THIRD QUARTER 2014

Report to Shareholders for the period ended September 30, 2014

MEG Energy Corp. reported third quarter 2014 operational and financial results on October 29, 2014. Highlights include:

- Record quarterly production of 76,471 barrels per day (bpd), an increase of 11 per cent over second quarter 2014 results;

- Record non-energy operating costs of $7.16 per barrel with cash operating netbacks of $48.70 per barrel, a continuation of strong second quarter 2014 results;

- Near-record cash flow from operations of $238.7 million, driven by increased production levels and continuing strong cash operating netbacks.

"While there has been significant volatility in the general oil markets this quarter, MEG's third quarter shows that we are very much on track with our strategy," said Bill McCaffrey, President and Chief Executive Officer. "The critical parts of the equation – higher production, lower costs and attractive and more stable heavy oil pricing – are all reflected in our results."

MEG's production during the third quarter of 2014 increased to a record of 76,471 barrels per day (bpd), more than 120 per cent over comparative third quarter 2013 production of 34,246 bpd. Higher production rates reflect the ramp-up of MEG's Christina Lake Phase 2B project, as well as incremental production associated with the company's RISER initiative on phases 1 and 2 of the Christina Lake Project. For the first nine months of 2014, average production rose to 68,108 bpd from 32,980 bpd in the same period of 2013. Nine month production volumes for both 2013 and 2014 were impacted by planned maintenance.

On phases 1 and 2 of the Christina Lake Project, commercial deployment of MEG's proprietary *enhanced and modified steam and gas push* (eMSAGP) continued to advance, with its implementation on all original well pads from both phases. Steam-oil ratios and production trends have met or exceeded expectations.

Bitumen sales for the third quarter of 2014 were 69,757 bpd. The difference between sales and production in the third quarter is primarily due to MEG utilizing approximately 6,100 bpd of bitumen for linefill for the Access Pipeline expansion. The pipeline (50% MEG-owned) and the Stonefell Terminal (100% MEG-owned) are central to the company's 'Hub and Spoke' marketing strategy. MEG's Hub and Spoke strategy provides low-cost transportation to the Edmonton area marketing hub and the ability to temporarily store products during periods of market disruption or transportation constraint.

Third quarter 2014 non-energy operating costs decreased to $7.16 per barrel from $9.20 per barrel in the same period of 2013, primarily as a result of production increases that spread fixed costs over higher volumes. Net operating costs, which include natural gas energy costs as well as the benefit of electricity sales, were $10.31 per barrel in the third quarter of 2014, compared to $9.40 per barrel in the third quarter of 2013. The difference reflects higher natural gas energy costs and a decrease of approximately 22 per cent in average prices for electricity sold into the Alberta power grid.

Cash operating netback – the net revenue received by MEG after adjusting for operating and transportation costs – remained strong at $48.70 per barrel in the third quarter of 2014 compared to $51.45 per barrel in the second quarter. Cash operating netbacks for the first nine months of 2014 were $48.18 per barrel compared to $40.32 per barrel for the first nine months of 2013. The increase in year-to-date cash operating netbacks is primarily due to increased crude oil benchmark prices and narrowing light-heavy oil differentials, partially offset by an increase in natural gas energy prices and a decrease in power sales pricing.

“Pricing for Western Canadian heavy oil blends remains attractive,” said McCaffrey. “This is a trend that we expect to see continue as new infrastructure, such as the Flanagan-Seaway pipeline system and expanded rail-loading facilities, come into play over the next several months."

Record production volumes, low operating costs and strong price realizations in the third quarter of 2014 contributed to quarterly cash flow from operations of $238.7 million ($1.06 per share, diluted), compared to $144.5 million ($0.64 per share, diluted) in the third quarter of 2013. MEG’s third quarter 2014 cash flow from operations is the second highest quarter on record for the company.

Operating earnings, which are adjusted for items that are not indicative of operating performance, increased to $87.5 million ($0.39 per share, diluted) in the third quarter of 2014 from $56.2 million ($0.25 per share, diluted) in the same period of 2013, reflecting the same factors that impacted cash flow from operations.

MEG recorded a net loss of $101.0 million ($0.45 per share, diluted) in the third quarter of 2014 compared to net income of $115.4 million ($0.51 per share, diluted) in the third quarter of 2013. The difference primarily reflects $203.1 million of unrealized foreign exchange losses on the translation of the company’s US$ denominated debt in the third quarter of 2014 compared to unrealized foreign exchange gains of $64.3 million in the third quarter of 2013.

Forward-Looking Information and Non-GAAP Financial Measures

This quarterly report contains forward-looking information and financial measures that are not defined by IFRS and should be read in conjunction with the "Forward-Looking Information" and Non-GAAP Measurements" sections 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 period ended September 30, 2014 is dated October 28, 2014. This MD&A should be read in conjunction with the Corporation's MD&A for the year ended December 31, 2013, the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2013 and the unaudited interim consolidated financial statements and notes thereto for the period ended September 30, 2014. All tabular amounts are stated in thousands of Canadian dollars ($ or C$) unless indicated otherwise.

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1. OVERVIEW

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

MEG owns a 100% working interest in over 900 square miles of oil sands leases. In a report dated effective December 31, 2013, with a preparation date of January 16, 2014, GLJ Petroleum Consultants Ltd. estimated that the oil sands leases it had evaluated contained 2.9 billion barrels of proved plus probable bitumen reserves and 3.7 billion barrels of contingent bitumen resources (best estimate).

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 of each phase, the performance of each phase and the development schedule. In addition, the Corporation holds other leases (the "Growth Properties") that are still in the resource definition stage and that are anticipated to provide significant additional development opportunities.

MEG is currently focused on the phased development of the Christina Lake Project. MEG's first two production phases at the Christina Lake Project, Phases 1 and 2, commenced production in 2008 and 2009, respectively, with a combined design capacity of 25,000 bbls/d. Phase 2B, an expansion with a design capacity of 35,000 bbls/d, commenced production in the fourth quarter of 2013 and attained its full design capacity during the second quarter of 2014. In 2012, the Corporation announced the RISER initiative for Phases 1 and 2, which was designed to achieve increased production from existing Phase 1 and 2 assets, with relatively low capital and operating costs. The RISER initiative uses a combination of proprietary reservoir technologies, redeployment of steam, and facilities modifications including plant debottlenecking and expansions. As a result of the operational success achieved from the application of the RISER initiative on Phases 1 and 2, and the successful ramp-up of Phase 2B, MEG anticipates reaching production of 80,000 bbls/d from Christina Lake Phases 1, 2 and 2B in early 2015.

MEG's next phase of production growth will be primarily driven by the application of RISER on Phase 2B. RISER 2B includes the application of a combination of proprietary reservoir technologies, redeployment of steam and a major brownfield expansion of the existing Phase 2B facilities. Utilizing the results of recent production testing of the Phase 2B facility, MEG is in the process of designing a series of brownfield expansions of Phase 2B. Given the economic attractiveness of this strategy, MEG has prioritized RISER 2B ahead of its next greenfield expansion at Christina Lake.

MEG has also filed regulatory applications for the Surmont Project. The Surmont Project, which is situated along the same geological trend as Christina Lake, has an anticipated design capacity of approximately 120,000 bbls/d over multiple phases. MEG filed a regulatory application for the project in September 2012. The proposed project is expected to benefit from the use of a standardized plant design which will include the use of 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 operations. 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 also holds a 50% interest in the Access Pipeline, a strategic 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 the third quarter of 2014, MEG completed an expansion of the Access Pipeline, which included the construction of a 42-inch blend line from Christina Lake to the Edmonton, Alberta area. The expansion of the Access Pipeline will accommodate anticipated increases in production from Christina Lake as well as provide expansion capacity for future production volumes from the Surmont Project and from MEG's Growth Properties. MEG's 50% interest of the initial capacity in the expanded 42-inch line is approximately 200,000 bbls/d of blended bitumen. The previous 24-inch blend line is planned to be reversed and converted to diluent service in 2015.

In addition to the Access Pipeline, MEG owns 100% of the Stonefell Terminal, located near Edmonton, Alberta. The Stonefell Terminal was commissioned in the fourth quarter of 2013 and has 900,000 barrels of strategic terminalling and storage capacity. The Stonefell Terminal is strategically located near the southern end of the Access Pipeline and is connected to local and export markets by pipeline, in addition to being pipeline connected to a third party rail-loading terminal at Bruderheim, Alberta. This combination of pipeline and rail facilities allows for both the loading of bitumen blend for transport and the receipt of diluent, thereby giving access to multiple blend markets and diluent sources throughout North America.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

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:

	Three months ended September 30		Nine months ended September 30	
	2014	**2013**	**2014**	**2013**
Bitumen production - bbls/d	76,471	34,246	68,108	32,980
Bitumen sales - bbls/d	69,757	32,175	66,275	32,948
Steam to oil ratio (SOR)	2.5	2.5	2.5	2.4
West Texas Intermediate (WTI) US$/bbl	97.16	105.83	99.61	98.14
West Texas Intermediate (WTI) C$/bbl	105.84	109.90	109.02	100.45
Access Western Blend (AWB) US$/bbl	72.16	83.20	73.54	68.98
Access Western Blend (AWB) C$/bbl	78.60	86.40	80.49	70.60
Differential - WTI vs AWB - %	25.7%	21.4%	26.2%	29.7%
Bitumen realization - $/bbl	65.12	74.33	67.02	53.35
Net operating costs(1) - $/bbl	10.31	9.40	12.76	9.56
Non-energy operating costs - $/bbl	7.16	9.20	8.59	9.33
Cash operating netback(2) - $/bbl	48.70	59.59	48.18	40.32
Total cash capital investment(3) - $000	310,814	476,362	974,643	1,799,121
Net income (loss)(4) - $000	(100,975)	115,383	44,538	(18,223)
Per share, diluted	(0.45)	0.51	0.20	(0.08)
Operating earnings(5) - $000	87,471	56,171	239,269	33,071
Per share, diluted(5)	0.39	0.25	1.06	0.15
Cash flow from operations(5) - $000	238,659	144,521	657,359	230,776
Per share, diluted(5)	1.06	0.64	2.92	1.03
Cash, cash equivalents and short-term investments - $000	776,522	647,096	776,522	647,096
Long-term debt - $000(6)	4,217,536	2,857,740	4,217,536	2,857,740

(1) Net operating costs include energy and non-energy operating costs, reduced by power revenue. Please refer to Cash Operating Netbacks discussed further under the heading "RESULTS OF OPERATIONS".

(2) Cash operating netbacks are calculated by deducting the related diluent, transportation, operating expenses and royalties from proprietary sales volumes and power revenues, on a per barrel basis. Please refer to note 3 of the Cash Operating Netbacks table within "RESULTS OF OPERATIONS".

(3) Includes capitalized interest of $19.5 million and $61.1 million for the three and nine months ended September 30, 2014, respectively ($21.8 million and $53.6 million respectively, for the three and nine months ended September 30, 2013).

(4) Includes an unrealized foreign exchange loss on conversion of the U.S. dollar denominated debt of $203.1 million and $218.5 million, respectively, for the three and nine months ended September 30, 2014. Includes an unrealized foreign exchange gain on conversion of U.S. dollar denominated debt of $64.3 million and an unrealized foreign exchange loss of $85.9 million, respectively, for the three and nine months ended September 30, 2013.

(5) Operating earnings, cash flow from operations 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. These non-GAAP measurements are reconciled to net income (loss) and net cash provided by (used in) operating activities in accordance with IFRS under the heading "NON-GAAP MEASUREMENTS" and discussed further in the "ADVISORY" section.

(6) Includes current and non-current portion.

Bitumen production for the three months ended September 30, 2014 averaged 76,471 bbls/d compared to 68,984 bbls/d for the three months ended June 30, 2014 and 34,246 bbls/d for the three months ended September 30, 2013. Bitumen production for the nine months ended September 30, 2014 averaged 68,108 bbls/d compared to 32,980 bbls/d for the nine months ended September 30, 2013. The increase in production volumes in the third quarter of 2014 compared to the second quarter of 2014 is primarily due to the successful ramp-up of Phase 2B. During the second quarter of 2014, the Phase 1 and 2 facilities were down for approximately three weeks for scheduled plant maintenance. The increase in production volumes in the third quarter of 2014 compared to the same period in 2013 is due to the start-up of Phase 2B and the continued success of RISER at Christina Lake Phases 1 and 2. The implementation of the RISER initiative within Phases 1 and 2 has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production. The Corporation achieved first production from Phase 2B in the fourth quarter of 2013. As a result of the successful ramp-up of Phase 2B, in combination with the success achieved from applying RISER to Phases 1 and 2, MEG anticipates reaching production of 80,000 bbls/d from Christina Lake Phases 1, 2 and 2B in early 2015.

Bitumen sales for the three months ended September 30, 2014 were 69,757 bbls/d compared to production of 76,471 bbls/d for the same period. The difference between bitumen sales and production is primarily due to the Corporation utilizing approximately 6,100 bbls/d of production for blend linefill for the Access Pipeline expansion in the third quarter of 2014.

Bitumen sales for the nine months ended September 30, 2014 were 66,275 bbls/d compared to production of 68,108 bbls/d for the same period. The difference between bitumen sales and production was primarily due to utilizing production for blend linefill for the Access Pipeline expansion in the third quarter of 2014.

The Corporation’s average steam to oil ratio (“SOR”) was 2.5 for the three months ended September 30, 2014 and September 30, 2013. The SOR averaged 2.5 during the nine months ended September 30, 2014 and 2.4 for the nine months ended September 30, 2013. The average SOR in the first nine months of 2014 has decreased from an SOR of 2.9 for the fourth quarter of 2013, as more Phase 2B well pairs have been converted from steam circulation to production.

For the three months ended September 30, 2014, average bitumen realizations decreased compared to the three months ended September 30, 2013 primarily due to lower crude oil benchmark prices and a higher differential between the Corporation’s blend sales price and the C$/bbl West Texas Intermediate (“WTI”) price which was 25.7% during the three months ended September 30, 2014 compared to a differential of 21.4% during the three months ended September 30, 2013. The C$/bbl WTI price averaged $105.84 per barrel during the third quarter of 2014 compared to $109.90 per barrel during the third quarter of 2013.

The C$/bbl WTI price averaged $109.02 per barrel during the first nine months of 2014 compared to $100.45 per barrel during the first nine months of 2013. The differential between the Corporation's blend sales price and WTI improved to an average of 26.2% for the nine months ended September 30, 2014 compared to 29.7% for the nine months ended September 30, 2013.

Net operating costs averaged $10.31 per barrel for the three months ended September 30, 2014 compared to $9.40 per barrel for the three months ended September 30, 2013. The increase in net operating costs on a per barrel basis is primarily attributable to the increase in energy operating costs and the decrease in the average power sales price, partially offset by a decrease in non-energy operating costs on a per barrel basis.

- Energy operating costs increased to $5.58 per barrel for the three months ended September 30, 2014 compared to $3.32 per barrel for the three months ended September 30, 2013. Energy costs increased as a result of the increase in natural gas prices, which increased to an average of $4.00 per thousand cubic feet ("mcf") in the third quarter of 2014, compared to $2.17 per mcf in the third quarter of 2013.

- Non-energy operating costs decreased to $7.16 per barrel for the three months ended September 30, 2014 compared to $9.20 per barrel for the three months ended September 30, 2013. On a per barrel basis, non-energy operating costs decreased as a result of the increase in production, as relatively fixed components of operating costs are spread over a greater number of barrels of production.

- Power revenue decreased to $2.43 per barrel for the three months ended September 30, 2014 compared to $3.12 per barrel for the three months ended September 30, 2013. The Corporation's realized power price during the three months ended September 30, 2014 averaged $59.07 per megawatt hour compared to $75.96 per megawatt hour for the same period in 2013. The decrease in the power price is mainly a result of increased power generation capacity in the province. Power revenue had the effect of offsetting 43% of energy operating costs during the three months ended September 30, 2014 compared to 94% of energy operating costs during the three months ended September 30, 2013.

Net operating costs for the nine months ended September 30, 2014 averaged $12.76 per barrel compared to $9.56 per barrel for the nine months ended September 30, 2013. The increase in net operating costs on a per barrel basis is attributable to an increase in energy operating costs and a decrease in the average power sales price, partially offset by a decrease in non-energy operating costs on a per barrel basis.

- Energy operating costs increased to $6.71 per barrel for the nine months ended September 30, 2014 compared to $4.34 per barrel for the nine months ended September 30, 2013. Energy costs increased as a result of the increase in natural gas prices, which increased to an average of $5.04 per mcf for the nine months ended September 30, 2014 compared to $3.04 per mcf for the nine months ended September 30, 2013.

- Non-energy operating costs decreased to $8.59 per barrel for the nine months ended September 30, 2014 compared to $9.33 per barrel for the nine months ended September 30, 2013. On a per barrel basis, non-energy operating costs decreased as a result of the increase in production, as relatively fixed components of operating costs are spread over a greater number of barrels of production. This was partially offset by an increase in turnaround costs which were

$0.67 per barrel in the nine months ended September 30, 2014 compared to $0.20 per barrel for the nine months ended September 30, 2013.

- Power revenue decreased to $2.54 per barrel for the nine months ended September 30, 2014 compared to $4.11 per barrel for the nine months ended September 30, 2013. The Corporation's realized power price during the nine months ended September 30, 2014 decreased to $54.87 per megawatt hour compared to $88.89 per megawatt hour for the same period in 2013. The decrease in the power price is mainly a result of increased power generation capacity in the province. The first nine months of 2013 were affected by significant power supply disruptions, which led to strong power prices. Power revenue had the effect of offsetting 38% of energy operating costs during the nine months ended September 30, 2014 compared to 95% of energy operating costs during the nine months ended September 30, 2013.

Cash operating netback for the three months ended September 30, 2014 was $48.70 per barrel compared to $59.59 per barrel for the three months ended September 30, 2013. The decrease in the cash operating netback in the third quarter of 2014 compared to the third quarter of 2013 is primarily due to a decrease in bitumen realizations. Cash operating netback for the first nine months of 2014 was $48.18 per barrel compared to $40.32 per barrel for the first nine months of 2013. The increase in cash operating netback for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013 is due primarily to the increase in bitumen realizations partially offset by an increase in energy operating costs and a decrease in power sales pricing.

Total cash capital investment for the third quarter of 2014 totalled $310.8 million (including $19.5 million of capitalized interest) compared to a total of $476.4 million (including $21.8 million of capitalized interest) for the third quarter of 2013. Total cash capital investment for the nine months ended September 30, 2014 totalled $974.6 million (including $61.1 million of capitalized interest) compared to a total of $1.8 billion (including $53.6 million of capitalized interest) for the nine months ended September 30, 2013. Capital investment during the first nine months of 2014 has been focused on the initial investment in RISER 2B, engineering and procurement of long-lead items for future expansions at Christina Lake, the expansion of the Access Pipeline, and delineation drilling at Christina Lake, Surmont and the Growth Properties. In the third quarter of 2014, MEG completed the expansion of the Access Pipeline, which included the construction of a 42-inch blend line from Christina Lake to the Edmonton, Alberta area to accommodate anticipated increases in production, as well as provide expansion capacity for future production volumes that are expected to be produced from the Christina Lake Project, from the Surmont Project and from MEG's Growth Properties.

The Corporation recognized a net loss of $101.0 million for the three months ended September 30, 2014 compared to net income of $115.4 million for the three months ended September 30, 2013. The net loss for the third quarter was primarily due to an unrealized foreign exchange loss of $203.1 million on the conversion of U.S. dollar denominated debt in the third quarter of 2014 compared to an unrealized foreign exchange gain of $64.3 million on the conversion of U.S. dollar denominated debt in the third quarter of 2013.

The Corporation recognized net income of $44.5 million for the nine months ended September 30, 2014 compared to a net loss of $18.2 million for the nine months ended September 30, 2013. Net income for the first nine months of 2014 was positively impacted by higher production and blend sales volumes as well as an increase in bitumen realizations compared to the first nine months of 2013. Net income for the nine months ended September 30, 2014 included an unrealized foreign exchange loss of $218.5 million on conversion of the Corporation's U.S. dollar denominated debt. The net loss for the nine months ended September 30, 2013 included an unrealized foreign exchange loss of $85.9 million on conversion of U.S. dollar denominated debt.

Operating earnings for the three months ended September 30, 2014 were $87.5 million compared to $56.2 million for the three months ended September 30, 2013. The increase in operating earnings is primarily due to the 108% increase in blend sales volumes, partially offset by a 12% decrease in bitumen realization per barrel and an increase in energy and non-energy operating costs.

The Corporation recognized operating earnings of $239.3 million for the nine months ended September 30, 2014 compared to operating earnings of $33.1 million for the nine months ended September 30, 2013. Operating earnings have increased significantly for the first nine months of 2014 as blend sales volumes have doubled, and bitumen realizations per barrel have increased by 26% compared to the first nine months of 2013, partially offset by an increase in energy and non-energy costs.

Cash flow from operations increased to $238.7 million for the three months ended September 30, 2014 from $144.5 million for the three months ended September 30, 2013. Cash flow from operations increased primarily due to higher blend sales volumes. Cash flow from operations increased to $657.4 million for the nine months ended September 30, 2014 from $230.8 million for the nine months ended September 30, 2013. Cash flow from operations increased primarily due to higher blend sales volumes.

The Corporation's cash and cash equivalents balance totalled $0.8 billion as at September 30, 2014 compared to a cash, cash equivalents and short-term investments balance of $0.6 billion as at September 30, 2013. The Corporation's cash, cash equivalents and short-term investments balances have been impacted by an increase in cash flow from operations in 2014, increases in long-term debt during 2013 and capital investments over the past year. Long-term debt increased to $4.2 billion as at September 30, 2014 from $2.9 billion as at September 30, 2013. The increase in long-term debt is due to the issuance of US$1.0 billion of senior unsecured notes in the fourth quarter of 2013 and the decrease in the value of the Canadian dollar relative to the U.S. dollar.

As at September 30, 2014, the Corporation's capital resources included $0.8 billion of cash and cash equivalents and an undrawn US$2.0 billion revolving credit facility. As at September 30, 2014, US$106.3 million of the revolving credit facility was utilized to support letters of credit.

3. OUTLOOK

As part of the Corporation’s second quarter reporting, MEG increased its 2014 production guidance, primarily as a result of the operational success achieved to date on Phase 2B and the ongoing success of RISER. MEG’s targeted 2014 annual average bitumen production volume is anticipated to be 65,000 – 70,000 bbls/d. Annual non-energy operating costs are anticipated to be in the range of $8 to $10 per barrel.

The Corporation anticipates capital investment for the fourth quarter of 2014 will be approximately $500 to $700 million, dependent on the timing of ongoing capital projects.

4. BUSINESS ENVIRONMENT

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

	Nine months ended September 30		2014			2013			
	2014	2013	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Commodity Prices									
Crude oil prices									
West Texas Intermediate (WTI) US$/bbl at Cushing	99.61	98.14	97.16	102.99	98.68	97.43	105.83	94.22	94.37
West Texas Intermediate (WTI) C$/bbl at Cushing	109.02	100.45	105.84	112.31	108.89	102.08	109.90	96.42	95.21
Western Canadian Select (WCS) C$/bbl at Chicago	85.89	77.19	83.82	90.44	83.41	68.31	91.75	76.82	63.01
Differential – WTI vs WCS (C$/bbl)	23.13	23.26	22.02	21.87	25.48	33.77	18.15	19.60	32.20
Differential – WTI vs WCS (%)	21.2%	23.2%	20.8%	19.5%	23.4%	33.1%	16.5%	20.3%	33.8%
Natural gas prices									
AECO (C$/mcf)	4.80	3.04	4.00	4.70	5.69	3.52	2.42	3.51	3.18
Electric power prices									
Alberta power pool (C$/MWh)	55.64	90.76	63.91	42.43	60.58	48.60	83.61	123.41	65.26
Foreign exchange rates									
C$ equivalent of 1 US$ - average	1.0944	1.0236	1.0893	1.0905	1.1035	1.0477	1.0385	1.0233	1.0089
C$ equivalent of 1 US$ - period end	1.1208	1.0285	1.1208	1.0676	1.1053	1.0636	1.0285	1.0512	1.0156

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$97.16 per barrel in the third quarter of 2014 compared to US$102.99 per barrel for the second quarter of 2014. The WTI price decreased to US$97.16 per barrel in the three months ended September 30, 2014 from US$105.83 per barrel for the three months ended September 30, 2013. The decrease is primarily due to increased supply in North America. The WTI price averaged US$99.61 per barrel for the nine months ended September 30, 2014 compared to US$98.14 per barrel for the nine months ended September 30, 2013. WTI increased slightly on a year-to-date basis in 2014 compared to 2013 as a result of new pipeline infrastructure developed in the first half of 2013 which relieved capacity constraints and enabled North American inland production to gain greater access to the U.S. Gulf Coast.

The Western Canadian Select ("WCS") benchmark reflects mid-continent North American prices at Chicago, Illinois. 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. Despite the decrease in WTI in the third quarter of 2014, market conditions remained positive with the WTI to WCS differential remaining relatively static at approximately 20% for the second and third quarters of 2014. In the third quarter of 2014, WCS pricing benefited from the weakening of the Canadian dollar relative to the U.S. dollar. The WTI to WCS differential averaged 20.8% for the third quarter of 2014 compared to 16.5% for the third quarter of 2013. The WTI to WCS differential averaged 21.2% for the first nine months of 2014 compared to a WTI to WCS differential of 23.2% for the first nine months of 2013.

Pipeline congestion between western Canada and the U.S. coastal markets can negatively impact the price received for WCS, and hence the value that MEG receives for its blend sales. Recent additions of crude-by-rail, new pipeline connections from the U.S. mid-continent to the U.S. Gulf Coast and refinery modifications in the U.S. Midwest are collectively relieving some of this price pressure and, once complete, should help realign Canadian crude oil prices with international benchmarks.

Natural gas is a primary energy input cost for the Corporation, as it is used to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facilities. The AECO natural gas price averaged $4.00 per mcf for the three months ended September 30, 2014 compared to $2.42 per mcf for the three months ended September 30, 2013. The AECO natural gas price averaged $4.80 per mcf for the first nine months of 2014 compared to $3.04 per mcf for the first nine months of 2013. Natural gas prices have retreated from the five year high they reached in February 2014, but are still significantly higher than the same period in 2013 as a result of depleted natural gas storage levels across North America.

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 $63.91 per megawatt hour during the three months ended September 30, 2014 compared to an average price of $83.61 per megawatt hour for the three months ended September 30, 2013. The Alberta power pool price averaged $55.64 per megawatt hour during the first nine months of 2014 compared to $90.76 per megawatt hour during the first nine months of 2013. The decrease in the Alberta Pool price is mainly a result of increased year over year power generation capacity in the province. The first nine months of 2013 was affected by significant supply disruptions. Incremental power generation in the province is anticipated to continue to moderate power prices.

Changes in the value of the Canadian dollar relative to the U.S. dollar have an impact on the Corporation's bitumen revenues, as blend sales prices 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 bitumen revenues and a negative impact on principal and interest payments, while an increase in the value of the Canadian dollar has a negative impact on bitumen revenues and a positive impact on principal and interest payments. As at September 30, 2014, the Canadian dollar, at a rate of 1.1208, had decreased in value by approximately 5% against the U.S. dollar compared to its value as at June 30, 2014, when the rate was 1.0676. The value of the Canadian dollar as at September 30, 2014 has decreased by approximately 5% from its value as at December 31, 2013, when the rate was 1.0636.

5. RESULTS OF OPERATIONS

	Three months ended September 30		Nine months ended September 30	
	2014	**2013**	**2014**	**2013**
Bitumen production – bbls/d	76,471	34,246	68,108	32,980
Bitumen sales – bbls/d	69,757	32,175	66,275	32,948
Steam to oil ratio (SOR)	2.5	2.5	2.5	2.4

Production

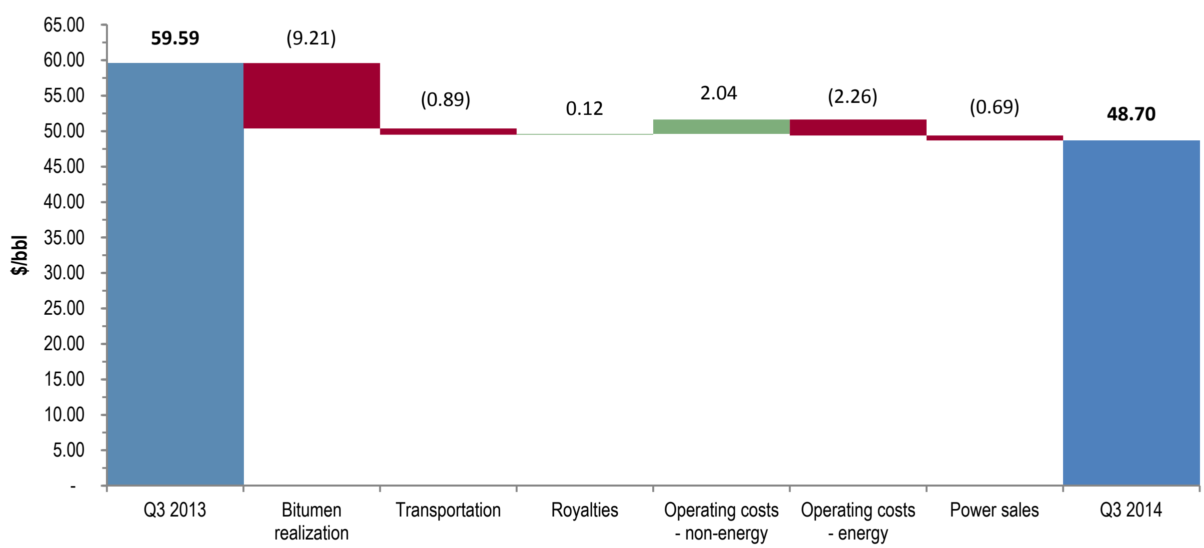
Production for the three months ended September 30, 2014 averaged 76,471 bbls/d compared to 34,246 bbls/d for the three months ended September 30, 2013. Production for the first nine months of 2014 averaged 68,108 bbls/d compared to 32,980 bbls/d for the first nine months of 2013. The increase in production volumes in 2014 compared to 2013 is due to the start-up of Phase 2B and the implementation of RISER on Christina Lake Phases 1 and 2. The implementation of the RISER initiative within Phases 1 and 2 has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production. The Corporation achieved first production from Phase 2B in the fourth quarter of 2013 and as a result of the successful ramp-up of Phase 2B, along with the success achieved from applying RISER to Phases 1 and 2, MEG anticipates reaching production of 80,000 bbls/d from Christina Lake Phases 1, 2 and 2B in early 2015.

Bitumen sales for the three months ended September 30, 2014 averaged 69,757 bbls/d compared to production of 76,471 bbls/d for the same period. During the third quarter of 2014, the Corporation utilized approximately 6,100 bbls/d of production for blend linefill for the Access Pipeline expansion.

Bitumen sales for the nine months ended September 30, 2014 were 66,275 bbls/d compared to production of 68,108 bbls/d for the same period. The difference between bitumen sales and production was primarily due to utilizing production for blend linefill for the Access Pipeline expansion in the third quarter of 2014.

The Corporation's average SOR was 2.5 for the three months ended September 30, 2014 and September 30, 2013. The SOR averaged 2.5 during the nine months ended September 30, 2014 and 2.4 for the nine months ended September 30, 2013. As expected, the average SOR in 2014 has decreased from an SOR of 2.9 for the fourth quarter of 2013, as more Phase 2B well pairs have now been converted to production mode.

Cash Operating Netback – Three months ended September 30, 2014 versus September 30, 2013:



The following table summarizes the Corporation's cash operating netback for the three months ended September 30:

	2014		2013	
	$000	**$ per bbl**	**$000**	**$ per bbl**
Bitumen realization[(1)]	417,888	65.12	234,269	74.33
Transportation[(2)]	(6,988)	(1.09)	(636)	(0.20)
Royalties	(32,188)	(5.02)	(16,195)	(5.14)
	378,712	**59.01**	**217,438**	**68.99**
Operating costs – non-energy[(3)]	(45,944)	(7.16)	(28,986)	(9.20)
Operating costs – energy[(3)]	(35,835)	(5.58)	(10,463)	(3.32)
Power revenue	15,570	2.43	9,837	3.12
Net operating costs	**(66,209)**	**(10.31)**	**(29,612)**	**(9.40)**
Cash operating netback[(4)]	**312,503**	**48.70**	**187,826**	**59.59**

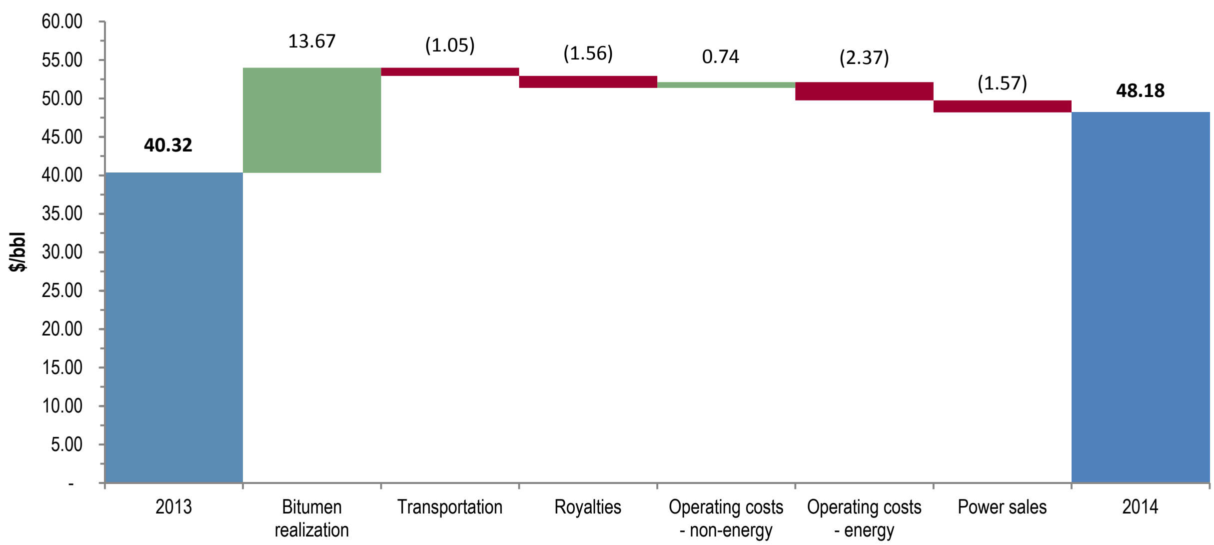
(1) *Net of diluent costs. For further details, refer to the "Bitumen Realization" section. Bitumen realization is a non-GAAP measure defined in the "NON-GAAP MEASUREMENTS" section of this MD&A.*

(2) *For further details, refer to the "Transportation" section. Transportation is a non-GAAP measure defined in the "NON-GAAP MEASUREMENTS" section of this MD&A.*

(3) *Operating costs–non-energy and Operating costs–energy are non-GAAP measures defined in the "NON-GAAP MEASUREMENTS" section of this MD&A.*

(4) *Cash operating netback is a non-GAAP measure defined in the "NON-GAAP MEASUREMENTS" section of this MD&A.*

Cash Operating Netback – Nine months ended September 30, 2014 versus September 30, 2013:



The following table summarizes the Corporation's cash operating netback for the nine months ended September 30:

	2014		2013	
	$000	**$ per bbl**	**$000**	**$ per bbl**
Bitumen realization(1)	1,212,515	67.02	479,897	53.35
Transportation(2)	(22,102)	(1.22)	(1,496)	(0.17)
Royalties	(87,894)	(4.86)	(29,664)	(3.30)
	1,102,519	**60.94**	**448,737**	**49.88**
Operating costs – non-energy(3)	(155,407)	(8.59)	(83,955)	(9.33)
Operating costs – energy(3)	(121,474)	(6.71)	(39,029)	(4.34)
Power revenue	46,013	2.54	37,008	4.11
Net operating costs	**(230,868)**	**(12.76)**	**(85,976)**	**(9.56)**
Cash operating netback(4)	**871,651**	**48.18**	**362,761**	**40.32**

(1) *Net of diluent costs. For further details, refer to the "Bitumen Realization" section. Bitumen realization is a non-GAAP measure defined in the "NON-GAAP MEASUREMENTS" section of this MD&A.*

(2) *For further details, refer to the "Transportation" section. Transportation is a non-GAAP measure defined in the "NON-GAAP MEASUREMENTS" section of this MD&A.*

(3) *Operating costs–non-energy and Operating costs–energy are non-GAAP measures defined in the "NON-GAAP MEASUREMENTS" section of this MD&A.*

(4) *Cash operating netback is a non-GAAP measure defined in the "NON-GAAP MEASUREMENTS" section of this MD&A.*

Bitumen Realization

	Three months ended September 30		Nine months ended September 30	
($000)	**2014**	**2013**	**2014**	**2013**
Petroleum sales – proprietary	712,383	375,894	2,109,283	913,994
Cost of diluent	(294,495)	(141,625)	(896,768)	(434,097)
Bitumen realization	417,888	234,269	1,212,515	479,897

Proprietary petroleum sales represents MEG's revenue from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend sales is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. Bitumen realization as discussed in this document represents the Corporation's realized proprietary blend sales revenues, net of the cost of diluent.

Blend sales for the three months ended September 30, 2014 were $712.4 million compared to $375.9 million for the three months ended September 30, 2013. The increase in blend sales in the third quarter of 2014 compared to the third quarter of 2013 is due to a 108% increase in sales volumes partially offset by a 9% decrease in the average realized blend price. Sales volumes have increased as a result of the increase in production volumes due to the start-up of Phase 2B in the fourth quarter of 2013 and the implementation of RISER on Christina Lake Phases 1 and 2. Blend sales averaged $78.60 per barrel during the three months ended September 30, 2014 compared to $86.40 per barrel for the three months ended September 30, 2013.

Blend sales for the nine months ended September 30, 2014 were $2.1 billion compared to $0.9 billion for the nine months ended September 30, 2013. The increase in blend sales in the first nine months of 2014 compared to the first nine months of 2013 is due to a 102% increase in sales volumes combined with a 14% increase in the average realized blend price. Blend sales averaged $80.49 per barrel for the nine months ended September 30, 2014 compared to $70.60 per barrel for the nine months ended September 30, 2013.

The cost of diluent for the three months ended September 30, 2014 was $294.5 million compared to $141.6 million for the three months ended September 30, 2013. The total cost of diluent increased primarily due to the higher volumes of diluent purchased as a result of increased blend sales volumes. The Corporation's average cost of diluent was $111.33 per barrel during the three months ended September 30, 2014 compared to $118.12 per barrel during the three months ended September 30, 2013.

The cost of diluent for the nine months ended September 30, 2014 was $896.8 million compared to $434.1 million for the nine months ended September 30, 2013. The total cost of diluent increased primarily due to the higher volumes of diluent purchased as a result of increased blend sales volumes. The Corporation's average cost of diluent was $110.52 per barrel during the nine months ended September 30, 2014 compared to $109.88 per barrel during the nine months ended September 30, 2013.

Transportation

Transportation costs include rail and the Stonefell Terminal costs, as well as MEG's share of the operating costs for the Access Pipeline, net of third party recoveries. Transportation costs resulted in an expense of $7.0 million for the three months ended September 30, 2014 compared to $0.6 million for the three months ended September 30, 2013. The Corporation recognized third party recoveries of $6.2 million during the three months ended September 30, 2014 compared to $4.1 million during the same period in 2013. On a per barrel basis, transportation costs averaged $1.09 per barrel for the three months ended September 30, 2014 compared to $0.20 per barrel for the three months ended September 30, 2013. The increase in transportation costs is primarily due to the use of unit-train rail shipments in 2014, and to a lesser extent, costs associated with the Corporation's Stonefell Terminal.

Transportation costs totalled $22.1 million, net of $23.3 million in third party recoveries, for the nine months ended September 30, 2014 compared to $1.5 million, net of $15.2 million in third party recoveries, for the nine months ended September 30, 2013. Transportation costs averaged $1.22 per barrel for the first nine months of 2014 compared to $0.17 per barrel for the first nine months of 2013. The increase in transportation costs is primarily due to the use of unit-train rail shipments in 2014, and to a lesser extent, costs associated with the Corporation's Stonefell Terminal.

Royalties

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

Royalties totalled $32.2 million for the three months ended September 30, 2014 compared to $16.2 million for the three months ended September 30, 2013. The increase in royalties for the three months ended September 30, 2014 compared to the same period in 2013 is primarily attributable to the increase in sales. Royalties averaged $5.02 per barrel during the third quarter of 2014 compared to $5.14 per barrel for the third quarter of 2013. The Corporation's royalty rate, expressed as a percentage of bitumen realizations, averaged 7.7% for the three months ended September 30, 2014 compared to 6.9% for the three months ended September 30, 2013.

Royalties totalled $87.9 million for the nine months ended September 30, 2014 compared to $29.7 million for the nine months ended September 30, 2013. The increase in royalties for the nine months ended September 30, 2014 compared to the same period in 2013 is attributable to the increase in bitumen realizations, the increase in sales volumes and the increase in the Canadian dollar price of WTI. Royalties averaged $4.86 per barrel during the first nine months of 2014 compared to $3.30 per barrel for the first nine months of 2013. The Corporation's royalty rate averaged 7.2% for the nine months ended September 30, 2014 compared to 6.2% for the same period in 2013.

Operating Expenses

Non-energy operating costs were $45.9 million for the three months ended September 30, 2014 compared to $29.0 million for the three months ended September 30, 2013. The increase in non-energy operating costs is primarily attributable to the increased costs associated with Phase 2B production volumes. The increase in non-energy operating costs was more than offset on a per barrel basis by higher sales volumes. Non-energy operating costs averaged $7.16 per barrel for the three months ended September 30, 2014 compared to $9.20 per barrel for the three months ended September 30, 2013.

Non-energy operating costs totalled $155.4 million for the first nine months of 2014 compared to $84.0 million for the first nine months of 2013. The increase in non-energy operating costs is primarily attributable to the costs associated with Phase 2B sales volumes and higher turnaround costs in 2014. Non-energy operating costs include $12.5 million, or $0.67 per barrel, for the approximately three-week turnaround in the second quarter of 2014 compared to $1.8 million, or $0.20 per barrel, for the minor turnaround carried out in the second quarter of 2013. The increase in non-energy operating costs was offset on a per barrel basis by higher sales volumes. Non-energy operating costs averaged $8.59 per barrel for the nine months ended September 30, 2014 compared to $9.33 per barrel for the nine months ended September 30, 2013.

Energy related operating costs were $35.8 million for the three months ended September 30, 2014 compared to $10.5 million for the three months ended September 30, 2013. The increase in energy operating costs for the third quarter of 2014 compared to the third quarter of 2013 is attributable to the start-up of Phase 2B in the fourth quarter of 2013 and the increase in natural gas prices. On a per barrel basis, energy related operating costs averaged $5.58 per barrel for the three months ended September 30, 2014 compared to $3.32 per barrel for the same period in 2013. The Corporation's natural gas purchase price averaged $4.00 per mcf during the third quarter of 2014 compared to $2.17 per mcf for the third quarter of 2013.

Energy related operating costs were $121.5 million for the nine months ended September 30, 2014 compared to $39.0 million for the nine months ended September 30, 2013. The increase in energy operating costs for the first nine months of 2014 compared to the first nine months of 2013 is attributable to the start-up of Phase 2B and the increase in natural gas prices. On a per barrel basis, energy related operating costs averaged $6.71 per barrel for the nine months ended September 30, 2014 compared to $4.34 per barrel for the nine months ended September 30, 2013. The Corporation's natural gas purchase price averaged $5.04 per mcf during the first nine months of 2014 compared to $3.08 per mcf for the first nine months of 2013.

Power Revenue

The Corporation operates two 85 megawatt cogeneration facilities which produce steam for its SAGD operations. MEG's Christina Lake facilities utilize the heat produced by the cogeneration facilities and a portion of the power generated. Surplus power is sold into the Alberta power pool.

Power revenue was $15.6 million for the three months ended September 30, 2014 compared to $9.8 million for the three months ended September 30, 2013. The increase in power revenue is due to the increase in the Corporation's electrical power generation capacity as a result of the second cogeneration facility becoming operational with the start-up of Christina Lake Phase 2B. The additional power generation capacity was partially offset by a decrease in the Corporation's average realized power price. The Corporation's average realized power price during the three months ended September 30, 2014 was $59.07 per megawatt hour compared to $75.96 per megawatt hour for the same period in 2013.

Power revenue was $46.0 million for the nine months ended September 30, 2014 compared to $37.0 million for the nine months ended September 30, 2013. The increase in power revenue is due to the increase in the Corporation's electrical power generation capacity as a result of the second cogeneration facility becoming operational with the start-up of Christina Lake Phase 2B. The additional power generation capacity was partially offset by a decrease in the Corporation's average realized power price. The Corporation's average realized power price during the nine months ended September 30, 2014 was $54.87 per megawatt hour compared to $88.89 per megawatt hour for the same period in 2013. Variations in the Corporation's realized power prices during the periods are largely consistent with variations in the Alberta power pool prices during the periods noted.

Depletion and Depreciation

Depletion and depreciation expense was $98.0 million for the three months ended September 30, 2014 compared to $49.0 million for the three months ended September 30, 2013. Depletion and depreciation expense for the nine months ended September 30, 2014 totalled $277.8 million compared to $137.6 million for same period in 2013. The increase is primarily due to the 104% increase in bitumen sales volumes for the third quarter of 2014, and a 101% increase for the nine months ended September 30, 2014, compared to the same periods in 2013. The depletion and depreciation rate for the three months ended September 30, 2014 was $15.26 per barrel compared to $15.54 per barrel for the three months ended September 30, 2013. Depletion and depreciation expense was $15.36 per barrel for the first nine months of 2014 compared to $15.28 per barrel for the first nine months of 2013.

The Corporation's producing oil sands properties are depleted on a unit of production basis based on estimated proved reserves. Major facilities and equipment are depreciated on a unit of production basis over the estimated total productive capacity of the facilities and equipment. Pipeline and storage assets are depreciated on a straight-line basis over their estimated useful lives.

General and Administrative

	Three months ended September 30		Nine months ended September 30	
($000)	**2014**	**2013**	**2014**	**2013**
General and administrative costs	33,577	29,246	103,196	88,492
Capitalized general and administrative costs	(8,827)	(6,145)	(26,351)	(18,326)
General and administrative expense	24,750	23,101	76,845	70,166

General and administrative expense for the three months ended September 30, 2014 was $24.8 million compared to $23.1 million for the three months ended September 30, 2013. General and administrative expense for the nine months ended September 30, 2014 was $76.8 million compared to $70.2 million for the nine months ended September 30, 2013. The increase in expense is primarily the result of the planned growth in the Corporation's professional staff and office costs to support the operation and development of its oil sands assets.

Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
($000)	**2014**	**2013**	**2014**	**2013**
Stock-based compensation costs	16,463	15,492	46,014	35,867
Capitalized stock-based compensation costs	(4,202)	(2,878)	(10,450)	(6,735)
Stock-based compensation expense	12,261	12,614	35,564	29,132

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 in its consolidated financial statements. Fair value is determined using the Black-Scholes option pricing model. Stock-based compensation expense was $12.3 million for the three months ended September 30, 2014 compared to $12.6 million for the three months ended September 30, 2013. Stock based compensation expense for the first nine months of 2014 totalled $35.6 million compared to $29.1 million for the first nine months of 2013. The increase in stock-based compensation costs is due to the increased number of share-based awards granted and as a result of the growth in the Corporation's staff.

The Corporation capitalizes a portion of stock-based compensation associated with capitalized salaries and benefits. The Corporation capitalized $4.2 million of stock-based compensation for the three months ended September 30, 2014 compared to $2.9 million during the three months ended September 30, 2013. The Corporation capitalized $10.5 million of stock-based compensation for the nine months ended September 30, 2014 compared to $6.7 million for the nine months ended September 30, 2013.

Research and Development

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 $1.9 million for the three months ended September 30, 2014 and September 30, 2013. Research and development expenditures were $3.8 million for the nine months ended September 30, 2014 compared to $3.9 million for the nine months ended September 30, 2013.

Net Finance Expense

	Three months ended September 30		Nine months ended September 30	
($000)	**2014**	**2013**	**2014**	**2013**
Total interest expense	65,366	44,439	196,140	126,156
Less capitalized interest	(19,505)	(21,773)	(61,074)	(53,618)
Net interest expense	45,861	22,666	135,066	72,538
Accretion on decommissioning provision	1,123	1,484	3,265	3,746
Unrealized fair value loss (gain) on embedded derivative financial liabilities	(3,079)	648	(5,325)	(12,255)
Unrealized fair value loss (gain) on interest rate swaps	(1,617)	1,139	(1,588)	(5,063)
Realized loss on interest rate swaps	1,257	1,225	3,745	3,508
Unrealized fair value (gain) on other assets	(429)	(919)	(429)	(919)
Net finance expense	43,116	26,243	134,734	61,555
Average effective interest rate	5.8%	5.4%	5.8%	5.5%

Total interest expense, before capitalization, was $65.4 million for the three months ended September 30, 2014 compared to $44.4 million for the three months ended September 30, 2013. Total interest expense for the nine months ended September 30, 2014 was $196.1 million compared to $126.2 million for the nine months ended September 30, 2013. Total interest expense increased primarily as a result of the increased debt outstanding in 2014. In the first quarter of 2013, the senior secured term loan was increased by US$300.0 million to approximately US$1.3 billion and in the fourth quarter of 2013 the Corporation issued US$1.0 billion in aggregate principal amount of 7.0% senior unsecured notes.

The Corporation recognized an unrealized gain on embedded derivative financial liabilities of $3.1 million for the three months ended September 30, 2014 compared to an unrealized loss of $0.6 million for the three months ended September 30, 2013. The Corporation recognized an unrealized gain on embedded derivative financial liabilities of $5.3 million for the nine months ended September 30, 2014 compared to an unrealized gain of $12.3 million for the nine months ended September 30, 2013. These gains and losses relate to the change in fair value of the interest rate floor associated with the Corporation's senior secured credit facilities. The interest rate floor is considered an embedded derivative as the floor rate was higher than the London Interbank Offered Rate ("LIBOR") at the time that the debt agreements were entered into. Accordingly, the fair value of the embedded derivatives at the time the debt agreements were entered into was netted against the carrying value of the long-term debt and is amortized over the life of the debt agreements. The fair value of the embedded derivative is included in derivative financial liabilities on the balance sheet and gains and losses associated with changes in the fair value of the embedded derivative are included in net finance expense.

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$1.3 billion senior secured term loan until September 30, 2016. The Corporation realized a loss of $1.3 million for the three months ended September 30, 2014 and a loss of $3.7 million for the nine months ended September 30, 2014, on the interest rate swap contracts. This compared to a loss of $1.2 million for the three months ended September 30, 2013 and a loss of $3.5 million for the nine months ended September 30, 2013. In addition, the Corporation recognized an unrealized gain of $1.6 million for the third quarter of 2014 and an unrealized gain of $1.6 million for the nine months ended September 30, 2014. This compared to an unrealized loss of $1.1 million for the third quarter of 2013 and an unrealized gain of $5.1 million for nine months ended September 30, 2013.

Net Foreign Exchange Gain (Loss)

	Three months ended September 30		**Nine months ended September 30**	
($000)	**2014**	**2013**	**2014**	**2013**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	(203,097)	64,264	(218,531)	(85,882)
US$ denominated cash and cash equivalents	14,410	(5,871)	24,391	20,944
Realized gain (loss) on foreign exchange	(2,586)	1,110	(3,699)	(1,735)
Net foreign exchange gain (loss)	(191,273)	59,503	(197,839)	(66,673)

Period End	**September 30, 2014**	**June 30, 2014**	**December 31, 2013**	**September 30, 2013**	**June 30, 2013**	**December 31, 2012**
C$ equivalent of 1 US$	1.1208	1.0676	1.0636	1.0285	1.0512	0.9949

The Corporation recognized a net foreign exchange loss of $191.3 million for the three months ended September 30, 2014 compared to a gain of $59.5 million for the three months ended September 30, 2013. The net foreign exchange loss for the third quarter of 2014 is primarily due to an unrealized foreign exchange loss on the conversion of U.S. dollar denominated debt as a result of weakening of the Canadian dollar compared to the U.S. dollar by approximately 5% during the quarter. In the third quarter of 2013, the Canadian dollar strengthened in value by approximately 2%.

The Corporation recognized a net foreign exchange loss of $197.8 million for the nine months ended September 30, 2014 compared to a net foreign exchange loss of $66.7 million for the nine months ended September 30, 2013. The increase in the net foreign exchange loss is primarily due to an unrealized foreign exchange loss on the conversion of U.S. dollar denominated debt as a result of weakening of the Canadian dollar compared to the U.S. dollar by approximately 6% during the nine months ended September 30, 2014. In the nine months ended September 30, 2013, the Canadian dollar weakened in value by approximately 3%.

Net Marketing Activity

	Three months ended September 30		Nine months ended September 30	
($000)	**2014**	**2013**	**2014**	**2013**
Petroleum sales – Third party	4,448	28,196	124,460	47,595
Purchased product and storage	(10,413)	(29,124)	(132,525)	(48,830)
Net marketing activity (1)	(5,965)	(928)	(8,065)	(1,235)

(1) Net marketing activity is a non-GAAP measure as defined in the "NON-GAAP MEASURMENTS" section of this MD&A.

Net marketing activity includes the Corporation's increased activities toward enhancing its ability to transport proprietary crude oil products to a wider range of markets in the United States. Accordingly, the Corporation has entered into product storage arrangements and transportation arrangements for rail, barge and US-based pipelines. To the extent that the Corporation is not fully utilizing all of these arrangements for proprietary purposes, MEG purchases and sells third-party crude oil and related products to optimize the returns on these transportation and storage arrangements.

Income Taxes

The Corporation recognized a deferred income tax expense of $38.2 million for the three months ended September 30, 2014 compared to a deferred income tax expense of $21.3 million for the three months ended September 30, 2013. The Corporation recognized a deferred income tax expense of $99.8 million for the nine months ended September 30, 2014 compared to a deferred income tax expense of $25.2 million for the nine months ended September 30, 2013.

The Corporation's effective income tax rate 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 foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the three months ended September 30, 2014, the non-taxable loss was $101.5 million compared to a non-taxable gain of $32.1 million for the three months ended September 30, 2013. For the nine months ended September 30, 2014, the non-taxable loss was $109.3 million compared to a non-taxable loss of $42.9 million for the nine months ended September 30, 2013.

- As at September 30, 2014, the Corporation had not recognized the tax benefit related to $198.9 million of unrealized taxable capital foreign exchange losses.

- Non-taxable stock-based compensation expense for the three months ended September 30, 2014 was $12.3 million compared to $12.6 million for the three months ended September 30, 2013. Non-taxable stock-based compensation expense for the nine months ended September 30, 2014 was $35.6 million compared to $29.1 million for the nine months ended September 30, 2013.

The Corporation is not currently taxable. As of September 30, 2014, the Corporation had approximately $6.9 billion of available tax pools and had recognized a deferred income tax liability of $193.6 million. In addition, at September 30, 2014, the Corporation had $0.7 billion of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

6. SUMMARY OF QUARTERLY RESULTS

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

	2014			2013				2012
($ millions, except per share amounts)	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Revenue[1]	706.4	829.2	679.6	350.3	401.8	324.4	258.0	297.6
Net income (loss)	(101.0)	249.0	(103.4)	(148.2)	115.4	(62.3)	(71.3)	(18.7)
Per share – basic	(0.45)	1.12	(0.46)	(0.67)	0.52	(0.28)	(0.32)	(0.09)
Per share – diluted	(0.45)	1.11	(0.46)	(0.67)	0.51	(0.28)	(0.32)	(0.09)

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

Revenue for the eight most recent quarters has been impacted by the increases in production and fluctuations in blend sales pricing. Revenue for the second quarter of 2014 and 2013 had reduced production volumes as a result of scheduled annual maintenance activities at the Christina Lake facilities.

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

- increased blend sales volumes due to the start-up of Christina Lake Phase 2B in the fourth quarter of 2013 and implementation of RISER on Phases 1 and 2, which has allowed additional wells to be placed into production;
- fluctuations in natural gas and power pricing;
- fluctuations in blend sales pricing due to changes in the price of WTI and the differential between WTI and the Corporation's AWB;
- changes in the value of the Canadian dollar relative to the U.S. dollar as blend sales prices are determined by reference to U.S. benchmarks;
- foreign exchange gains and losses attributable to fluctuations in the rate of exchange between the Canadian and U.S. dollar in translating the Corporation's U.S. dollar denominated debt (net of U.S. dollar denominated cash, cash equivalents and short-term investments);
- an increase in depletion and depreciation expense as a result of the increase in bitumen sales volumes and higher estimated future development costs;
- higher general and administrative expense as a result of the planned increase in office staff to support growth;
- an increase in interest expense as a result of the increase in long-term debt;
- scheduled annual plant maintenance activities performed in June 2014 and May 2013; and
- use of production for blend linefill for the Access Pipeline expansion in the third quarter of 2014.

7. CAPITAL INVESTING

	Three months ended September 30		Nine months ended September 30	
($000)	**2014**	**2013**	**2014**	**2013**
Intraphase growth	93,053	140,340	243,168	477,020
Portfolio growth				
Christina Lake	47,572	25,954	153,032	154,503
Resource development	5,587	18,693	72,515	189,174
Growth infrastructure	17,444	133,711	67,882	369,825
Enhancements and other	9,267	64	40,255	39,413
Total portfolio growth	79,870	178,422	333,684	752,915
Marketing initiatives				
Access pipeline	56,604	61,136	170,723	199,792
Other	14,718	19,178	39,327	132,653
Total marketing initiatives	71,322	80,314	210,050	332,445
Sustaining and maintenance	34,876	14,925	92,038	53,236
Other	12,188	40,588	34,629	129,887
Total base capital investment	**291,309**	**454,589**	**913,569**	**1,745,503**
Capitalized interest	19,505	21,773	61,074	53,618
Total cash capital investment	**310,814**	**476,362**	**974,643**	**1,799,121**
Non-cash	35,033	973	57,001	34,661
Total capital investment	**345,847**	**477,335**	**1,031,644**	**1,833,782**

MEG's total capital investment for the three months ended September 30, 2014 was $345.8 million (including capitalized interest of $19.5 million and non-cash items of $35.0 million) in comparison to $477.3 million (including capitalized interest of $21.8 million and non-cash items of $1.0 million) for the three months ended September 30, 2013. Total capital investment for the nine months ended September 30, 2014 was $1.0 billion (including capitalized interest of $61.1 million and non-cash items of $57.0 million) in comparison to $1.8 billion (including capitalized interest of $53.6 million and non-cash items of $34.7 million) for the nine months ended September 30, 2013.

MEG invested $243.2 million during the nine months ended September 30, 2014 on intraphase growth, which includes RISER 2B. RISER 2B includes the application of a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including a major brownfield expansion of the existing Phase 2B facilities.

The Corporation invested $153.0 million in portfolio growth for Christina Lake during the first nine months of 2014 for engineering, the procurement of long lead-time items and site preparation for future Christina Lake expansions.

Resource development investment of $72.5 million during the first nine months of 2014 included the drilling of 80 stratigraphic wells to support horizontal well placement and to further delineate the resource base at Christina Lake. The investment also included the drilling of eight stratigraphic wells and two water source wells at Surmont and four stratigraphic wells on the Growth Properties.

A total of $67.9 million was invested in the Corporation's growth infrastructure during the nine months ended September 30, 2014. Growth infrastructure investment was primarily directed towards the construction of a sulphur recovery plant at Christina Lake, which commenced operating during the third quarter of 2014.

A total of $210.1 million was invested during the nine months ended September 30, 2014 in the Corporation's marketing initiatives. The majority of the investment in marketing initiatives related to the expansion of the 50%-owned Access Pipeline. The expansion for the 300-kilometer pipeline was placed into service in the third quarter of 2014.

A total of $92.0 million was invested during the nine months ended September 30, 2014 for sustaining and maintenance capital and primarily represents costs related to sustaining SAGD well pairs and well pads.

The Corporation capitalizes interest associated with qualifying assets. A total of $19.5 million in interest was capitalized during the three months ended September 30, 2014 compared to $21.8 million during the three months ended September 30, 2013. A total of $61.1 million of interest was capitalized during the nine months ended September 30, 2014 compared to $53.6 million for the nine months ended September 30, 2013.

Non-cash capital investment for the three months ended September 30, 2014 included a $22.3 million increase in the provision for future reclamation and decommissioning of the Corporation's property, plant and equipment and $4.2 million in capitalized stock-based compensation. Non-cash capital investment for the nine months ended September 30, 2014 included a $38.0 million provision for future reclamation and decommissioning and $10.5 million in capitalized stock-based compensation.

8. LIQUIDITY AND CAPITAL RESOURCES

($000)	**As at September 30, 2014**	**As at December 31, 2013**
Cash and cash equivalents	776,522	1,179,072
Senior secured term loan (September 30, 2014 – US$1.265 billion; December 31, 2013 – US$1.275 billion; due 2020)	1,417,532	1,355,558
US$2.0 billion revolver; due 2018	-	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	840,600	797,700
6.375% senior unsecured notes (US$800.0 million; due 2023)	896,640	850,880
7.0% senior unsecured notes (US$1.0 billion; due 2024)	1,120,800	1,063,600
Total debt(1)	4,275,572	4,067,738
Shareholders' equity	4,894,444	4,788,430
Total book capitalization(2)	9,170,016	8,856,168
Total debt/book capitalization(2)	46.6%	45.9%

(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 measurement 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 consolidated financial statements as at September 30, 2014 and December 31, 2013.

(2) Non-GAAP measurements are defined in the "NON-GAAP MEASUREMENTS" section of this MD&A.

Capital Resources

As at September 30, 2014, the Corporation's available capital resources included $0.8 billion of cash and cash equivalents and an additional undrawn US$2.0 billion syndicated revolving credit facility. While the revolving credit facility remains undrawn as at September 30, 2014, US$106.3 million of the revolving credit facility was utilized to support letters of credit, leaving unutilized borrowing capacity of US$1.9 billion. The revolving credit facility is syndicated with 12 banks and has a renewal date of May 2018.

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 below.

Effective October 1, 2013, the Corporation issued US$800.0 million in aggregate principal amount of 7.0% senior unsecured notes, with a maturity date of March 31, 2024. On November 6, 2013 an additional US$200 million of 7.0% senior unsecured notes were issued under the same indenture. Interest is paid semi-annually, beginning on March 31, 2014. The $13.0 million of debt-issue costs have been deferred and are being amortized over the term of the revolving credit facility.

On May 24, 2013, MEG expanded its senior secured revolving credit facility from US$1.0 billion to US$2.0 billion. In addition, the Corporation extended the maturity of the revolving credit facility by one year to May 24, 2018. The transaction was completed through an amendment of MEG's existing credit facility. The $8.7 million of debt-issue costs have been deferred and are being amortized over the term of the revolving credit facility.

On February 25, 2013, the Corporation re-priced, increased and extended its US$987.5 million senior secured term loan. The Corporation extended the maturity date to March 31, 2020 and increased its borrowing under the senior secured term loan by US$300.0 million. In addition, the Corporation reduced the interest rate on the term loan by 25 basis points. The amended term loan bears a floating interest rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 175 or 275 basis points, respectively. The term loan also has an interest rate floor of 200 basis points based on U.S. Prime or 100 basis points based on LIBOR. The term loan is being repaid in quarterly installments of US$3.25 million, with the balance due March 31, 2020. The $6.8 million of debt-issue costs have been deferred and are being amortized over the term of the revolving credit facility.

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$1.3 billion senior secured term loan until September 30, 2016.

The Corporation's cash is held in high interest savings accounts with a diversified group of highly-rated financial institutions. The Corporation has also invested in high grade, liquid, short-term instruments such as government, commercial and bank paper as well as term deposits. To date, 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 policy 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 Flows Summary

	Three months ended September 30		Nine months ended September 30	
($000)	**2014**	**2013**	**2014**	**2013**
Net cash provided by (used in):				
Operating activities	222,008	104,312	558,436	126,024
Investing activities	(298,675)	(696,397)	(985,409)	(1,453,558)
Financing activities	(1,091)	13,748	32	313,797
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	14,410	(5,871)	24,391	20,944
Change in cash and cash equivalents	(63,348)	(584,208)	(402,550)	(992,793)

Cash Flows – Operating Activities

Net cash provided by operating activities totalled $222.0 million for the three months ended September 30, 2014 compared to $104.3 million for the three months ended September 30, 2013. The increase in cash flows from operating activities is primarily due to increased blend sales revenues as a result of the increased production. Net cash provided by operating activities in the third quarter of 2014 has been reduced to include a $16.7 million increase in non-cash working capital items. Net cash provided by operating activities in the third quarter of 2013 has been reduced to include a $40.2 million increase in non-cash working capital items.

Net cash provided by operating activities totalled $558.4 million for the nine months ended September 30, 2014 compared to $126.0 million for the nine months ended September 30, 2013. The increase in cash flows from operating activities is primarily due to increased blend sales revenues as a result of the increase in production and increased bitumen realizations. Net cash provided by operating activities in the first nine months of 2014 has been reduced to include a $98.9 million increase in non-cash working capital items. Net cash provided by operating activities in the first nine months of 2013 has been reduced to include a $104.8 million increase in non-cash working capital items.

Cash Flows – Investing Activities

Net cash used in investing activities during the three months ended September 30, 2014 primarily consisted of $310.8 million in cash capital investment (refer to the "CAPITAL INVESTING" section of this MD&A for further details) and a $10.3 million decrease in non-cash investing working capital. Net cash used in investing activities during the nine months ended September 30, 2014 primarily consisted of $974.6 million in cash capital investment and an $11.9 million increase in non-cash investing working capital.

Net cash used in investing activities during the three months ended September 30, 2013 primarily consisted of $476.4 million in cash capital investment, a $178.0 million increase in non-cash investing working capital and a $41.9 million purchase of diluent linefill. Net cash used in investing activities during the nine months ended September 30, 2013 primarily consisted of $1.8 billion in cash capital investment and a $41.9 million purchase of diluent linefill partially offset by a $391.3 million decrease in non-cash investing working capital primarily related to a decrease in short-term investments.

Cash Flows – Financing Activities

Net cash used in financing activities for the three months ended September 30, 2014 consisted of $3.6 million of debt principal repayment on the senior secured term loan, partially offset by $2.5 million of proceeds received from the exercise of stock options. Net cash provided by financing activities for the nine months ended September 30, 2014 consisted of $10.7 million of proceeds received from the exercise of stock options, almost completely offset by $10.7 million of debt principal repayment.

Net cash provided by financing activities for the three months ended September 30, 2013 consisted of $17.1 million in proceeds from the exercise of stock options, partially offset by $3.3 million in debt principal repayment. Net cash provided by financing activities for the nine months ended September 30, 2013 consisted of $308.0 million of net proceeds from the increase in the senior secured term loan and $31.4 million received from the exercise of stock options. These amounts were partially offset by $15.5 million in financing costs and $10.0 million of debt principal repayment.

9. SHARES OUTSTANDING

Common shares	223,793,837
Convertible securities	
Stock options outstanding - exercisable and unexercisable	9,552,501
RSUs and PSUs outstanding	2,709,218

As at October 20, 2014, the Corporation had 223,810,970 common shares, 7,928,992 stock options and 2,705,227 restricted share units and performance share units outstanding.

10. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

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

($000)	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long-term debt(1)	4,275,572	14,514	29,029	29,029	4,203,000
Interest on long-term debt(1)	1,917,065	243,083	484,663	482,478	706,841
Decommissioning obligation(2)	696,249	3,927	5,401	5,671	681,250
Transportation and storage(3)	3,733,369	118,427	356,963	435,948	2,822,031
Contracts and purchase orders(4)	589,636	353,373	81,520	44,840	109,903
Operating leases(5)	430,610	13,464	42,318	50,904	323,924
	11,642,501	746,788	999,894	1,048,870	8,846,949

(1) *This represents the scheduled principal repayment 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 September 30, 2014.*

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

(3) *This represents transportation and storage commitments from 2014 to 2037.*

(4) *This represents the future commitment associated with the Corporation's capital program, diluent purchases and other operating and maintenance commitments.*

(5) *This represents the future commitments for the Calgary Corporate office.*

11. NON-GAAP MEASUREMENTS

Certain financial measures in this MD&A including: Bitumen realization, Non-energy and energy operating costs, Transportation, Net marketing activity, Cash flow from operations, Operating earnings, Cash operating netback, Total book capitalization and Total debt/book capitalization 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.

Bitumen Realization

Bitumen realization is a non-GAAP measure which the Corporation utilizes to analyze operating performance. Bitumen realization represents the Corporation's realized proprietary blend sales revenues less the cost of diluent. Proprietary blend sales and the cost of diluent are disclosed in Notes 16 and 18, respectively, in the Notes to Interim Consolidated Financial Statements.

Non-Energy and Energy Operating Costs

Non-energy and energy operating costs are non-GAAP measures which the Corporation utilizes to analyze the components of operating expenses. Non-energy and energy operating costs reconcile to Operating expenses, an IFRS measure, as outlined in the table below.

	Three months ended September 30		Nine months ended September 30	
($000)	**2014**	**2013**	**2014**	**2013**
Operating costs – non-energy	45,944	28,986	155,407	83,955
Operating costs – energy	35,835	10,463	121,474	39,029
Operating expenses	81,779	39,449	276,881	122,984

Transportation

Transportation is a non-GAAP measure and is used by the Corporation to assess the net cost of Transportation. Transportation is calculated as the net of Transportation revenue less Transportation expense.

	Three months ended September 30		Nine months ended September 30	
($000)	**2014**	**2013**	**2014**	**2013**
Transportation revenue(1)	6,207	4,098	23,312	15,226
Transportation expense(2)	(13,195)	(4,734)	(45,414)	(16,722)
Transportation	(6,988)	(636)	(22,102)	(1,496)

(1) *See Note 17 of the Notes to Interim Consolidated Financial Statements for reconciliation to Other Revenue.*

(2) *See Note 18 of the Notes to Interim Consolidated Financial Statements for reconciliation to Diluent and Transportation.*

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 transportation and storage arrangements. Net Marketing Activity represents the Corporation's third-party petroleum sales less the cost of purchased product, related transportation and storage. Petroleum sales – third party is disclosed in Note 16 in the Notes to Interim Consolidated Financial Statements and Purchased product and storage is presented as a line item on the Consolidated Statement of Income and Comprehensive Income.

Cash Flow from Operations

Cash flow from operations is a non-GAAP measure utilized by the Corporation to analyze operating performance and liquidity. Cash flow from operations excludes the net change in non-cash operating working capital, while the IFRS measurement "Net cash provided by (used in) operating activities" includes these items. Cash flow from Operations is reconciled to Net cash provided by (used in) operating activities in the table below.

	Three months ended September 30		Nine months ended September 30	
($000)	**2014**	**2013**	**2014**	**2013**
Net cash provided by (used in) operating activities	222,008	104,312	558,436	126,024
Add:				
Net change in non-cash operating working capital items	16,651	40,209	98,923	104,752
Cash flow from operations	238,659	144,521	657,359	230,776

Operating Earnings

Operating earnings is a non-GAAP measure which the Corporation uses for its own performance measures and to provide its shareholders with a measurement of the Corporation's ability to internally fund future capital investments. Operating earnings is defined as net income (loss) as reported, excluding the after-tax unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial liabilities, and unrealized fair value gains and losses on other assets. Operating earnings is reconciled to "Net income (loss)", the nearest IFRS measure, in the table below.

Cash Operating Netback

Cash operating netback 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. Cash operating netbacks are calculated by deducting the related diluent, transportation, field operating costs and royalties from proprietary production revenues and power revenue. Netbacks on a per-unit basis are calculated by dividing related production revenue, costs and royalties by bitumen sales volumes. Cash operating netback is reconciled to "Net income (loss)", the nearest IFRS measure, in the table below.

	Three months ended September 30		Nine months ended September 30	
($000)	**2014**	**2013**	**2014**	**2013**
Net income (loss)	(100,975)	115,383	44,538	(18,223)
Add (deduct):				
Unrealized foreign exchange loss (gain), net of tax(1)	192,290	(59,862)	200,238	64,972
Unrealized loss (gain) on derivative financial liabilities, net of tax(2)	(3,522)	1,339	(5,185)	(12,989)
Unrealized fair value (gain) on other assets, net of tax(3)	(322)	(689)	(322)	(689)
Operating earnings	87,471	56,171	239,269	33,071
Add (deduct):				
Interest and other income	(2,027)	(3,068)	(7,345)	(14,564)
Depletion and depreciation	97,960	48,972	277,822	137,639
General and administrative	24,750	23,101	76,845	70,166
Stock-based compensation	12,261	12,614	35,564	29,132
Research and development	1,935	1,873	3,806	3,943
Interest expense	45,861	22,666	135,066	72,538
Accretion	1,123	1,484	3,265	3,746
Realized loss (gain) on foreign exchange	2,586	(1,110)	3,699	1,735
Realized loss on derivative financial liabilities	1,257	1,225	3,745	3,508
Net marketing activity	5,965	928	8,065	1,235
Deferred income tax expense, operating	33,361	22,970	91,850	20,612
Cash operating netback	312,503	187,826	871,651	362,761

(1) *Unrealized foreign exchange gains and losses result from the translation of U.S. dollar denominated long-term debt and cash and cash equivalents to period-end exchange rates. Unrealized foreign exchange gains and losses are presented net of a deferred tax expense of $3,603 and a deferred tax expense of $6,098 for the three and nine months ended September 30, 2014 (deferred tax recovery of $1,469 for the three months ended September 30, 2013 and a deferred tax expense of $35 for the nine months ended September 30, 2013).*

(2) *Unrealized gains and losses on derivative financial liabilities result from the interest rate floor on the Corporation's long-term debt and interest rate swaps entered into to effectively fix a portion of its variable rate long-term debt. Unrealized gains and losses on derivative liabilities are presented net of a deferred tax expense of $1,174 and $1,728 for the three and nine months ended September 30, 2014 (deferred tax recovery of $447 for the three months ended September 30, 2013 and a deferred tax expense of $4,329 for the nine months ended September 30, 2013).*

(3) *Unrealized fair value gain on other assets results from the fair market valuation of the other assets held at September 30, 2014 and 2013, net of deferred tax expense of $107 for the three and nine months ended September 31, 2014 (deferred tax expense of $230 for the three months and nine months ended September 30, 2013).*

Total Book Capitalization and Total Debt/Book Capitalization

The Corporation uses the non-GAAP measures of Total book capitalization and Total debt/book capitalization to analyze the Corporation's leverage and liquidity. Total book capitalization is defined as total debt plus shareholders' equity, while total debt is defined as long-term debt, including the current portion.

12. NEW ACCOUNTING POLICIES

The Corporation has adopted the following revised standards effective January 1, 2014. These changes, along with all the corresponding amendments, are made in accordance with the applicable transitional provisions. The adoption of these revisions did not have an impact on the Corporation’s consolidated financial statements.

IAS 32, Financial Instruments: Presentation, has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.

IAS 36, Impairment of Assets, has been amended to require additional disclosures in the event of recognizing an impairment of assets.

Accounting standards issued but not yet applied

IFRS 15, Revenue From Contracts With Customers, provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework that applies to contracts with customers. The new standard is 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 IFRS 15 on the Corporation’s consolidated financial statements.

IFRS 9, Financial Instruments, is intended to replace IAS 39, Financial Instruments: Recognition and Measurement and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39, and incorporates new hedge accounting requirements. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The Corporation is currently assessing the impact of the adoption of IFRS 9 on the Corporation’s consolidated financial statements.

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. The following are the critical accounting estimates used in the preparation of the Corporation's consolidated financial statements.

Property, Plant and Equipment

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

Exploration and Evaluation Assets

Pre-exploration costs incurred before the Corporation obtains the legal right to explore an area are expensed. Exploration and evaluation costs associated with the Corporation's oil sands activities are capitalized. These costs are accumulated in cost centres pending determination of technical feasibility and commercial viability at which point the costs are transferred to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. The determination of proved or probable reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Impairments

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

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

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves. Fair value less costs to sell is defined as the amount obtainable from the sale of an asset or CGU in an arm's length transaction between knowledgeable, willing parties, less the costs of disposal.

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

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

Bitumen Reserves

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the cost and timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Corporation expects that over time its reserves estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion and depreciation charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of oil sands property, plant and equipment carrying amounts.

Decommissioning Provision

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

Deferred Income Taxes

The Corporation recognizes deferred income taxes in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date. The periods in which timing differences reverse are impacted by future earnings and capital expenditures. Rates are also affected by changes to tax legislation.

Stock-based Compensation

Amounts recorded for stock-based compensation expense are based on the historical volatility of the Corporation's share price and those of similar publicly listed enterprises, which may not be indicative of future volatility. Accordingly, these amounts are subject to measurement uncertainty.

Derivative Financial Instruments

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

14. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any related party transactions during the three and nine month periods ended September 30, 2014 or September 30, 2013, other than compensation of key management personnel.

15. OFF-BALANCE SHEET ARRANGEMENTS

At September 30, 2014 and December 31, 2013 the Corporation did not have any off balance sheet arrangements.

16. 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, 2013. In addition, MEG is also subject to other risks and uncertainties which are described in the Corporation's Annual Information Form dated March 5, 2014 under the heading "Regulatory Matters" and "Risk Factors".

17. 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.

18. 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.

19. 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 ("SORs"), 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 (e.g. operational risks and delays in the development, exploration or production associated with MEG's projects; the securing of adequate supplies and access to markets and transportation infrastructure; the availability of capacity on the electrical 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 and foreign exchange rates; and risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the continued expansion of 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 annual information form ("AIF") dated March 5, 2014, 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 the Corporation 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 and Resources

This document contains references to estimates of the Corporation's reserves and contingent resources. For supplemental information regarding the classification and uncertainties related to MEG's estimated reserves and resources please see "Independent Reserve and Resource Evaluation" in the AIF.

Non-GAAP Financial Measures

Certain financial measures in this MD&A do not have a standardized meaning as prescribed by IFRS including: Bitumen realization, Non-energy and energy operating costs, Transportation, Net marketing activity, Cash flow from operations, Operating earnings, Cash operating netback, Total book capitalization and Total debt/book capitalization. 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 the Corporation's ability to generate funds and to finance its operations as well as profitability measures specific to the oil sands industry. The Corporation uses the non-GAAP measures of Total book capitalization and Total debt/book capitalization to analyze the Corporation's leverage and liquidity. The definition and reconciliation of each non-GAAP measure is presented in the "NON-GAAP MEASUREMENTS" section of this MD&A.

20. 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.

21. QUARTERLY SUMMARIES

	2014			2013				2012
Unaudited	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
FINANCIAL ($000 unless specified)								
Net income (loss)[1]	(100,975)	248,954	(103,441)	(148,182)	115,383	(62,312)	(71,294)	(18,740)
Per share, diluted	(0.45)	1.11	(0.46)	(0.67)	0.51	(0.28)	(0.32)	(0.09)
Operating earnings (loss)	87,471	111,139	40,659	(32,685)	56,171	13,612	(36,712)	(538)
Per share, diluted	0.39	0.49	0.18	(0.15)	0.25	0.06	(0.16)	0.00
Cash flow from operations	238,659	261,713	156,987	22,648	144,521	79,184	7,071	56,106
Per share, diluted	1.06	1.16	0.70	0.10	0.64	0.35	0.03	0.27
Capital investment	345,847	332,232	353,565	394,370	477,335	674,576	681,871	500,223
Cash, cash equivalents and short-term investments	776,522	839,870	890,335	1,179,072	647,096	1,203,457	1,803,338	2,007,841
Working capital	747,928	805,742	877,069	1,045,607	365,676	731,290	1,298,955	1,655,915
Long-term debt	4,217,536	4,016,257	4,162,209	4,004,575	2,857,740	2,923,382	2,823,207	2,488,609
Shareholders' equity	4,894,444	4,970,144	4,705,966	4,788,430	4,919,407	4,771,616	4,817,253	4,870,534
BUSINESS ENVIRONMENT								
West Texas Intermediate (WTI) US$/bbl	97.16	102.99	98.68	97.43	105.83	94.22	94.37	88.18
C$ equivalent of 1US$ - average	1.0893	1.0905	1.1035	1.0477	1.0385	1.0233	1.0089	0.9913
Differential – WTI vs blend ($/bbl)	27.24	27.04	31.93	41.48	23.50	26.17	39.96	26.13
Differential – WTI vs blend (%)	25.7%	24.1%	29.3%	40.6%	21.4%	27.1%	41.9%	29.9%
Natural gas – AECO ($/mcf)	4.00	4.70	5.69	3.52	2.42	3.51	3.18	3.20
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	76,471	68,984	58,643	42,251	34,246	32,144	32,531	32,292
Bitumen sales – bbls/d	69,757	70,849	58,089	35,990	32,175	32,175	32,393	32,722
Diluent usage – bbls/d	28,753	31,617	28,797	16,680	13,032	14,176	16,239	14,810
Blend sales – bbls/d	98,510	102,446	86,886	52,670	47,288	46,351	48,632	47,532
Steam to oil ratio (SOR)	2.5	2.4	2.5	2.9	2.5	2.3	2.5	2.4
Blend sales	78.60	85.27	76.96	60.60	86.40	70.25	55.24	61.29
Cost of diluent	(13.48)	(12.52)	(14.68)	(22.38)	(12.07)	(16.27)	(25.20)	(15.62)
Bitumen realization	65.12	72.75	62.28	38.22	74.33	53.98	30.04	45.67
Transportation – net	(1.09)	(1.80)	(0.67)	(0.51)	(0.20)	(0.17)	(0.12)	(0.05)
Royalties	(5.02)	(5.01)	(4.47)	(2.71)	(5.14)	(3.03)	(1.58)	(2.23)
Operating costs – non-energy	(7.16)	(9.64)	(9.05)	(8.09)	(9.20)	(10.00)	(8.81)	(8.70)
Operating costs – energy	(5.58)	(6.45)	(8.43)	(5.38)	(3.32)	(4.85)	(4.93)	(4.65)
Power revenue	2.43	1.60	3.85	2.25	3.12	6.00	3.30	4.40
Cash operating netback	**48.70**	**51.45**	**43.51**	**23.78**	**59.59**	**41.93**	**17.90**	**34.44**
Power sales price (C$/MWh)	59.07	40.98	62.26	44.63	75.96	138.96	59.92	79.62
Power sales (MW/h)	119	115	150	76	59	58	74	75
Depletion and depreciation rate per bbl	15.26	15.30	15.54	15.56	15.54	15.11	15.24	14.79
COMMON SHARES								
Shares outstanding, end of period (000)	223,794	223,673	222,575	222,507	222,489	221,829	221,256	220,190
Volume traded (000)	30,649	70,199	32,102	33,400	28,403	43,789	28,495	20,370
Common share price ($)								
High	40.75	41.29	37.84	36.00	36.69	32.98	35.67	38.74
Low	34.00	35.52	29.41	28.60	28.81	25.50	30.89	30.25
Close (end of period)	34.38	38.89	37.36	30.61	35.54	28.83	32.61	30.44

(1) Includes unrealized foreign exchange gains and losses on conversion of U.S. dollar denominated debt.

Interim Financial Statements

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

As at	Note	September 30, 2014	December 31, 2013
Assets			
Current assets			
Cash and cash equivalents	20	**$ 776,522**	$ 1,179,072
Trade receivables and other	6	**256,344**	186,183
Inventories	7	**131,884**	129,943
		1,164,750	1,495,198
Non-current assets			
Property, plant and equipment	8	**7,985,980**	7,254,951
Exploration and evaluation assets	9	**587,117**	579,497
Other intangible assets	10	**71,810**	63,205
Other assets	11	**53,006**	54,890
Total assets		**$ 9,862,663**	$ 9,447,741
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	12	**$ 379,451**	$ 416,288
Current portion of long-term debt	13	**14,570**	13,827
Current portion of provisions and other liabilities	14	**22,801**	19,477
		416,822	449,592
Non-current liabilities			
Long-term debt	13	**4,202,966**	3,990,748
Provisions and other liabilities	14	**154,861**	125,177
Deferred income tax liability		**193,570**	93,794
Total liabilities		**4,968,219**	4,659,311
Commitments and contingencies	22		
Shareholders' equity			
Share capital	15	**4,796,187**	4,751,374
Contributed surplus	15	**138,597**	126,666
Deficit		**(47,955)**	(92,493)
Accumulated other comprehensive income		**7,615**	2,883
Total shareholders' equity		**4,894,444**	4,788,430
Total liabilities and shareholders' equity		**$ 9,862,663**	$ 9,447,741

The accompanying notes are an integral part of these interim consolidated financial statements.

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

		Three months ended September 30		Nine months ended September 30	
	Note	**2014**	2013	**2014**	2013
Petroleum revenue, net of royalties	16	**$ 684,643**	$ 387,895	**$2,145,849**	$ 931,925
Other revenue	17	**21,777**	13,935	**69,325**	52,234
		706,420	401,830	**2,215,174**	984,159
Diluent and transportation	18	**307,690**	146,360	**942,182**	450,820
Purchased product and storage	16	**10,413**	29,124	**132,525**	48,830
Operating expenses		**81,779**	39,449	**276,881**	122,984
Depletion and depreciation	8, 10	**97,960**	48,972	**277,822**	137,639
General and administrative		**24,750**	23,101	**76,845**	70,166
Stock-based compensation	15	**12,261**	12,614	**35,564**	29,132
Research and development		**1,935**	1,873	**3,806**	3,943
		536,788	301,493	**1,745,625**	863,514
Revenues less expenses		**169,632**	100,337	**469,549**	120,645
Other income (expense)					
Interest and other income		**2,027**	3,068	**7,345**	14,564
Foreign exchange gain (loss), net		**(191,273)**	59,503	**(197,839)**	(66,673)
Net finance expense	19	**(43,116)**	(26,243)	**(134,734)**	(61,555)
		(232,362)	36,328	**(325,228)**	(113,664)
Income (loss) before income taxes		**(62,730)**	136,665	**144,321**	6,981
Deferred income tax expense		**38,245**	21,282	**99,783**	25,204
Net income (loss)		**(100,975)**	115,383	**44,538**	(18,223)
Other comprehensive income (loss)					
Foreign currency translation adjustment		**6,281**	(172)	**4,732**	(75)
Comprehensive income (loss) for the period		**$ (94,694)**	$ 115,211	**$ 49,270**	$ (18,298)

Net earnings (loss) per share					
Basic	21	**$ (0.45)**	$ 0.52	**$ 0.20**	$ (0.08)
Diluted	21	**$ (0.45)**	$ 0.51	**$ 0.20**	$ (0.08)

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	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at January 1, 2014		**$ 4,751,374**	**$ 126,666**	**$ (92,493)**	**$ 2,883**	**$ 4,788,430**
Stock options exercised	15	**14,098**	**(3,368)**	**-**	**-**	**10,730**
RSUs vested and released	15	**30,715**	**(30,715)**	**-**	**-**	**-**
Stock-based compensation	15	**-**	**46,014**	**-**	**-**	**46,014**
Net income		**-**	**-**	**44,538**	**-**	**44,538**
Other comprehensive income		**-**	**-**	**-**	**4,732**	**4,732**
Balance at September 30, 2014		**$ 4,796,187**	**$ 138,597**	**$ (47,955)**	**$ 7,615**	**$ 4,894,444**
Balance at January 1, 2013		$ 4,694,378	$ 102,219	$ 73,912	$ 25	$ 4,870,534
Share issue costs, net of tax		332	-	-	-	332
Stock options exercised		40,095	(9,123)	-	-	30,972
RSUs vested and released		16,216	(16,216)	-	-	-
Stock-based compensation		-	35,867	-	-	35,867
Net loss		-	-	(18,223)	-	(18,223)
Other comprehensive loss		-	-	-	(75)	(75)
Balance at September 30, 2013		$ 4,751,021	$ 112,747	$ 55,689	$ (50)	$ 4,919,407

The accompanying notes are an integral part of these interim consolidated financial statements.

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

		Three months ended September 30		Nine months ended September 30	
	Note	**2014**	2013	**2014**	2013
Cash provided by (used in):					
Operating activities					
Net income (loss)		**$ (100,975)**	$ 115,383	**$ 44,538**	$ (18,223)
Adjustments for:					
Depletion and depreciation		**97,960**	48,972	**277,822**	137,639
Stock-based compensation		**12,261**	12,614	**35,564**	29,132
Unrealized loss (gain) on foreign exchange		**188,687**	(58,393)	**194,140**	64,937
Unrealized loss (gain) on derivative financial liabilities	19	**(4,696)**	1,787	**(6,913)**	(17,318)
Deferred income tax expense		**38,245**	21,282	**99,783**	25,204
Other		**7,177**	2,876	**12,425**	9,405
Net change in non-cash operating working capital items	20	**(16,651)**	(40,209)	**(98,923)**	(104,752)
Net cash provided by (used in) operating activities		**222,008**	104,312	**558,436**	126,024
Investing activities					
Capital investments		**(310,814)**	(476,362)	**(974,643)**	(1,799,121)
Purchase of other assets	11	**-**	(41,890)	**-**	(41,890)
Other		**1,840**	(193)	**1,181**	(3,848)
Net change in non-cash investing working capital items	20	**10,299**	(177,952)	**(11,947)**	391,301
Net cash provided by (used in) investing activities		**(298,675)**	(696,397)	**(985,409)**	(1,453,558)
Financing activities					
Issue of shares		**2,531**	17,090	**10,730**	31,417
Issue of long-term debt, net of debt issue costs		**-**	-	**-**	307,950
Repayment of long-term debt		**(3,622)**	(3,342)	**(10,698)**	(10,049)
Financing costs		**-**	-	**-**	(15,521)
Net cash provided by (used in) financing activities		**(1,091)**	13,748	**32**	313,797
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**14,410**	(5,871)	**24,391**	20,944
Change in cash and cash equivalents		**(63,348)**	(584,208)	**(402,550)**	(992,793)
Cash and cash equivalents, beginning of period		**839,870**	1,066,258	**1,179,072**	1,474,843
Cash and cash equivalents, end of period		**$ 776,522**	$ 482,050	**$ 776,522**	$ 482,050

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 sections of oil sands leases in the 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 Regional Project ("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 financial statements for the year ended December 31, 2013, except as described in Note 3 below. 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 3 of the Corporation’s audited financial statements for the year ended December 31, 2013. These interim consolidated financial statements should be read in conjunction with the Corporation’s audited financial statements for the year ended December 31, 2013, which are included in the Corporation’s 2013 annual report.

These interim consolidated financial statements were approved by the Corporation’s Audit Committee on October 28, 2014.

3. CHANGE IN ACCOUNTING POLICIES

The Corporation has adopted the following revised standards effective January 1, 2014. These changes, along with all the consequential amendments, are made in accordance with the applicable transitional provisions. The adoption of these revisions did not have an impact on the Corporation’s consolidated financial statements.

IAS 32, Financial Instruments: Presentation, has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.

IAS 36, Impairment of Assets, has been amended to require additional disclosures in the event of recognizing an impairment of assets.

Accounting standards issued but not yet applied

IFRS 15, Revenue From Contracts With Customers, provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework that applies to contracts with customers. The new standard is 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 IFRS 15 on the Corporation's consolidated financial statements.

IFRS 9, Financial Instruments, is intended to replace IAS 39, Financial Instruments: Recognition and Measurement and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39, and incorporates new hedge accounting requirements. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The Corporation is currently assessing the impact of the adoption of IFRS 9 on the Corporation's consolidated financial statements.

4. PRINCIPLES OF CONSOLIDATION

The interim consolidated financial statements of the Corporation comprise the Corporation and its wholly-owned subsidiary, MEG Energy (U.S.) Inc. All intercompany transactions and balances are eliminated on consolidation.

5. FINANCIAL INSTRUMENTS AND DERIVATIVE FINANCIAL LIABILITIES

The financial instruments recognized on the balance sheet are comprised of cash and cash equivalents, trade receivables and other, other assets, accounts payable and accrued liabilities, derivative financial liabilities and long-term debt. As at September 30, 2014, other assets and derivative financial liabilities were classified as held-for-trading financial instruments; cash and cash equivalents and trade receivables and other were classified as loans and receivables; and accounts payable and accrued liabilities were classified as other financial liabilities. Long-term debt was carried at amortized cost.

The carrying value of cash and cash equivalents, trade receivables and other, and accounts payable and accrued liabilities included on the 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 other assets, derivative financial liabilities and long-term debt

			Fair value measurements using		
As at September 30, 2014	**Carrying amount**	**Fair value**	**Quoted prices in active markets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
Recurring measurements:					
Financial assets					
Other assets	**$ 2,810**	**$ 2,810**	**$ -**	**$ 2,810**	**$ -**
Financial liabilities					
Derivative financial liabilities	**24,067**	**24,067**	**-**	**24,067**	**-**
Long-term debt	**4,275,572**	**4,333,400**	**4,333,400**	**-**	**-**

			Fair value measurements using		
As at December 31, 2013	Carrying amount	Fair value	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Recurring measurements:					
Financial assets					
Other assets	$ 2,252	$ 2,252	$ -	$ -	$ 2,252
Financial liabilities					
Derivative financial liabilities	30,981	30,981	-	30,981	-
Long-term debt	4,067,738	4,135,639	4,135,639	-	-

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

The fair value of long-term debt is derived using quoted prices in an active market.

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

The fair value of 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 for the Corporation's interest rate swaps and floors. Management's assumptions rely on external observable market data including interest rate yield curves. The observable inputs may be adjusted using certain methods, which include extrapolation to the end of the term of the contract.

Other assets are comprised of investments in U.S. auction rate securities (“ARS”). The estimated fair value of the ARS is derived using quoted prices in an inactive market from a third party independent broker.

Level 3 fair value measurements are based on unobservable information.

Level 3 measurements consist of financial instruments with a fair value that is determined by reference to prices with significant unobservable inputs. As at September 30, 2014, the Corporation does 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. At September 30, 2014, the fair value measurement of ARS in the amount of $2.8 million was transferred from Level 3 to Level 2 as a result of the Corporation's ability to obtain independent market corroborated data.

During the period ended September 30, 2014, a gain of $429 thousand was recognized within net finance expense to recognize a change in fair value of ARS.

(b) 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. As noted below, in order to mitigate a portion of this risk, the Corporation has entered into interest rate swap contracts to effectively fix the interest rate on US$748.0 million of the US$1.3 billion senior secured term loan. At September 30, 2014, there was an unrealized loss on the interest rate swaps of $5.9 million (December 31, 2013 - $7.5 million).

Amount	Effective date	Remaining term	Fixed rate	Floating rate
US$300 million	September 30, 2011	Oct 2014-Sept 2016	4.436%	3 month LIBOR[1]
US$150 million	December 31, 2011	Oct 2014-Sept 2016	4.376%	3 month LIBOR[1]
US$150 million	January 12, 2012	Oct 2014-Sept 2016	4.302%	3 month LIBOR[1]
US$148 million	January 27, 2012	Oct 2014-Sept 2016	4.218%	3 month LIBOR[1]

[1] *London Interbank Offered Rate*

6. TRADE RECEIVABLES AND OTHER

	September 30, 2014	December 31, 2013
Trade receivables	$ 248,958	$ 174,935
Deposits and advances	4,049	7,908
Current portion of deferred financing costs	3,337	3,340
	$ 256,344	$ 186,183

7. INVENTORIES

	September 30, 2014	December 31, 2013
Diluent	$ 105,543	$ 84,628
Bitumen blend	24,263	43,358
Materials and supplies	2,078	1,957
	$ 131,884	$ 129,943

During the nine month period ended September 30, 2014, a total of $896.8 million (nine month period ended September 30, 2013 - $434.1 million) in inventory product costs were charged to earnings through diluent and transportation expense.

8. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Corporate assets	Total
Cost				
Balance as at December 31, 2012	$ 4,799,595	$ 793,671	$ 33,597	$ 5,626,863
Additions	1,694,070	480,263	7,438	2,181,771
Transfer from exploration and evaluation assets (note 9)	-	2,513	-	2,513
Balance as at December 31, 2013	$ 6,493,665	$ 1,276,447	$ 41,035	$ 7,811,147
Additions	771,637	237,543	3,686	1,012,866
Balance as at September 30, 2014	**$ 7,265,302**	**$ 1,513,990**	**$ 44,721**	**$ 8,824,013**
Accumulated depletion and depreciation				
Balance as at December 31, 2012	$ 329,556	$ 22,831	$ 6,591	$ 358,978
Depletion and depreciation for the period	183,866	8,621	4,731	197,218
Balance as at December 31, 2013	$ 513,422	$ 31,452	$ 11,322	$ 556,196
Depletion and depreciation for the period	265,495	12,505	3,837	281,837
Balance as at September 30, 2014	**$ 778,917**	**$ 43,957**	**$ 15,159**	**$ 838,033**
Carrying Amounts				
As at December 31, 2013	$ 5,980,243	$ 1,244,995	$ 29,713	$ 7,254,951
As at September 30, 2014	**$ 6,486,385**	**$ 1,470,033**	**$ 29,562**	**$ 7,985,980**

During the nine months ended September 30, 2014, the Corporation capitalized $26.4 million (nine months ended September 30, 2013 - $18.3 million) of general and administrative costs and $10.5 million (nine months ended September 30, 2013 - $6.7 million) of stock-based compensation costs relating to oil sands exploration and development activities. In addition, $61.1 million of interest and finance charges related to the development of capital projects were capitalized during the nine months ended September 30, 2014 (nine months ended September 30, 2013 - $53.6 million). As at September 30, 2014, $764.7 million of assets under construction were included within the Crude oil component of property, plant and equipment. Assets under construction are not subject to depletion and depreciation.

9. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2012	$	554,349
Additions		27,661
Transfer to property, plant and equipment (note 8)		(2,513)
Balance as at December 31, 2013	$	579,497
Additions		7,620
Balance as at September 30, 2014	**$**	**587,117**

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 of September 30, 2014, no impairment has been recognized on these assets.

10. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2012	$	47,489
Additions		18,720
Balance as at December 31, 2013	$	66,209
Additions		11,158
Balance as at September 30, 2014	**$**	**77,367**

Accumulated depreciation		
Balance as at December 31, 2012	$	1,456
Depreciation		1,548
Balance as at December 31, 2013	$	3,004
Depreciation		2,553
Balance as at September 30, 2014	**$**	**5,557**

Carrying Amounts		
As at December 31, 2013	$	63,205
As at September 30, 2014	**$**	**71,810**

Other intangible assets at September 30, 2014 include $54.1 million invested to maintain the right to participate in a potential pipeline project and $17.7 million invested in software that is not an integral part of the related computer hardware.

11. OTHER ASSETS

	September 30, 2014	December 31, 2013
Long-term pipeline linefill[(a)]	**$ 41,576**	$ 41,517
ARS[(b)]	**2,810**	2,252
Deferred financing costs[(c)]	**11,957**	14,461
	56,343	58,230
Less current portion of deferred financing costs	**(3,337)**	(3,340)
	$ 53,006	$ 54,890

(a) In 2013, the Corporation entered into an agreement to transport diluent on a third party pipeline and was required to supply diluent linefill for the pipeline. As the pipeline is owned by a third party, the linefill is not considered to be a part of the Corporation's property, plant and equipment.

(b) The investment in ARS is considered a long-term asset and is recorded at its fair value based on quoted prices in an inactive market from a third party independent broker. Changes in fair value are included in net finance expense in the period in which they arise.

(c) Costs associated with establishing the Corporation's revolving credit facility are deferred and amortized over the term of the credit facility.

12. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	September 30, 2014	December 31, 2013
Trade payables	**$ 34,258**	$ 114,752
Accrued and other liabilities	**333,334**	244,972
Interest payable	**11,859**	56,564
	$ 379,451	$ 416,288

13. LONG-TERM DEBT

	September 30, 2014	December 31, 2013
Senior secured term loan (September 30, 2014 – US$1.265 billion; December 31, 2013 – US$1.275 billion)[(a)]	**$ 1,417,532**	$ 1,355,558
6.5% senior unsecured notes (US$750 million)[(b)]	**840,600**	797,700
6.375% senior unsecured notes (US$800 million)[(c)]	**896,640**	850,880
7.0% senior unsecured notes (US$1.0 billion)[(d)]	**1,120,800**	1,063,600
	4,275,572	4,067,738
Less current portion of senior secured term loan	**(14,570)**	(13,827)
Less unamortized financial derivative liability discount	**(18,291)**	(20,565)
Less unamortized deferred debt issue costs	**(39,745)**	(42,598)
	$ 4,202,966	$ 3,990,748

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.1208 (December 31, 2013 - US$1 = C$1.0636).

There are no maintenance financial covenants associated with the Corporation's debt as at September 30, 2014 and December 31, 2013.

(a) On February 25, 2013, the Corporation re-priced, increased and extended its existing US$987.5 million senior secured term loan. The Corporation extended the maturity date to March 31, 2020 and increased its borrowing under the senior secured term loan by US$300.0 million. In addition, the Corporation reduced the interest rate on the term loan by 25 basis points.

Effective May 24, 2013, the Corporation agreed to amend, extend and increase its revolving credit facility from US$1.0 billion to US$2.0 billion with a maturity date of May 24, 2018. As at September 30, 2014, US$106.3 million (December 31, 2013 - US$125.8 million) of the revolving credit facility was utilized to support letters of credit. As at September 30, 2014, no amount had been drawn under the revolving credit facility.

The senior secured credit facilities are comprised of a US$1.265 billion term loan and a US$2.0 billion revolving credit facility. The senior secured credit facilities are secured by substantially all the assets of the Corporation. The term loan bears a floating interest rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 175 or 275 basis points, respectively. The term loan also has an interest rate floor of 200 basis points based on U.S. Prime or 100 basis points based on LIBOR. The term loan is to be repaid in quarterly installment payments equal to US$3.25 million, with the balance due on March 31, 2020. Interest is paid quarterly. The Corporation has deferred the associated remaining debt issue costs of $5.4 million and is amortizing these costs over the life of the loan utilizing the effective interest method.

(b) Effective March 18, 2011, the Corporation issued US$750.0 million in aggregate principal amount of 6.5% Senior Unsecured Notes, with a maturity date of March 15, 2021. Interest is paid semi-annually on March 15 and September 15. No principal payments are required until March 15, 2021. The Corporation has deferred the associated remaining debt issue costs of $10.4 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

(c) Effective July 19, 2012, the Corporation issued US$800.0 million in aggregate principal amount of 6.375% Senior Unsecured Notes, with a maturity date of January 30, 2023. Interest is paid semi-annually on January 30 and July 30. No principal payments are required until January 30, 2023. The Corporation has deferred the associated remaining debt issue costs of $11.5 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

(d) Effective October 1, 2013, the Corporation issued US$800.0 million in aggregate principal amount of 7.0% Senior Unsecured Notes, with a maturity date of March 31, 2024. On November 6, 2013 an additional US$200 million of 7.0% Senior Unsecured Notes were issued under the same indenture. Interest is paid semi-annually on March 31 and September 30. No principal payments are required until March 31, 2024. The Corporation has deferred the associated remaining debt issue costs of $12.4 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

14. PROVISIONS AND OTHER LIABILITIES

	September 30, 2014	December 31, 2013
Derivative financial liabilities[a]	**$ 24,067**	$ 30,981
Decommissioning provision[b]	**149,072**	108,695
Deferred lease inducements[c]	**4,523**	4,978
Provisions and other liabilities	**177,662**	144,654
Less current portion	**(22,801)**	(19,477)
Non-current portion	**$ 154,861**	$ 125,177

(a) Derivative financial liabilities

	September 30, 2014	December 31, 2013
1% interest rate floor	**$ 18,172**	$ 23,497
Interest rate swaps	**5,895**	7,484
Derivative financial liabilities	**24,067**	30,981
Less current portion of derivative financial liabilities	**(14,085)**	(13,886)
Non-current portion of derivative financial liabilities	**$ 9,982**	$ 17,095

The interest rate floor on the senior secured term loan has been recognized as an embedded derivative, as the floor rate exceeded the market rate of interest at the time that the debt was incurred. As a result, the interest rate floor derivative is required to be separated from the carrying value of long-term debt and accounted for as a separate derivative financial liability measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

The Corporation is exposed to interest rate risk in relation to interest income earned on cash, cash equivalents and short-term investments and in relation to interest expense on floating rate long-term debt. To mitigate a portion of the risk of interest rate increases on long-term debt, the Corporation periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. As of September 30, 2014, the Corporation had entered into interest rate swaps on US$748.0 million (note 5(b)) and these interest rate swap contracts expire on 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 net finance expense in the period in which they arise.

(b) The following table presents the decommissioning provision associated with the reclamation and abandonment of crude oil and transportation and storage assets:

	September 30, 2014	December 31, 2013
Decommissioning provision, beginning of period	**$ 108,695**	$ 82,087
Changes in estimated future cash flows	**18,001**	15,082
Changes in discount rates	**11,741**	(19,110)
Liabilities incurred	**8,291**	30,068
Liabilities settled	**(921)**	(4,195)
Accretion	**3,265**	4,763
Decommissioning provision, end of period	**149,072**	108,695
Less current portion of decommissioning provision	**(7,978)**	(4,848)
Non-current portion of decommissioning provision	**$ 141,094**	$ 103,847

The total decommissioning provision is based on the estimated costs to reclaim and abandon the Corporation's crude oil properties and transportation and storage assets and the estimated timing of the costs to be incurred in future years. The Corporation has estimated the net present value of the decommissioning obligations to be $149.1 million as at September 30, 2014 (December 31, 2013 - $108.7 million) based on an undiscounted total future liability of $696.2 million (December 31, 2013 - $569.5 million) and a credit-adjusted rate of 5.9% (December 31, 2013 – 6.4%). This obligation is estimated to be settled in periods up to the year 2063.

(c) Deferred lease inducements

	September 30, 2014	December 31, 2013
Deferred lease inducements	**$ 4,523**	$ 4,978
Less current portion of deferred lease inducements	**(738)**	(743)
Non-current portion of deferred lease inducements	**$ 3,785**	$ 4,235

Leasehold inducements were received when the Corporation entered into the corporate office lease. These inducements are recognized as a deferred liability and amortized through general and administrative expense over the life of the lease.

15. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

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

	Nine months ended September 30, 2014		Year ended December 31, 2013	
	Number of shares	**Amount**	Number of shares	Amount
Balance, beginning of period	**222,506,896**	**$ 4,751,374**	220,190,084	$ 4,694,378
Share issue costs, net of tax	**-**	**-**	-	79
Issued upon exercise of stock options	**395,511**	**14,098**	1,893,732	40,522
Issued upon vesting and release of RSUs	**891,430**	**30,715**	423,080	16,395
Balance, end of period	**223,793,837**	**$ 4,796,187**	222,506,896	$ 4,751,374

(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.

	Nine months ended September 30, 2014		Year ended December 31, 2013	
	Stock options	**Weighted average exercise price per share**	Stock options	Weighted average exercise price per share
Outstanding, beginning of period	**8,859,028**	**$ 35.49**	9,147,404	$ 32.50
Granted	**1,763,902**	**37.87**	1,774,854	30.95
Exercised	**(395,511)**	**27.13**	(1,893,732)	16.53
Forfeited	**(293,169)**	**38.96**	(169,498)	38.19
Expired	**(381,749)**	**40.36**	-	-
Outstanding, end of period	**9,552,501**	**$ 35.98**	8,859,028	$ 35.49

(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. An RSU, including a PSU, represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares. A PSU is an RSU, the vesting of which has been made conditional on the satisfaction of certain performance criteria. PSUs become eligible to vest if the Corporation satisfies the performance criteria identified by the Corporation's Board of Directors within a target range. A pre-determined multiplier is then applied to PSUs that have become eligible to vest, dependent on the point in the target range to which such performance criteria are satisfied. RSUs granted under the Restricted Share Unit Plan generally vest annually over a three year period. PSUs granted under the Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that the performance criteria have been satisfied, and that the holder remains actively employed, a director or a consultant with the Corporation on the vesting date.

RSUs and PSUs outstanding	**Nine months ended September 30, 2014**	Year ended December 31, 2013
Outstanding, beginning of period	**2,589,700**	953,804
Granted	**1,088,034**	2,157,534
Vested and released	**(891,430)**	(423,080)
Forfeited	**(77,086)**	(98,558)
Outstanding, end of period	**2,709,218**	2,589,700

(e) Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of Deferred Share Units ("DSUs") to directors of the Corporation. A DSU represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares purchased through a broker. DSUs are vested when they are granted and are redeemed on the third business day following the date on which the holder ceases to be a director. At September 30, 2014, there were 17,281 DSUs outstanding.

(f) Contributed Surplus:

		Nine months ended September 30, 2014		Year ended December 31, 2013
Balance, beginning of period	**$**	**126,666**	$	102,219
Stock-based compensation - expensed		**35,564**		38,792
Stock-based compensation - capitalized		**10,450**		11,267
Stock options exercised		**(3,368)**		(9,217)
RSUs vested and released		**(30,715)**		(16,395)
Balance, end of period	**$**	**138,597**	$	126,666

16. PETROLEUM REVENUE, NET OF ROYALTIES

	Three months ended September 30				**Nine months ended September 30**			
		2014		2013		**2014**		2013
Petroleum sales:								
Proprietary	**$**	**712,383**	$	375,894	**$**	**2,109,283**	$	913,994
Third party[(a)]		**4,448**		28,196		**124,460**		47,595
		716,831		404,090		**2,233,743**		961,589
Royalties		**(32,188)**		(16,195)		**(87,894)**		(29,664)
Petroleum revenue, net of royalties	**$**	**684,643**	$	387,895	**$**	**2,145,849**	$	931,925

(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 Income and Comprehensive Income under the caption "Purchased product and storage".

17. OTHER REVENUE

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Power revenue	**$ 15,570**	$ 9,837	**$ 46,013**	$ 37,008
Transportation revenue	**6,207**	4,098	**23,312**	15,226
Other revenue	**$ 21,777**	$ 13,935	**$ 69,325**	$ 52,234

18. DILUENT AND TRANSPORTATION

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Diluent	**$ 294,495**	$ 141,626	**$ 896,768**	$ 434,098
Transportation expense	**13,195**	4,734	**45,414**	16,722
Diluent and transportation	**$ 307,690**	$ 146,360	**$ 942,182**	$ 450,820

19. NET FINANCE EXPENSE

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Total interest expense	**$ 65,366**	$ 44,439	**$ 196,140**	$ 126,156
Less capitalized interest	**(19,505)**	(21,773)	**(61,074)**	(53,618)
Net interest expense	**45,861**	22,666	**135,066**	72,538
Accretion on decommissioning provision	**1,123**	1,484	**3,265**	3,746
Unrealized fair value loss (gain) on embedded derivative liabilities	**(3,079)**	648	**(5,325)**	(12,255)
Unrealized fair value loss (gain) on interest rate swaps	**(1,617)**	1,139	**(1,588)**	(5,063)
Realized loss on interest rate swaps	**1,257**	1,225	**3,745**	3,508
Unrealized fair value gain on other assets	**(429)**	(919)	**(429)**	(919)
Net finance expense	**$ 43,116**	$ 26,243	**$ 134,734**	$ 61,555

20. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Changes in non-cash working capital				
Operating activities:				
Trade receivables and other	**$ 36,826**	$ (6,131)	**$ (70,164)**	$ (42,591)
Inventories[(a)]	**(31,875)**	(4,293)	**(3,870)**	(7,034)
Accounts payable and accrued liabilities	**(21,602)**	(29,785)	**(24,889)**	(55,127)
Change in operating non-cash working capital	**$ (16,651)**	$ (40,209)	**$ (98,923)**	$ (104,752)
Investing activities:				
Short-term investments	**$ -**	$ (27,846)	**$ -**	$ 367,952
Accounts payable and accrued liabilities	**10,299**	(135,241)	**(11,947)**	38,214
Trade receivables and other	**-**	(14,865)	**-**	(14,865)
Change in investing non-cash working capital	**$ 10,299**	$ (177,952)	**$ (11,947)**	$ 391,301
Change in total non-cash working capital	**$ (6,352)**	$ (218,161)	**$ (110,870)**	$ 286,549
Cash and cash equivalents:				
Cash	**$ 293,555**	$ 423,548	**$ 293,555**	$ 423,548
Cash equivalents	**482,967**	58,502	**482,967**	58,502
	$ 776,522	$ 482,050	**$ 776,522**	$ 482,050

(a) The three and nine months ended September 30, 2014 amounts exclude a non-cash increase in inventory of $782 and decrease of $1,929, respectively (three and nine months ended September 30, 2013 – nil).

21. EARNINGS PER COMMON SHARE

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Net income (loss)	**$ (100,975)**	$ 115,383	**$ 44,538**	$ (18,223)
Weighted average common shares outstanding	**223,779,396**	222,148,731	**223,128,996**	221,564,016
Dilutive effect of stock options, RSUs and PSUs[(a)]	**-**	2,861,576	**1,653,882**	-
Weighted average common shares outstanding – diluted	**223,779,396**	225,010,307	**224,782,878**	221,564,016
Net earnings (loss) per share, basic	**$ (0.45)**	$ 0.52	**$ 0.20**	$ (0.08)
Net earnings (loss) per share, diluted	**$ (0.45)**	$ 0.51	**$ 0.20**	$ (0.08)

(a) For the three months ended September 30, 2014, and nine months ended September 30, 2013, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss during these periods. If the Corporation would have had net income during these periods, the dilutive effect of stock options, RSUs and PSUs would have been 1,679,019 and 2,465,198, respectively.

22. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at September 30, 2014:

Operating:

	2014	2015	2016	2017	2018	Thereafter
Office lease rentals	$ 3,655	$ 15,703	$ 16,111	$ 34,082	$ 32,202	$ 328,857
Diluent purchases	132,074	121,973	17,229	17,182	17,182	83,085
Transportation and storage	29,808	118,159	147,533	239,854	209,285	2,988,730
Other commitments	5,767	12,721	7,136	5,967	6,055	42,634
Commitments	**$ 171,304**	**$ 268,556**	**$ 188,009**	**$ 297,085**	**$ 264,724**	**$ 3,443,306**

Capital:

As part of normal operations, the Corporation has entered into a total of $121.0 million of capital commitments to be made in periods through 2016.

(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.