# FIRST QUARTER 2014

Report to Shareholders for the period ended March 31, 2014

MEG Energy Corp. reported first quarter 2014 operational and financial results on April 30, 2014. Highlights include:

- Record cash flow from operations of $157.0 million;
- Record quarterly production of 58,643 barrels per day (bpd), an increase of 80% over first quarter 2013 production volumes driven by the continuing ramp-up of production at Christina Lake Phase 2B and MEG's RISER initiative;
- Quarterly exit rate production for the month of March was over 60,600 bpd, supporting targeted annual average production of 60,000 to 65,000 bpd in 2014 and 80,000 bpd by 2015; and
- First quarter non-energy operating costs of $9.05 per barrel, in line with annual guidance of an average of $8 to $10 per barrel.

"The first quarter has set the stage for a very solid year," said Bill McCaffrey, MEG President and Chief Executive Officer. "The implementation of RISER at Phase 1 and 2 has already exceeded our initial expectations. With this strong performance, combined with the steady production ramp-up we are seeing at Phase 2B, we believe we are well on track to achieve our 2014 average production target of 60,000 to 65,000 barrels per day, as well as our 80,000 barrels per day target by 2015."

With the benefits of its RISER initiative at its Phase 1 and 2 assets and the ramp-up of production from Phase 2B, MEG reached a production record of 58,643 bpd in the first quarter of 2014, an increase of 80% over first quarter 2013 volumes of 32,531 bpd.

"The ramp-up of Phase 2B to its initial design capacity of 35,000 barrels per day is going very well," said McCaffrey. "We are now in the early planning stages for a RISER initiative on Phase 2B, which will be the next phase of production growth for the company."

RISER 2B will employ the same proven and proprietary technologies which drove increased production and resource recovery at Phase 1 and 2, but this time with a major brownfield expansion of the Phase 2B plant. RISER 2B is anticipated to add significant production above initial design capacity at lower capital and operating costs than a typical greenfield development.

Cash flow from operations reached a record $157.0 million ($0.70 per share, diluted) for the first quarter of 2014, compared to $7.1 million ($0.03 per share, diluted) for the same period of 2013. The increase in cash flow from operations was primarily due to higher sales volumes and increased price realizations per barrel.

First quarter 2014 net operating costs were $13.63 per barrel, compared to $10.44 per barrel in the first quarter of 2013. The increase was primarily due to higher natural gas energy prices. Net operating costs were partially offset by electricity sales revenue from MEG's cogeneration facilities. Non-energy costs were slightly higher at $9.05 per barrel in the first quarter of 2014, compared to $8.81 in the first quarter of 2013, primarily due to the ramp-up of Phase 2B.

Operating earnings, which are adjusted to exclude unrealized items such as foreign exchange conversion, were $40.7 million in the first quarter of 2014, compared to a loss of $36.7 million in the same period of 2013. Increased operating earnings were primarily driven by higher sales volumes and increased price realizations per barrel.

MEG recognized a net loss of $103.4 million for the first quarter of 2014 compared to a net loss of $71.3 million for same period in 2013. The loss in the first quarter of 2014 was primarily due to the $159.5 million impact of the conversion of the company's U.S. dollar denominated debt as a result of the strengthening of the U.S. dollar against the Canadian dollar.

Average bitumen price realizations increased more than 60% in the first quarter of 2014 compared to the previous quarter and were more than double the price realizations in the first quarter of 2013. Continued logistics enhancements, including recent additions of crude-by-rail facilities, pipelines connecting the U.S. mid-continent to the U.S. Gulf Coast and refinery modifications in the U.S. Midwest contributed to improved pricing. The expected completion of the Flanagan-Seaway pipeline system in the second half of 2014 will further enhance transportation logistics and is expected to assist in alleviating ongoing pipeline congestion.

"The combination of increasing production volumes, low and stable operating costs and our efforts to increase the market price we realize on every barrel is anticipated to further strengthen our cash flow profile," said McCaffrey.

**Forward-Looking Information and Non-IFRS 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-IFRS Financial Measures" 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 March 31, 2014 is dated April 29, 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 condensed consolidated interim financial statements and notes thereto for the period ended March 31, 2014. All tabular amounts are stated in thousands of Canadian dollars ($ or C$) unless indicated otherwise.*

**MD&A – Table of Contents**



## 1. OVERVIEW

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

MEG owns a 100% working interest in over 900 square miles of oil sands leases. In a report dated effective December 31, 2013 (the "GLJ Report"), with a preparation date of January 16, 2014, GLJ Petroleum Consultants Ltd. ("GLJ") 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 could 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 designed capacity of 25,000 bbls/d. Phase 2B, an expansion with a designed capacity of 35,000 bbls/d, commenced production in the fourth quarter of 2013. MEG anticipates that Phase 2B will ramp-up to full designed capacity over the 9 to 12 months following the initial well steaming phase. On July 16, 2012, the Corporation announced the RISER initiative for Phases 1 and 2, which is designed to increase production from existing assets at relatively low capital and operating costs using a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including debottlenecking and expansions (collectively, "RISER"). As a result of the operational success achieved from applying RISER, and the ongoing ramp-up of Phase 2B, MEG anticipates reaching a near-term production target from Christina Lake Phases 1, 2 and 2B of 80,000 bbls/d by 2015.

Production growth beyond our near-term target will be primarily driven by the application of the RISER initiative to Phase 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 (collectively, "RISER 2B"). Given the attractiveness of this brownfield strategy, MEG will prioritize RISER 2B ahead of its next greenfield expansion.

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 designed 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 use SAGD technology and include multi-well production pads, electricity and steam cogeneration and other facilities similar to MEG's current Christina Lake Project. The Surmont Project is located approximately 30 miles north of the Corporation's Christina Lake 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 addition to the Access Pipeline, MEG owns 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 connected to the Access Pipeline and is also connected by pipeline to a third party rail-loading terminal. This combination of facilities allows for both the loading of bitumen blend for transport by rail and the receipt of railed diluent, giving direct 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 three months ended March 31:

| | 2014 | 2013 |
|---|---|---|
| Bitumen production - bbls/d | 58,643 | 32,531 |
| Bitumen sales - bbls/d | 58,089 | 32,393 |
| Steam to oil ratio (SOR) | 2.5 | 2.5 |
| | | |
| West Texas Intermediate (WTI) US$/bbl | 98.68 | 94.37 |
| West Texas Intermediate (WTI) C$/bbl | 108.89 | 95.21 |
| Differential - Blend vs WTI - % | 29.3% | 41.9% |
| | | |
| Bitumen realization - $/bbl | 62.28 | 30.04 |
| | | |
| Net operating costs(1) - $/bbl | 13.63 | 10.44 |
| | | |
| Non-energy operating costs - $/bbl | 9.05 | 8.81 |
| | | |
| Cash operating netback(2) - $/bbl | 43.51 | 17.90 |
| | | |
| Total cash capital investment(3) - $000 | 343,003 | 668,932 |
| | | |
| Net income (loss)(4) - $000 | (103,441) | (71,294) |
| Per share, diluted | (0.46) | (0.32) |
| Operating earnings (loss)(5) - $000 | 40,659 | (36,712) |
| Per share, diluted(5) | 0.18 | (0.16) |
| Cash flow from operations(5) - $000 | 156,987 | 7,071 |
| Per share, diluted(5) | 0.70 | 0.03 |
| | | |
| Cash, cash equivalents and short-term investments - $000 | 890,335 | 1,803,338 |
| Long-term debt - $000 | 4,162,209 | 2,823,207 |

(1) *Net operating costs include energy and non-energy operating costs, reduced by power sales. 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, field operating costs 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 for the three months ended March 31, 2014 ($13.6 million for three months ended March 31, 2013).*

(4) *Includes a foreign exchange loss of $159.5 million on conversion of the U.S. dollar denominated debt for the three months ended March 31, 2014 ($49.3 million loss for the three months ended March 31, 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. The Corporation uses these non-IFRS measurements for its own performance measures and to provide its shareholders with a measurement of the Corporation's ability to internally fund future capital investments. These non-IFRS measurements are reconciled to net income (loss) and net cash provided by (used in) operating activities in accordance with IFRS under the heading "NON-IFRS MEASUREMENTS" and discussed further in the "ADVISORY" section.*

Bitumen production for the three months ended March 31, 2014 averaged 58,643 bbls/d compared to 32,531 bbls/d for the three months ended March 31, 2013. The increase in production volumes in 2014 compared to 2013 is due to the implementation of RISER on Christina Lake Phases 1 and 2 and the start-up of Phase 2B. The implementation of the RISER initiative within Phases 1 and 2 has expanded the steam generation capacity and improved reservoir efficiency, 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 ongoing ramp-up of Phase 2B, along with the success achieved from applying RISER to Phases 1 and 2, MEG anticipates reaching a near-term production target from Christina Lake Phases 1, 2 and 2B of 80,000 bbls/d by 2015.

The Corporation's average steam to oil ratio ("SOR") was 2.5 for the three months ended March 31, 2014 and March 31, 2013. The Corporation continues to focus on increasing production and improving efficiency of current production through a lower SOR, which is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The average SOR has decreased throughout the first quarter of 2014, compared to an average SOR of 2.9 for the fourth quarter of 2013, as more Phase 2B well pairs have been converted to production mode.

During the first quarter of 2014, the continued implementation of MEG's marketing strategy enabled the Corporation to broaden its access to downstream markets and thus bypass market access restrictions. For the three months ended March 31, 2014, average bitumen realizations increased compared to the three months ended March 31, 2013 primarily due to the decrease in the average differential between the Corporation's blend sales price and the price of West Texas Intermediate ("WTI"). The WTI price averaged $108.89 per barrel during the first quarter of 2014 compared to an average price of $95.21 per barrel during the first quarter of 2013. The differential between the Corporation's blend sales price and WTI improved to an average of 29.3% during the three months ended March 31, 2014 compared to a differential of 41.9% during the three months ended March 31, 2013.

Net operating costs on a per barrel basis averaged $13.63 per barrel for the three months ended March 31, 2014 compared to $10.44 per barrel for the three months ended March 31, 2013. The increase in net operating costs on a per barrel basis is primarily attributable to the increase in energy operating costs partially offset by an increase in power sales.

- Energy costs increased as natural gas prices increased to an average of $6.09 per thousand cubic feet ("mcf") in the first quarter of 2014 compared to $3.46 per mcf in the first quarter of 2013.
- The Corporation's average realized power price during the first three months of 2014 was $62.26 per megawatt hour compared to $59.92 per megawatt hour for the same period in 2013. Power sales had the effect of offsetting 46% of energy operating costs during the three months ended March 31, 2014 compared to 67% of energy operating costs during the three months ended March 31, 2013.

Cash operating netback for the three months ended March 31, 2014 was $43.51 per barrel compared to $17.90 per barrel for the three months ended March 31, 2013. The increase in cash operating netback is due mainly to the increase in bitumen realizations for the three months ended March 31, 2014 as compared to the three months ended March 31, 2013.

Capital investment for the first quarter of 2014 totaled $343.0 million (including $19.5 million of capitalized interest) compared to a total of $668.9 million for the first quarter of 2013. Capital investment during the first three months of 2014 focused on the initial planning of 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.

The Corporation recognized a net loss of $103.4 million for the three months ended March 31, 2014. The net loss was primarily due to the $159.5 million loss on conversion of the Corporation's U.S. dollar denominated debt. As at March 31, 2014, the Canadian dollar had decreased in value against the U.S. dollar by approximately 4% from its value as at December 31, 2013. The net loss of $71.3 million for the three months ended March 31, 2013 included a foreign exchange loss of $49.3 million on conversion of U.S. dollar denominated debt. The net loss for the first quarter of 2014 was positively impacted by the increase in bitumen realizations and higher sales volumes compared to the first quarter of 2013.

Operating earnings for the three months ended March 31, 2014 were $40.7 million compared to an operating loss of $36.7 million for the three months ended March 31, 2013. The increase in operating earnings is primarily due to the 79% increase in sales volumes, and a 105% increase in bitumen realization per barrel, for the first quarter of 2014 compared to the first quarter of 2013.

Cash flow from operations totalled $157.0 million for the three months ended March 31, 2014. This compared to cash flow from operations of $7.1 million for the three months ended March 31, 2013. Cash flow from operations increased primarily due to higher cash operating netbacks which resulted from the increase in bitumen sales volumes and bitumen realizations. These increases were partially offset by higher general and administrative and interest expense during the three months ended March 31, 2014 as compared to the same period in 2013.

The Corporation's cash and cash equivalents balance totalled $0.9 billion as at March 31, 2014 compared to a cash, cash equivalents and short-term investments balance of $1.8 billion as at March 31, 2013. The Corporation's cash, cash equivalents and short-term investments balances have been impacted by the increases in long-term debt and capital investments over the past year. Long-term debt increased to $4.2 billion as at March 31, 2014 from $2.8 billion as at March 31, 2013. The increase in long-term debt is due to the issuance of senior unsecured notes and the impact of foreign exchange on the U.S. dollar denominated debt. During the fourth quarter of 2013, the Corporation issued US$1.0 billion in aggregate principal amount of 7.0% senior unsecured notes which will mature on March 31, 2024.

As at March 31, 2014, the Corporation's capital resources included $0.9 billion of cash and cash equivalents and an undrawn US$2.0 billion revolving credit facility. As at March 31, 2014, $118.5 million of the revolving credit facility was utilized to support letters of credit.

## 3. OUTLOOK

Annual bitumen production volumes for 2014 are targeted to be in the 60,000 to 65,000 bbls/d range and annual non-energy operating costs are targeted to be in the range of $8 to $10 per barrel.

The Corporation's remaining 2014 capital budget totals approximately $1.5 billion, including $200 million in discretionary capital that is subject to the timing of current and future projects.

## 4. BUSINESS ENVIRONMENT

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

| | 2014 | 2013 | | | |
|---|---|---|---|---|---|
| | Q1 | Q4 | Q3 | Q2 | Q1 |
| **Average Commodity Prices** | | | | | |
| **Crude oil prices** | | | | | |
| West Texas Intermediate (WTI) US$/bbl | 98.68 | 97.43 | 105.83 | 94.22 | 94.37 |
| West Texas Intermediate (WTI) C$/bbl | 108.89 | 102.08 | 109.90 | 96.42 | 95.21 |
| Western Canadian Select (WCS) C$/bbl | 83.41 | 68.31 | 91.75 | 76.82 | 63.01 |
| Differential – WTI vs WCS (C$/bbl) | 25.48 | 33.77 | 18.15 | 19.60 | 32.20 |
| Differential – WTI vs WCS (%) | 23.4% | 33.1% | 16.5% | 20.3% | 33.8% |
| **Natural gas prices** | | | | | |
| AECO (C$/mcf) | 5.69 | 3.52 | 2.42 | 3.51 | 3.18 |
| **Electric power prices** | | | | | |
| Alberta power pool (C$/MWh) | 60.58 | 48.60 | 83.61 | 123.41 | 65.26 |
| **Foreign exchange rates** | | | | | |
| C$ equivalent of 1 US$ - average | 1.1035 | 1.0477 | 1.0385 | 1.0233 | 1.0089 |
| C$ equivalent of 1 US$ - period end | 1.1053 | 1.0636 | 1.0285 | 1.0512 | 1.0156 |

The price of WTI is the current benchmark for Canadian crude oil, as it reflects mid-continent North American prices and its Canadian dollar equivalent is the basis for determining royalties on the Corporation's bitumen sales. The WTI price averaged US$98.68 per barrel for the three months ended March 31, 2014 compared to US$94.37 per barrel for the three months ended March 31, 2013.

Western Canadian Select ("WCS") is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. WCS typically trades at a differential below the WTI benchmark price. The WTI to WCS differential averaged 23.4% for the first quarter of 2014 compared to 33.8% for the first quarter 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 anticipated to relieve 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 $5.69 per mcf for the first three months of 2014 compared to $3.18 per mcf for the first three months of 2013. The increase in natural gas prices during the first quarter of 2014 compared to the first quarter of 2013 is due to increased demand as a result of the extremely cold weather experienced throughout much of Canada and the eastern United States during the first quarter of 2014.

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 $60.58 per megawatt hour during the three months ended March 31, 2014 compared to an average price of $65.26 per megawatt hour for the three months ended March 31, 2013.

Changes in the value of the Canadian dollar relative to the U.S. dollar have an impact on the Corporation's bitumen revenues, as 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 March 31, 2014, the Canadian dollar, at a rate of 1.1053, had decreased in value by approximately 4% against the U.S. dollar compared to its value as at December 31, 2013, when the rate was 1.0636.

## 5. RESULTS OF OPERATIONS

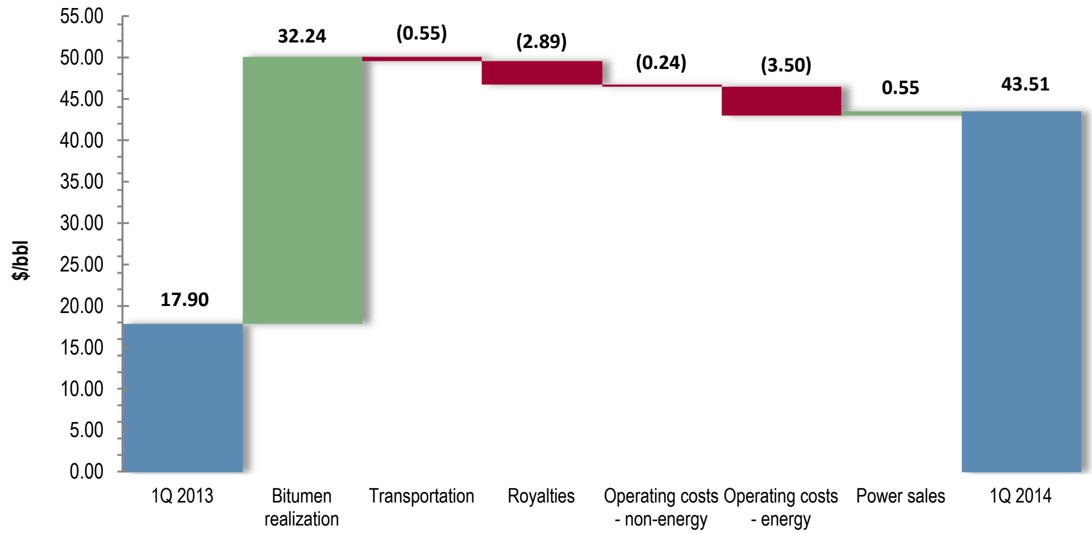
| | Three months ended March 31 | |
|---|---|---|
| | **2014** | **2013** |
| Bitumen production – bbls/d | 58,643 | 32,531 |
| Bitumen sales – bbls/d | 58,089 | 32,393 |
| Steam to oil ratio (SOR) | 2.5 | 2.5 |

### Production

Production for the three months ended March 31, 2014 averaged 58,643 bbls/d compared to 32,531 bbls/d for the three months ended March 31, 2013. The increase in production volumes in 2014 compared to 2013 is due to the implementation of RISER on Christina Lake Phases 1 and 2 and the start-up of Phase 2B. The implementation of the RISER initiative within Phases 1 and 2 has expanded the steam generation capacity and improved reservoir efficiency, 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 ongoing ramp-up of Phase 2B, along with the success achieved from applying RISER to Phases 1 and 2, MEG anticipates reaching a near-term production target from Christina Lake Phases 1, 2 and 2B of 80,000 bbls/d by 2015.

The Corporation's average SOR was 2.5 for the three months ended March 31, 2014 and March 31, 2013. The Corporation continues to focus on increasing production and improving efficiency of current production through a lower SOR, which is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The average SOR has decreased throughout the first quarter of 2014, compared to an average SOR of 2.9 for the fourth quarter of 2013, as more Phase 2B well pairs have been converted to production mode. Each new well pair requires steam preheating prior to conversion to production mode. Once well pairs commence production, the SOR generally begins to decrease.

## Cash Operating Netback – Three months ended March 31, 2014 versus March 31, 2013:




The following table summarizes the Corporation's cash operating netback for the three months ended March 31:

| | 2014 | | 2013 | |
|---|---|---|---|---|
| | **$000** | **$ per bbl** | **$000** | **$ per bbl** |
| Bitumen realization[1] | 325,620 | 62.28 | 87,589 | 30.04 |
| Transportation[2] | (3,512) | (0.67) | (360) | (0.12) |
| Royalties | (23,383) | (4.47) | (4,602) | (1.58) |
| **Net bitumen revenue** | **298,725** | **57.14** | **82,627** | **28.34** |
| Operating costs – non-energy | (47,312) | (9.05) | (25,682) | (8.81) |
| Operating costs – energy | (44,078) | (8.43) | (14,359) | (4.93) |
| Power sales | 20,131 | 3.85 | 9,616 | 3.30 |
| **Net operating costs** | **(71,259)** | **(13.63)** | **(30,425)** | **(10.44)** |
| **Cash operating netback[3]** | **227,466** | **43.51** | **52,202** | **17.90** |

(1) *Net of diluent costs. For further details, refer to the "Bitumen Realization" section.*

(2) *Net of third-party recoveries on diluent transportation arrangements. For further details, refer to the "Transportation" section.*

(3) *Cash operating netbacks are calculated by deducting the related diluent, transportation, field operating costs and royalties from proprietary sales volumes and power revenues. Netbacks on a per-unit basis are calculated by dividing related production revenue, costs and royalties by bitumen sales volumes. Netbacks do not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. This non-IFRS measurement is widely used in the oil and gas industry as a supplemental measure of the Corporation's efficiency and its ability to fund future growth through capital expenditures. "Cash operating netback is reconciled to "Net income (loss)", the nearest IFRS measure, under the heading "NON-IFRS MEASUREMENTS".*

### Bitumen Realization

Bitumen produced at the Christina Lake Project is mixed with purchased diluent and marketed as a heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Bitumen realization as discussed in this document represents the Corporation's realized proprietary blend sales revenues, net of the cost of diluent.

| | Three months ended March 31 | |
|---|---|---|
| **($000)** | **2014** | **2013** |
| Blend sales – proprietary | 601,828 | 241,800 |
| Cost of diluent | (276,208) | (154,211) |
| Bitumen realization | 325,620 | 87,589 |

Blend sales for the three months ended March 31, 2014 were $601.8 million compared to $241.8 million for the three months ended March 31, 2013. The increase in blend sales in the first quarter of 2014 compared to the first quarter of 2013 is due to a 79% increase in sales volumes combined with a 39% increase in the average realized price. Sales volumes have increased as a result of the increase in production volumes due to the start-up of Phase 2B and the implementation of RISER on Christina Lake Phases 1 and 2. Blend sales averaged $76.96 per barrel during the three months ended March 31, 2014 compared to $55.24 per barrel for the three months ended March 31, 2013.

The cost of diluent for the three months ended March 31, 2014 was $276.2 million compared to $154.2 million for the three months ended March 31, 2013. The total cost of diluent increased primarily due to the higher volumes of diluent purchased as a result of increased blend sales. The Corporation's average cost of diluent was $106.57 per barrel during the three months ended March 31, 2014 compared to $105.51 per barrel during the three months ended March 31, 2013.

**Transportation**

Transportation costs, which include MEG's share of the operating costs for the Access Pipeline and the Stonefell Terminal, net of third party recoveries, resulted in an expense of $3.5 million for the three months ended March 31, 2014 compared to $0.4 million for the three months ended March 31, 2013. The Corporation recognized third-party recoveries of $9.4 million during the three months ended March 31, 2014 compared to $5.4 million during the three months ended March 31, 2013. On a per barrel basis, transportation costs averaged $0.67 per barrel for the three months ended March 31, 2014 compared to $0.12 per barrel for the three months ended March 31, 2013. The increase in transportation costs is primarily due to the terminal fees associated with the Corporation's use of unit-train rail shipments in 2014.

**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 $23.4 million for the three months ended March 31, 2014 compared to $4.6 million for the three months ended March 31, 2013. The increase in royalties for the three months ended March 31, 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 $4.47 per barrel during the first three months of 2014 compared to $1.58 per barrel for the first three months of 2013. The Corporation's royalty rate, expressed as a percentage of bitumen realizations, averaged 7.2% for the three months ended March 31, 2014 compared to 5.3% for the three months ended March 31, 2013.

### Operating Costs

Non-energy operating costs were $47.3 million for the three months ended March 31, 2014 compared to $25.7 million for the three months ended March 31, 2013. The increase in non-energy operating costs is primarily attributable to higher sales volumes and higher materials and labour costs associated with the Phase 2B ramp-up. Despite incremental initial Phase 2B ramp-up costs, non-energy operating costs averaged $9.05 per barrel for the three months ended March 31, 2014 compared to $8.81 per barrel for the same period in 2013.

Energy related operating costs were $44.1 million for the three months ended March 31, 2014 compared to $14.4 million for the three months ended March 31, 2013. On a per barrel basis, energy related operating costs averaged $8.43 per barrel for the three months ended March 31, 2014 compared to $4.93 per barrel for the same period in 2013. The increase in energy related operating costs per barrel is primarily the result of higher natural gas prices due to increased demand as a result of the extremely cold weather experienced throughout much of Canada and the eastern United States during the first quarter of 2014. Natural gas prices averaged $6.09 per mcf during the first quarter of 2014 compared to $3.46 per mcf for the first quarter of 2013.

### Power Sales

The Corporation currently 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 sales were $20.1 million for the three months ended March 31, 2014 compared to $9.6 million for the three months ended March 31, 2013. The increase in power sales for the first quarter of 2014 compared to the first quarter of 2013 is due mainly 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 Corporation's average realized power price during the first three months of 2014 was $62.26 per megawatt hour compared to $59.92 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.

## 6. NON-IFRS MEASUREMENTS

The following tables reconcile the non-IFRS measurements "Operating earnings (loss)" and "Cash operating netback" to "Net income (loss)", the nearest IFRS measure, and also reconcile the non-IFRS measurement "Cash flow from operations" to "Net cash provided by (used in) operating activities", the nearest IFRS measure. Operating earnings (loss) 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. 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 operating netback is comprised of proprietary petroleum and power sales less royalties, operating costs, cost of diluent and transportation costs.

| | Three months ended March 31 | |
|---|---|---|
| **($000)** | **2014** | **2013** |
| Net income (loss) | (103,441) | (71,294) |
| Add (deduct): | | |
| Unrealized foreign exchange loss, net of tax[1] | 145,320 | 37,810 |
| Unrealized loss (gain) on derivative financial liabilities, net of tax[2] | (1,220) | (3,228) |
| Operating earnings (loss) | 40,659 | (36,712) |
| Add (deduct): | | |
| Interest income | (3,260) | (5,271) |
| Depletion and depreciation | 81,244 | 44,415 |
| General and administrative | 26,375 | 22,767 |
| Stock-based compensation | 12,622 | 6,955 |
| Research and development | 991 | 1,283 |
| Interest expense | 46,230 | 25,089 |
| Accretion | 1,037 | 1,076 |
| Realized loss on foreign exchange | 2,643 | 1,228 |
| Realized loss on derivative financial liabilities | 1,121 | 1,101 |
| Net marketing activity | 55 | 233 |
| Deferred income tax expense (recovery), operating | 17,749 | (9,962) |
| Cash operating netback | 227,466 | 52,202 |

(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 losses are presented net of a deferred tax expense of $4,720 for the three months ended March 31, 2014 (deferred tax recovery of $3,107 for the three months ended March 31, 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 on derivative liabilities are presented net of a deferred tax expense of $407 for the three months ended March 31, 2014 (deferred tax expense of $1,076 for the three months ended March 31, 2013).*

| | Three months ended March 31 | |
|---|---|---|
| **($000)** | **2014** | **2013** |
| Net cash provided by (used in) operating activities | 39,224 | (24,992) |
| Add: | | |
| Net change in non-cash operating working capital items | 117,763 | 32,063 |
| Cash flow from operations | 156,987 | 7,071 |

### Depletion and Depreciation

Depletion and depreciation expense was $81.2 million for the three months ended March 31, 2014 compared to $44.4 million for the three months ended March 31, 2013. The increase is primarily due to the 79% increase in sales volumes for the first quarter of 2014 compared to the first quarter of 2013. The depletion and depreciation rate for the three months ended March 31, 2014 was $15.54 per barrel compared to $15.24 per barrel for the three months ended March 31, 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 March 31 | |
|---|---|---|
| **($000)** | **2014** | **2013** |
| General and administrative costs | 35,189 | 28,647 |
| Capitalized general and administrative costs | (8,814) | (5,880) |
| General and administrative expense | 26,375 | 22,767 |

General and administrative expense for the three months ended March 31, 2014 was $26.4 million compared to $22.8 million for the three months ended March 31, 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 March 31 | |
|---|---|---|
| **($000)** | **2014** | **2013** |
| Stock-based compensation costs | 15,638 | 8,615 |
| Capitalized stock-based compensation costs | (3,016) | (1,660) |
| Stock-based compensation expense | 12,622 | 6,955 |

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 $12.6 million for the three months ended March 31, 2014 compared to $7.0 million for the three months ended March 31, 2013. The increase in stock-based compensation is due to the increased number of share based awards granted and as a result of the growth in the Corporation's professional staff. The Corporation capitalizes a portion of stock-based compensation expense associated with capitalized salaries and benefits. The Corporation capitalized $3.0 million of stock-based compensation for the three months ended March 31, 2014 compared to $1.7 million during the three months ended March 31, 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 $1.0 million for the three months ended March 31, 2014 compared to $1.3 million for the three months ended March 31, 2013.

**Net Finance Expense**

| | Three months ended March 31 | |
|---|---|---|
| **($000)** | **2014** | **2013** |
| Total interest expense | 65,700 | 38,723 |
| Less capitalized interest | (19,470) | (13,634) |
| Net interest expense | 46,230 | 25,089 |
| Accretion on decommissioning provision | 1,037 | 1,076 |
| Unrealized fair value loss (gain) on embedded derivative financial liabilities | (1,110) | (3,075) |
| Unrealized fair value loss (gain) on interest rate swaps | (517) | (1,229) |
| Realized loss on interest rate swaps | 1,121 | 1,101 |
| Net finance expense | 46,761 | 22,962 |

| | | |
|---|---|---|
| Average effective interest rate | 6.2% | 5.8% |

Total interest expense, before capitalization, was $65.7 million for the three months ended March 31, 2014 compared to $38.7 million for the three months ended March 31, 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 $1.1 million for the three months ended March 31, 2014 compared to an unrealized gain of $3.1 million for the same period in 2013. These gains 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 $1.1 million for the three months ended March 31, 2014 and for the three months ended March 31, 2013. In addition, the Corporation recognized an unrealized gain of $0.5 million for the first quarter of 2014 compared to an unrealized gain of $1.2 million for the first quarter of 2013.

**Net Foreign Exchange Gain (Loss)**

| | Three months ended March 31 | |
|---|---|---|
| **($000)** | **2014** | **2013** |
| Foreign exchange gain (loss) on: | | |
| Long-term debt | (159,485) | (49,256) |
| US$ denominated cash and cash equivalents | 18,884 | 8,339 |
| Other | (2,643) | (1,228) |
| Net foreign exchange gain (loss) | (143,244) | (42,145) |

| **C$-US$ exchange rate at** | **March 31, 2014** | **December 31, 2013** | **March 31, 2013** | **December 31, 2012** |
|---|---|---|---|---|
| C$ equivalent of 1 US$ | 1.1053 | 1.0636 | 1.0156 | 0.9949 |

The Corporation recognized a net foreign exchange loss of $143.2 million for the three months ended March 31, 2014 compared to a loss of $42.1 million for the three months ended March 31, 2013. The increase in the net foreign exchange loss is due to the increase in U.S. dollar denominated debt outstanding during the first quarter of 2014 compared to the first quarter of 2013, combined with the decline in the value of the Canadian dollar compared to the U.S. dollar. During the first quarter of 2014, the Canadian dollar weakened in value compared to the U.S. dollar by approximately 4%. In comparison, the Canadian dollar weakened in value by approximately 2% during the first quarter of 2013.

**Net Marketing Activity**

| | Three months ended March 31 | |
|---|---|---|
| **($000)** | **2014** | **2013** |
| Sales of purchased product | 71,607 | 5,778 |
| Purchased product and storage | (71,662) | (6,011) |
| Net marketing activity | (55) | (233) |

Net marketing activity includes the Corporation's activities to secure pipeline capacity and to pursue opportunities to move product to a wider range of markets through the development of proprietary transportation and storage facilities.

**Income Taxes**

The Corporation recognized a deferred income tax expense of $22.9 million for the three months ended March 31, 2014 compared to a deferred income tax recovery of $12.0 million for the three months ended March 31, 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 March 31, 2014, the non-taxable loss was $79.7 million compared to a non-taxable loss of $24.6 million for the three months ended March 31, 2013.

- As at March 31, 2014, the Corporation had not recognized the tax benefit related to $169.6 million in unrealized taxable capital foreign exchange losses.

- Non-taxable stock-based compensation expense for the three months ended March 31, 2014 was $12.6 million compared to $7.0 million for the three months ended March 31, 2013.

The Corporation is not currently taxable. As of March 31, 2014, the Corporation had approximately $6.9 billion of available tax pools and had recognized a deferred income tax liability of $116.7 million. In addition, at March 31, 2014, the Corporation had $651.3 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

## 7. 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)** | **Q1** | **Q4** | **Q3** | **Q2** | **Q1** | **Q4** | **Q3** | **Q2** |
| Revenue | 679.6 | 350.3 | 401.8 | 324.4 | 258.0 | 297.6 | 213.7 | 259.7 |
| Net income (loss) | (103.4) | (148.2) | 115.4 | (62.3) | (71.3) | (18.7) | 47.5 | (29.5) |
| Per share - basic | (0.46) | (0.67) | 0.52 | (0.28) | (0.32) | (0.09) | 0.24 | (0.15) |
| Per share - diluted | (0.46) | (0.67) | 0.51 | (0.28) | (0.32) | (0.09) | 0.24 | (0.15) |

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 2013 and the third quarter of 2012 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 and implementation of RISER on Phases 1 and 2, which has allowed additional wells to be placed into production;
- fluctuations in natural gas pricing;
- fluctuations in blend sales pricing due to changes in the price of WTI and the differential between WTI and the Corporation's AWB;
- 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; and
- scheduled annual plant maintenance activities performed in May 2013 and September 2012.

## 8. CAPITAL INVESTING

| | Three months ended March 31 | |
|---|---|---|
| **($000)** | **2014** | **2013** |
| Intraphase growth | 72,791 | 103,476 |
| Portfolio growth | | |
| Christina Lake | 49,495 | 65,995 |
| Resource development | 59,178 | 27,958 |
| Growth infrastructure | 28,990 | 124,715 |
| Enhancements and other | 10,033 | 137,535 |
| Total portfolio growth | 147,696 | 356,203 |
| Marketing initiatives | | |
| Access pipeline | 73,226 | 90,811 |
| Other | 2,118 | 69,375 |
| Total marketing initiatives | 75,344 | 160,186 |
| Sustaining and maintenance | 16,285 | 10,512 |
| Other | 11,417 | 24,921 |
| **Total base capital investment** | **323,533** | **655,298** |
| Capitalized interest | 19,470 | 13,634 |
| **Total cash capital investment** | **343,003** | **668,932** |
| Non-cash | 10,562 | 12,939 |
| **Total capital investment** | **353,565** | **681,871** |

MEG's total capital investment for the three months ended March 31, 2014 was $353.6 million (including capitalized interest of $19.5 million and non-cash items of $10.6 million) in comparison to $681.9 million (including capitalized interest of $13.6 million and non-cash items of $12.9 million) for the three months ended March 31, 2013.

MEG invested $72.8 million during the three months ended March 31, 2014 on RISER 2B. The RISER 2B initiative 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 RISER 2B investment was directed towards engineering and the procurement of long lead-time items. The investment during the first quarter included the drilling of six infill wells.

During the first three months of 2014, the Corporation invested a total of $49.5 million in engineering and the procurement of long lead-time items for future Christina Lake Phase expansions.

Resource development investment of $59.2 million during the first quarter of 2014 included the drilling of 80 stratigraphic wells to support horizontal well placement and 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 $29.0 million was invested in the Corporation's growth infrastructure during the three months ended March 31, 2014. Growth infrastructure investment was directed towards the construction of a sulphur recovery plant at Christina Lake and the installation of electrical submersible pumps.

A total of $75.3 million was invested during the three months ended March 31, 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. Regulatory approval of the pipeline expansion was received in 2012 and over 80% of the expansion for the 300 kilometer pipeline has been installed. The expansion is expected to be complete and in service by the second half of 2014.

The Corporation capitalizes interest associated with qualifying assets. A total of $19.5 million in interest was capitalized during the three months ended March 31, 2014 compared to $13.6 million during the three months ended March 31, 2013.

Non-cash capital investment for the three months ended March 31, 2014 included a $7.5 million increase in the provision for future reclamation and decommissioning of the Corporation's property, plant and equipment and $3.0 million in capitalized stock-based compensation.

## 9. LIQUIDITY AND CAPITAL RESOURCES

| | As at March 31 | |
|---|---|---|
| **($000)** | **2014** | **2013** |
| Cash, cash equivalents and short-term investments | 890,335 | 1,803,338 |
| Senior secured term loan (March 31, 2014 – US$1.271 billion; December 31, 2013 – US$1.275 billion; due 2020) | 1,405,113 | 1,304,284 |
| US$2.0 billion revolver; due 2018 | - | - |
| 6.5% senior unsecured notes (US$750.0 million; due 2021) | 828,975 | 761,700 |
| 6.375% senior unsecured notes (US$800.0 million; due 2023) | 884,240 | 812,480 |
| 7.0% senior unsecured notes (US$1.0 billion; due 2024) | 1,105,300 | - |
| Total debt[(1)] | 4,223,628 | 2,878,464 |
| Shareholders' equity | 4,705,966 | 4,817,253 |
| Total book capitalization[(2)] | 8,929,594 | 7,695,717 |
| Total debt/book capitalization[(2)] | 47.3% | 37.4% |

*(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-IFRS 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 March 31, 2014 and 2013.*

*(2) Non-IFRS measurements and related metrics that use total debt plus shareholders' equity.*

### Capital Resources

As at March 31, 2014, the Corporation's available capital resources included $0.9 billion of cash and cash equivalents and an additional undrawn US$2.0 billion syndicated revolving credit facility. As at March 31, 2014, $118.5 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 cost of the transaction has been deferred and is 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 cost of the transaction has been deferred and is 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 cost of the transaction has been deferred and is 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 March 31 | |
|---|---|---|
| **($000)** | **2014** | **2013** |
| Net cash provided by (used in): | | |
| Operating activities | 39,224 | (24,992) |
| Investing activities | (344,886) | (80,326) |
| Financing activities | (1,959) | 306,946 |
| Foreign exchange gains on cash and cash equivalents held in foreign currency | 18,884 | 8,339 |
| **Change in cash and cash equivalents** | **(288,737)** | **209,967** |

**Cash Flows – Operating Activities**

Net cash provided by operating activities totaled $39.2 million for the three months ended March 31, 2014 compared to a net use of cash of $25.0 million for the three months ended March 31, 2013. The increase in cash flows from operating activities is primarily due to increased bitumen realizations and blend sales revenues partially offset by higher operating expenses, higher general and administrative expense and higher interest expense. Net cash provided by operating activities in the first quarter of 2014 has been reduced to include a $117.8 million increase in non-cash working capital items. Net use of cash in the first quarter of 2013 includes a $32.1 million increase in non-cash working capital items.

**Cash Flows – Investing Activities**

Net cash used for investing activities during the first quarter of 2014 primarily consisted of $343.0 million in cash capital investment (refer to the "CAPITAL INVESTING" section of this MD&A for further details). Net cash used for investing activities during the first quarter of 2013 consisted of $668.9 million in cash capital investment offset by a $590.5 million increase in non-cash investing working capital primarily related to the decrease in short-term investments.

**Cash Flows – Financing Activities**

Net cash used in financing activities for the three months ended March 31, 2014 consisted of $3.6 million of debt principal repayment partially offset by $1.6 million of proceeds received from the exercise of stock options.

Net cash provided by financing activities for the three months ended March 31, 2013 consisted of $300.8 million in net proceeds from the increase in the senior secured term loan and $9.5 million in proceeds received from the exercise of stock options. These amounts were partially offset by $3.3 million of debt principal repayment on the senior secured term loan.

## 10. SHARES OUTSTANDING

| | |
|---|---|
| Common shares | 222,575,191 |
| Convertible securities | |
| Stock options outstanding - exercisable and unexercisable | 8,563,584 |
| RSUs and PSUs outstanding | 2,566,273 |

As at April 21, 2014, the Corporation had 222,687,857 common shares, 8,414,618 stock options and 2,564,421 restricted share units and performance share units outstanding.

## 11. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

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

| ($000) | Total | Less than 1 year | 1 - 3 years | 4 - 5 years | More than 5 years |
|---|---|---|---|---|---|
| Long-term debt(1) | 4,223,628 | 10,777 | 28,738 | 28,738 | 4,155,375 |
| Interest on long-term debt(1) | 1,951,330 | 239,997 | 478,478 | 476,323 | 756,532 |
| Decommissioning obligation(2) | 587,102 | 4,673 | 5,401 | - | 577,028 |
| Transportation and storage(3) | 3,711,751 | 130,699 | 316,068 | 454,165 | 2,810,819 |
| Contracts and purchase orders(4) | 684,166 | 398,278 | 104,073 | 44,373 | 137,442 |
| Operating leases(5) | 411,396 | 12,334 | 29,935 | 57,108 | 312,019 |
| | 11,569,373 | 796,758 | 962,693 | 1,060,707 | 8,749,215 |

(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 March 31, 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 2028.*

(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.*

## 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 9, Financial Instruments is intended to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 will be published in three phases. The first two phases, which have been published, address classification and measurement requirements for financial assets and liabilities and hedge accounting. The third phase of the project will address impairment of financial instruments.

IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, when the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. The Corporation does not currently apply hedge accounting to any of its risk management contracts.

The IASB has decided to defer the mandatory effective date of IFRS 9 and the mandatory effective date will be left open pending the finalization of the impairment requirements. IFRS 9 will still be available for early adoption. The impact of the new standard on the Corporation's consolidated financial statements will not be known until the project is complete.

## 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 month periods ended March 31, 2014 or March 31, 2013, other than compensation of key management personnel.

## 15. OFF-BALANCE SHEET ARRANGEMENTS

At March 31, 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, 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; the anticipated capital requirements, timing for receipt of regulatory approvals, development plans, timing for completion, commissioning and start-up, capacities and performance of the Access Pipeline expansion, the RISER initiative, the Stonefell Terminal, third party barging and rail facilities, the future phases and expansions of the Christina Lake Project, the Surmont Project and potential projects on the Growth Properties; 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 (including the amount, nature and sources of funding thereof), 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 the Christina Lake Project and the development of the Corporation's other projects and facilities. 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.

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. For more information regarding forward-looking information see "Notice Regarding Forward Looking Information", "Risk Factors" and "Regulatory Matters" within MEG's Annual Information Form dated March 5, 2014 (the "AIF") along with MEG's other public disclosure documents. Copies of the AIF and MEG's other public disclosure documents are available through the SEDAR website (www.sedar.com) or by contacting MEG's investor relations department.

### 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-IFRS Financial Measures**

This document includes references to financial measures commonly used in the crude oil and natural gas industry, such as net bitumen revenue, operating earnings, cash flow from operations and cash operating netback. These financial measures are not defined by IFRS as issued by the International Accounting Standards Board and therefore are referred to as non-IFRS measures. The non-IFRS measures used by the Corporation may not be comparable to similar measures presented by other companies. The Corporation uses these non-IFRS measures to help evaluate its performance. Management considers net bitumen revenue, operating earnings and cash operating netback important measures as they indicate profitability relative to current commodity prices. Management uses cash flow from operations to measure the Corporation's ability to generate funds to finance capital expenditures and repay debt. These non-IFRS measures should not be considered as an alternative to or more meaningful than net income (loss) or net cash provided by (used in) operating activities, as determined in accordance with IFRS, as an indication of the Corporation's performance. The non-IFRS operating earnings and cash operating netback measures are reconciled to net income (loss), while cash flow from operations is reconciled to net cash provided by (used in) operating activities.

## 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** | **Q1** | **Q4** | **Q3** | **Q2** | **Q1** | **Q4** | **Q3** | **Q2** |
| **FINANCIAL ($000 unless specified)** | | | | | | | | |
| Net income (loss)[1] | (103,441) | (148,182) | 115,383 | (62,312) | (71,294) | (18,740) | 47,474 | (29,534) |
| Per share, diluted | (0.46) | (0.67) | 0.51 | (0.28) | (0.32) | (0.09) | 0.24 | (0.15) |
| Operating earnings (loss) | 40,659 | (32,685) | 56,171 | 13,612 | (36,712) | (538) | (12,883) | 11,134 |
| Per share, diluted | 0.18 | (0.15) | 0.25 | 0.06 | (0.16) | 0.00 | (0.07) | 0.06 |
| Cash flow from operations | 156,987 | 22,648 | 144,521 | 79,184 | 7,071 | 56,106 | 24,442 | 59,975 |
| Per share, diluted | 0.70 | 0.10 | 0.64 | 0.35 | 0.03 | 0.27 | 0.12 | 0.30 |
| Capital investment | 353,565 | 394,370 | 477,335 | 674,576 | 681,871 | 500,223 | 406,526 | 341,840 |
| Cash, cash equivalents and short-term investments | 890,335 | 1,179,072 | 647,096 | 1,203,457 | 1,803,338 | 2,007,841 | 1,607,036 | 1,111,150 |
| Working capital | 877,069 | 1,045,607 | 365,676 | 731,290 | 1,298,955 | 1,655,915 | 1,307,325 | 902,424 |
| Long-term debt | 4,162,209 | 4,004,575 | 2,857,740 | 2,923,382 | 2,823,207 | 2,488,609 | 2,461,676 | 1,751,552 |
| Shareholders' equity | 4,705,966 | 4,788,430 | 4,919,407 | 4,771,616 | 4,817,253 | 4,870,534 | 4,092,556 | 4,027,652 |
| **BUSINESS ENVIRONMENT** | | | | | | | | |
| West Texas Intermediate (WTI) US$/bbl | 98.68 | 97.43 | 105.83 | 94.22 | 94.37 | 88.18 | 92.22 | 93.49 |
| C$ equivalent of 1US$ - average | 1.1035 | 1.0477 | 1.0385 | 1.0233 | 1.0089 | 0.9913 | 0.9948 | 1.0102 |
| Differential – WTI vs blend ($/bbl) | 31.93 | 41.48 | 23.50 | 26.17 | 39.96 | 26.13 | 29.54 | 29.83 |
| Differential – WTI vs blend (%) | 29.3% | 40.6% | 21.4% | 27.1% | 41.9% | 29.9% | 32.2% | 31.6% |
| Natural gas – AECO ($/mcf) | 5.69 | 3.52 | 2.42 | 3.51 | 3.18 | 3.20 | 2.27 | 1.89 |
| **OPERATIONAL ($/bbl unless specified)** | | | | | | | | |
| Bitumen production – bbls/d | 58,643 | 42,251 | 34,246 | 32,144 | 32,531 | 32,292 | 23,941 | 30,429 |
| Bitumen sales – bbls/d | 58,089 | 35,990 | 34,256 | 32,175 | 32,393 | 32,722 | 23,876 | 30,229 |
| Diluent usage – bbls/d | 28,797 | 16,680 | 13,032 | 14,176 | 16,239 | 14,810 | 9,466 | 13,800 |
| Blend sales – bbls/d | 86,886 | 52,670 | 47,288 | 46,351 | 48,632 | 47,532 | 33,342 | 44,029 |
| Steam to oil ratio (SOR) | 2.5 | 2.9 | 2.5 | 2.3 | 2.5 | 2.4 | 2.5 | 2.4 |
| Blend sales | 76.96 | 60.60 | 86.40 | 70.25 | 55.24 | 61.29 | 62.19 | 64.62 |
| Cost of diluent | (14.68) | (22.38) | (12.07) | (16.27) | (25.20) | (15.62) | (15.70) | (19.03) |
| Bitumen realization | 62.28 | 38.22 | 74.33 | 53.98 | 30.04 | 45.67 | 46.49 | 45.59 |
| Transportation – net | (0.67) | (0.51) | (0.20) | (0.17) | (0.12) | (0.05) | (0.93) | (0.03) |
| Royalties | (4.47) | (2.71) | (5.14) | (3.03) | (1.58) | (2.23) | (2.10) | (2.84) |
| Operating costs – non-energy | (9.05) | (8.09) | (9.20) | (10.00) | (8.81) | (8.70) | (15.23) | (7.79) |
| Operating costs – energy | (8.43) | (5.38) | (3.32) | (4.85) | (4.93) | (4.65) | (3.22) | (2.62) |
| Power sales | 3.85 | 2.25 | 3.12 | 6.00 | 3.30 | 4.40 | 2.84 | 1.86 |
| **Cash operating netback** | **43.51** | **23.78** | **59.59** | **41.93** | **17.90** | **34.44** | **27.85** | **34.17** |
| Power sales price (C$/MWh) | 62.26 | 44.63 | 75.96 | 138.96 | 59.92 | 79.62 | 57.99 | 36.85 |
| Power sales (MW/h) | 150 | 76 | 59 | 58 | 74 | 75 | 49 | 64 |
| Depletion and depreciation rate per bbl | 15.54 | 15.56 | 15.54 | 15.11 | 15.24 | 14.79 | 13.45 | 13.09 |
| **COMMON SHARES** | | | | | | | | |
| Shares outstanding, end of period (000) | 222,575 | 222,507 | 222,489 | 221,829 | 221,256 | 220,190 | 195,248 | 194,326 |
| Volume traded (000) | 32,102 | 33,400 | 28,403 | 43,789 | 28,495 | 20,370 | 13,578 | 21,560 |
| Common share price ($) | | | | | | | | |
| High | 37.84 | 36.00 | 36.69 | 32.98 | 35.67 | 38.74 | 41.90 | 43.96 |
| Low | 29.41 | 28.60 | 28.81 | 25.50 | 30.89 | 30.25 | 35.20 | 32.92 |
| Close (end of period) | 37.36 | 30.61 | 35.54 | 28.83 | 32.61 | 30.44 | 37.39 | 36.49 |

(1) Includes 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 | March 31, 2014 | December 31, 2013 |
|---|---|---|---|
| **Assets** | | | |
| Current assets | | | |
| Cash and cash equivalents | 20 | **$ 890,335** | $ 1,179,072 |
| Trade receivables and other | 6 | **276,361** | 186,183 |
| Inventories | 7 | **146,864** | 129,943 |
| | | **1,313,560** | 1,495,198 |
| Non-current assets | | | |
| Property, plant and equipment | 8 | **7,522,056** | 7,254,951 |
| Exploration and evaluation assets | 9 | **582,243** | 579,497 |
| Other intangible assets | 10 | **65,874** | 63,205 |
| Other assets | 11 | **55,202** | 54,890 |
| **Total assets** | | **$ 9,538,935** | $ 9,447,741 |
| **Liabilities** | | | |
| Current liabilities | | | |
| Accounts payable and accrued liabilities | 12 | **$ 402,772** | $ 416,288 |
| Current portion of long-term debt | 13 | **14,369** | 13,827 |
| Current portion of provisions and other liabilities | 14 | **19,350** | 19,477 |
| | | **436,491** | 449,592 |
| Non-current liabilities | | | |
| Long-term debt | 13 | **4,147,840** | 3,990,748 |
| Provisions and other liabilities | 14 | **131,975** | 125,177 |
| Deferred income tax liability | | **116,663** | 93,794 |
| Total liabilities | | **4,832,969** | 4,659,311 |
| Commitments and contingencies | 22 | | |
| **Shareholders' equity** | | | |
| Share capital | 15 | **4,753,584** | 4,751,374 |
| Contributed surplus | 15 | **141,731** | 126,666 |
| Deficit | | **(195,934)** | (92,493) |
| Accumulated other comprehensive income | | **6,585** | 2,883 |
| Total shareholders' equity | | **4,705,966** | 4,788,430 |
| **Total liabilities and shareholders' equity** | | **$ 9,538,935** | $ 9,447,741 |

*The accompanying notes are an integral part of these condensed 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 March 31 | | |
|---|---|---|---|---|---|
| | Note | | **2014** | | 2013 |
| Petroleum revenue, net of royalties | 16 | $ | **650,052** | $ | 242,976 |
| Other revenue | 17 | | **29,510** | | 14,993 |
| | | | **679,562** | | 257,969 |
| Diluent and transportation | 18 | | **289,098** | | 159,948 |
| Purchased product and storage | | | **71,662** | | 6,011 |
| Operating expenses | | | **91,390** | | 40,041 |
| Depletion and depreciation | 8, 10 | | **81,244** | | 44,415 |
| General and administrative | | | **26,375** | | 22,767 |
| Stock-based compensation | 15 | | **12,622** | | 6,955 |
| Research and development | | | **991** | | 1,283 |
| | | | **573,382** | | 281,420 |
| Revenues less operating expenses | | | **106,180** | | (23,451) |
| Other income (expense) | | | | | |
| Interest and other income | | | **3,260** | | 5,271 |
| Foreign exchange loss, net | | | **(143,244)** | | (42,145) |
| Net finance expense | 19 | | **(46,761)** | | (22,962) |
| | | | **(186,745)** | | (59,836) |
| Loss before income taxes | | | **(80,565)** | | (83,287) |
| Deferred income tax expense (recovery) | | | **22,876** | | (11,993) |
| Net loss | | | **(103,441)** | | (71,294) |
| Other comprehensive income | | | | | |
| Foreign currency translation adjustment | | | **3,702** | | 52 |
| Comprehensive income (loss) for the period | | $ | **(99,739)** | $ | (71,242) |
| Net earnings (loss) per share | | | | | |
| Basic | 21 | $ | **(0.46)** | $ | (0.32) |
| Diluted | 21 | $ | **(0.46)** | $ | (0.32) |

*The accompanying notes are an integral part of these condensed 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 (AOCI) | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| Balance at January 1, 2014 | | **$ 4,751,374** | **$ 126,666** | **$ (92,493)** | **$ 2,883** | **$ 4,788,430** |
| Stock options exercised | 15 | **2,130** | **(493)** | **-** | - | **1,637** |
| Stock-based compensation | 15 | **-** | **15,638** | **-** | - | **15,638** |
| RSUs vested and released | 15 | **80** | **(80)** | **-** | - | **-** |
| Net loss | | **-** | **-** | **(103,441)** | - | **(103,441)** |
| Other comprehensive income | | **-** | **-** | **-** | **3,702** | **3,702** |
| **Balance at March 31, 2014** | | **$ 4,753,584** | **$ 141,731** | **$ (195,934)** | **$ 6,585** | **$ 4,705,966** |
| | | | | | | |
| 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 | | 11,726 | (2,711) | - | - | 9,015 |
| Stock-based compensation | | - | 8,614 | - | - | 8,614 |
| Net loss | | - | - | (71,294) | - | (71,294) |
| Other comprehensive income | | - | - | - | 52 | 52 |
| Balance at March 31, 2013 | | $ 4,706,436 | $ 108,122 | $ 2,618 | $ 77 | $ 4,817,253 |

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

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

| | | Three months ended March 31 | |
|---|---|---|---|
| | Note | **2014** | 2013 |
| **Cash provided by (used in):** | | | |
| Operating activities | | | |
| Net loss | | **$ (103,441)** | $ (71,294) |
| Adjustments for: | | | |
| Depletion and depreciation | 8, 10 | **81,244** | 44,415 |
| Stock-based compensation | 15 | **12,622** | 6,955 |
| Unrealized loss on foreign exchange | | **140,601** | 40,917 |
| Unrealized (gain) on derivative financial liabilities | 19 | **(1,627)** | (4,304) |
| Deferred income tax expense (recovery) | | **22,876** | (11,993) |
| Other | | **4,712** | 2,375 |
| Net change in non-cash operating working capital items | 20 | **(117,763)** | (32,063) |
| **Net cash provided by (used in) operating activities** | | **39,224** | (24,992) |
| Investing activities | | | |
| Capital investments | | **(343,003)** | (668,932) |
| Other | | **1,127** | (1,888) |
| Net change in non-cash investing working capital items | 20 | **(3,010)** | 590,494 |
| **Net cash provided by (used in) investing activities** | | **(344,886)** | (80,326) |
| Financing activities | | | |
| Issue of shares | 15 | **1,637** | 9,457 |
| Issue of long-term debt, net of debt issue costs | | **-** | 300,790 |
| Repayment of long-term debt | 13 | **(3,596)** | (3,301) |
| **Net cash provided by (used in) financing activities** | | **(1,959)** | 306,946 |
| **Effect of exchange rate changes on cash and cash equivalents held in foreign currency** | | **18,884** | 8,339 |
| Change in cash and cash equivalents | | **(288,737)** | 209,967 |
| Cash and cash equivalents, beginning of period | | **1,179,072** | 1,474,843 |
| Cash and cash equivalents, end of period | | **$ 890,335** | $ 1,684,810 |

*The accompanying notes are an integral part of these condensed 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 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 April 29, 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 9, Financial Instruments, is intended to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 will be published in three phases. The first two phases, which have been published, address classification and measurement requirements for financial assets and liabilities and hedge accounting. The third phase of the project will address impairment of financial instruments.

IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, when the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. The Corporation does not currently apply hedge accounting to any of its risk management contracts.

The IASB has decided to defer the mandatory effective date of IFRS 9 and the mandatory effective date will be left open pending the finalization of the impairment requirements. IFRS 9 will still be available for early adoption. The impact of the new standard on the Corporation's consolidated financial statements will not be known until the project is complete.

## 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 March 31, 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 March 31, 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** | **$ 2,340** | **$ 2,340** | **$ -** | **$ -** | **$ 2,340** |
| **Financial liabilities** | | | | | |
| **Derivative financial liabilities** | **29,354** | **29,354** | **-** | **29,354** | **-** |
| **Long-term debt** | **4,162,209** | **4,365,914** | **4,365,914** | **-** | **-** |

| | | | 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 and foreign exchange rates.

Level 3 fair value measurements are based on unobservable information.

Other assets are comprised of investments in U.S. auction rate securities ("ARS"). The Corporation estimated the fair value of the ARS based on the following: (i) the underlying structure of the notes and the securities; (ii) the present value of future principal and interest payments discounted at rates considered to reflect current market conditions for similar securities; and (iii) consideration of the probabilities of default, based on the quoted credit rating for the respective notes and securities. These estimated fair values could change significantly based on future market conditions.

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. There were no transfers between levels of the fair value hierarchy during the period ended March 31, 2014.

(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 March 31, 2014, there was an unrealized loss on the interest rate swaps of $7.0 million (December 31, 2013 - $7.5 million).

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

[(1)] *London Interbank Offered Rate*

## 6. TRADE RECEIVABLES AND OTHER

| | | **March 31, 2014** | | December 31, 2013 |
|---|---|---|---|---|
| Trade receivables | **$** | **267,416** | $ | 174,935 |
| Deposits and advances | | **5,605** | | 7,908 |
| Current portion of deferred financing costs | | **3,340** | | 3,340 |
| | **$** | **276,361** | $ | 186,183 |

## 7. INVENTORIES

| | March 31, 2014 | December 31, 2013 |
|---|---|---|
| Diluent | **$ 109,221** | $ 84,628 |
| Bitumen blend | **35,516** | 43,358 |
| Materials and supplies | **2,127** | 1,957 |
| | **$ 146,864** | $ 129,943 |

During the period ended March 31, 2014, a total of $276.2 million (2013 - $153.4 million) in inventory product costs were charged to earnings through diluent and transportation.

## 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 | 264,768 | 80,604 | 2,072 | 347,444 |
| **Balance as at March 31, 2014** | **$ 6,758,433** | **$ 1,357,051** | **$ 43,107** | **$ 8,158,591** |

| | Crude oil | Transportation and storage | Corporate assets | Total |
|---|---|---|---|---|
| **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 | 75,287 | 3,776 | 1,276 | 80,339 |
| **Balance as at March 31, 2014** | **$ 588,709** | **$ 35,228** | **$ 12,598** | **$ 636,535** |

| | Crude oil | Transportation and storage | Corporate assets | Total |
|---|---|---|---|---|
| **Carrying Amounts** | | | | |
| As at December 31, 2013 | $ 5,980,243 | $ 1,244,995 | $ 29,713 | $ 7,254,951 |
| **As at March 31, 2014** | **$ 6,169,724** | **$ 1,321,823** | **$ 30,509** | **$ 7,522,056** |

During the three months ended March 31, 2014, the Corporation capitalized $8.8 million (three months ended March 31, 2013 - $5.9 million) of general and administrative costs and $3.0 million (three months ended March 31, 2013 - $1.7 million) of stock-based compensation costs relating to oil sands exploration and development activities. In addition, $19.5 million of interest and finance charges related to the development of capital projects were capitalized during the three months ended March 31, 2014 (three months ended March 31, 2013 - $13.6 million).

## 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 | | 2,746 |
| **Balance as at March 31, 2014** | **$** | **582,243** |

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 March 31, 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 | | 3,375 |
| **Balance as at March 31, 2014** | **$** | **69,584** |

| **Accumulated depreciation** | | |
|---|---|---|
| Balance as at December 31, 2012 | $ | 1,456 |
| Depreciation | | 1,548 |
| Balance as at December 31, 2013 | $ | 3,004 |
| Depreciation | | 706 |
| **Balance as at March 31, 2014** | **$** | **3,710** |

| **Carrying Amounts** | | |
|---|---|---|
| As at December 31, 2013 | $ | 63,205 |
| **As at March 31, 2014** | **$** | **65,874** |

Other intangible assets include the cost to maintain the right to participate in a potential pipeline project and the cost of software that is not an integral part of the related computer hardware.

## 11. OTHER ASSETS

| | March 31, 2014 | December 31, 2013 |
|---|---|---|
| Long-term pipeline linefill[a] | **$ 42,576** | $ 41,517 |
| ARS[b] | **2,340** | 2,252 |
| Deferred financing costs[c] | **13,626** | 14,461 |
| | **58,542** | 58,230 |
| Less current portion of deferred financing costs | **(3,340)** | (3,340) |
| | **$ 55,202** | $ 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 an illiquid asset and is recorded at its fair value based on a discounted cash flow valuation using observable information, with changes in fair value 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

| | March 31, 2014 | December 31, 2013 |
|---|---|---|
| Trade payables | **$ 65,426** | $ 114,752 |
| Accrued liabilities | **325,599** | 244,972 |
| Interest payable | **11,747** | 56,564 |
| | **$ 402,772** | $ 416,288 |

## 13. LONG-TERM DEBT

| | March 31, 2014 | December 31, 2013 |
|---|---|---|
| Senior secured term loan (March 31, 2014 – US$1.271 billion; December 31, 2013 – US$1.275 million)[a] | **$ 1,405,113** | $ 1,355,558 |
| 6.5% senior unsecured notes (US$750 million)[b] | **828,975** | 797,700 |
| 6.375% senior unsecured notes (US$800 million)[c] | **884,240** | 850,880 |
| 7.0% senior unsecured notes (US$1.0 billion)[d] | **1,105,300** | 1,063,600 |
| | **4,223,628** | 4,067,738 |
| Less current portion of senior secured term loan | **(14,369)** | (13,827) |
| Less unamortized financial derivative liability discount | **(19,821)** | (20,565) |
| Less unamortized deferred debt issue costs | **(41,598)** | (42,598) |
| | **$ 4,147,840** | $ 3,990,748 |

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.1053 (December 31, 2013 - US$1 = C$1.0636).

There are no maintenance financial covenants associated with the Corporation's debt as at March 31, 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 March 31, 2014, $118.5 million (December 31, 2013 - $133.9 million) of the revolving credit facility was utilized to support letters of credit. As at March 31, 2014, no amount had been drawn under the revolving credit facility.

The senior secured credit facilities are comprised of a US$1.271 billion term loan and a US$2.0 billion revolving credit facility. 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 $5.8 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 $10.9 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 $12.0 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 $12.8 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

## 14. PROVISIONS AND OTHER LIABILITIES

| | | March 31, 2014 | | December 31, 2013 |
|---|---|---|---|---|
| Derivative financial liabilities[(a)] | $ | 29,354 | $ | 30,981 |
| Decommissioning provision[(b)] | | 117,145 | | 108,695 |
| Deferred lease inducements[(c)] | | 4,826 | | 4,978 |
| Provisions and other liabilities | | 151,325 | | 144,654 |
| Less current portion | | (19,350) | | (19,477) |
| Non-current portion | $ | 131,975 | $ | 125,177 |

(a) Derivative financial liabilities

| | | March 31, 2014 | | December 31, 2013 |
|---|---|---|---|---|
| 1% interest rate floor | $ | 22,387 | $ | 23,497 |
| Interest rate swaps | | 6,967 | | 7,484 |
| Derivative financial liabilities | | 29,354 | | 30,981 |
| Less current portion of derivative financial liabilities | | (13,939) | | (13,886) |
| Non-current portion of derivative financial liabilities | $ | 15,415 | $ | 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 and 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 March 31, 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:

| | **March 31, 2014** | December 31, 2013 |
|---|---|---|
| Decommissioning provision, beginning of period | **$ 108,695** | $ 82,087 |
| Changes in estimated future cash flows | **1,617** | 15,082 |
| Changes in discount rates | **2,531** | (19,110) |
| Liabilities incurred | **3,440** | 30,068 |
| Liabilities settled | **(175)** | (4,195) |
| Accretion | **1,037** | 4,763 |
| Decommissioning provision, end of period | **117,145** | 108,695 |
| Less current portion of decommissioning provision | **(4,673)** | (4,848) |
| Non-current portion of decommissioning provision | **$ 112,472** | $ 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 $117.1 million as at March 31, 2014 (December 31, 2013 - $108.7 million) based on an undiscounted total future liability of $577.0 million (December 31, 2013 - $569.5 million) and a credit-adjusted rate of 6.3% (December 31, 2013 – 6.4%). This obligation is estimated to be settled in periods up to 2064.

(c) 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:

| | **Three months ended March 31, 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 | **65,890** | **2,130** | 1,893,732 | 40,522 |
| Issued upon vesting and release of RSUs | **2,405** | **80** | 423,080 | 16,395 |
| Balance, end of period | **222,575,191** | **$ 4,753,584** | 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.

| | **Three months ended March 31, 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 | **8,481** | **33.63** | 1,774,854 | 30.95 |
| Exercised | **(65,890)** | **24.84** | (1,893,732) | 16.53 |
| Forfeited | **(205,285)** | **39.71** | (169,498) | 38.19 |
| Expired | **(32,750)** | **33.50** | - | - |
| Outstanding, end of period | **8,563,584** | **$ 35.48** | 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 | **Three months ended March 31, 2014** | Year ended December 31, 2013 |
|---|---|---|
| Outstanding, beginning of period | **2,589,700** | 953,804 |
| Granted | **-** | 2,157,534 |
| Vested and released | **(2,405)** | (423,080) |
| Forfeited | **(21,022)** | (98,558) |
| Outstanding, end of period | **2,566,273** | 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 March 31, 2014, there were 8,874 DSUs outstanding.

(f) Contributed Surplus:

| | **Three months ended March 31, 2014** | Year ended December 31, 2013 |
|---|---|---|
| Balance, beginning of period | **$ 126,666** | $ 102,219 |
| Stock-based compensation - expensed | **12,622** | 38,792 |
| Stock-based compensation - capitalized | **3,016** | 11,267 |
| Stock options exercised | **(493)** | (9,217) |
| RSUs vested and released | **(80)** | (16,395) |
| Balance, end of period | **$ 141,731** | $ 126,666 |

## 16. PETROLEUM REVENUE, NET OF ROYALTIES

| | Three months ended March 31 | |
|---|---|---|
| | **2014** | 2013 |
| Petroleum sales: | | |
| Proprietary | **$ 601,828** | $ 241,800 |
| Third party | **71,607** | 5,778 |
| | **673,435** | 247,578 |
| Royalties | **(23,383)** | (4,602) |
| Petroleum revenue, net of royalties | **$ 650,052** | $ 242,976 |

## 17. OTHER REVENUE

| | Three months ended March 31 | |
|---|---|---|
| | **2014** | **2013** |
| Power revenue | **$ 20,131** | **$ 9,616** |
| Transportation revenue | **9,379** | **5,377** |
| Other revenue | **$ 29,510** | **$ 14,993** |

## 18. DILUENT AND TRANSPORTATION

| | Three months ended March 31 | |
|---|---|---|
| | **2014** | **2013** |
| Diluent | **$ 276,208** | **$ 154,211** |
| Transportation | **12,890** | **5,737** |
| Diluent and transportation | **$ 289,098** | **$ 159,948** |

## 19. NET FINANCE EXPENSE

| | Three months ended March 31 | |
|---|---|---|
| | **2014** | **2013** |
| Total interest expense | **$ 65,700** | **$ 38,723** |
| Less capitalized interest | **(19,470)** | **(13,634)** |
| Net interest expense | **46,230** | **25,089** |
| Accretion on decommissioning provision | **1,037** | **1,076** |
| Unrealized fair value loss (gain) on embedded derivative liabilities | **(1,110)** | **(3,075)** |
| Unrealized fair value loss (gain) on interest rate swaps | **(517)** | **(1,229)** |
| Realized loss on interest rate swaps | **1,121** | **1,101** |
| Net finance expense | **$ 46,761** | **$ 22,962** |

## 20. SUPPLEMENTAL CASH FLOW DISCLOSURES

| | | Three months ended March 31 | | |
|---|---|---|---|---|
| | | **2014** | | 2013 |
| **Changes in non-cash working capital** | | | | |
| Operating activities: | | | | |
| Trade receivables and other | $ | **(90,178)** | $ | **(22,005)** |
| Inventories[a] | | **(17,079)** | | **(3,296)** |
| Accounts payable and accrued liabilities | | **(10,506)** | | **(6,762)** |
| Change in operating non-cash working capital | $ | **(117,763)** | $ | **(32,063)** |
| Investing activities: | | | | |
| Short-term investments | $ | **-** | $ | **414,469** |
| Accounts payable and accrued liabilities | | **(3,010)** | | **176,025** |
| Change in investing non-cash working capital | $ | **(3,010)** | $ | **590,494** |
| Change in total non-cash working capital | $ | **(120,773)** | $ | **558,431** |
| Cash and cash equivalents: | | | | |
| Cash | $ | **486,227** | $ | **348,328** |
| Cash equivalents | | **404,108** | | **1,336,482** |
| | $ | **890,335** | $ | **1,684,810** |

(a) The three months ended March 31, 2014 amounts exclude a non-cash decrease in inventory of $158 (March 31, 2013 – nil).

## 21. NET EARNINGS (LOSS) PER COMMON SHARE

| | | Three months ended March 31 | | |
|---|---|---|---|---|
| | | **2014** | | **2013** |
| Net loss | $ | **(103,441)** | $ | **(71,294)** |
| Weighted average common shares outstanding | | **222,544,253** | | **221,046,678** |
| Dilutive effect of stock options, RSUs and PSUs | | **2,736,082** | | **1,700,746** |
| Weighted average common shares outstanding – diluted | | **225,280,335** | | **222,747,424** |
| Net earnings (loss) per share, basic | $ | **(0.46)** | $ | **(0.32)** |
| Net earnings (loss) per share, diluted | $ | **(0.46)** | $ | **(0.32)** |

## 22. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at March 31, 2014:

Operating:

| | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter |
|---|---|---|---|---|---|---|
| Office lease rentals | $ 9,213 | $ 12,485 | $ 12,895 | $ 30,704 | $ 30,791 | $ 315,308 |
| Diluent purchases | 273,847 | 75,289 | 16,944 | 16,944 | 16,944 | 88,944 |
| Pipeline transportation | 96,911 | 135,153 | 154,860 | 243,830 | 212,915 | 2,868,082 |
| Other commitments | 11,905 | 13,454 | 6,117 | 5,251 | 5,282 | 53,998 |
| Annual commitments | $ 391,876 | $ 236,381 | $ 190,816 | $ 296,729 | $ 265,932 | $3,326,332 |

Capital:

As part of normal operations, the Corporation has entered into a total of $99.2 million in 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.