized an operating loss of $197 million for the first quarter of 2016, compared to an operating loss of $124 million in the same period of 2015. Comparative results are primarily impacted by the same factors affecting cash flow used in operations.

In the first quarter of 2016, MEG reduced its 2016 capital budget to $170 million from $328 million and expects annual capital spending will be primarily directed towards sustaining activities. As a result of ongoing cost control initiatives, MEG has reduced, respectively, non-energy operating costs by 15% per barrel and general and administrative expenses by 12% per barrel, compared to the first quarter of 2015.

In addition, the company is implementing a strategic hedging program to increase the predictability of future cash flows.

At the end of the first quarter, MEG had $125 million of cash on hand. At current strip prices, MEG anticipates its US$2.5 billion revolving credit facility will be undrawn at the end of 2016.

Forward-Looking Information and Non-GAAP Financial Measures

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

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three-month period ended March 31, 2016 was approved by the Corporation's Audit Committee on April 27, 2016. This MD&A should be read in conjunction with the Corporation's unaudited condensed consolidated interim financial statements and notes thereto for the three-month period ended March 31, 2016, the audited consolidated financial statements and notes thereto for the year ended December 31, 2015 and the 2015 annual MD&A. This MD&A and the unaudited condensed consolidated interim financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in thousands of Canadian dollars, except where otherwise indicated.

MD&A – Table of Contents

1. OVERVIEW

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

MEG owns a 100% working interest in over 900 square miles of oil sands leases. For information regarding MEG's estimated reserves, 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." The Corporation is pursuing these opportunities for development and anticipates filing regulatory applications in 2016 for the May River Regional Project. MEG has been conducting core-hole programs at the May River Regional Project with the objectives of identifying additional contingent resources, defining areas for commercial development and determining the size of potential commercial developments. 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, Phases 1 and 2, commenced production in 2008 and 2009, respectively, with a combined designed capacity of 25,000 bbls/d. In 2012, the Corporation announced the RISER initiative, which is designed to increase production from existing assets at lower capital and operating costs using a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including debottlenecking and expansions (collectively, "RISER"). Phase 2B, an expansion with an initial designed capacity of 35,000 bbls/d, commenced production in the fourth quarter of 2013 and was successfully ramped up throughout 2014. Due to the successful ramp-up of Phase 2B, in combination with the success achieved from applying RISER, the Corporation achieved average production in excess of 80,000 bbls/d from the Christina Lake Project during the fourth quarter of 2014. Bitumen production for the year ended December 31, 2014 averaged 71,186 bbls/d and for the year ended December 31, 2015 averaged 80,025 bbls/d.

The Corporation is currently focused on the continuing application of RISER. The Corporation anticipates this strategy will allow the Corporation to increase production more efficiently and at lower capital intensity.

In addition, MEG has filed regulatory applications for the Surmont Project, which is situated along the same geological trend as the Christina Lake Project and has an anticipated designed capacity of approximately 120,000 bbls/d over multiple phases. MEG filed a regulatory application for the project in September 2012 and continues to actively work through the application process, currently engaging stakeholders as a normal part of the Alberta Energy Regulator's requirements. The proposed project is expected to use SAGD technology and include multi-well production pads, electricity and steam cogeneration and other facilities similar to MEG's current Christina Lake Project. The Surmont Project is located approximately 30 miles north of the Corporation's Christina Lake Project. This area has been extensively explored and developed for natural gas projects, and more recently for oil sands resources. Other thermal recovery projects are already operating in this area.

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. In 2014, MEG completed an expansion of the Access Pipeline to accommodate anticipated increases in production from the Christina Lake Project as well as provide expansion capacity for future production volumes from the Surmont Project, the May River Regional Project and the Growth Properties. MEG's 50% interest of the capacity in the expanded 42-inch blend line is approximately 200,000 bbls/d of blended bitumen. The system's former 24-inch blend line was converted to diluent service during the third quarter of 2015.

In August 2015, the Corporation announced the formation of a committee of the Board of Directors and that it had retained BMO Capital Markets and Credit Suisse to assist management in the review of options available to the Corporation to utilize its interest in the Access Pipeline to reduce the financial leverage of the Corporation. The potential monetization of MEG's 50% holding in the Access Pipeline continues to be a key priority. The Corporation is working diligently to complete this process, while ensuring the transaction is in the long-term interest of MEG's shareholders.

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.

As at January 1, 2016, MEG has 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.

For a list of abbreviations that are referenced in this MD&A, please refer to the "ABBREVIATIONS" section of this MD&A.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The ongoing global imbalance between supply and demand for crude oil and the deterioration and volatility of global crude oil prices continued to significantly impact the Corporation's operating and financial results during the first quarter of 2016. The C$/bbl West Texas Intermediate ("WTI") average price for the first quarter of 2016 decreased 24% compared to the first quarter of 2015. In addition, the WTI:WCS differential widened to an average of 42.6% for the three months ended March 31, 2016 compared to 30.2% for the three months ended March 31, 2015.

As the value of the Canadian dollar strengthens, the translated value of the Corporation's U.S. dollar denominated debt decreases. During the first quarter of 2016, the value of the Canadian dollar relative to the U.S. dollar increased 6%, resulting in a $330.1 million unrealized foreign exchange gain.

In the first quarter of 2016, the Corporation reduced the 2016 capital budget to $170 million. The Corporation anticipates 2016 capital spending will be directed towards sustaining activities. As a result of ongoing cost control initiatives, the Corporation reduced non-energy operating costs per barrel by 15% compared to the first quarter of 2015 and has reduced general and administrative expenses by 17% compared to the first quarter of 2015.

In addition, the Corporation implemented a strategic commodity risk management program to increase the predictability of the Corporation's future cash flows as governed by MEG's Risk Management Committee. During the first quarter of 2016, the Corporation entered into commodity risk management contracts to partially manage its exposure on condensate purchases and blend sales.

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

	2016	**2015**				**2014**		
($ millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Bitumen production - bbls/d	**76,640**	83,514	82,768	71,376	82,398	80,349	76,471	68,984
Bitumen realization - $/bbl	**11.43**	23.17	31.03	44.54	25.82	50.48	65.12	72.75
Net operating costs - $/bbl(1)	**8.53**	8.52	9.10	9.43	10.49	10.13	10.31	14.49
Non-energy operating costs - $/bbl	**6.45**	5.66	5.98	7.01	7.57	6.42	7.16	9.64
Cash operating netback - $/bbl(2)	**(3.71)**	9.05	16.41	29.64	9.83	35.56	48.70	51.45
Cash flow from (used in) operations(3)	**(131)**	(44)	24	99	(30)	134	239	262
Per share, diluted(3)	**(0.58)**	(0.20)	0.11	0.44	(0.13)	0.60	1.06	1.16
Operating earnings (loss)(3)	**(197)**	(140)	(87)	(23)	(124)	8	87	111
Per share, diluted(3)	**(0.88)**	(0.62)	(0.39)	(0.10)	(0.56)	0.04	0.39	0.49
Revenue(4)	**290**	445	460	555	467	615	706	829
Net earnings (loss)(5)	**131**	(297)	(428)	63	(508)	(150)	(101)	249
Per share, basic	**0.58**	(1.32)	(1.90)	0.28	(2.27)	(0.67)	(0.45)	1.12
Per share, diluted	**0.58**	(1.32)	(1.90)	0.28	(2.27)	(0.67)	(0.45)	1.11
Total cash capital investment(6)	**35**	54	32	90	80	324	291	299
Cash and cash equivalents	**125**	408	351	438	471	656	777	840
Long-term debt(7)	**4,859**	5,190	5,024	4,678	4,759	4,350	4,203	4,002

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

(2) Cash operating netbacks are calculated by deducting the related diluent expense, transportation, operating expenses and royalties from proprietary blend revenues and power revenues, on a per barrel of bitumen sales volume basis.

(3) Cash flow from (used in) operations, Operating earnings (loss), and the related per share amounts do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. For the three months ended March 31, 2016 and March 31, 2015, the non-GAAP measure of cash flow used in operations is reconciled to net cash used in operating activities and the non-GAAP measure of operating loss is reconciled to net earnings (loss) in accordance with IFRS under the heading "NON-GAAP MEASURES" and discussed further in the "ADVISORY" section.

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

(5) Includes a net unrealized foreign exchange gain of $320.3 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents for the three months ended March 31, 2016. The net loss for the three months ended March 31, 2015 includes a net unrealized foreign exchange loss of $370.8 million.

(6) Defined as total capital investment excluding dispositions, capitalized interest, and non-cash items.

(7) On February 3, 2016, Moody's Investors Service ("Moody's") downgraded the Corporation's Corporate Family Rating (CFR) to Caa2 from B1, Probability of Default Rating to Caa2-PD from B1-PD, secured bank credit facility rating to B3 from Ba2 and senior unsecured notes rating to Caa3 from B2. The Speculative Grade Liquidity Rating was lowered to SGL-2 from SGL-1. The rating outlook is negative. The Corporation's senior secured term loan and senior unsecured notes do not include any provision that would require any changes in payment schedules or terminations as a result of a credit downgrade.

(8) Totals may not add due to rounding.

Bitumen Production

Bitumen production for the three months ended March 31, 2016 averaged 76,640 bbls/d compared to 82,398 bbls/d for the three months ended March 31, 2015. The decrease in production volumes is primarily due to planned capital activity on the Phase 2B heat recovery steam generator at the Christina Lake Project that was substantially completed in the first quarter of 2016. There were no similar activities that impacted production volumes in the same period in 2015. In addition, in March 2016, there was a small fire at the Corporation's sulphur recovery unit at the Christina Lake Project that resulted in production being temporarily suspended. The Corporation has worked with regulatory authorities to safely resume operations, repairs have been completed, and the recovery unit has resumed operations. The total repair costs are estimated to be approximately $6 million, which are largely anticipated to be recovered through insurance.

Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary petroleum revenue ("blend sales revenue"), net of the cost of diluent, 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 the cost of diluent is effectively recovered in the sales price of the blended product. The cost of diluent 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.

For the three months ended March 31, 2016, average bitumen realization decreased to $11.43 per barrel compared to $25.82 per barrel for the three months ended March 31, 2015. The decrease in bitumen realization is primarily a result of the significant decline of U.S. crude oil benchmark pricing, which resulted in lower blend sales revenue.

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 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.

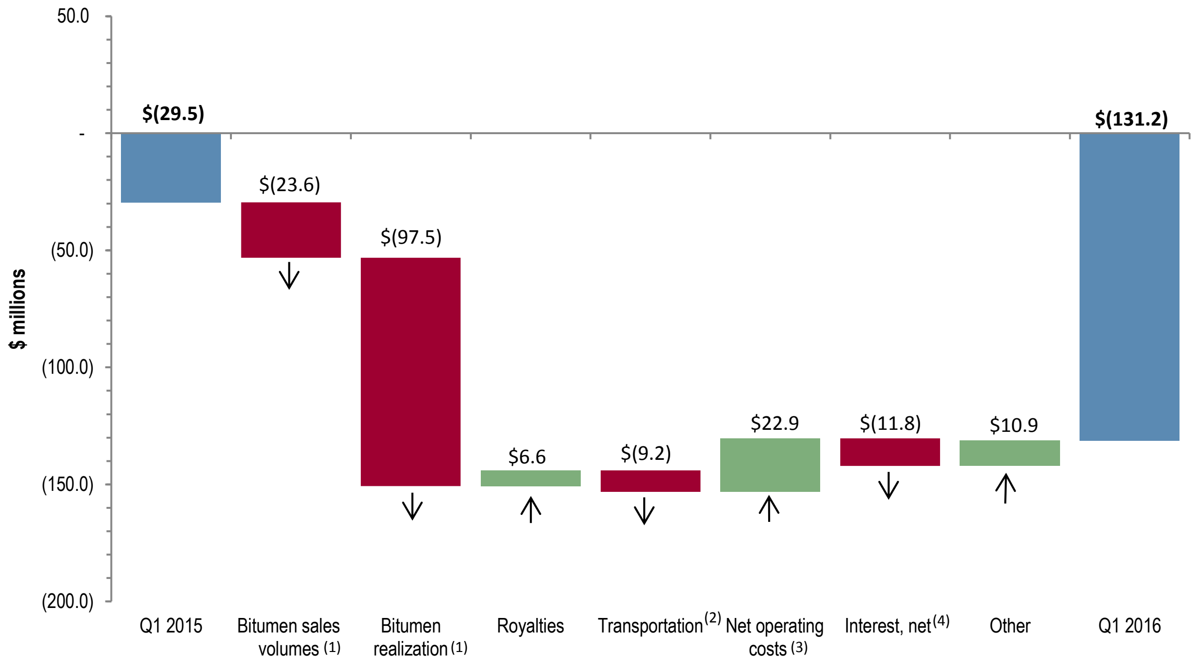
Net operating costs for the three months ended March 31, 2016 averaged $8.53 per barrel compared to $10.49 per barrel for the three months ended March 31, 2015. The decrease in net operating costs is attributable to a per barrel decrease in energy and non-energy operating costs, partially offset by a decrease in power revenue.

- Energy operating costs decreased to $2.90 per barrel for the three months ended March 31, 2016 compared to $4.07 per barrel for the same period in 2015. The Corporation's energy operating costs decreased primarily as a result of the decline in natural gas prices, which decreased to an average of $2.27 per mcf for the three months ended March 31, 2016 compared to $3.19 per mcf for the same period in 2015.
- Non-energy operating costs decreased to $6.45 per barrel for the three months ended March 31, 2016 compared to $7.57 per barrel for the same period in 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, camp, site services and site travel costs.
- Power revenue decreased to $0.82 per barrel for the three months ended March 31, 2016 compared to $1.15 per barrel for the same period in 2015. The decrease is primarily due to a decrease in the Corporation's realized power price. The Corporation's realized power price during the three months ended March 31, 2016 decreased to $19.77 per megawatt hour compared to $28.21 per megawatt hour for the same period in 2015. Power revenue had the effect of offsetting 28% of energy operating costs during the three months ended March 31, 2016 and during the same period in 2015.

Cash Operating Netback

Cash operating netback for the three months ended March 31, 2016 was a negative netback of $3.71 per barrel compared to a positive netback of $9.83 per barrel for the three months ended March 31, 2015. The decrease in the cash operating netback is primarily due to a decrease in bitumen realization as a result of the significant decline of U.S. crude oil benchmark pricing, partially offset by lower net operating costs.

Cash Flow Used In Operations



(1) *Net of diluent.*

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

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

(4) *Includes cash interest expense, net of capitalized interest, and realized gain/loss on interest rate swaps less interest income.*

Cash flow used in operations was $131.2 million for the three months ended March 31, 2016 compared to cash flow used in operations of $29.5 million for the three months ended March 31, 2015. Cash flow used in operations increased primarily due to lower bitumen realization, a decrease in bitumen sales volumes, higher interest costs and higher transportation, partially offset by lower net operating costs and lower royalties. The decrease in bitumen realization and decrease in royalties is directly correlated to the significant decline of U.S. crude oil benchmark pricing.

Operating Loss

The Corporation recognized an operating loss of $197.3 million for the three months ended March 31, 2016 compared to an operating loss of $124.4 million for the three months ended March 31, 2015. The increase in the operating loss was due to lower bitumen realization, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, an increase in interest expense and higher transportation. These items were partially offset by lower net operating costs due to lower natural gas prices and operating cost efficiencies.

Revenue

Revenue for the three months ended March 31, 2016 totalled $290.3 million compared to $467.0 million for the three months ended March 31, 2015. Revenue decreased primarily due to a decrease in blend sales revenue as a result of the significant decline of U.S. crude oil benchmark pricing. Revenue represents the total of petroleum revenue, net of royalties and other revenue.

Net Earnings (Loss)

The Corporation recognized net earnings of $130.8 million for the three months ended March 31, 2016 compared to a net loss of $508.3 million for the three months ended March 31, 2015. The net earnings for the three months ended March 31, 2016 included a net unrealized foreign exchange gain of $320.3 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. The net loss for the three months ended March 31, 2015 included a net unrealized foreign exchange loss of $370.8 million on U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. Net earnings were also affected by lower bitumen realization, primarily as a result of the significant decline of U.S. crude oil benchmark pricing.

Total Cash Capital Investment

Total cash capital investment during the three months ended March 31, 2016 totalled $35.0 million, as compared to $80.1 million for the three months ended March 31, 2015. 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.

Capital Resources

The Corporation's cash and cash equivalents balance totalled $124.6 million as at March 31, 2016 compared to a cash and cash equivalents balance of $408.2 million as at December 31, 2015. The Corporation's cash and cash equivalents balance decreased primarily due to negative cash flow from operations directly correlated to the significant decline of U.S. crude oil benchmark pricing, the use of cash for semi-annual and quarterly interest and principal payments and the settlement of accounts payable related to 2015 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$4.9 billion as at March 31, 2016 from C$5.2 billion as at December 31, 2015. All of MEG's long-term debt is "covenant lite" in structure, meaning it is free of any financial maintenance covenants and is not dependent on, nor calculated from, the Corporation's crude oil reserves. The first maturity of any of the Corporation's long-term debt obligations is March 2020.

As at March 31, 2016, the Corporation's capital resources included $124.6 million of cash and cash equivalents, an additional undrawn US$2.5 billion syndicated revolving credit facility that matures November 2019, and a US$500 million guaranteed letter of credit facility that matures November 2019, under which US$200.7 million of letters of credit have been issued under the facility with Export Development Canada ("EDC"). Similar to the Corporation's long-term debt, the revolving credit facility is "covenant lite" in structure.

3. OUTLOOK

Summary of 2016 Guidance	Initial Guidance[(1)]	Revised Guidance[(1)]
Capital investment - $ millions	$328	$170
Bitumen production - bbls/d	80,000 – 83,000	80,000 – 83,000
Non-energy operating costs - $/bbl	$6.75 – $7.75	$6.75 – $7.75

(1) *Initial guidance was announced on December 4, 2015. Capital investment guidance was revised on February 4, 2016.*

The Corporation's 2016 planned capital program totals $170 million. Annual bitumen production volumes are targeted to be in the range of 80,000 to 83,000 bbls/d and annual non-energy operating costs are targeted to be in the range of $6.75 to $7.75 per barrel.

In August 2015, the Corporation announced the formation of a committee of the Board of Directors and that it had retained BMO Capital Markets and Credit Suisse to assist management in the review of options available to the Corporation to utilize its interest in the Access Pipeline to reduce the financial leverage of the Corporation. The potential monetization of MEG's 50% holding in the Access Pipeline continues to be a key priority. The Corporation is working diligently to complete this process, while ensuring the transaction is in the long-term interest of MEG's shareholders.

4. BUSINESS ENVIRONMENT

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

	2016	2015				2014		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Average Commodity Prices								
Crude oil prices								
Brent (US$/bbl)	**35.10**	44.71	51.17	63.50	55.16	76.98	103.39	109.77
WTI (US$/bbl)	**33.45**	42.18	46.43	57.94	48.63	73.15	97.16	102.99
WTI (C$/bbl)	**45.99**	56.32	60.79	71.24	60.35	83.08	105.84	112.31
Differential – Brent:WTI (US$/bbl)	**1.65**	2.53	4.74	5.56	6.53	3.83	6.23	6.78
Differential – Brent:WTI (%)	**4.7%**	5.7%	9.3%	8.8%	11.8%	5.0%	6.0%	6.2%
WCS (C$/bbl)	**26.41**	36.97	43.29	56.98	42.13	66.74	83.82	90.44
Differential – WTI:WCS (C$/bbl)	**19.58**	19.35	17.50	14.25	18.22	16.34	22.02	21.87
Differential – WTI:WCS (%)	**42.6%**	34.4%	28.8%	20.0%	30.2%	19.7%	20.8%	19.5%
Condensate prices								
Condensate at Edmonton (C$/bbl)	**47.27**	55.57	57.89	71.17	56.59	81.98	101.72	114.72
Condensate at Edmonton as % of WTI	**102.8%**	98.7%	95.2%	99.9%	93.8%	98.7%	96.1%	102.1%
Condensate at Mont Belvieu, Texas (US$/bbl)	**32.03**	40.76	41.27	52.89	46.01	62.47	88.49	92.90
Condensate at Mont Belvieu, Texas as % of WTI	**95.8%**	96.6%	88.9%	91.3%	94.6%	85.4%	91.1%	90.2%
Natural gas prices								
AECO (C$/mcf)	**1.82**	2.57	2.89	2.64	2.74	3.58	4.00	4.70
Electric power prices								
Alberta power pool (C$/MWh)	**18.09**	21.19	26.04	57.25	29.14	30.55	63.91	42.43
Foreign exchange rates								
C$ equivalent of 1 US$ - average	**1.3748**	1.3353	1.3093	1.2294	1.2411	1.1357	1.0893	1.0905
C$ equivalent of 1 US$ - period end	**1.2971**	1.3840	1.3394	1.2474	1.2683	1.1601	1.1208	1.0676

Crude Oil Pricing

Brent crude is the primary world price benchmark for global light sweet crude oil. The Brent benchmark price averaged US$35.10 per barrel for the three months ended March 31, 2016 compared to US$55.16 per barrel for the three months ended March 31, 2015. The global supply of crude oil is currently greater than demand, which has resulted in a decrease in 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$33.45 per barrel for the three months ended March 31, 2016 compared to US$48.63 per barrel for the three months ended March 31, 2015. The global supply of crude oil is currently greater than demand, which has resulted in a decrease in prices.

The Western Canadian Select ("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 widened to an average of $19.58 per barrel, or 42.6%, for the three months ended March 31, 2016, compared to $18.22 per barrel, or 30.2%, for the same period in 2015.

In order to facilitate pipeline transportation, MEG uses condensate as diluent for blending with the Corporation's bitumen. Condensate prices, benchmarked at Edmonton, averaged $47.27 per barrel, or 102.8% as a percentage of WTI, for the three months ended March 31, 2016 compared to $56.59 per barrel, or 93.8% as a percentage of WTI, for the three months ended March 31, 2015. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$32.03 per barrel, or 95.8% as a percentage of WTI, for the three months ended March 31, 2016 compared to US$46.01 per barrel, or 94.6% as a percentage of WTI, for the three months ended March 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 $1.82 per mcf for the three months ended March 31, 2016 compared to $2.74 per mcf for the three months ended March 31, 2015. The North American natural gas market continues to be over-supplied, resulting in lower prices. Natural gas prices have fallen to 15-year lows due to high inventory levels caused by record production and an unseasonably warm winter.

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 $18.09 per megawatt hour for the three months ended March 31, 2016 compared to $29.14 per megawatt hour for the same period in 2015. The decline in the Alberta power pool price is primarily due to a 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 cost of diluent, as blend sales prices and cost of diluent 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 the cost of diluent 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 the cost of diluent 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 March 31, 2016, the Canadian dollar, at a rate of 1.2971, had increased in value by approximately 6% against the U.S. dollar compared to its value as at December 31, 2015, when the rate was 1.3840. As at March 31, 2016, the Canadian dollar has weakened in value by approximately 2% from March 31, 2015, when the rate was 1.2683.

5. RESULTS OF OPERATIONS

	Three months ended March 31	
	2016	**2015**
Bitumen production – bbls/d	**76,640**	82,398
Steam to oil ratio (SOR)	**2.4**	2.6

Bitumen Production

Bitumen production for the three months ended March 31, 2016 averaged 76,640 bbls/d compared to 82,398 bbls/d for the three months ended March 31, 2015. The decrease in production volumes is primarily due to planned capital activity on the Phase 2B heat recovery steam generator at the Christina Lake Project that was substantially completed in the first quarter of 2016. There were no similar activities that impacted production volumes in the same period in 2015. In addition, in March 2016, there was a small fire at the Corporation’s sulphur recovery unit at the Christina Lake Project that resulted in production being temporarily suspended. The Corporation has worked with regulatory authorities to safely resume operations, repairs have been completed, and the recovery unit has resumed operations.

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 2.4 during the three months ended March 31, 2016 and 2.6 during the three months ended March 31, 2015. The SOR in the first quarter of 2015 was higher due to additional steam being directed to wells that were not yet in production mode.

Operating Cash Flow

	Three months ended March 31	
($000)	**2016**	**2015**
Petroleum revenue – proprietary[1]	**$ 250,397**	$ 455,753
Diluent expense	**(172,865)**	(257,048)
	77,532	198,705
Royalties	**497**	(6,150)
Transportation expense	**(50,498)**	(38,662)
Operating expenses	**(63,388)**	(89,598)
Power revenue	**5,554**	8,819
Transportation revenue	**5,160**	2,494
Operating cash flow[2]	**$ (25,143)**	$ 75,608

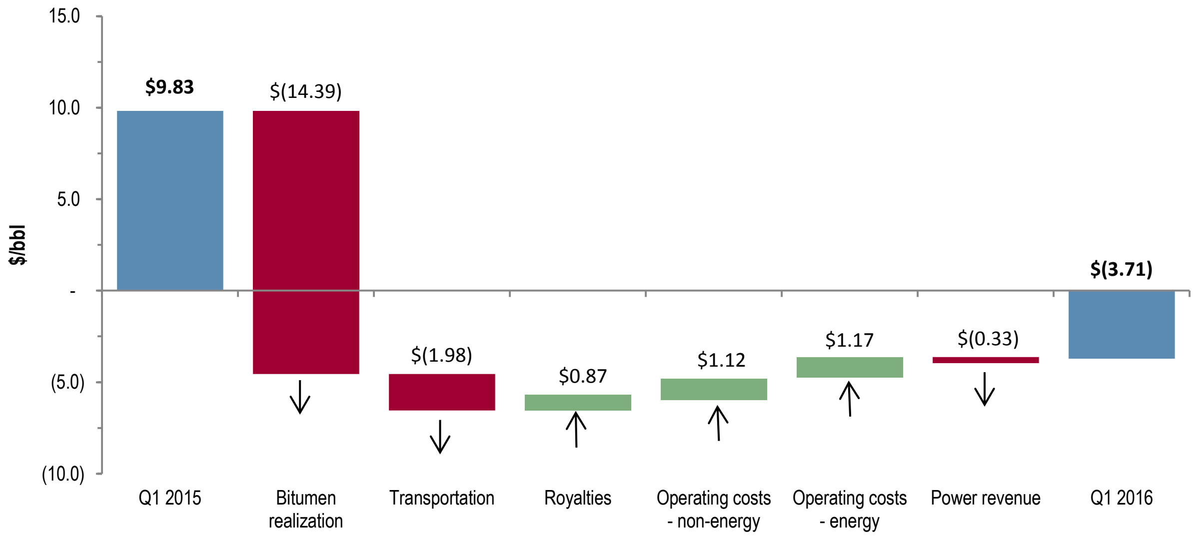
(1) Proprietary petroleum revenue represents MEG's revenue ("blend sales revenue") from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.

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

Blend sales revenue for the three months ended March 31, 2016 was $250.4 million compared to $455.8 million for the three months ended March 31, 2015. The decrease in blend sales revenue is primarily due to a 38% decrease in the average realized blend price and a 13% decrease in blend sales volumes. The cost of diluent for the three months ended March 31, 2016 was $172.9 million compared to $257.0 million for the three months ended March 31, 2015. The cost of diluent decreased primarily due to the decrease in condensate prices and lower volumes of diluent required for the decreased blend sales volumes.

Operating cash flow decreased primarily due to lower blend sales revenue as a result of the significant decline of U.S. crude oil benchmark pricing, partially offset by a decrease in the cost of diluent and lower operating expenses.

Cash Operating Netback



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

	Three months ended March 31	
($/bbl)	**2016**	**2015**
Bitumen realization[1]	**$ 11.43**	$ 25.82
Transportation[2]	**(6.68)**	(4.70)
Royalties	**0.07**	(0.80)
	4.82	20.32
Operating costs – non-energy	**(6.45)**	(7.57)
Operating costs – energy	**(2.90)**	(4.07)
Power revenue	**0.82**	1.15
Net operating costs	**(8.53)**	(10.49)
Cash operating netback	**$ (3.71)**	$ 9.83

(1) Blend sales net of diluent costs.

(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.

Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary petroleum revenue, net of the cost of diluent. Bitumen realization averaged $11.43 per barrel for the three months ended March 31, 2016 compared to $25.82 per barrel for the three months ended March 31, 2015. The decrease in bitumen realization is primarily a result of the significant decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue.

For the three months ended March 31, 2016, the Corporation's cost of diluent was $52.66 per barrel of diluent compared to $69.20 per barrel of diluent for the three months ended March 31, 2015. The decrease in the cost of diluent is primarily a result of the significant decline of U.S. crude oil benchmark pricing.

Transportation

The Corporation utilizes many facilities to transport and sell its blend to refiners throughout North America. As at January 1, 2016, the Corporation increased its transportation capacity on the Flanagan South and Seaway pipeline systems by 25,000 bbls/d, thus furthering the Corporation's strategy of broadening market access to world prices to improve netbacks.

Transportation costs averaged $6.68 per barrel for the three months ended March 31, 2016 compared to $4.70 per barrel for the three months ended March 31, 2015. Transportation expense increased primarily due to the cost of transporting 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.

The decrease in royalties for the three months ended March 31, 2016, as compared to the three months ended March 31, 2015, is primarily attributable to lower royalties as a result of lower realized prices.

Net Operating Costs

Non-energy operating costs

Non-energy operating costs decreased to $6.45 per barrel for the three months ended March 31, 2016 compared to $7.57 per barrel for the three months ended March 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, camp, site services and site travel costs.

Energy operating costs

Energy operating costs averaged $2.90 per barrel for the three months ended March 31, 2016 compared to $4.07 per barrel for the three months ended March 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 $2.27 per mcf during the first quarter of 2016 compared to $3.19 per mcf for the first quarter of 2015.

Power revenue

Power revenue averaged $0.82 per barrel for the three months ended March 31, 2016 compared to $1.15 per barrel for the three months ended March 31, 2015. The Corporation's average realized power sales price during the three months ended March 31, 2016 was $19.77 per megawatt hour compared to $28.21 per megawatt hour for the same period in 2015. The decrease in the realized power sales price is primarily due to the current surplus of power generation capacity in the province of Alberta.

6. OTHER OPERATING RESULTS

Net Marketing Activity

	Three months ended March 31	
($000)	**2016**	**2015**
Petroleum sales – third party	**$ 28,730**	$ 6,079
Purchased product and storage:		
Purchased product	**(28,810)**	(6,042)
Marketing and storage arrangements	**-**	(6,065)
	(28,810)	(12,107)
Net marketing activity(1)	**$ (80)**	$ (6,028)

(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 barge, 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, the Corporation purchases and sells third-party crude oil and related products and enters into transactions to optimize the returns on these 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. As a result, marketing and storage arrangements for the three months ended March 31, 2016 decreased $6.1 million compared to the three months ended March 31, 2015.

Depletion and Depreciation

	Three months ended March 31	
($000)	**2016**	**2015**
Depletion and depreciation expense	**$ 116,993**	$ 115,571
Depletion and depreciation expense per barrel of production	**$ 16.78**	$ 15.58

Depletion and depreciation expense for the three months ended March 31, 2016 totalled $117.0 million compared to $115.6 million for the three months ended March 31, 2015. Depletion and depreciation expense was $16.78 per barrel for the three months ended March 31, 2016 compared to $15.58 per barrel for the three months ended March 31, 2015. The increase in the depletion and depreciation expense per barrel was primarily due to an increase in the estimate of future development costs associated with the Corporation's proved reserves and an increase in depreciable costs for facilities.

Gain on Commodity Risk Management

	Three months ended March 31					
($000)	**2016**			**2015**		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Condensate	**$ -**	**$ 17,554**	**$ 17,554**	$ -	$ -	$ -
Crude oil	**-**	**(591)**	**(591)**	-	-	-
Gain on commodity risk management	**$ -**	**$ 16,963**	**$ 16,963**	$ -	$ -	$ -

For the three months ended March 31, 2016, the Corporation entered into commodity risk management contracts to effectively fix the average percentage differential between the price of condensate at Mont Belvieu, Texas to the price of WTI for a portion of its condensate purchases. The Corporation also entered into commodity risk management contracts to effectively fix the WCS price on a portion of its bitumen blend sales. The Corporation has not designated any of its commodity risk management contracts currently in place as accounting hedges and, as such, has recorded its derivatives at fair value through net earnings (loss). Realized gains or losses on commodity risk management contracts are the result of cash settlement during the period. 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. The Corporation recognized an unrealized gain on commodity risk management contracts of $17.0 million for the three months ended March 31, 2016. Refer to the "RISK MANAGEMENT" section of this MD&A for further details.

General and Administrative

	Three months ended March 31	
($000)	**2016**	**2015**
General and administrative expense	**$ 27,716**	$ 33,306
General and administrative expense per barrel of production	**$ 3.97**	$ 4.49

General and administrative expense for the three months ended March 31, 2016 was $27.7 million compared to $33.3 million for the three months ended March 31, 2015. General and administrative expense was $3.97 per barrel for the three months ended March 31, 2016 compared to $4.49 per barrel for the three months ended March 31, 2015. General and administrative expense was lower due to the Corporation's continued focus on cost management in all areas of the business.

Stock-based Compensation

	Three months ended March 31	
($000)	**2016**	**2015**
Stock-based compensation expense	**$ 12,892**	$ 12,530

The fair value of compensation associated with the granting of stock options, restricted share units ("RSUs") and performance share units ("PSUs") to directors, officers, employees and consultants is recognized by the Corporation as stock-based compensation expense. Fair value is determined using the Black-Scholes option pricing model. Stock-based compensation expense for the three months ended March 31, 2016 was $12.9 million compared to $12.5 million for the three months ended March 31, 2015.

Research and Development

	Three months ended March 31	
($000)	**2016**	**2015**
Research and development expense	**$ 1,378**	$ 1,172

Research and development expenditures related to the Corporation's research of crude quality improvement and related technologies have been expensed. Research and development expenditures were $1.4 million for the three months ended March 31, 2016 compared to $1.2 million for the three months ended March 31, 2015.

Foreign Exchange Gain (Loss), Net

	Three months ended March 31	
($000)	**2016**	**2015**
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ 330,093**	$ (412,406)
US$ denominated cash, cash equivalents and other	**(9,812)**	41,557
Unrealized net gain (loss) on foreign exchange	**320,281**	(370,849)
Realized gain (loss) on foreign exchange	**5,666**	(7,230)
Foreign exchange gain (loss), net	**$ 325,947**	$ (378,079)
C$ equivalent of 1 US$		
Beginning of period	**1.3840**	1.1601
End of period	**1.2971**	1.2683

The Corporation recognized a net foreign exchange gain of $325.9 million for the three months ended March 31, 2016 compared to a net foreign exchange loss of $378.1 million for the three months ended March 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 6% during the three months ended March 31, 2016. During the three months ended March 31, 2015, the Canadian dollar weakened in value by approximately 9%.

Net Finance Expense

	Three months ended March 31	
($000)	**2016**	**2015**
Total interest expense	**$ 83,915**	$ 75,726
Less capitalized interest	**-**	(16,003)
Net interest expense	**83,915**	59,723
Accretion on provisions	**1,694**	1,312
Unrealized loss on derivative financial liabilities	**5,489**	3,531
Realized loss on interest rate swaps	**1,569**	1,401
Net finance expense	**$ 92,667**	$ 65,967
Average effective interest rate[1]	**5.8%**	5.8%

(1) 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 three months ended March 31, 2016 was $83.9 million compared to $75.7 million for the three months ended March 31, 2015. Total interest expense for the three months ended March 31, 2016 was higher due to a weaker average Canadian dollar and its impact on U.S. dollar denominated interest expense. During the three months ended March 31, 2016, the Canadian dollar, at an average rate of 1.3748, had weakened in value by approximately 11% against the U.S. dollar compared to the three months ended March 31, 2015, when the average rate was 1.2411.

The Corporation capitalizes interest associated with qualifying assets. As a result of the reduction in the Corporation’s 2016 capital budget and expenditures, the Corporation did not capitalize interest during the three months ended March 31, 2016. During the three months ended March 31, 2015, the Corporation capitalized $16.0 million of interest.

The Corporation recognized an unrealized loss on derivative financial liabilities of $5.5 million for the three months ended March 31, 2016 compared to an unrealized loss of $3.5 million for the three months ended March 31, 2015. These unrealized losses relate 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 realized a loss on the interest swap contracts of $1.6 million for the three months ended March 31, 2016, compared to a realized loss of $1.4 million for the three months ended March 31, 2015.

Other Expenses

	Three months ended March 31	
($000)	**2016**	**2015**
Onerous contracts	**$ 4,371**	$ -

During the first quarter of 2016, an onerous operating lease expense of $4.4 million was recognized primarily related to the reduction of the Corporation’s capital program for 2016 and its impact on drilling contracts.

Income Tax Recovery

	Three months ended March 31	
($000)	**2016**	**2015**
Current income tax expense	**$ 517**	$ -
Deferred income tax recovery	**(69,156)**	(27,774)
Income tax recovery	**$ (68,639)**	$ (27,774)

The Corporation recognized a current income tax expense of $0.5 million for the three months ended March 31, 2016 relating to U.S. income tax associated with its operations in the United States.

The Corporation recognized a deferred income tax recovery of $69.2 million for the three months ended March 31, 2016 compared to a deferred income tax recovery of $27.8 million for the three months ended March 31, 2015.

The Corporation's effective tax rate on earnings is impacted by permanent differences and variances in taxable capital losses not recognized. The significant 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 three months ended March 31, 2016, the non-taxable gain was $165.0 million compared to a non-taxable loss of $206.2 million for the three months ended March 31, 2015.

- Stock-based compensation expense is a permanent difference. Stock-based compensation expense for the three months ended March 31, 2016 was $12.9 million compared to $12.5 million for the three months ended March 31, 2015.

The Corporation's Canadian operations are not currently taxable. As at March 31, 2016, the Corporation had approximately $7.5 billion of available tax pools and had recognized a deferred income tax liability of $18.3 million. In addition, as at March 31, 2016, the Corporation had $625.8 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects. As at March 31, 2016, the Corporation had not recognized the tax benefit related to $532.5 million of unrealized taxable capital foreign exchange losses.

7. CAPITAL INVESTING

	Three months ended March 31	
($000)	**2016**	**2015**
Total cash capital investment	**$ 34,975**	$ 80,101
Capitalized interest	**-**	16,003
	$ 34,975	$ 96,104

Total cash capital investment for the three months ended March 31, 2016 was $35.0 million, as compared to $80.1 million for the three months ended March 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.

The Corporation capitalizes interest associated with qualifying assets. As a result of the reduction in the Corporation's 2016 capital budget and expenditures, the Corporation did not capitalize interest during the three months ended March 31, 2016. During the three months ended March 31, 2015, the Corporation capitalized $16.0 million of interest.

8. LIQUIDITY AND CAPITAL RESOURCES

($000)	March 31, 2016	December 31, 2015
Cash and cash equivalents	**$ 124,560**	$ 408,213
Senior secured term loan (March 31, 2016 – US$1.245 billion; December 31, 2015 – US$1.249 billion; due 2020)	**1,615,214**	1,727,924
US$2.5 billion revolver (due 2019)	**-**	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	**972,825**	1,038,000
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,037,680**	1,107,200
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,297,100**	1,384,000
Total debt[(1),(2)]	**$ 4,922,819**	$ 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 less the 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 interim consolidated financial statements as at March 31, 2016 and the Corporation's consolidated financial statements as at December 31, 2015.

(2) On February 3, 2016, Moody's Investors Service ("Moody's") downgraded the Corporation's Corporate Family Rating (CFR) to Caa2 from B1, Probability of Default Rating to Caa2-PD from B1-PD, secured bank credit facility rating to B3 from Ba2 and senior unsecured notes rating to Caa3 from B2. The Speculative Grade Liquidity Rating was lowered to SGL-2 from SGL-1. The rating outlook is negative. The Corporation's senior secured term loan and senior unsecured notes do not include any provision that would require any changes in payment schedules or terminations as a result of a credit downgrade.

Capital Resources

As at March 31, 2016, the Corporation's available capital resources included $124.6 million of cash and cash equivalents and an undrawn US$2.5 billion syndicated revolving credit facility. The Corporation also has a US$500 million guaranteed letter of credit facility, under which US$200.7 million of letters of credit have been issued.

The US$2.5 billion revolving credit facility remains undrawn as at March 31, 2016. All of MEG's long-term debt is "covenant lite" in structure, meaning it is free of any financial maintenance covenants and is not dependent on, nor calculated from, the Corporation's crude oil reserves. The first maturity of any of the Corporation's long-term debt obligations is March 2020. The term loan has quarterly installments of US$3.25 million. The Corporation has a five-year US$500 million letter of credit facility guaranteed by EDC that matures in November 2019.

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 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 guidelines 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.

Cash Flow Summary

	Three months ended March 31	
($000)	**2016**	**2015**
Net cash provided by (used in):		
Operating activities	**$ (220,671)**	$ (16,942)
Investing activities	**(47,562)**	(205,810)
Financing activities	**(4,213)**	(4,124)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(11,207)**	41,557
Change in cash and cash equivalents	**$ (283,653)**	$ (185,319)

Cash Flow – Operating Activities

Net cash used in operating activities totalled $220.7 million for the three months ended March 31, 2016 compared to net cash used in operating activities of $16.9 million for the three months ended March 31, 2015. The decrease in cash flow from operating activities is primarily due to lower bitumen realization primarily as a result of the significant decline of U.S. crude oil benchmark pricing. Net cash used in operating activities for the first quarter of 2016 included a decrease in the net change in non-cash working capital of $87.8 million primarily due to the use of cash for semi-annual and quarterly interest and principal payments.

Cash Flow – Investing Activities

Net cash used in investing activities for the three months ended March 31, 2016 primarily consisted of $35.0 million in capital investment (refer to the "CAPITAL INVESTING" section of this MD&A for further details) and an $11.3 million decrease in the net change in non-cash investing working capital.

Net cash used in investing activities for the three months ended March 31, 2015 primarily consisted of $96.1 million in capital investment, including $16.0 million of capitalized interest (refer to the "CAPITAL INVESTING" section of this MD&A for further details) and a $111.6 million decrease in the net change in non-cash investing working capital.

Cash Flow – Financing Activities

Net cash used in financing activities for the three months ended March 31, 2016 consisted of $4.2 million of debt principal repayment.

Net cash used in financing activities for the three months ended March 31, 2015 consisted of $4.1 million of debt principal repayment.

9. 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. MEG has implemented a strategic commodity risk management program through the use of derivative financial instruments to increase the predictability of the Corporation's 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 the fluctuation of global crude oil markets, the Corporation periodically enters into commodity risk management contracts to partially manage its exposure on condensate purchases and blend sales. As at March 31, 2016, the Corporation had entered into the following condensate purchase contracts that effectively fix the average percentage differentials of condensate prices at Mont Belvieu, Texas to a percentage of WTI (US$/bbl):

As at March 31, 2016	Term	Volume (bbls/d)	Average % of WTI
Condensate purchase contracts:			
Mont Belvieu fixed % of WTI	Apr 1, 2016 – Dec 31, 2016	6,000	82.8%
Mont Belvieu fixed % of WTI	Jul 1, 2016 – Sep 30, 2016	1,250	87.8%
Mont Belvieu fixed % of WTI	Oct 1, 2016 – Dec 31, 2016	6,250	84.6%
Mont Belvieu fixed % of WTI	Jan 1, 2017 – Dec 31, 2017	13,500	82.6%

As at March 31, 2016, the Corporation also entered into the following crude oil sales contracts to fix the WCS price on a portion of its bitumen blend sales:

As at March 31, 2016	Term	Volume (bbls/d)	Average WCS Price (US$/bbl)
Crude oil sales contracts:			
WCS fixed price	May 1, 2016 – Jun 30, 2016	5,000	$26.84
WCS fixed price	Jul 1, 2016 – Sep 30, 2016	5,000	$28.18

Interest Rate Risk Management

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. The Corporation has entered into interest rate swap contracts to effectively fix the interest rate at approximately 4.4% on US$748.0 million of the US$1.245 billion senior secured term loan until September 30, 2016.

10. SHARES OUTSTANDING

As at March 31, 2016, the Corporation had the following share capital instruments outstanding and exercisable:

	Outstanding
Common shares	224,996,989
Convertible securities	
Stock options[1]	9,527,669
RSUs and PSUs	3,276,125

(1) 5,052,094 stock options were exercisable as at March 31, 2016.

As at April 19, 2016, the Corporation had 224,996,989 common shares, 9,507,730 stock options and 3,268,359 restricted share units and performance share units outstanding and 5,046,422 stock options exercisable.

11. 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.

($000)	2016	2017	2018	2019	2020	Thereafter
Long-term debt[1]	$ 12,647	$ 16,862	$ 16,862	$ 16,862	$ 1,551,980	$ 3,307,606
Interest on long-term debt[1]	210,387	279,963	279,330	278,699	234,752	446,081
Decommissioning obligation[2]	1,659	2,180	2,420	2,420	2,420	801,552
Transportation and storage[3]	127,718	179,905	195,382	186,542	225,056	3,196,870
Office lease rentals[4]	11,807	34,137	32,700	32,729	33,619	268,259
Diluent purchases[5]	110,698	43,049	19,885	19,885	19,939	56,331
Other commitments[6]	26,460	14,041	5,998	9,822	10,454	76,071
Total	**$ 501,376**	**$ 570,137**	**$ 552,577**	**$ 546,959**	**$ 2,078,220**	**$ 8,152,770**

(1) This represents the scheduled principal repayments of the senior secured credit facility and the senior unsecured notes and associated interest payments based on interest and foreign exchange rates in effect on March 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 2016 to 2040, including various pipeline commitments which are awaiting regulatory approval.

(4) This represents the future 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.

12. NON-GAAP MEASURES

Certain financial measures in this MD&A including: net marketing activity, cash flow used in operations, 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 sales – third party is disclosed in Note 11 in the notes to the interim consolidated financial statements and purchased product and storage is presented as a line item on the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss).

Cash Flow Used In Operations

Cash flow used in operations is a non-GAAP measure utilized by the Corporation to analyze operating performance and liquidity. Cash flow used in operations excludes the net change in non-cash operating working capital, decommissioning expenditures and payments on onerous contracts while the IFRS measurement "Net cash used in operating activities" includes these items. Cash flow used in operations is reconciled to Net cash used in operating activities in the table below.

	Three months ended March 31	
($000)	**2016**	**2015**
Net cash used in operating activities	**$ (220,671)**	$ (16,942)
Add (deduct):		
Net change in non-cash operating working capital items	**87,840**	(13,488)
Decommissioning expenditures	**962**	896
Payments on onerous contracts	**629**	-
Cash flow used in operations	**$ (131,240)**	$ (29,534)

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 earnings (loss) as reported, excluding unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial instruments, onerous contracts and the respective deferred tax impact of these adjustments. Operating loss is reconciled to "Net earnings (loss)", the nearest IFRS measure, in the table below.

	Three months ended March 31	
($000)	**2016**	**2015**
Net earnings (loss)	**$ 130,829**	$ (508,307)
Add (deduct):		
Unrealized net loss (gain) on foreign exchange(1)	**(320,281)**	370,849
Unrealized loss (gain) on derivative financial instruments(2)	**(11,474)**	3,531
Onerous contracts(3)	**4,371**	-
Deferred tax expense (recovery) relating to these adjustments	**(731)**	9,506
Operating loss	**$ (197,286)**	$ (124,421)

(1) *Unrealized net foreign exchange 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. 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.*

(3) *During the first quarter of 2016, an onerous operating lease expense was recognized primarily related to the reduction of the Corporation's capital program for 2016 and its impact on drilling contracts.*

Operating Cash Flow

Operating cash flow is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of the Corporation's efficiency and its ability to fund future capital investments. Operating cash flow is calculated by deducting the related diluent expense, transportation, field operating costs and royalties from proprietary production revenues 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 and royalties from proprietary blend revenues and power revenues, on a per barrel of bitumen sales volume basis.

13. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

For a detailed discussion regarding the Corporation's critical accounting policies and estimates, please refer to the Corporation's 2015 annual MD&A.

14. TRANSACTIONS WITH RELATED PARTIES

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

15. OFF-BALANCE SHEET ARRANGEMENTS

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

16. NEW ACCOUNTING STANDARDS

There were no new accounting standards adopted during the three months ended March 31, 2016.

Accounting standards issued but not yet applied

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. The Corporation is currently assessing the impact of the adoption of these amendments 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. The Corporation is currently assessing the impact of the adoption of these amendments on the Corporation's consolidated financial statements.

A description of additional accounting standards that are anticipated to be adopted by the Corporation in future periods is provided within Note 3 of the Corporation's audited consolidated financial statements for the year ended December 31, 2015.

17. 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 and described in the Corporation's MD&A for the year ended December 31, 2015. 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.

18. 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.

19. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

20. 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
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
MD&A	Management's Discussion and Analysis
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam 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

21. 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; the anticipated reductions in operating costs as a result of optimization and scalability of certain operations; and the 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, 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, the securing of adequate supplies and access to markets and transportation infrastructure; the availability of capacity on the electricity transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of 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, cash flow used in operations, 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.

22. 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.

23. QUARTERLY SUMMARIES

	2016	2015				2014		
Unaudited	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
FINANCIAL ($000 unless specified)								
Net earnings (loss)[(1)]	**130,829**	(297,275)	(427,503)	63,414	(508,307)	(150,076)	(100,975)	248,954
Per share, diluted	**0.58**	(1.32)	(1.90)	0.28	(2.27)	(0.67)	(0.45)	1.11
Operating earnings (loss)	**(197,286)**	(140,234)	(86,769)	(22,950)	(124,421)	8,084	87,471	111,139
Per share, diluted	**(0.88)**	(0.62)	(0.39)	(0.10)	(0.56)	0.04	0.39	0.49
Cash flow from (used in) operations	**(131,240)**	(44,130)	23,877	99,243	(29,534)	134,099	238,659	261,713
Per share, diluted	**(0.58)**	(0.20)	0.11	0.44	(0.13)	0.60	1.06	1.16
Cash capital investment[(2)]	**34,975**	54,473	32,139	90,465	80,101	323,970	291,309	298,727
Cash and cash equivalents	**124,560**	408,213	350,736	438,238	470,778	656,097	776,522	839,870
Working capital	**183,649**	363,038	366,725	374,766	386,130	525,534	747,928	805,742
Long-term debt	**4,859,099**	5,190,363	5,023,976	4,677,577	4,759,102	4,350,421	4,202,966	4,002,378
Shareholders' equity	**3,812,566**	3,677,867	3,956,689	4,358,078	4,279,873	4,768,235	4,894,444	4,970,144
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**33.45**	42.18	46.43	57.94	48.63	73.15	97.16	102.99
C$ equivalent of 1US$ - average	**1.3748**	1.3353	1.3093	1.2294	1.2411	1.1357	1.0893	1.0905
Differential – WTI:WCS ($/bbl)	**19.58**	19.35	17.50	14.25	18.22	16.34	22.02	21.87
Differential – WTI:WCS (%)	**42.6%**	34.4%	28.8%	20.0%	30.2%	19.7%	20.8%	19.5%
Natural gas – AECO ($/mcf)	**1.82**	2.57	2.89	2.64	2.74	3.58	4.00	4.70
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**76,640**	83,514	82,768	71,376	82,398	80,349	76,471	68,984
Bitumen sales – bbls/d	**74,529**	82,282	84,651	71,401	85,519	70,116	69,757	70,849
Steam to oil ratio (SOR)	**2.4**	2.5	2.5	2.3	2.6	2.5	2.5	2.4
Bitumen realization	**11.43**	23.17	31.03	44.54	25.82	50.48	65.12	72.75
Transportation – net	**(6.68)**	(5.35)	(4.64)	(4.57)	(4.70)	(1.82)	(1.09)	(1.80)
Royalties	**0.07**	(0.25)	(0.88)	(0.90)	(0.80)	(2.97)	(5.02)	(5.01)
Operating costs – non-energy	**(6.45)**	(5.66)	(5.98)	(7.01)	(7.57)	(6.42)	(7.16)	(9.64)
Operating costs – energy	**(2.90)**	(3.58)	(3.97)	(3.71)	(4.07)	(5.16)	(5.58)	(6.45)
Power revenue	**0.82**	0.72	0.85	1.29	1.15	1.45	2.43	1.60
Cash operating netback	**(3.71)**	9.05	16.41	29.64	9.83	35.56	48.70	51.45
Power sales price (C$/MWh)	**19.77**	19.67	25.09	39.55	28.21	31.67	59.07	40.98
Power sales (MW/h)	**129**	125	119	97	145	134	119	115
Depletion and depreciation rate per bbl of production	**16.78**	16.55	15.99	15.84	15.58	13.63	13.92	15.71
COMMON SHARES								
Shares outstanding, end of period (000)	**224,997**	224,997	224,942	224,881	223,847	223,847	223,794	223,673
Volume traded (000)	**182,199**	76,631	73,099	40,929	57,657	94,588	30,649	70,199
Common share price ($)								
High	**8.26**	13.15	20.36	25.20	24.31	34.69	40.75	41.29
Low	**3.46**	7.33	7.87	17.56	14.84	13.30	34.00	35.52
Close (end of period)	**6.55**	8.02	8.24	20.40	20.46	19.55	34.38	38.89

(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 and non-cash items.

Interim Consolidated Financial Statements

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

As at	Note	March 31, 2016	December 31, 2015
Assets			
Current assets			
Cash and cash equivalents	18	**$ 124,560**	$ 408,213
Trade receivables and other		**144,370**	150,042
Inventories		**83,238**	53,079
Commodity risk management	20	**9,972**	-
		362,140	611,334
Non-current assets			
Property, plant and equipment	4	**7,909,237**	8,011,760
Exploration and evaluation assets	5	**546,111**	546,421
Other intangible assets	6	**83,595**	84,142
Other assets	7	**139,867**	146,612
Commodity risk management	20	**7,489**	-
Total assets		**$ 9,048,439**	$ 9,400,269
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 145,606**	$ 217,991
Current portion of long-term debt	8	**16,863**	17,992
Current portion of provisions and other liabilities	9	**16,022**	12,313
		178,491	248,296
Non-current liabilities			
Long-term debt	8	**4,859,099**	5,190,363
Provisions and other liabilities	9	**179,474**	196,274
Deferred income tax liability		**18,311**	87,469
Commodity risk management	20	**498**	-
Total liabilities		**5,235,873**	5,722,402
Shareholders' equity			
Share capital	10	**4,836,800**	4,836,800
Contributed surplus	10	**186,686**	171,835
Deficit		**(1,235,512)**	(1,366,341)
Accumulated other comprehensive income		**24,592**	35,573
Total shareholders' equity		**3,812,566**	3,677,867
Total liabilities and shareholders' equity		**$ 9,048,439**	$ 9,400,269

Commitments and contingencies (note 22)

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

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

		Three months ended March 31	
	Note	**2016**	**2015**
Revenues			
Petroleum revenue, net of royalties	11	**$ 279,624**	$ 455,682
Other revenue	12	**10,714**	11,313
		290,338	466,995
Expenses			
Diluent and transportation	13	**223,363**	295,710
Operating expenses		**63,388**	89,598
Purchased product and storage		**28,810**	12,107
Depletion and depreciation	4,6	**116,993**	115,571
Commodity risk management loss (gain)	20	**(16,963)**	-
General and administrative		**27,716**	33,306
Stock-based compensation	10	**12,892**	12,530
Research and development		**1,378**	1,172
Interest and other income		**(520)**	(964)
Foreign exchange loss (gain), net	14	**(325,947)**	378,079
Net finance expense	15	**92,667**	65,967
Other expenses	16	**4,371**	-
Earnings (loss) before income taxes		**62,190**	(536,081)
Income tax recovery	17	**(68,639)**	(27,774)
Net earnings (loss)		**130,829**	(508,307)
Other comprehensive income (loss), net of tax			
Items that may be reclassified to profit or loss:			
Foreign currency translation adjustment		**(10,981)**	5,838
Comprehensive income (loss) for the period		**$ 119,848**	$ (502,469)

Net earnings (loss) per common share			
Basic	19	**$ 0.58**	$ (2.27)
Diluted	19	**$ 0.58**	$ (2.27)

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

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

	Note	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2015		**$4,836,800**	**$ 171,835**	**$(1,366,341)**	**$ 35,573**	**$ 3,677,867**
Stock-based compensation	10	**-**	**14,851**	**-**	**-**	**14,851**
Comprehensive income (loss)		**-**	**-**	**130,829**	**(10,981)**	**119,848**
Balance as at March 31, 2016		**$4,836,800**	**$ 186,686**	**$(1,235,512)**	**$ 24,592**	**$ 3,812,566**
Balance as at December 31, 2014		$4,797,853	$ 153,837	$ (196,670)	$ 13,215	$ 4,768,235
Stock-based compensation		-	14,107	-	-	14,107
Comprehensive income (loss)		-	-	(508,307)	5,838	(502,469)
Balance as at March 31, 2015		$4,797,853	$ 167,944	$ (704,977)	$ 19,053	$ 4,279,873

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

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

		Three months ended March 31	
	Note	2016	2015
Cash provided by (used in):			
Operating activities			
Net earnings (loss)		**$ 130,829**	$ (508,307)
Adjustments for:			
Depletion and depreciation	4,6	**116,993**	115,571
Stock-based compensation	10	**12,892**	12,530
Unrealized loss (gain) on foreign exchange	14	**(320,281)**	370,849
Unrealized loss (gain) on derivative financial instruments	15,20	**(11,474)**	3,531
Onerous contracts	16	**4,371**	-
Deferred income tax recovery	17	**(69,156)**	(27,774)
Amortization of debt issue costs	7,8	**3,003**	2,885
Other		**1,583**	1,181
Decommissioning expenditures	9	**(962)**	(896)
Payments on onerous contracts	9	**(629)**	-
Net change in non-cash working capital items	18	**(87,840)**	13,488
Net cash provided by (used in) operating activities		**(220,671)**	(16,942)
Investing activities			
Capital investments:			
Property, plant and equipment	4	**(34,009)**	(91,590)
Exploration and evaluation	5	**(260)**	(247)
Other intangible assets	6	**(706)**	(4,267)
Other		**(1,239)**	1,941
Net change in non-cash working capital items	18	**(11,348)**	(111,647)
Net cash provided by (used in) investing activities		**(47,562)**	(205,810)
Financing activities			
Repayment of long-term debt	8	**(4,213)**	(4,124)
Net cash provided by (used in) financing activities		**(4,213)**	(4,124)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(11,207)**	41,557
Change in cash and cash equivalents		**(283,653)**	(185,319)
Cash and cash equivalents, beginning of period		**408,213**	656,097
Cash and cash equivalents, end of period		**$ 124,560**	$ 470,778

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

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange ("TSX") under the symbol "MEG". The Corporation owns a 100% interest in over 900 square miles of oil sands leases in the southern Athabasca oil sands region of northern Alberta and is primarily engaged in a steam assisted gravity drainage oil sands development at its 80 section Christina Lake Project. The Corporation is using a staged approach to development. The Corporation also holds a 50% interest in the Access Pipeline, a dual pipeline to transport diluent north from the Edmonton area to the Athabasca oil sands area and a blend of bitumen and diluent south from the Christina Lake Project into the Edmonton area. In addition to the Access Pipeline, the Corporation owns the Stonefell Terminal, located near Edmonton, Alberta, which offers 900,000 barrels of terminalling and storage capacity. The Stonefell Terminal is connected to the Access Pipeline and is also connected by pipeline to a third-party rail-loading terminal. The corporate office is located at 520 - 3rd Avenue S.W., Calgary, Alberta, Canada.

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements ("interim consolidated financial statements") were prepared using the same accounting policies and methods as those used in the Corporation's audited consolidated financial statements for the year ended December 31, 2015. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting ("IAS 34"). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"), have been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 4 of the Corporation's audited consolidated financial statements for the year ended December 31, 2015. These interim consolidated financial statements should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2015.

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

These interim consolidated financial statements were approved by the Corporation's Audit Committee on April 27, 2016.

3. CHANGE IN ACCOUNTING POLICIES

New accounting standards

There were no new accounting standards adopted during the three months ended March 31, 2016.

Accounting standards issued but not yet applied

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. The Corporation is currently assessing the impact of the adoption of these amendments 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. The Corporation is currently assessing the impact of the adoption of these amendments on the Corporation's consolidated financial statements.

A description of additional accounting standards that are anticipated to be adopted by the Corporation in future periods is provided within Note 3 of the Corporation's audited consolidated financial statements for the year ended December 31, 2015.

4. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Corporate assets	Total
Cost				
Balance as at December 31, 2014	$ 7,539,369	$ 1,560,314	$ 47,117	$ 9,146,800
Additions	254,586	54,515	3,959	313,060
Change in decommissioning liabilities	(25,711)	(2,344)	-	(28,055)
Transfer to other assets (Note 7)	-	(6,938)	-	(6,938)
Balance as at December 31, 2015	**$ 7,768,244**	**$ 1,605,547**	**$ 51,076**	**$ 9,424,867**
Additions	33,889	1,083	618	35,590
Change in decommissioning liabilities	(21,231)	(1,142)	-	(22,373)
Balance as at March 31, 2016	**$ 7,780,902**	**$ 1,605,488**	**$ 51,694**	**$ 9,438,084**
Accumulated depletion and depreciation				
Balance as at December 31, 2014	$ 883,723	$ 51,113	$ 16,474	$ 951,310
Depletion and depreciation	426,946	29,227	5,624	461,797
Balance as at December 31, 2015	**$ 1,310,669**	**$ 80,340**	**$ 22,098**	**$ 1,413,107**
Depletion and depreciation	107,046	7,382	1,312	115,740
Balance as at March 31, 2016	**$ 1,417,715**	**$ 87,722**	**$ 23,410**	**$ 1,528,847**
Carrying amounts				
Balance as at December 31, 2015	$ 6,457,575	$ 1,525,207	$ 28,978	$ 8,011,760
Balance as at March 31, 2016	**$ 6,363,187**	**$ 1,517,766**	**$ 28,284**	**$ 7,909,237**

As at March 31, 2016, $731.0 million of assets under construction were included within property, plant and equipment (December 31, 2015 - $727.7 million). Assets under construction are not subject to depletion and depreciation. As at March 31, 2016, no impairment has been recognized on these assets.

5. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2014	$	588,526
Additions		1,458
Dispositions		(41,827)
Change in decommissioning liabilities		(1,736)
Balance as at December 31, 2015	**$**	**546,421**
Additions		260
Change in decommissioning liabilities		(570)
Balance as at March 31, 2016	**$**	**546,111**

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. These assets are not subject to depletion, as they are in the exploration and evaluation stage, but are reviewed on a quarterly basis for any indication of impairment. As at March 31, 2016, no impairment has been recognized on these assets.

6. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2014	$	89,780
Additions		6,498
Balance as at December 31, 2015	$	96,278
Additions		706
Balance as at March 31, 2016	**$**	**96,984**

Accumulated depreciation		
Balance as at December 31, 2014	$	6,690
Depreciation		5,446
Balance as at December 31, 2015	$	12,136
Depreciation		1,253
Balance as at March 31, 2016	**$**	**13,389**

Carrying amounts		
Balance as at December 31, 2015	$	84,142
Balance as at March 31, 2016	**$**	**83,595**

As at March 31, 2016, other intangible assets include $64.3 million invested to maintain the right to participate in a potential pipeline project and $19.3 million invested in software that is not an integral component of the related computer hardware (December 31, 2015 - $63.6 million and $20.5 million, respectively). As at March 31, 2016, no impairment has been recognized on these assets.

7. OTHER ASSETS

As at	March 31, 2016	December 31, 2015
Long-term pipeline linefill[(a)]	**$ 125,704**	$ 131,141
Deferred financing costs	**15,275**	16,366
U.S. auction rate securities	**3,252**	3,470
	144,231	150,977
Less current portion of deferred financing costs	**(4,364)**	(4,365)
	$ 139,867	$ 146,612

(a) The Corporation has entered into agreements to transport diluent and bitumen blend on third-party owned pipelines and is required to supply linefill for these pipelines. As these pipelines are owned by third-parties, the linefill is not considered to be a component of the Corporation's property, plant and equipment. The linefill is classified as a long-term asset as these transportation contracts extend beyond the year 2024. As at March 31, 2016, no impairment has been recognized on these assets.

8. LONG-TERM DEBT

As at	March 31, 2016	December 31, 2015
Senior secured term loan (March 31, 2016 – US$1.245 billion; December 31, 2015 – US$1.249 billion)	**$ 1,615,214**	$ 1,727,924
6.5% senior unsecured notes (US$750 million)	**972,825**	1,038,000
6.375% senior unsecured notes (US$800 million)	**1,037,680**	1,107,200
7.0% senior unsecured notes (US$1.0 billion)	**1,297,100**	1,384,000
	4,922,819	5,257,124
Less current portion of senior secured term loan	**(16,863)**	(17,992)
Less unamortized financial derivative liability discount	**(13,581)**	(14,377)
Less unamortized deferred debt issue costs	**(33,276)**	(34,392)
	$ 4,859,099	$ 5,190,363

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2971 (December 31, 2015 - US$1 = C$1.3840).

All of the Corporation’s long-term debt is “covenant lite” in structure, meaning it is free of any financial maintenance covenants and is not dependent on, nor calculated from, the Corporation’s crude oil reserves. The first maturity of any of the Corporation’s long-term debt obligations is March 2020.

9. PROVISIONS AND OTHER LIABILITIES

As at		March 31, 2016		December 31, 2015
Decommissioning provision[(a)]	**$**	**108,112**	$	130,381
Onerous contracts provision[(b)]		**61,979**		58,178
Derivative financial liabilities[(c)]		**21,711**		16,223
Deferred lease inducements		**3,694**		3,805
Provisions and other liabilities		**195,496**		208,587
Less current portion		**(16,022)**		(12,313)
Non-current portion	**$**	**179,474**	$	196,274

(a) Decommissioning provision:

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

As at		March 31, 2016		December 31, 2015
Balance, beginning of year	**$**	**130,381**	$	156,382
Changes in estimated future cash flows		**(91)**		14,076
Changes in discount rates		**(23,883)**		(48,933)
Liabilities incurred		**1,031**		5,066
Liabilities settled		**(962)**		(1,873)
Accretion		**1,636**		5,663
Balance, end of period		**108,112**		130,381
Less current portion		**(1,659)**		(1,485)
Non-current portion	**$**	**106,453**	$	128,896

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The Corporation has estimated the net present value of the decommissioning obligations using a credit-adjusted risk-free rate of 10.7% (December 31, 2015 – 8.3%).

(b) Onerous contracts provision:

As at	March 31, 2016	December 31, 2015
Balance, beginning of year	**$ 58,178**	$ -
Changes in estimated future cash flows	**464**	-
Changes in discount rates	**4**	-
Liabilities incurred	**3,904**	58,719
Liabilities settled	**(629)**	(541)
Accretion	**58**	-
Balance, end of period	**61,979**	58,178
Less current portion	**(6,491)**	(1,993)
Non-current portion	**$ 55,488**	$ 56,185

As at March 31, 2016, the Corporation had recognized a total provision of $62.0 million related to certain onerous operating lease contracts (Note 16) (December 31, 2015 – $58.2 million). The provision represents the present value of the difference between the minimum future payments that the Corporation is obligated to make under the non-cancellable onerous operating lease contracts and estimated recoveries. These cash flows have been discounted using a risk-free discount rate of 0.9% (December 31, 2015 – 1.0%). This estimate may vary as a result of changes in estimated recoveries.

(c) Derivative financial liabilities:

As at	March 31, 2016	December 31, 2015
1% interest rate floor	**$ 18,758**	$ 11,740
Interest rate swaps (Note 20)	**2,953**	4,483
Derivative financial liabilities	**21,711**	16,223
Less current portion	**(7,351)**	(8,316)
Non-current portion	**$ 14,360**	$ 7,907

10. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

(b) Changes in issued common shares are as follows:

	Three months ended March 31, 2016		Year ended December 31, 2015	
	Number of shares	**Amount**	**Number of shares**	**Amount**
Balance, beginning of year	**224,996,989**	**$ 4,836,800**	223,846,891	$ 4,797,853
Issued upon vesting and release of RSUs	**-**	**-**	1,150,098	38,947
Balance, end of period	**224,996,989**	**$ 4,836,800**	224,996,989	$ 4,836,800

(c) Stock options outstanding:

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

Three months ended March 31, 2016	**Stock options**	**Weighted average exercise price**
Outstanding, beginning of year	**9,925,313**	**$ 29.94**
Forfeited	**(77,869)**	**33.62**
Expired	**(319,775)**	**24.00**
Outstanding, end of period	**9,527,669**	**$ 30.11**

(d) Restricted share units outstanding and performance share units outstanding:

The Restricted Share Unit Plan allows for the granting of Restricted Share Units ("RSUs"), including Performance Share Units ("PSUs"), to directors, officers, employees and consultants of the Corporation.

Three months ended March 31, 2016	
Outstanding, beginning of year	**3,280,112**
Forfeited	**(3,987)**
Outstanding, end of period	**3,276,125**

(e) Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of Deferred Share Units (“DSUs”) to directors of the Corporation. As at March 31, 2016, there were 47,696 DSUs outstanding (December 31, 2015 – 47,696 DSUs outstanding).

(f) Contributed surplus:

Three months ended March 31, 2016	
Balance, beginning of year	**$ 171,835**
Stock-based compensation - expensed	**12,892**
Stock-based compensation - capitalized	**1,959**
Balance, end of period	**$ 186,686**

11. PETROLEUM REVENUE, NET OF ROYALTIES

	Three months ended March 31	
	2016	**2015**
Petroleum revenue:		
Proprietary	**$ 250,397**	$ 455,753
Third-party[(a)]	**28,730**	6,079
Petroleum revenue	**$ 279,127**	$ 461,832
Royalties	**497**	(6,150)
Petroleum revenue, net of royalties	**$ 279,624**	$ 455,682

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

12. OTHER REVENUE

	Three months ended March 31	
	2016	**2015**
Power revenue	**$ 5,554**	$ 8,819
Transportation revenue	**5,160**	2,494
Other revenue	**$ 10,714**	$ 11,313

13. DILUENT AND TRANSPORTATION

	Three months ended March 31	
	2016	**2015**
Diluent expense	**$ 172,865**	$ 257,048
Transportation expense	**50,498**	38,662
Diluent and transportation	**$ 223,363**	$ 295,710

14. FOREIGN EXCHANGE LOSS (GAIN), NET

	Three months ended March 31	
	2016	**2015**
Unrealized foreign exchange loss (gain) on:		
Long-term debt	**$ (330,093)**	$ 412,406
US$ denominated cash, cash equivalents and other	**9,812**	(41,557)
Unrealized net loss (gain) on foreign exchange	**(320,281)**	370,849
Realized loss (gain) on foreign exchange	**(5,666)**	7,230
Foreign exchange loss (gain), net	**$ (325,947)**	$ 378,079

15. NET FINANCE EXPENSE

	Three months ended March 31	
	2016	**2015**
Total interest expense	**$ 83,915**	$ 75,726
Less capitalized interest	**-**	(16,003)
Net interest expense	**83,915**	59,723
Accretion on provisions	**1,694**	1,312
Unrealized loss on derivative financial liabilities	**5,489**	3,531
Realized loss on interest rate swaps	**1,569**	1,401
Net finance expense	**$ 92,667**	$ 65,967

16. OTHER EXPENSES

During the three months ended March 31, 2016, the Corporation recognized an expense of $4.4 million related to certain onerous operating lease contracts (Note 9) (three months ended March 31, 2015 - nil).

17. INCOME TAX RECOVERY

	Three months ended March 31	
	2016	**2015**
Current income tax expense	**$ 517**	$ -
Deferred income tax recovery	**(69,156)**	(27,774)
Income tax recovery	**$ (68,639)**	$ (27,774)

18. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended March 31	
	2016	**2015**
Cash provided by (used in):		
Trade receivables and other	**$ 2,506**	$ (6,070)
Inventories	**(31,391)**	36,200
Accounts payable and accrued liabilities	**(70,303)**	(128,289)
	$ (99,188)	$ (98,159)
Changes in non-cash working capital relating to:		
Operating	**$ (87,840)**	$ 13,488
Investing	**(11,348)**	(111,647)
	$ (99,188)	$ (98,159)
Cash and cash equivalents:[(a)]		
Cash	**$ 99,427**	$ 279,910
Cash equivalents	**25,133**	190,868
	$ 124,560	$ 470,778
Cash interest paid	**$ 129,013**	$ 123,054

(a) As at March 31, 2016, C$60.1 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (March 31, 2015 - C$325.1 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2971 (March 31, 2015 - US$1 = C$1.2683).

19. NET EARNINGS (LOSS) PER COMMON SHARE

	Three months ended March 31	
	2016	**2015**
Net earnings (loss)	**$ 130,829**	$ (508,307)
Weighted average common shares outstanding[(a)]	**225,138,919**	223,889,936
Dilutive effect of stock options, RSUs and PSUs[(b)]	**241,439**	-
Weighted average common shares outstanding – diluted	**225,380,358**	223,889,936
Net earnings (loss) per share, basic	**$ 0.58**	$ (2.27)
Net earnings (loss) per share, diluted	**$ 0.58**	$ (2.27)

(a) Weighted average common shares outstanding for the three months ended March 31, 2016 includes 141,930 PSUs that are vested but not yet released (three months ended March 31, 2015 – 43,044 PSUs)

(b) For the three months ended March 31, 2015, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss. If the Corporation had recognized net earnings during the three months ended March 31, 2015, the dilutive effect of stock options, RSUs and PSUs would have been 885,298 weighted average common shares.

20. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments recognized on the consolidated balance sheet are comprised of cash and cash equivalents, trade receivables and other, U.S. auction rate securities ("ARS") included within other assets, commodity risk management contracts, accounts payable and accrued liabilities, derivative financial liabilities and long-term debt. As at March 31, 2016, the ARS, commodity risk management contracts and the derivative financial liabilities were classified as held-for-trading financial instruments; cash and cash equivalents and trade receivables and other were classified as loans and receivables; and accounts payable and accrued liabilities were classified as other financial liabilities. Long-term debt was carried at amortized cost.

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

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

		Fair value measurements using		
As at March 31, 2016	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
ARS (Note 7)	**$ 3,252**	**$ -**	**$ 3,252**	**$ -**
Commodity risk management contracts	**17,461**	**-**	**17,461**	**-**
Financial liabilities				
Long-term debt[1] (Note 8)	**4,922,819**	**-**	**3,270,380**	**-**
Derivative financial liabilities (Note 9)	**21,711**	**-**	**21,711**	**-**
Commodity risk management contracts	**498**	**-**	**498**	**-**

		Fair value measurements using		
As at December 31, 2015	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
ARS (Note 7)	$ 3,470	$ -	$ 3,470	$ -
Financial liabilities				
Long-term debt[1] (Note 8)	5,257,124	-	3,999,317	-
Derivative financial liabilities (Note 9)	16,223	-	16,223	-

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

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

As at March 31, 2016, the Corporation did not have any financial instruments measured at Level 1 fair value.

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

The estimated fair values of the ARS and long-term debt are derived using quoted prices in an inactive market from a third-party independent broker.

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

Level 3 fair value measurements are based on unobservable information.

As at March 31, 2016, the Corporation did not have any financial instruments measured at Level 3 fair value. The Corporation recognizes transfers into and transfers out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer.

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

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

As at	**March 31, 2016**			**December 31, 2015**		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Gross amount	**$ 18,052**	**$ 1,089**	**$ 16,963**	$ -	$ -	$ -
Amount offset	**(591)**	**(591)**	**-**	-	-	-
Net amount	**$ 17,461**	**$ 498**	**$ 16,963**	$ -	$ -	$ -

Summary of unrealized commodity risk management positions:

As at	**March 31, 2016**			**December 31, 2015**		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Condensate	**$ 18,052**	**$ 498**	**$ 17,554**	$ -	$ -	$ -
Crude oil	**-**	**591**	**(591)**	-	-	-
Total fair value	**$ 18,052**	**$ 1,089**	**$ 16,963**	$ -	$ -	$ -

(b) Commodity price risk management:

In the first quarter of 2016, the Corporation entered into derivative financial instruments to manage commodity price risk. The use of derivative financial instruments is governed by a Risk Management Committee that follows guidelines and is subject to limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes. Commodity risk management contracts are measured at fair value, with gains and losses on re-measurement included in the consolidated statement of earnings (loss) and comprehensive income (loss) in the period in which they arise.

As at March 31, 2016	**Term**	**Volume (bbls/d)**	**Average % of WTI**
Condensate purchase contracts:			
Mont Belvieu fixed % of WTIl	Apr 1, 2016 – Dec 31, 2016	6,000	82.8%
Mont Belvieu fixed % of WTI	Jul 1, 2016 – Sep 30, 2016	1,250	87.8%
Mont Belvieu fixed % of WTI	Oct 1, 2016 – Dec 31, 2016	6,250	84.6%
Mont Belvieu fixed % of WTI	Jan 1, 2017 – Dec 31, 2017	13,500	82.6%

As at March 31, 2016, the Corporation had entered into the above condensate purchase contracts that effectively fix the average percentage differentials of condensate prices at Mont Belvieu, Texas to a percentage of WTI (US$/bbl). As at March 31, 2016, a 1% increase or decrease in the differential of condensate price to the US$ price of WTI would have resulted in a C$3.9 million decrease or increase in net earnings before income taxes.

As at March 31, 2016	**Term**	**Volume (bbls/d)**	**Average WCS Price (US$/bbl)**
Crude oil sales contracts:			
WCS fixed price	May 1, 2016 – Jun 30, 2016	5,000	$26.84
WCS fixed price	Jul 1, 2016 – Sep 30, 2016	5,000	$28.18

As at March 31, 2016, the Corporation had entered into the above crude oil sales contracts to effectively fix the Western Canadian Select ("WCS") price on a portion of its bitumen blend sales. As at March 31, 2016, a US$1.00/bbl increase or decrease in the price of WCS would have resulted in a C$1.0 million decrease or increase in net earnings before income taxes.

Commodity risk management loss (gain):

	Three months ended March 31	
	2016	**2015**
Realized gain on commodity risk management	**$ -**	$ -
Unrealized gain on commodity risk management	**(16,963)**	-
Commodity risk management loss (gain)	**$ (16,963)**	$ -

(c) Interest rate risk management:

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. In order to mitigate a portion of this risk, the Corporation has entered into interest rate swap contracts to effectively fix the interest rate at approximately 4.4% on US$748.0 million of the US$1.245 billion senior secured term loan until September 30, 2016. Interest rate swaps are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in the statement of consolidated earnings (loss) and comprehensive income (loss) in the period in which they arise.

21. GEOGRAPHICAL DISCLOSURE

As at March 31, 2016, the Corporation had non-current assets related to operations in the United States of $104.7 million (December 31, 2015 - $111.1 million). For the three months ended March 31, 2016, petroleum revenue related to operations in the United States was $96.3 million (three months ended March 31, 2015 - $108.9 million).

22. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at March 31, 2016:

	2016	2017	2018	2019	2020	Thereafter
Transportation and storage	$ 127,718	$ 179,905	$ 195,382	$ 186,542	$ 225,056	$ 3,196,870
Office lease rentals	11,807	34,137	32,700	32,729	33,619	268,259
Diluent purchases	110,698	43,049	19,885	19,885	19,939	56,331
Other operating commitments	12,941	9,945	5,998	9,822	10,454	76,071
Capital commitments	13,519	4,096	-	-	-	-
Commitments	**$ 276,683**	**$ 271,132**	**$ 253,965**	**$ 248,978**	**$ 289,068**	**$ 3,597,531**

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

(b) Contingencies

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