FOURTH QUARTER 2013

Report to Shareholders for the period ended December 31, 2013

MEG Energy Corp. reported fourth quarter and full year 2013 operational and financial results on February 6, 2014. Highlights included:

- Strong performance from the recently commissioned Phase 2B project and continued success of RISER driving record exit production of 48,557 barrels per day (bpd), 13% above the top end of guidance and setting a strong foundation for MEG's near-term target of 80,000 bpd by 2015;

- Establishing Canada's first well-head to unit-train rail loading connection via pipeline, with MEG's first unit-train shipment made in December 2013;

- Annual net operating costs of $10 per barrel, maintaining MEG's position as a low-cost producer; and

- A 13% increase in proved reserves to 1.4 billion barrels and a 10% increase in proved plus probable reserves to 2.9 billion barrels.

"The use of proven technologies was a key component to our performance in 2013 and will remain the central focus of our future plans. The success of MEG's RISER initiative, coupled with the strong start-up performance of Christina Lake Phase 2B in the fourth quarter, were the main contributors to our solid production results in 2013," said Bill McCaffrey, MEG President and Chief Executive Officer. "Exit rates were about 13 per cent above the high end of our expectations, which provides a strong foundation for a very exciting year in 2014 as we ramp-up toward our near-term target of 80,000 barrels per day by 2015."

Exit rate production for the month of December averaged 48,557 bpd. Annual production for 2013 averaged 35,317 bpd, an increase of 23% over 2012 volumes of 28,773 bpd, marking MEG's fifth consecutive year of annual production gains. Production for the fourth quarter of 2013 increased to a record 42,251 bpd from fourth quarter 2012 production of 32,292 bpd.

Average non-energy operating costs for 2013, at $9.00 per barrel, were at the low end of MEG's targeted range of $9 to $11 per barrel, an improvement of 7% from 2012 averages. Net operating costs (including energy costs and revenue from electricity sales) for 2013 averaged $10.01 per barrel, consistent with 2012 full-year results and maintaining MEG's low operating cost position. Net operating costs for the fourth quarter of 2013 were $11.22 per barrel compared to fourth quarter 2012 results of $8.95 per barrel. The difference in fourth quarter net operating costs reflects the benefit of lower non-energy operating costs, offset by higher natural gas energy costs and lower realized prices for electricity sales.

Concurrent with the ramp-up of production in the fourth quarter, MEG commissioned its proprietary 900,000 barrel Stonefell storage terminal and completed its proprietary pipeline connection to the Canexus rail-loading facility at Bruderheim, establishing the first direct well-head to rail pipeline connection in the Canadian oil industry. The first unit-train of MEG product was loaded in December with additional unit-trains loaded in January.

"The strategic advantage of having storage capability at the Stonefell Terminal was demonstrated in the fourth quarter," said McCaffrey. "With the Alberta oil industry subject to unscheduled pipeline apportionment, we were able to continue producing at maximum rates while positioning ourselves to take greater control of which markets our barrels are sold into, and the timing for the sale of those barrels."

While fourth quarter 2013 production levels were up 31% from the same period in 2012, sales volumes increased 10% due to approximately 6,300 bpd of production being placed in storage, used as line-fill or capitalized in association with the commissioning of Phase 2B.

Fourth quarter 2013 cash flow from operations was $22.6 million ($0.10 per share, diluted) compared to cash flow from operations of $56.1 million ($0.27 per share, diluted) in the fourth quarter of 2012. Cash flow for the fourth quarter of 2013 was impacted by production volumes that were not sold in the quarter (as noted above), as well as wider light-heavy oil differentials and an increase in diluent costs compared to the same period in 2012.

MEG recognized a net loss for the fourth quarter of 2013 of $148.2 million compared to a net loss of $18.7 million for the fourth quarter of 2012. The loss is primarily due to the unrealized foreign exchange loss on 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.

Capital and growth strategy

MEG's capital program in 2013 was approximately $2.1 billion. Investment was primarily focused on completion of Christina Lake Phase 2B, continued application of RISER at Christina Lake Phases 1 and 2, early work on RISER 2B, and infrastructure to support MEG's future growth and marketing strategies.

"We've already put the capital in place to reach our target of 80,000 barrels per day by 2015," said McCaffrey. "The investment focus in 2014 is on our next stage of growth through the RISER 2B initiative. The expansion of our existing assets through this brownfield approach will significantly lower the capital intensity of new production and accelerate our cash flows compared to a typical greenfield expansion."

MEG ended the year with net debt of $2.9 billion, including $1.2 billion in cash and cash equivalents. MEG's capital resources also include an undrawn US$2.0 billion revolving credit facility.

Reserves update

GLJ Petroleum Consultants Ltd. (GLJ), an independent reservoir engineering firm, completed an evaluation of MEG's bitumen reserves and resources effective as of December 31, 2013. Proved bitumen reserves increased by 13% to an estimated 1.4 billion barrels from the previous year. Proved plus probable reserves increased to 2.9 billion barrels from 2.6 billion barrels reflecting higher expected recovery factors and further resource delineation. GLJ's estimate of contingent resources (on a best estimate basis) was approximately 3.7 billion barrels, compared to 3.4 billion barrels a year earlier.

The pre-tax net present value of the future net cash flows of the proved reserves and of the proved plus probable reserves, discounted at 10% per annum, were $13.5 billion and $21.0 billion, respectively. A summary of GLJ's report, along with important information regarding net present value calculations and the classification of reserves and contingent resources is included under the heading "Reserves and Resources."

OPERATIONAL AND FINANCIAL HIGHLIGHTS

The following table summarizes selected operational and financial information of the Corporation for the periods ended:

	Three months ended December 31		Year ended December 31	
	2013	**2012**	**2013**	**2012**
Bitumen production – bpd	42,251	32,292	35,317	28,773
Bitumen sales – bpd	35,990	32,722	33,715	28,845
Steam to oil ratio (SOR)	2.9	2.4	2.6	2.4
West Texas Intermediate (WTI) US$/bbl	97.43	88.18	97.96	94.21
Differential – Blend vs WTI - %	40.6%	29.9%	32.7%	31.2%
Bitumen realization - $/bbl	38.22	45.67	49.28	46.93
Net operating costs(1) - $/bbl	11.22	8.95	10.01	9.98
Non-energy operating costs - $/bbl	8.09	8.70	9.00	9.71
Cash operating netback(2) - $/bbl	23.78	34.44	35.87	34.18
Total cash capital investment(3) - $000	389,232	494,916	2,188,353	1,598,514
Net income (loss) - $000	(148,182)	(18,740)	(166,405)	52,569
Per share, diluted	(0.67)	(0.09)	(0.75)	0.26
Operating earnings (loss) - $000(4)	(32,685)	(538)	386	21,242
Per share, diluted(4)	(0.15)	(0.00)	0.00	0.11
Cash flow from operations - $000(4)	22,648	56,106	253,424	212,514
Per share, diluted(4)	0.10	0.27	1.13	1.06
Cash, cash equivalents and short-term investments - $000	1,179,072	2,007,841	1,179,072	2,007,841
Long-term debt - $000	4,004,575	2,488,609	4,004,575	2,488,609
Bitumen Reserves and Contingent Resources (millions of barrels, before royalties)				
Bitumen Reserves (millions of barrels, before royalties)				
Proved (1P) Reserves(5)			1,446	1,284
Probable Reserves(6)			1,451	1,360
Proved Plus Probable (2P) Reserves(5)(6)			2,897	2,644
Bitumen Contingent Resources (millions of barrels, before royalties)				
Best Estimate Contingent Resources (2C)(7)(8)(9)			3,653	3,420

(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 $22.9 million and $76.5 million for the three months and year ended December 31, 2013 respectively ($10.4 million and $30.6 million for the three months and year ended December 31, 2012).*

(4) 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 operating activities in accordance with IFRS under the heading "NON-IFRS MEASUREMENTS" and discussed further in the "ADVISORY" section.

(5) "Proved Reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Proved Reserves are also referred to as "1P Reserves".

(6) "Probable Reserves" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Proved plus probable reserves are also referred to as "2P Reserves".

(7) "Contingent Resources" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Such contingencies include further reservoir delineation, additional facility and reservoir design work, submission of regulatory applications and the receipt of corporate approvals. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

(8) There are three categories in evaluating Contingent Resources: Low Estimate, Best Estimate and High Estimate. The resource numbers presented all refer to the Best Estimate category. Best Estimate is a classification of resources described in the Canadian Oil and Gas Evaluation (COGE) Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate. Best Estimate Contingent Resources are also referred to as "2C Resources".

(9) These volumes are the arithmetic sums of the Best Estimate Contingent Resources for Christina Lake, Surmont and the Growth Properties.

Bitumen production for the three months ended December 31, 2013 averaged 42,251 bpd compared to 32,292 bpd for the same period in 2012. Production for the year ended December 31, 2013 averaged 35,317 bpd compared to 28,773 bpd for the year ended December 31, 2012. The increase in production volumes in 2013 compared to 2012 is due to the implementation of RISER on Christina Lake Phases 1 and 2 and the startup of Christina Lake Phase 2B. The expanded steam generation capacity and improved reservoir efficiency from the RISER implementation has enabled the Corporation to place additional wells into production in 2013. Steam injection into the Phase 2B well pairs commenced in the third quarter of 2013 and the Corporation achieved first production from Phase 2B in the fourth quarter of 2013.

Bitumen sales averaged 35,990 bpd for the fourth quarter of 2013 and 33,715 bpd for the year ended December 31, 2013. Production volumes exceeded sales volumes in the fourth quarter of 2013 due to approximately 6,300 bpd of production being placed in storage, used as line-fill or capitalized in association with the commissioning of Phase 2B.

For the three months ended December 31, 2013, the average steam to oil ratio ("SOR") was 2.9, compared to an average SOR of 2.4 during the three months ended December 31, 2012. For the year ended December 31, 2013, the average SOR was 2.6, compared to an average SOR of 2.4 for the year ended December 31, 2012. The increase in the average SOR for these periods is the result of Phase 2B start-up. It is anticipated that the SOR for the next several months will be higher than historical values due to the start-up of new well pairs in Phase 2B. Each of these new well pairs will require steam preheating prior to conversion to production mode. Once well pairs commence production, the SOR will decrease. 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.

Bitumen realizations decreased in the fourth quarter of 2013 as compared to the fourth quarter of 2012. The decrease in bitumen realizations is due primarily to the widening of the differential between the price of West Texas Intermediate ("WTI") and the Corporation's blend sales. The price of WTI increased to an average of US$97.43 per barrel during the fourth quarter of 2013 from US$88.18 per barrel during the fourth quarter of 2012. However, the differential between the price of WTI and the Corporation's blend sales price increased to 40.6% in the fourth quarter of 2013, compared to 29.9% in the fourth quarter of 2012.

Bitumen realizations increased for the year ended December 31, 2013 as compared to the year ended December 31, 2012 primarily as a result of the increase in the price of WTI. The price of WTI averaged US$97.96 per barrel during 2013 compared to US$94.21 per barrel during 2012. For the year ended December 31, 2013, the differential between WTI and the Corporation's blend sales price was 32.7% compared to a differential of 31.2% for the year ended December 31, 2012.

Net operating costs include energy and non-energy operating costs reduced by power sales. For the three months ended December 31, 2013 net operating costs were $11.22 per barrel, compared to $8.95 per barrel for the three months ended December 31, 2012. The increase in net operating costs, on a per barrel basis, is attributable to:

- the increase in energy operating costs, as natural gas prices increased to $3.55 per thousand cubic feet ("mcf") during the fourth quarter of 2013, from an average of $3.21 per mcf during the fourth quarter of 2012;
- a decrease in power realizations to $44.63 per megawatt hour during the fourth quarter of 2013, from $79.62 per megawatt hour during the fourth quarter of 2012; and
- the impacts of these changes were partially offset by a decrease in non-energy costs, as expressed on a per barrel basis, to $8.09 per barrel in the fourth quarter of 2013, from $8.70 per barrel in the fourth quarter of 2012. This decrease is largely the result of higher production volumes from the implementation of RISER and the start-up of Christina Lake Phase 2B.

Net operating costs on a per barrel basis for the year ended December 31, 2013 were $10.01 per barrel, compared to $9.98 per barrel for the year ended December 31, 2012. The increase in net operating costs on a per barrel basis is attributable to the increase in energy operating costs, as natural gas prices increased to $3.21 per mcf in 2013, from an average of $2.49 per mcf in 2012. This was partially offset by:

- an increase in power realizations to $76.23 per megawatt hour in 2013 from $59.22 per megawatt hour in 2012, and;
- a decrease in non-energy costs, as expressed on a per barrel basis, to $9.00 per barrel in 2013, from $9.71 per barrel in 2012. This decrease is largely the result of higher production volumes from the implementation of RISER.

Power sales had the effect of offsetting 42% of energy operating costs during the fourth quarter of 2013 compared to 95% of energy operating costs during the fourth quarter of 2012. Power sales had the effect of offsetting 78% of energy operating costs during the year ended December 31, 2013 compared to 92% of energy operating costs during the year ended December 31, 2012. Power prices in the fourth quarter of 2013 were below the same period in 2012 as the result of lower Alberta power generation volatility in the fourth quarter of 2013 compared to the fourth quarter of 2012. However, power generation volatility in Alberta was higher during the first half of 2013, which resulted in full year 2013 power prices above 2012 levels.

Cash operating netback for the three months ended December 31, 2013 was $23.78 per barrel compared to $34.44 per barrel for the same period in 2012. The decrease in cash operating netback for the three months ended December 31, 2013 compared to the three months ended December 31, 2012 was primarily due to the decrease in bitumen realizations combined with the increase in net operating costs. Bitumen realizations were primarily impacted by higher differentials realized on the sale of the Corporation's blend product.

Cash operating netback for the year ended December 31, 2013 was $35.87 per barrel compared to $34.18 per barrel for the year ended December 31, 2012. The increase in cash operating netbacks is due largely to the increase in bitumen realizations for the year ended December 31, 2013 as compared to the year ended December 31, 2012.

Total cash capital investment was $389.2 million during the fourth quarter of 2013 compared to $494.9 million during the fourth quarter of 2012. Total cash capital investment for the year ended December 31, 2013 was $2.2 billion (including $76.5 million of capitalized interest) compared to $1.6 billion for the year ended December 31, 2012. Capital investment during 2013 has focused on the completion of Phase 2B, the RISER initiative, completion of the Stonefell Terminal, the expansion of the Access Pipeline, engineering, procurement of long-lead equipment and site preparation for Phase 3A and delineation drilling at Christina Lake and Surmont.

The Corporation recognized a net loss for the fourth quarter of 2013 of $148.2 million, which was primarily due to the $127.8 million foreign exchange loss on conversion of the Corporation's U.S. dollar denominated debt. As at December 31, 2013, the Canadian dollar, at a rate of 1.0636, had decreased in value by approximately 3% against the U.S. dollar compared to its value as at September 30, 2013, when the rate was 1.0285. The net loss of $18.7 million for the fourth quarter of 2012 included a foreign exchange loss of $28.4 million on the conversion of the Corporation's U.S. dollar denominated debt.

The net loss for the year ended December 31, 2013 was $166.4 million, which was primarily due to the $213.7 million foreign exchange loss on conversion of the Corporation's U.S. dollar denominated debt. As at December 31, 2013, the Canadian dollar, at a rate of 1.0636, had decreased in value by approximately 7% against the U.S. dollar compared to its value as at December 31, 2012, when the rate was 0.9949. Net income for the year ended December 31, 2012 was $52.6 million and included a foreign exchange gain of $48.8 million on conversion of the Corporation’s U.S. dollar denominated debt.

Operating loss for the three months ended December 31, 2013 was $32.7 million compared to an operating loss of $0.5 million for the three months ended December 31, 2012. The increases in bitumen sales volumes and WTI in the fourth quarter of 2013 were primarily offset by higher differentials realized on the sale of the Corporation's blend product and higher depletion and depreciation compared to the same period in 2012.

The Corporation recognized operating earnings for the year ended December 31, 2013 of $0.4 million compared to operating earnings of $21.2 million for the year ended December 31, 2012. In 2013, the increase in cash operating netback resulting from higher bitumen sales volumes and bitumen realizations was offset by higher depletion and depreciation, general and administrative and interest expense compared to the same period in 2012.

Cash flow from operations was $22.6 million for the fourth quarter of 2013, compared to $56.1 million for the fourth quarter of 2012. The 10% increase in bitumen sales volumes in the fourth quarter of 2013, compared to the fourth quarter of 2012, was more than offset by a decrease in the bitumen realization.

Cash flow from operations was $253.4 million for the year ended December 31, 2013, compared to $212.5 million for the year ended December 31, 2012. Cash flow from operations increased due to higher bitumen sales volumes and bitumen realizations. These increases were partially offset by higher general and administrative and interest expense as compared to the same periods in 2012. Cash flow from operations was further impacted by approximately 6,300 bpd of production being placed in storage, used as line-fill or capitalized in association with the commissioning of Phase 2B.

The Corporation's cash, cash equivalents and short-term investments balance was $1.2 billion as at December 31, 2013 compared to $2.0 billion as at December 31, 2012. 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 $4.0 billion as at December 31, 2013, from $2.5 billion as at December 31, 2012. The increase in long-term debt is due to the increase in the senior secured term loan, the issuance of senior unsecured notes and the impact of foreign exchange on the U.S. dollar denominated debt. Effective 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 0.25 percent. 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 December 31, 2013, the Corporation's capital resources included $1.2 billion of cash and cash equivalents and an undrawn US$2.0 billion revolving credit facility. As at December 31, 2013, $133.9 million of the revolving credit facility was utilized to support letters of credit.

BUSINESS ENVIRONMENT

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

	Year ended December 31		2013				2012			
	2013	2012	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Commodity Prices (Averages)										
Crude oil prices										
West Texas Intermediate (WTI) US$/bbl	97.96	94.21	97.43	105.83	94.22	94.37	88.18	92.22	93.49	102.92
West Texas Intermediate (WTI) C$/bbl	100.86	94.14	102.08	109.90	96.42	95.21	87.41	91.73	94.44	103.06
Western Canadian Select (WCS) C$/bbl	74.97	73.13	68.31	91.75	76.82	63.01	69.47	70.06	71.34	81.66
Differential – WTI vs WCS (C$/bbl)	25.89	21.01	33.77	18.15	19.60	32.20	17.94	21.67	23.10	21.39
Differential – WTI vs WCS (%)	25.7%	22.3%	33.1%	16.5%	20.3%	33.8%	20.5%	23.6%	24.5%	20.8%
Natural gas prices										
AECO (C$/mcf)	3.16	2.38	3.52	2.42	3.51	3.18	3.20	2.27	1.89	2.14
Electric power prices										
Alberta power pool (C$/MWh)	80.22	64.24	48.60	83.61	123.41	65.26	78.73	78.09	40.03	60.10
Foreign exchange rates										
C$ equivalent of 1 US$ - average	1.0296	0.9994	1.0477	1.0385	1.0233	1.0089	0.9913	0.9948	1.0102	1.0012
C$ equivalent of 1 US$ - period end	1.0636	0.9949	1.0636	1.0285	1.0512	1.0156	0.9949	0.9837	1.0191	0.9991

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 average price for WTI for the fourth quarter of 2013 was US$97.43 per barrel compared to US$88.18 per barrel for the fourth quarter of 2012. The WTI price averaged US$97.96 per barrel for the year ended December 31, 2013 compared to US$94.21 per barrel for the year ended December 31, 2012.

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. During the fourth quarter of 2013, the WTI to WCS differential averaged 33.1% compared to 20.5% during the fourth quarter of 2012. The WTI to WCS differential averaged 25.7% for the year ended December 31, 2013 compared to 22.3% for the year ended December 31, 2012.

Ongoing pipeline congestion between the Western Canada and U.S. coastal markets negatively impacts the price received for WCS. Recent additions of crude-by-rail to access new markets as well as pipeline additions connecting the U.S. mid-continent to the U.S. Gulf Coast and refinery modifications in the U.S. Midwest are anticipated to relieve some of this price pressure in the first half of 2014. Incrementally, initiatives to access additional markets, including the recently completed TransCanada Gulf Coast Pipeline and the ongoing construction of the Flanagan South pipeline and Seaway expansion, 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 benchmark AECO natural gas price averaged $3.52 per mcf during the three months ended December 31, 2013, compared to $3.20 per mcf during the same period in 2012. During the year ended December 31, 2013, the AECO natural gas price averaged $3.16 per mcf compared to $2.38 per mcf for the year ended December 31, 2012.

The Alberta power pool price averaged $48.60 per megawatt hour for the three months ended December 31, 2013, compared to $78.73 per megawatt hour for the same period in 2012. During the year ended December 31, 2013, the Alberta power pool price averaged $80.22 per megawatt hour compared to an average price of $64.24 per megawatt hour for 2012. Power prices in the fourth quarter were below the same period in 2012 as the result of lower power generation volatility. However, power generation volatility over the first half of 2013 resulted in full year 2013 prices above 2012 levels.

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 December 31, 2013, the Canadian dollar, at a rate of 1.0636, had decreased in value by approximately 3% against the U.S. dollar compared to its value as at September 30, 2013, when the rate was 1.0285 and by approximately 7% against the U.S. dollar compared to its value as at December 31, 2012, when the rate was 0.9949.

RESULTS OF OPERATIONS

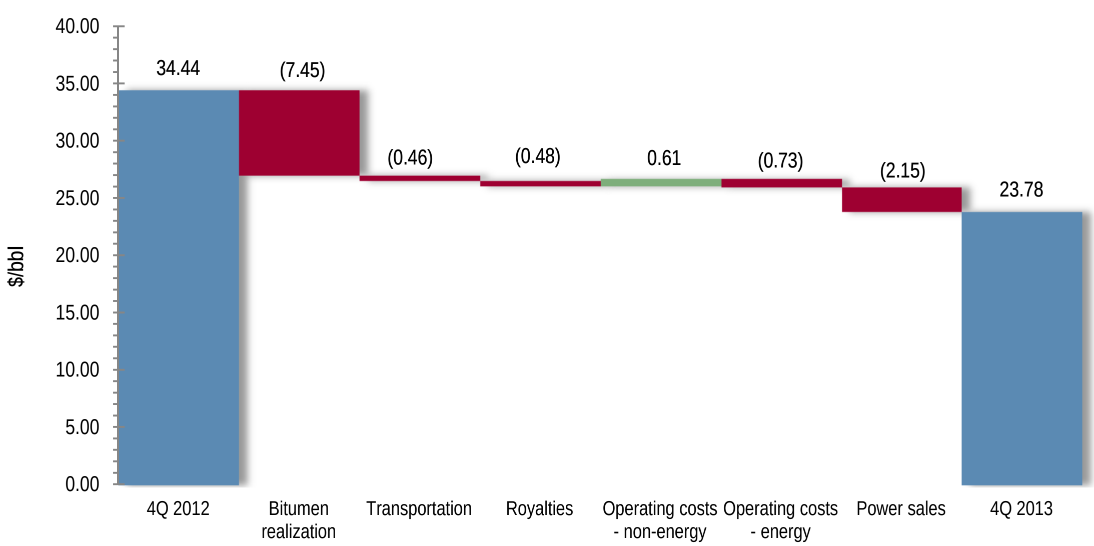
	Three months ended December 31		Year ended December 31	
	2013	2012	2013	2012
Bitumen production – bpd	42,251	32,292	35,317	28,773
Steam to oil ratio (SOR)	2.9	2.4	2.6	2.4

Production

Production averaged 42,251 bpd for the fourth quarter of 2013, compared to 32,292 bpd for the fourth quarter of 2012. Production for the year ended December 31, 2013 averaged 35,317 bpd compared to 28,773 bpd for the year ended December 31, 2012. The increase in production volumes in 2013 compared to 2012 is due to the implementation of RISER on Phases 1 and 2 and the startup of Christina Lake Phase 2B, which achieved first production in the fourth quarter of 2013. 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 in 2013.

For the three months ended December 31, 2013, the average SOR was 2.9, compared to an average SOR of 2.4 for the three months ended December 31, 2012. For the year ended December 31, 2013, the average SOR was 2.6, compared to an average SOR of 2.4 for the year ended December 31, 2012. The increase in the average SOR for these periods is the result of Phase 2B start-up. It is anticipated that the SOR for the next several months will be higher than historical values due to the start-up of new well pairs in Phase 2B. Each of these new well pairs will require steam preheating prior to conversion to production mode. Once well pairs commence production, the SOR will decrease. 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.

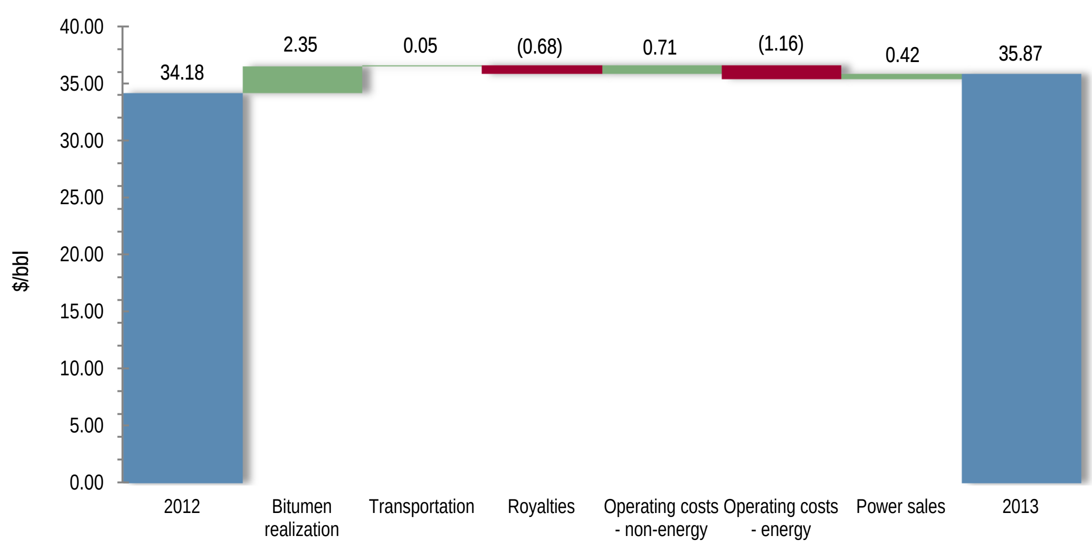
Cash Operating Netback – Three Months Ended December 31, 2013 versus December 31, 2012:



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

	2013		2012	
	$000	$ per bbl	$000	$ per bbl
Bitumen realization[1]	126,561	38.22	137,500	45.67
Transportation[2]	(1,675)	(0.51)	(144)	(0.05)
Royalties	(8,978)	(2.71)	(6,709)	(2.23)
Net bitumen revenue	**115,908**	**35.00**	**130,647**	**43.39**
Operating costs – non-energy	(26,787)	(8.09)	(26,179)	(8.70)
Operating costs – energy	(17,815)	(5.38)	(13,984)	(4.65)
Power sales	7,447	2.25	13,248	4.40
Net operating costs	**(37,155)**	**(11.22)**	**(26,915)**	**(8.95)**
Cash operating netback[3]	**78,753**	**23.78**	**103,732**	**34.44**

Cash Operating Netback – Year Ended December 31, 2013 versus December 31, 2012:



The following table summarizes the Corporation's cash operating netback for the years ended December 31:

	2013		2012	
	$000	**$ per bbl**	**$000**	**$ per bbl**
Bitumen realization(1)	606,458	49.28	495,425	46.93
Transportation(2)	(3,172)	(0.26)	(3,231)	(0.31)
Royalties	(38,642)	(3.14)	(25,959)	(2.46)
Net bitumen revenue	**564,644**	**45.88**	**466,235**	**44.16**
Operating costs – non-energy	(110,742)	(9.00)	(102,481)	(9.71)
Operating costs – energy	(56,844)	(4.62)	(36,538)	(3.46)
Power sales	44,455	3.61	33,634	3.19
Net operating costs	**(123,131)**	**(10.01)**	**(105,385)**	**(9.98)**
Cash operating netback(3)	**441,513**	**35.87**	**360,850**	**34.18**

(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 December 31		Year ended December 31	
($000)	**2013**	**2012**	**2013**	**2012**
Blend sales – proprietary	293,655	268,007	1,207,649	991,975
Cost of diluent	(167,094)	(130,507)	(601,191)	(496,550)
Bitumen realization	126,561	137,500	606,458	495,425

Blend sales for the three months ended December 31, 2013 were $293.7 million compared to $268.0 million for the three months ended December 31, 2012. The increase in blend sales for the fourth quarter of 2013 compared to the fourth quarter of 2012 is due to the 10% increase in sales volumes, partially offset by a decrease in the Corporation's average realized blend sales price. Blend sales averaged $60.60 per barrel for the fourth quarter of 2013, compared to $61.29 per barrel for the fourth quarter of 2012. Sales volumes increased as a result of the increased production volumes in the fourth quarter of 2013. Production increased compared to 2012 due to the implementation of RISER, which has allowed additional wells to be placed into production in 2013, and the startup of Christina Lake Phase 2B.

Blend sales for the year ended December 31, 2013 were $1.2 billion compared to $1.0 billion for the year ended December 31, 2012. The increase in blend sales for 2013 compared to 2012 is due to a 17% increase in sales volumes combined with an increase in the average realized price. Blend sales averaged $67.88 per barrel during the year ended December 31, 2013 compared to $64.78 per barrel for the year ended December 31, 2012.

The cost of diluent was $167.1 million for the three months ended December 31, 2013, compared to $130.5 million for the same period in 2012. The increase in the cost of diluent in the fourth quarter of 2013 compared to the fourth quarter of 2012 is a result of increased sales due to the implementation of RISER and the startup of Phase 2B, and an increase in the per barrel cost of diluent. On a per barrel basis, the Corporation's cost of diluent increased to $108.89 per barrel for the fourth quarter of 2013, from $95.78 per barrel for the fourth quarter of 2012.

The cost of diluent for the year ended December 31, 2013 was $601.2 million compared to $496.6 million for the year ended December 31, 2012. The total cost of diluent increased due to the increase in the per barrel cost of diluent and the higher volumes of diluent purchased as a result of increased bitumen sales. On a per barrel basis, the Corporation's average cost of diluent was $109.60 per barrel during the year ended December 31, 2013 compared to an average cost of $104.41 per barrel during the year ended December 31, 2012.

Transportation

Transportation costs, which include MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries, were $1.7 million for the three months ended December 31, 2013 compared to $0.1 million for the three months ended December 31, 2012. In the fourth quarter of 2013, the Corporation recognized third-party recoveries of $4.1 million compared to $3.7 million in the fourth quarter of 2012. The increase in transportation costs for the three months ended December 31, 2013 compared to the same period in 2012 is primarily due to the additional costs associated with the Corporation beginning to ship product by rail in the fourth quarter of 2013. On a per barrel basis, transportation costs averaged $0.51 per barrel during the three months ended December 31, 2013, compared to $0.05 per barrel during the three months ended December 31, 2012.

Transportation costs totalled $3.2 million for both the year ended December 31, 2013 and December 31, 2012, net of $19.3 million and $13.0 million in recoveries, respectively. Transportation costs averaged $0.26 per barrel for the year ended December 31, 2013 compared to $0.31 per barrel for the year ended December 31, 2012.

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 were $9.0 million for the fourth quarter of 2013 compared to $6.7 million for the fourth quarter of 2012. The increase in royalties in the fourth quarter of 2013 is primarily a result of increased blend sales due to the implementation of RISER and the startup of Christina Lake Phase 2B and the increase in the Canadian dollar price of WTI. Royalties averaged $2.71 per barrel for the fourth quarter of 2013, compared to $2.23 per barrel for the fourth quarter of 2012. The Corporation's royalty rate averaged 7.1% for the fourth quarter of 2013 compared to 4.9% for the fourth quarter of 2012.

Royalties were $38.6 million for the year ended December 31, 2013 compared to $26.0 million for the year ended December 31, 2012. The increase in royalties for the year ended December 31, 2013 compared to the same period in 2012 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 $3.14 per barrel during the year ended December 31, 2013 compared to $2.46 per barrel for the year ended December 31, 2012. The Corporation's royalty rate averaged 6.4% for the year ended December 31, 2013 compared to 5.2% for the year ended December 31, 2012.

Operating Costs

Non-energy operating costs were $26.8 million for the three months ended December 31, 2013, compared to $26.2 million for the three months ended December 31, 2012. Non-energy operating costs decreased to an average of $8.09 per barrel in the fourth quarter of 2013, from $8.70 per barrel in the fourth quarter of 2012. For the year ended December 31, 2013, non-energy operating costs were $110.7 million compared to $102.5 million for the year ended December 31, 2012. Non-energy operating costs averaged $9.00 per barrel for the year ended December 31, 2013 compared to $9.71 per barrel for the same period in 2012. The increase in non-energy related operating costs is primarily attributable to higher materials, camp and labor costs. These increases were more than offset on a per barrel basis by the increase in sales volumes.

Energy related operating costs were $17.8 million for the three months ended December 31, 2013 compared to $14.0 million for the three months ended December 31, 2012. On a per barrel basis, energy operating costs were $5.38 per barrel for the three months ended December 31, 2013 compared to $4.65 per barrel for the same period in 2012. Energy related operating costs were $56.8 million for the year ended December 31, 2013 compared to $36.5 million for the year ended December 31, 2012. On a per barrel basis, energy related operating costs were $4.62 per barrel for the year ended December 31, 2013 compared to $3.46 per barrel for the year ended December 31, 2012. The increase in energy related operating costs per barrel is primarily the result of higher natural gas prices. The benchmark AECO natural gas price averaged $3.52 per mcf for the fourth quarter of 2013, compared to $3.20 per mcf for the fourth quarter of 2012. The benchmark AECO natural gas price averaged $3.16 per mcf during the year ended December 31, 2013 compared to $2.38 per mcf for the year ended December 31, 2012.

Power Sales

With the completion of the Christina Lake Phase 2B cogeneration facility, the Corporation now has two 85 megawatt cogeneration facilities which produce steam for current SAGD operations. MEG's Christina Lake facilities utilize the heat produced by the cogeneration facility and a portion of the power generated. Surplus power is sold into the Alberta power pool.

Power sales were $7.4 million for the three months ended December 31, 2013, compared to $13.2 million for the three months ended December 31, 2012. The Corporation realized an average power price of $44.63 per megawatt hour for the three months ended December 31, 2013, compared to $79.62 per megawatt hour for the three months ended December 31, 2012. Power sales were $44.5 million for the year ended December 31, 2013, compared to $33.6 million for the year ended December

31, 2012. The average realized power price in 2013 was $76.23 per megawatt hour compared to $59.22 per megawatt hour in 2012. 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. Power prices in the fourth quarter were below the same period in 2012 as the result of lower power generation volatility. However, generation volatility over the first half of 2013 resulted in full year 2013 prices above 2012 levels.

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 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 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 December 31		Year ended December 31	
($000)	**2013**	**2012**	**2013**	**2012**
Net income (loss)	(148,182)	(18,740)	(166,405)	52,569
Add (deduct):				
Unrealized foreign exchange (gain) loss, net of tax[(1)]	116,262	20,136	181,234	(39,090)
Unrealized (gain) loss on derivative financial liabilities, net of tax[(2)]	(1,454)	(1,934)	(14,443)	9,651
Unrealized fair value (gain) loss on other assets, net of tax[(3)]	689	-	-	(1,888)
Operating earnings (loss)	(32,685)	(538)	386	21,242
Add (deduct):				
Interest income	(7,986)	(4,650)	(22,550)	(19,896)
Depletion and depreciation	51,508	44,593	189,147	144,950
General and administrative	22,662	22,173	92,828	70,597
Stock-based compensation	9,660	7,271	38,792	25,246
Research and development	1,645	966	5,588	5,157
Interest expense	37,768	27,600	110,306	91,816
Accretion	1,017	999	4,763	3,670
Gain on disposition of assets	(1,410)	-	(1,410)	(3,075)
Realized (gain) loss on foreign exchange	1,180	372	2,916	(796)
Realized loss on derivative financial liabilities	1,212	1,169	4,720	4,518
Net marketing activity	1,131	1,537	2,365	1,762
Deferred income tax expense (recovery), operating	(6,949)	2,240	13,662	15,659
Cash operating netback	78,753	103,732	441,513	360,850

(1) Unrealized foreign exchange 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 $3,837 for the three months ended December 31, 2013 and a deferred tax expense of $3,872 for the year ended December 31, 2013 (deferred tax recovery of $618 for the three months ended December 31, 2012 and a deferred tax recovery of $3,269 for the year ended December 31, 2012).

(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 fix a portion of its variable rate long-term debt, net of a deferred tax expense of $484 for the three months ended December 31, 2013 and a deferred tax expense of $4,813 for the year ended December 31, 2013 (deferred tax expense of $645 for the three months ended December 31, 2012 and a deferred tax recovery of $3,217 for the year ended December 31, 2012).*

(3) *Unrealized fair value gain on other assets results from the fair market valuation of other assets held during the year, net of a deferred tax recovery of $230 for the three months ended December 31, 2013 (deferred tax expense of $630 for the year ended December 31, 2012).*

	Three months ended December 31		Year ended December 31	
Non-IFRS Measurements - Reconciliation of net cash provided by operating activities to cash flow from operations ($000)	**2013**	**2012**	**2013**	**2012**
Net cash provided by operating activities	3,939	48,491	129,963	240,824
Add:				
Net change in non-cash operating working capital items	18,709	7,615	123,461	(28,310)
Cash flow from operations	22,648	56,106	253,424	212,514

Depletion and Depreciation

Depletion and depreciation expense was $51.5 million for the three months ended December 31, 2013, compared to $44.6 million for the same period in 2012. For the year ended December 31, 2013, depletion and depreciation expense was $189.1 million compared to $145.0 million for the year ended December 31, 2012. The increase is primarily due to higher sales volumes and an increase in the rate per barrel as a result of an increase in GLJ's estimate of future development costs of the producing oil sands properties. The future development costs are a key element of the rate determination. Sales volumes increased by approximately 10% in the fourth quarter, and 17% year-to-date in 2013, as compared to the same periods in 2012. The depletion and depreciation rates for the three and twelve month periods ended December 31, 2013 were $15.56 per barrel, and $15.37 per barrel, respectively. This compared to depletion and depreciation rates of $14.98 per barrel for the three months ended December 31, 2012 and $13.76 per barrel for the year ended December 31, 2012. 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 Costs

	Three months ended December 31		Year ended December 31	
($000)	**2013**	**2012**	**2013**	**2012**
General and administrative costs	34,702	27,986	123,194	91,510
Capitalized general and administrative costs	(12,040)	(5,813)	(30,366)	(20,913)
General and administrative expense	22,662	22,173	92,828	70,597

General and administrative expense for the three months ended December 31, 2013 was $22.7 million, compared to $22.2 million for the same period in 2012. General and administrative expense for the year ended December 31, 2013 was $92.8 million compared to $70.6 million for the year ended December 31, 2012. 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 December 31		Year ended December 31	
($000)	**2013**	**2012**	**2013**	**2012**
Stock-based compensation costs	14,192	9,189	50,060	32,042
Capitalized stock-based compensation costs	(4,532)	(1,918)	(11,268)	(6,796)
Stock-based compensation expense	9,660	7,271	38,792	25,246

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 $9.7 million for the three months ended December 31, 2013, compared to $7.3 million for the three months ended December 31, 2012. For the year ended December 31, 2013, stock-based compensation expense was $38.8 million compared to $25.2 million for the year ended December 31, 2012. The increase in stock-based compensation for the periods ended December 31, 2013 compared to the same periods in 2012 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 $4.5 million of stock-based compensation to property, plant and equipment during the three months ended December 31, 2013, compared to $1.9 million during the three months ended December 31, 2012. The Corporation capitalized $11.3 million of stock-based compensation for the year ended December 31, 2013 compared to $6.8 million during the year ended December 31, 2012.

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 $1.6 million for the three months ended December 31, 2013, compared to $1.0 million for the three months ended December 31, 2012. For the year ended December 31, 2013, research and development expenditures were $5.6 million compared to $5.2 million for the year ended December 31, 2012.

Net Finance Expense

	Three months ended December 31		Year ended December 31	
($000)	**2013**	**2012**	**2013**	**2012**
Total interest expense	60,679	37,954	186,835	122,424
Less capitalized interest	(22,911)	(10,354)	(76,529)	(30,608)
Net interest expense	37,768	27,600	110,306	91,816
Accretion on decommissioning provision	1,017	999	4,763	3,670
Unrealized fair value (gain) loss on embedded derivative financial liabilities	(2,097)	(2,023)	(14,352)	2,953
Unrealized fair value (gain) loss on interest rate swaps	159	(556)	(4,904)	9,915
Realized loss on interest rate swaps	1,212	1,169	4,720	4,518
Fair value (gain) loss on other assets	919	-	-	(2,518)
Net finance expense	38,978	27,189	100,533	110,354
Average effective interest rate	6.2%	6.0%	6.0%	5.8%

Total interest expense was $60.7 million for the three months ended December 31, 2013, compared to $38.0 million for the three months ended December 31, 2012. The increase in the fourth quarter of 2013 is primarily due to the Corporation's issuance of US$1.0 billion in aggregate principal amount of 7.0% senior unsecured notes in the fourth quarter of 2013.

For the year ended December 31, 2013, total interest expense increased to $186.8 million compared to $122.4 million for the year ended December 31, 2012. Total interest expense increased primarily as a result of the increased debt outstanding. 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 $2.1 million during the fourth quarter of 2013, compared to an unrealized gain of $2.0 million during the fourth quarter of 2012. The Corporation recognized an unrealized gain on embedded derivative financial liabilities of $14.4 million for the year ended December 31, 2013 compared to an unrealized loss of $3.0 million for the same period in 2012. These gains and losses relate to the change in fair value of the interest rate floor associated with the Corporation's senior secured credit facilities. The interest rate floor is considered an embedded derivative as the floor rate was higher than the London Interbank Offered Rate ("LIBOR") at the time that the debt agreements were entered into. Accordingly, the fair value of the embedded derivatives at the time the debt agreements were entered into was netted against the carrying value of the long-term debt and is amortized over the life of the debt agreements. The fair value of the embedded derivative is included in derivative financial liabilities on the balance sheet and gains and losses associated with changes in the fair value of the embedded derivative are included in net finance expense.

The Corporation has entered into interest rate swap contracts to effectively fix the interest rate at approximately 4.4% on US$748.0 million of the US$1.3 billion senior secured term loan until September 30, 2016. The Corporation realized a $1.2 million loss on these contracts for the three months ended December 31, 2013 and a loss of $4.7 million for the year ended December 31, 2013. This compared to a realized loss of $1.2 million for the three months ended December 31, 2012 and a loss of $4.5 million for the year ended December 31, 2012. In addition, the Corporation recognized an unrealized loss of $0.2

million on these contracts for the three months ended December 31, 2013 and an unrealized gain of $4.9 million for the year ended December 31, 2013. This compared to an unrealized gain of $0.6 million and an unrealized loss of $9.9 million during the same periods in 2012.

Net Foreign Exchange Gain (Loss)

	Three months ended December 31		Year ended December 31	
($000)	**2013**	**2012**	**2013**	**2012**
Foreign exchange gain (loss) on:				
Long-term debt	(127,834)	(28,449)	(213,715)	48,822
US$ denominated cash and cash equivalents	15,409	7,695	36,353	(13,000)
Other	(1,180)	(372)	(2,916)	796
Net foreign exchange gain (loss)	(113,605)	(21,126)	(180,278)	36,618

C$-US$ exchange rate as at	**December 31, 2013**	**September 30, 2013**	**December 31, 2012**	**September 30, 2012**	**December 31, 2011**
C$ equivalent of 1 US$	1.0636	1.0285	0.9949	0.9837	1.0170

The Corporation recognized a net foreign exchange loss for the three months ended December 31, 2013 of $113.6 million in comparison to a net foreign exchange loss of $21.1 million for the three months ended December 31, 2012. For the year ended December 31, 2013, the net foreign exchange loss was $180.3 million compared to a net foreign exchange gain of $36.6 million for the year ended December 31, 2012. The Canadian dollar weakened by approximately 3% during the fourth quarter of 2013, while it weakened by approximately 1% during the fourth quarter of 2012. During the year ended December 31, 2013, the Canadian dollar weakened in value compared to the U.S. dollar by approximately 7%. In comparison, the Canadian dollar strengthened by approximately 2% during the year ended December 31, 2012.

Net Marketing Activity

	Three months ended December 31		Year ended December 31	
($000)	**2013**	**2012**	**2013**	**2012**
Sales of purchased product	54,154	19,323	101,750	37,822
Purchased product and storage	(55,285)	(20,860)	(104,115)	(39,584)
Net marketing activity	(1,131)	(1,537)	(2,365)	(1,762)

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 recovery of $2.9 million for the three months ended December 31, 2013, compared to a deferred income tax expense of $2.3 million for the three months ended December 31, 2012. Deferred income tax expense was $22.3 million for the year ended December 31, 2013 compared to $9.8 million for the year ended December 31, 2012.

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 non-taxable portion of foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt is a permanent difference. For the three months ended December 31, 2013, the non-taxable loss was $63.9 million compared to a non-taxable loss of $14.3 million for the same period in 2012. For the year ended December 31, 2013, the non-taxable loss was $106.9 million compared to a non-taxable gain of $24.4 million for the year ended December 31, 2012.

- As at December 31, 2013, the Corporation had not recognized the tax benefit related to $86.0 million in unrealized taxable capital foreign exchange losses.

- Non-taxable stock-based compensation expense was $9.7 million for the fourth quarter of 2013, in comparison to $7.3 million for the fourth quarter of 2012. For the year ended December 31, 2013, non-taxable stock-based compensation expense was $38.8 million compared to $25.2 million for the year ended December 31, 2012.

The Corporation is not currently taxable. As of December 31, 2013, the Corporation had approximately $6.8 billion of available tax pools and had recognized a deferred income tax liability of $93.8 million. In addition, at December 31, 2013, the Corporation had $508.1 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

SUMMARY OF QUARTERLY RESULTS

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

	2013				2012			
($ millions, except per share amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue	350.3	401.8	324.4	258.0	297.6	213.7	259.7	279.6
Net income (loss)	(148.2)	115.4	(62.3)	(71.3)	(18.7)	47.5	(29.5)	53.4
Per share – basic	(0.67)	0.52	(0.28)	(0.32)	(0.09)	0.24	(0.15)	0.28
Per share – diluted	(0.67)	0.51	(0.28)	(0.32)	(0.09)	0.24	(0.15)	0.27

Revenue for the eight most recent quarters has been impacted by an increase in production and fluctuations in blend sales pricing. Revenues in the second quarter of 2013 and the third quarter of 2012 had reduced production volumes as the result of scheduled annual maintenance activities at the Christina Lake facilities.

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

- increased production due to the implementation of RISER on Phases 1 and 2, which has allowed additional wells to be placed into production;
- 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);
- changes in the fair value of the LIBOR floor on the senior secured term loans (embedded derivative financial liability);
- risk management activities for interest rate swaps;
- an increase in depletion and depreciation expense as a result of the increase in production and higher estimated future development costs;
- higher general and administrative expense as a result of the planned increase in office staff to support growth;
- an increase in interest expense as a result of the increase in long-term debt;
- scheduled annual plant maintenance activities performed in May 2013 and September 2012; and
- the startup of Christina Lake Phase 2B.

CAPITAL INVESTING

	Three months ended December 31		Year ended December 31	
($000)	**2013**	**2012**	**2013**	**2012**
Christina Lake Phase 2B	1,215	138,572	200,789	631,495
Christina Lake Phase 3A	7,303	3,431	196,359	61,982
RISER	27,982	94,720	502,711	166,782
Inventory wells	30,875	40,824	132,260	92,277
Delineation drilling and seismic	6,326	27,535	93,025	127,959
Regulatory	2,024	882	5,109	5,577
Other	65,089	15,871	198,027	47,797
Growth	**140,814**	**321,835**	**1,328,280**	**1,133,869**
Access Pipeline	57,837	35,473	257,629	115,807
Stonefell Terminal	14,416	52,375	124,155	136,399
Field infrastructure	89,634	57,016	179,072	118,372
Infrastructure related to growth	**161,887**	**144,864**	**560,856**	**370,578**
Sustaining	42,481	11,588	100,305	42,277
Land and other	21,139	6,275	122,383	21,182
Cash capital investment	**366,321**	**484,562**	**2,111,824**	**1,567,906**
Capitalized interest	22,911	10,354	76,529	30,608
Total cash capital investment	**389,232**	**494,916**	**2,188,353**	**1,598,514**
Non-cash	5,138	5,307	39,799	21,169
Total capital investment	**394,370**	**500,223**	**2,228,152**	**1,619,683**

MEG's capital investment for the three months ended December 31, 2013 totalled $394.4 million (including capitalized interest of $22.9 million and non-cash items of $5.1 million), compared to $500.2 million (including capitalized interest of $10.4 million and non-cash items of $5.3 million) invested during the three months ended December 31, 2012. For the year ended December 31, 2013, capital investment was $2.2 billion (including capitalized interest of $76.5 million and non-cash items of $39.8 million) in comparison to $1.6 billion (including capitalized interest of $30.6 million and non-cash items of $21.2 million) for the year ended December 31, 2012. Capital investment included $140.8 million in growth focused investment during the fourth quarter of 2013 and $1.3 billion for the year ended December 31, 2013, compared to $321.8 million and $1.1 billion in the corresponding periods of 2012.

MEG invested $1.2 million in Phase 2B of the Christina Lake project during the fourth quarter of 2013, and $200.8 million during the year ended December 31, 2013. The Phase 2B facility is now complete and attained first oil in the fourth quarter of 2013.

The Corporation invested $7.3 million for the three months ended, and $196.4 million for the year ended December 31, 2013 on engineering, purchasing of long-lead equipment and materials, and site preparation activity for Phase 3A.

MEG invested $28.0 million during the fourth quarter of 2013 and $502.7 million during the year ended December 31, 2013 on RISER. The investment was made to accommodate the implementation of RISER on Phases 1 and 2 and to prepare Phase 2B for the first stage of adoption.

The Corporation invested $30.9 million for the drilling of inventory wells at the Christina Lake project during the fourth quarter of 2013 and $132.3 million during the year ended December 31, 2013. These inventory wells will be placed on production as freed-up steam becomes available from the implementation of the enhanced Modified Steam and Gas Push (eMSAGP) process.

The Corporation invested $6.3 million during the fourth quarter of 2013 on delineation drilling and seismic and $93.0 million during the year ended December 31, 2013. The Corporation drilled 132 stratigraphic wells, one water observation well and four water source wells to support horizontal well placement, further delineate the resource base at Christina Lake and to increase deliverability to the source water system. A total of 24 stratigraphic wells, one water source well and three water test wells were completed at Surmont.

Other capital investment during 2013 includes $128.1 million of commissioning costs for Phase 2B of the Christina Lake project. These commissioning costs include labour and services, spare parts and inventory, initial chemicals and lubricants, and demobilization costs required for the Phase 2B facility.

A total of $161.9 million was invested during the fourth quarter and $560.9 million during the year ended December 31, 2013 in the Corporation's growth-related infrastructure. During 2013 the Corporation invested $257.6 million on material purchases and construction related to the expansion of the 50%-owned Access Pipeline. Regulatory approval of the pipeline expansion was received in 2012 and over half of the expansion for the 300 kilometer pipeline has been installed. The expansion is expected to be complete and in service by the fourth quarter of 2014. Investment in the Stonefell storage terminal totaled $124.2 million for the year ended December 31, 2013. The Stonefell storage terminal is a 900,000 barrel marketing terminal that is connected to the Access Pipeline. The Corporation completed the commissioning of the terminal in the fourth quarter of 2013 and it is now operational. The Corporation also completed the connection from the Stonefell storage terminal to the Canexus operated rail terminal in the fourth quarter and has commenced shipping blend by unit-train rail facilities. The Corporation invested an additional $179.1 million in field infrastructure for current and future operations at Christina Lake.

The Corporation capitalizes interest associated with qualifying assets. During the three months ended December 31, 2013, $22.9 million of interest was capitalized, in comparison to $10.4 million during the three months ended December 31, 2012. A total of $76.5 million in interest was capitalized during the year ended December 31, 2013 compared to $30.6 million during the year ended December 31, 2012.

Land and other investments includes $39.0 million for land acquired northeast of Edmonton, Alberta in the second quarter of 2013 and $23.5 million to purchase undeveloped oil sands leases near Leismer, Alberta in the third quarter of 2013. Other investments include investments in administrative assets and amounts paid to maintain the right to participate in a potential pipeline project.

Non-cash capital investment for the three months ended December 31, 2013 included $4.5 million in capitalized stock-based compensation and $2.5 million in capitalized depletion and depreciation expense related to the commissioning of Phase 2B, partially offset by a $1.9 million reduction in the future reclamation and decommissioning provision associated with the Corporation's property, plant and equipment. Non-cash capital investment for the year ended December 31, 2013 included a $26.0 million provision for future reclamation and decommissioning of the Corporation's property, plant and equipment, $11.3 million in capitalized stock-based compensation and $2.5 million in capitalized depletion and depreciation expense related to the commissioning of Phase 2B.

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 February 27, 2013 (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 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 operating activities.

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.

QUARTERLY SUMMARIES

	2013				2012			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL ($000 unless specified)								
Net income (loss)	(148,182)	115,383	(62,312)	(71,294)	(18,740)	47,474	(29,534)	53,369
Per share, diluted	(0.67)	0.51	(0.28)	(0.32)	(0.09)	0.24	(0.15)	0.27
Operating earnings (loss)	(32,685)	56,171	13,612	(36,712)	(538)	(12,883)	11,134	23,529
Per share, diluted	(0.15)	0.25	0.06	(0.16)	0.00	(0.07)	0.06	0.12
Cash flow from operations	22,648	144,521	79,184	7,071	56,106	24,442	59,975	71,991
Per share, diluted	0.10	0.64	0.35	0.03	0.27	0.12	0.30	0.36
Capital investment	394,370	477,335	674,576	681,871	500,223	406,526	341,840	371,094
Cash, cash equivalents and short-term investments	1,179,072	647,096	1,203,457	1,803,338	2,007,841	1,607,036	1,111,150	1,402,390
Working capital	1,045,606	365,676	731,290	1,298,955	1,655,915	1,307,325	902,424	1,183,628
Long-term debt	4,004,575	2,857,740	2,923,382	2,823,207	2,488,609	2,461,676	1,751,552	1,718,474
Shareholders' equity	4,788,430	4,919,407	4,771,616	4,817,253	4,870,534	4,092,556	4,027,652	4,049,633
BUSINESS ENVIRONMENT								
West Texas Intermediate (WTI) US$/bbl	97.43	105.83	94.22	94.37	88.18	92.22	93.49	102.92
C$ equivalent of 1US$ - average	1.0477	1.0385	1.0233	1.0089	0.9913	0.9948	1.0102	1.0012
Differential – WTI vs blend ($/bbl)	41.48	23.50	26.17	39.96	26.13	29.54	29.83	32.10
Differential – WTI vs blend (%)	40.6%	21.4%	27.1%	41.9%	29.9%	32.2%	31.6%	31.2%
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bpd	42,251	34,246	32,144	32,531	32,292	23,941	30,429	28,446
Bitumen sales – bpd	35,990	34,256	32,175	32,393	32,722	23,876	30,229	28,567
Diluent usage – bpd	16,680	13,032	14,176	16,239	14,810	9,466	13,800	13,919
Blend sales – bpd	52,670	47,288	46,351	48,632	47,532	33,342	44,029	42,486
Steam to oil ratio (SOR)	2.9	2.5	2.3	2.5	2.4	2.5	2.4	2.5
Blend sales	60.60	86.40	70.25	55.24	61.29	62.19	64.62	70.95
Cost of diluent	(22.38)	(12.07)	(16.27)	(25.20)	(15.62)	(15.70)	(19.03)	(20.80)
Bitumen realization	38.22	74.33	53.98	30.04	45.67	46.49	45.59	50.15
Transportation – net	(0.51)	(0.20)	(0.17)	(0.12)	(0.05)	(0.93)	(0.03)	(0.37)
Royalties	(2.71)	(5.14)	(3.03)	(1.58)	(2.23)	(2.10)	(2.84)	(2.63)
Operating costs – non-energy	(8.09)	(9.20)	(10.00)	(8.81)	(8.70)	(15.23)	(7.79)	(8.24)
Operating costs – energy	(5.38)	(3.32)	(4.85)	(4.93)	(4.65)	(3.22)	(2.62)	(3.18)
Power sales	2.25	3.12	6.00	3.30	4.40	2.84	1.86	3.47
Cash operating netback	**23.78**	**59.59**	**41.93**	**17.90**	**34.44**	**27.85**	**34.17**	**39.20**
Power sales price (C$/MWh)	44.63	75.96	138.96	59.92	79.62	57.99	36.85	58.25
Power sales (MW/h)	76	59	58	74	75	49	64	71
Depletion and depreciation rate per bbl	15.56	15.54	15.13	15.16	14.98	13.39	13.01	13.44
COMMON SHARES								
Shares outstanding, end of period (000)	222,507	222,489	221,829	221,256	220,190	195,248	194,326	193,986
Volume traded (000)	33,400	28,403	43,789	28,495	20,370	13,578	21,560	18,230
Common share price ($)								
High	36.00	36.69	32.98	35.67	38.74	41.90	43.96	47.11
Low	28.60	28.81	25.50	30.89	30.25	35.20	32.92	36.73
Close (end of period)	30.61	35.54	28.83	32.61	30.44	37.39	36.49	38.46

Interim Financial Statements

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

As at December 31,	Note	2013	2012
Assets			
Current assets			
Cash and cash equivalents	20	**$ 1,179,072**	$ 1,474,843
Short-term investments		**-**	532,998
Trade receivables and other	6	**186,183**	110,823
Inventories	7	**129,943**	17,536
		1,495,198	2,136,200
Non-current assets			
Property, plant and equipment	8	**7,254,951**	5,267,885
Exploration and evaluation assets	9	**579,497**	554,349
Other intangible assets	10	**63,205**	46,033
Other assets	11	**54,890**	14,212
Total assets		**$ 9,447,741**	$ 8,018,679
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	12	**$ 416,288**	$ 463,077
Current portion of long-term debt	13	**13,827**	9,949
Current portion of provisions and other liabilities	14	**19,477**	7,259
		449,592	480,285
Non-current liabilities			
Long-term debt	13	**3,990,748**	2,478,660
Provisions and other liabilities	14	**125,177**	117,756
Deferred income tax liability		**93,794**	71,444
Total liabilities		**4,659,311**	3,148,145
Commitments and contingencies	22		
Shareholders' equity			
Share capital	15	**4,751,374**	4,694,378
Contributed surplus	15	**126,666**	102,219
Retained earnings (deficit)		**(92,493)**	73,912
Accumulated other comprehensive income		**2,883**	25
Total shareholders' equity		**4,788,430**	4,870,534
Total liabilities and shareholders' equity		**$ 9,447,741**	$ 8,018,679

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 December 31		Year ended December 31	
	Note	**2013**	2012	**2013**	2012
Petroleum revenue, net of royalties	16	**$ 338,832**	$ 280,621	**$ 1,270,757**	$1,003,838
Other revenue	17	**11,506**	16,957	**63,740**	46,666
		350,338	297,578	**1,334,497**	1,050,504
Diluent and transportation	18	**172,828**	134,360	**623,648**	512,814
Purchased product and storage		**55,285**	20,860	**104,115**	39,584
Operating expenses		**44,602**	40,163	**167,586**	139,019
Depletion and depreciation	8, 10	**51,508**	44,593	**189,147**	144,950
General and administrative		**22,662**	22,173	**92,828**	70,597
Stock-based compensation	15	**9,660**	7,271	**38,792**	25,246
Research and development		**1,645**	966	**5,588**	5,157
		358,190	270,386	**1,221,704**	937,367
Revenues less expenses		**(7,852)**	27,192	**112,793**	113,137
Other income (expense)					
Interest and other income		**7,986**	4,650	**22,550**	19,896
Gain on disposition of assets		**1,410**	-	**1,410**	3,075
Foreign exchange gain (loss), net		**(113,605)**	(21,126)	**(180,278)**	36,618
Net finance expense	19	**(38,978)**	(27,189)	**(100,533)**	(110,354)
		(143,187)	(43,665)	**(256,851)**	(50,765)
Income (loss) before income taxes		**(151,039)**	(16,473)	**(144,058)**	62,372
Deferred income tax expense (recovery)		**(2,857)**	2,267	**22,347**	9,803
Net income (loss)		**(148,182)**	(18,740)	**(166,405)**	52,569
Other comprehensive income					
Foreign currency translation adjustment		**3,039**	25	**2,858**	25
Comprehensive income (loss) for the period		**$(145,143)**	$(18,715)	**$ (163,547)**	$ 52,594
Net earnings (loss) per common share					
Basic	21	**$ (0.67)**	$ (0.09)	**$ (0.75)**	$ 0.27
Diluted	21	**$ (0.67)**	$ (0.09)	**$ (0.75)**	$ 0.26

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 as at January 1, 2013		**$ 4,694,378**	**$ 102,219**	**$ 73,912**	**$ 25**	**$ 4,870,534**
Share issue costs, net of tax		**79**				**79**
Stock options exercised	15	**40,522**	**(9,217)**			**31,305**
RSUs vested and released	15	**16,395**	**(16,395)**			**-**
Stock-based compensation	15		**50,059**			**50,059**
Net loss				**(166,405)**		**(166,405)**
Other comprehensive Income					**2,858**	**2,858**
Balance as at December 31, 2013		**$ 4,751,374**	**$ 126,666**	**$ (92,493)**	**$ 2,883**	**$ 4,788,430**
Balance as at January 1, 2012		$ 3,877,193	$ 85,568	$ 21,343	$ -	$ 3,984,104
Shares issued		800,125				800,125
Share issue costs, net of tax		(18,988)				(18,988)
Stock options exercised		26,520	(5,863)			20,657
RSUs vested and released		9,528	(9,528)			-
Stock-based compensation			32,042			32,042
Net income				52,569		52,569
Other comprehensive Income					25	25
Balance as at December 31, 2012		$ 4,694,378	$ 102,219	$ 73,912	$ 25	$ 4,870,534

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 December 31		Year ended December 31	
	Note	**2013**	2012	**2013**	2012
Cash provided by (used in):					
Operating activities					
Net income (loss)		**$ (148,182)**	$(18,740)	**$ (166,405)**	$ 52,569
Adjustments for:					
Depletion and depreciation	8,10	**51,508**	44,593	**189,147**	144,950
Stock-based compensation	15	**9,660**	7,271	**38,792**	25,246
Unrealized (gain) loss on foreign exchange		**112,425**	20,753	**177,362**	(35,822)
Unrealized (gain) loss on derivative financial liabilities	19	**(1,938)**	(2,579)	**(19,256)**	12,868
Deferred income tax expense (recovery)		**(2,857)**	2,267	**22,347**	9,803
Other		**2,032**	2,541	**11,437**	2,900
Net change in non-cash operating working capital	20	**(18,709)**	(7,615)	**(123,461)**	28,310
Net cash provided by operating activities		**3,939**	48,491	**129,963**	240,824
Investing activities					
Capital investments		**(389,232)**	(494,916)	**(2,188,353)**	(1,598,514)
Purchase of other assets	11	**373**	-	**(41,517)**	-
Proceeds on disposition of assets		**6,801**	-	**6,801**	7,456
Other		**2,426**	899	**(1,422)**	1,176
Net change in non-cash investing working capital items	20	**39,015**	(143,200)	**430,316**	(230,638)
Net cash used in investing activities		**(340,617)**	(637,217)	**(1,794,175)**	(1,820,520)
Financing activities					
Issue of shares, net of issue costs	15	**330**	781,176	**31,747**	795,466
Issue of long-term debt, net of issue costs	13	**1,021,418**	-	**1,322,540**	792,552
Repayment of long-term debt		**(3,457)**	(2,489)	**(13,506)**	(9,988)
Financing costs		**-**	-	**(8,693)**	(5,622)
Net cash provided by financing activities		**1,018,291**	778,687	**1,332,088**	1,572,408
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**15,409**	7,695	**36,353**	(13,000)
Change in cash and cash equivalents		**697,022**	197,656	**(295,771)**	(20,288)
Cash and cash equivalents, beginning of period		**482,050**	1,277,187	**1,474,843**	1,495,131
Cash and cash equivalents, end of period	20	**$ 1,179,072**	$1,474,843	**$ 1,179,072**	$ 1,474,843

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 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, 2012, 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, 2012. These interim consolidated financial statements should be read in conjunction with the Corporation's audited financial statements for the year ended December 31, 2012, which are included in the Corporation's 2012 annual report. The accompanying interim consolidated financial statements include all adjustments, comprised of normal recurring adjustments considered necessary by management to fairly state the Corporation's results of operations, financial position and cash flows. The operating results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the full year.

3. CHANGE IN ACCOUNTING POLICIES

The Corporation has adopted the following new and revised standards, along with all consequential amendments, effective January 1, 2013. These changes are made in accordance with the applicable transitional provisions.

IFRS 10, Consolidated Financial Statements, replaces the guidance on control and consolidation in IAS 27, Consolidated and Separate Financial Statements, and SIC-12, Consolidation – Special Purpose Entities. IFRS 10 requires consolidation of an investee only if the investor possesses power over the investee, has exposure to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect its returns. Detailed guidance is provided on applying the definition of control. The accounting requirements for consolidation have remained largely consistent with IAS 27. The Corporation assessed its consolidation conclusions on January 1, 2013 and determined that the adoption of IFRS 10 did not result in any change in the consolidation status of its wholly-owned subsidiary, MEG Energy (U.S.) Inc.

IFRS 11, Joint Arrangements, supersedes IAS 31, Interests in Joint Ventures, and requires joint arrangements to be classified either as joint operations or joint ventures depending on the contractual rights and obligations of each investor that jointly controls the arrangement. For joint operations, a company recognizes its share of assets, liabilities, revenues and expenses of the joint operation. An investment in a joint venture is accounted for using the equity method as set out in IAS 28, Investments in Associates and Joint Ventures. The other amendments to IAS 28 did not affect the Corporation. The Corporation classified its joint arrangements in accordance with IFRS 11 on January 1, 2013 and concluded that the adoption of the standard did not result in any changes in the accounting for its joint arrangements.

IFRS 13, Fair Value Measurement, provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. Under IFRS 13, the fair value of a liability must reflect the effect of non-performance risk, which includes an entity's own credit risk. Upon adoption of IFRS 13, the Corporation began including an estimate of its own credit risk in determining the fair value of its derivative financial liabilities. The Corporation adopted IFRS 13 and the required change in valuation techniques on January 1, 2013 on a prospective basis. Upon adoption of IFRS 13, derivative financial liabilities decreased by $1.8 million.

The Corporation has adopted the amendments to IAS 1, Presentation of Financial Statements, effective January 1, 2013. These amendments required the Corporation to group other comprehensive income items by those that will be reclassified subsequently to profit or loss and those that will not be reclassified. These changes did not result in any adjustments to other comprehensive income or comprehensive income.

The Corporation has adopted the amendments to IAS 19, Employee Benefits, effective January 1, 2013. These amendments make significant changes to the recognition and measurement of defined benefit pension expense and termination benefits and to enhance the disclosure of all employee benefits. The adoption of these amendments did not have an impact on the Corporation's consolidated financial statements.

4. PRINCIPLES OF CONSOLIDATION

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

5. FINANCIAL INSTRUMENTS AND DERIVATIVE FINANCIAL LIABILITIES

The financial instruments recognized on the balance sheet are comprised of cash and cash equivalents, short-term investments, trade receivables and other, components of other assets, accounts payable and accrued liabilities, derivative financial liabilities and long-term debt. As at December 31, 2013, short-term investments, components of 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, short-term investments, 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 components of other assets, derivative financial liabilities and long-term debt

			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**	**-**	**-**

			Fair value measurements using		
As at December 31, 2012	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	$ 7,581	$ 7,581	$ -	$ -	$ 7,581
Financial liabilities					
Derivative financial liabilities	37,195	37,195	-	37,195	-
Long-term debt	2,488,609	2,612,763	2,612,763	-	-

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 year ended December 31, 2013.

(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$1.275 billion senior secured term loan. At December 31, 2013, there was an unrealized loss on the interest rate swaps of $7.5 million (December 31, 2012 - $12.4 million).

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

(1) *London Interbank Offered Rate*

6. TRADE RECEIVABLES AND OTHER

As at December 31,		2013		2012
Trade receivables	$	**174,935**	$	104,008
Deposits and advances		**7,908**		4,757
Current portion of deferred financing costs		**3,340**		2,058
	$	**186,183**	$	110,823

7. INVENTORIES

As at December 31,		**2013**		2012
Diluent	$	**84,628**	$	14,778
Bitumen blend		**43,358**		1,948
Materials and supplies		**1,957**		810
	$	**129,943**	$	17,536

During the year ended December 31, 2013, a total of $601.2 million (2012 - $496.6 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, 2011	$	3,027,073	$	530,684	$	27,610	$	3,585,367
Additions		1,300,515		262,987		5,987		1,569,489
Disposals		(6,340)		-		-		(6,340)
Transfer from exploration and evaluation assets (note 9)		478,347		-		-		478,347
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**

Accumulated depletion and depreciation								
Balance as at December 31, 2011	$	197,469	$	15,758	$	3,321	$	216,548
Depletion and depreciation for the period		134,045		7,073		3,270		144,388
Disposals		(1,958)		-		-		(1,958)
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**

Carrying Amounts								
As at December 31, 2012	$	4,470,039	$	770,840	$	27,006	$	5,267,885
As at December 31, 2013	**$**	**5,980,243**	**$**	**1,244,995**	**$**	**29,713**	**$**	**7,254,951**

During the year ended December 31, 2013, the Corporation capitalized $30.4 million (year ended December 31, 2012 - $20.9 million) of general and administrative costs and $11.3 million (year ended December 31, 2012 - $6.8 million) of stock-based compensation costs relating to oil sands exploration and development activities. In addition, $76.5 million of interest and finance charges related to the development of capital projects were capitalized during the year ended December 31, 2013 (year ended December 31, 2012 - $30.6 million).

9. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2011	$	991,805
Additions		40,891
Transfer to property, plant and equipment (note 8)		(478,347)
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**

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 December 31, 2013, no impairment has been recognized on these assets.

10. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2011	$	38,186
Additions		9,303
Balance as at December 31, 2012	$	47,489
Additions		18,720
Balance as at December 31, 2013	**$**	**66,209**

Accumulated depreciation		
Balance as at December 31, 2011	$	894
Depreciation		562
Balance as at December 31, 2012	$	1,456
Depreciation		1,548
Balance as at December 31, 2013	**$**	**3,004**

Carrying Amounts		
As at December 31, 2012	$	46,033
As at December 31, 2013	**$**	**63,205**

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

As at December 31,		2013		2012
Long-term pipeline linefill[(a)]	**$**	**41,517**	$	-
MAV notes[(b)]		**-**		5,475
Auction rate securities ("ARS")[(c)]		**2,252**		2,106
Deferred financing costs[(d)]		**14,461**		8,689
		58,230		16,270
Less current portion of deferred financing costs		**(3,340)**		(2,058)
	$	**54,890**	$	14,212

(a) The Corporation has entered into an agreement to transport diluent on a third-party pipeline and is 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) In December 2013, the Corporation sold its remaining investment in the MAV notes for proceeds of $6.8 million and recognized a gain of $1.4 million.

(c) 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.

(d) 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

As at December 31,		2013		2012
Trade payables	**$**	**114,752**	$	51,651
Accrued liabilities		**230,984**		370,431
Interest payable		**56,564**		36,848
Other payables		**13,988**		4,147
	$	**416,288**	$	463,077

13. LONG-TERM DEBT

As at December 31,		2013		2012
Senior secured term loan (December 31, 2013 – US$1.275 billion; December 31, 2012 - US$987.5 million)[(a)]	**$**	**1,355,558**	$	982,464
6.5% senior unsecured notes (US$750 million)[(b)]		**797,700**		746,175
6.375% senior unsecured notes (US$800 million)[(c)]		**850,880**		795,920
7.0% senior unsecured notes (US$1.0 billion)[(d)]		**1,063,600**		-
		4,067,738		2,524,559
Less current portion of senior secured term loan		**(13,827)**		(9,949)
Less unamortized financial derivative liability discount		**(20,565)**		(10,324)
Less unamortized deferred debt issue costs		**(42,598)**		(25,626)
	$	**3,990,748**	$	2,478,660

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.0636 (December 31, 2012 - US$1 = C$0.9949).

There are no maintenance financial covenants associated with the Corporation's debt as at December 31, 2013 and 2012.

(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 December 31, 2013, $133.9 million (December 31, 2012 - $2.6 million) of the revolving credit facility was utilized to support letters of credit. As at December 31, 2013, no amount had been drawn under the revolving credit facility.

The senior secured credit facilities are comprised of a US$1.275 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 $6.1 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 $11.2 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 $12.2 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, beginning on March 31, 2014. No principal payments are required until March 31, 2024. The Corporation has deferred the associated remaining debt issue costs of $13.1 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

14. PROVISIONS AND OTHER LIABILITIES

As at December 31,		2013		2012
Derivative financial liabilities[a]	$	**30,981**	$	37,195
Decommissioning provision[b]		**108,695**		82,087
Deferred lease inducements[c]		**4,978**		5,733
Provisions and other liabilities		**144,654**		125,015
Less current portion		**(19,477)**		(7,259)
Non-current portion	$	**125,177**	$	117,756

(a) Derivative financial liabilities

As at December 31,		2013		2012
1% interest rate floor	$	**23,497**	$	24,807
Interest rate swaps		**7,484**		12,388
Derivative financial liabilities		**30,981**		37,195
Less current portion		**(13,886)**		(6,509)
Non-current portion	$	**17,095**	$	30,686

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 December 31, 2013, 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:

As at December 31,		**2013**		2012
Decommissioning provision, beginning of Year	**$**	**82,087**	$	65,360
Change in estimated future cash flow		**15,082**		-
Changes in discount rates		**(19,110)**		(3,846)
Liabilities incurred		**30,068**		18,218
Liabilities settled		**(4,195)**		(1,315)
Accretion		**4,763**		3,670
Decommissioning provision, end of year		**108,695**		82,087
Less current portion		**(4,848)**		-
Non-current portion	**$**	**103,847**	$	82,087

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 $108.7 million as at December 31, 2013 (December 31, 2012 - $82.1 million) based on an undiscounted total future liability of $293.8 million (December 31, 2012 - $228.1 million) and a credit-adjusted rate of 6.4% (December 31, 2012 – 5.7%). This obligation is estimated to be settled in periods up to 2064.

(c) Lease 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:

	2013			2012		
	Number of shares		**Amount**	Number of shares		Amount
Balance, beginning of year	**220,190,084**	**$**	**4,694,378**	193,471,705	$	3,877,193
Shares issued	**-**		**-**	24,246,212		800,125
Share issue costs, net of tax	**-**		**79**	-		(18,988)
Issued upon exercise of stock options	**1,893,732**		**40,522**	2,243,319		26,520
Issued upon vesting and release of RSUs	**423,080**		**16,395**	228,848		9,528
Balance, end of year	**222,506,896**	**$**	**4,751,374**	220,190,084	$	4,694,378

On December 28, 2012, the Corporation issued 24,246,212 common shares at a price of $33.00 per share for gross proceeds of $800.1 million.

(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 by the third anniversary of the grant date and expire seven years after the grant date.

	2013			2012		
	Stock options		**Weighted average exercise price per share**	Stock options		Weighted average exercise price per share
Outstanding, beginning of year	**9,147,404**	**$**	**32.50**	10,190,103	$	27.12
Granted	**1,774,854**		**30.95**	1,456,537		35.67
Exercised	**(1,893,732)**		**16.53**	(2,243,319)		9.21
Forfeited	**(169,498)**		**38.19**	(255,917)		40.29
Outstanding, end of year	**8,859,028**	**$**	**35.49**	9,147,404	$	32.50

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

The Restricted Share Unit Plan allows for the granting of Restricted Share Units ("RSUs"), (including Performance Share Units ("PSUs"), effective June 13, 2013) 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	**2013**	2012
Outstanding, beginning of year	**953,804**	554,362
Granted	**2,157,534**	664,796
Vested and released	**(423,080)**	(228,848)
Forfeited	**(98,558)**	(36,506)
Outstanding, end of year	**2,589,700**	953,804

(e) Deferred share units outstanding:

Effective June 13, 2013, the Corporation's Board of Directors approved the Deferred Share Unit Plan. 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 December 31, 2013, there were 8,874 DSUs outstanding.

(f) Contributed Surplus:

		2013		2012
Balance, beginning of year	**$**	**102,219**	$	85,568
Stock-based compensation - expensed		**38,792**		25,246
Stock-based compensation - capitalized		**11,267**		6,796
Stock options exercised		**(9,217)**		(5,863)
RSUs vested and released		**(16,395)**		(9,528)
Balance, end of year	**$**	**126,666**	$	102,219

16. PETROLEUM REVENUE

	Three months ended December 31				Year ended December 31			
		2013		2012		**2013**		2012
Petroleum sales:								
Proprietary	**$**	**293,657**	$	268,007	**$**	**1,207,650**	$	991,975
Third party		**54,154**		19,323		**101,750**		37,822
		347,811		287,330		**1,309,400**		1,029,797
Royalties		**(8,979)**		(6,709)		**(38,643)**		(25,959)
Petroleum revenue	**$**	**338,832**	$	280,621	**$**	**1,270,757**	$	1,003,838

17. OTHER REVENUE

	Three months ended December 31				Year ended December 31			
		2013		2012		**2013**		2012
Power revenue	**$**	**7,448**	$	13,248	**$**	**44,456**	$	33,634
Transportation revenue		**4,058**		3,709		**19,284**		13,032
Other revenue	**$**	**11,506**	$	16,957	**$**	**63,740**	$	46,666

18. DILUENT AND TRANSPORTATION

	Three months ended December 31				Year ended December 31			
		2013		2012		**2013**		2012
Diluent	**$**	**167,094**	$	130,731	**$**	**601,191**	$	496,548
Transportation		**5,734**		3,629		**22,457**		16,266
Diluent and transportation	**$**	**172,828**	$	134,360	**$**	**623,648**	$	512,814

19. NET FINANCE EXPENSE

	Three months ended December 31		Year ended December 31	
	2013	2012	**2013**	2012
Total interest expense	**$ 60,679**	$ 37,954	**$ 186,835**	$ 122,424
Less capitalized interest	**(22,911)**	(10,354)	**(76,529)**	(30,608)
Net interest expense	**37,768**	27,600	**110,306**	91,816
Accretion on decommissioning provision	**1,017**	999	**4,763**	3,670
Unrealized fair value (gain) loss on embedded derivative liabilities	**(2,097)**	(2,023)	**(14,352)**	2,953
Unrealized fair value (gain) loss on interest rate swaps	**159**	(556)	**(4,904)**	9,915
Realized loss on interest rate swaps	**1,212**	1,169	**4,720**	4,518
Unrealized fair value (gain) loss on other assets	**919**	-	**-**	(2,518)
Net finance expense	**$ 38,978**	$ 27,189	**$ 100,533**	$ 110,354

20. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended December 31		Year ended December 31	
	2013	2012	**2013**	2012
Changes in non-cash working capital				
Operating activities:				
Trade receivables and other	**$ (17,651)**	$(60,495)	**$ (75,107)**	$ 26,640
Inventories[(a)]	**(98,243)**	(1,894)	**(105,276)**	(8,329)
Accounts payable and accrued liabilities	**97,185**	54,774	**56,922**	9,999
Change in operating non-cash working capital	**$ (18,709)**	$(7,615)	**$ (123,461)**	$ 28,310
Investing activities:				
Short-term investments	**$ 165,046**	$ (203,149)	**$ 532,998**	$ (381,060)
Accounts payable and accrued liabilities	**(126,031)**	60,978	**(103,711)**	151,451
Trade receivables and other	**-**	(1,029)	**1,029**	(1,029)
Change in investing non-cash working capital	**$ 39,015**	$(143,200)	**$ 430,316**	$ (230,638)
Change in total non-cash working capital	**$ 20,306**	$ (150,815)	**$ 306,855**	$ (202,328)
Cash and cash equivalents:				
Cash	**$ 1,065,179**	$ 224,241	**$ 1,065,179**	$ 224,241
Cash equivalents	**113,893**	1,250,602	**113,893**	1,250,602
	$ 1,179,072	$ 1,474,843	**$ 1,179,072**	$ 1,474,843

(a) The three months and year ended December 31, 2013 amounts exclude a non-cash increase in inventory of $7,131 (2012 – nil).

21. NET EARNINGS (LOSS) PER COMMON SHARE

	Three months ended December 31		Year ended December 31	
	2013	2012	**2013**	2012
Net income (loss)	**$ (148,182)**	$ (18,740)	**$ (166,405)**	$ 52,569
Weighted average common shares outstanding	**222,502,613**	203,799,672	**221,800,594**	196,667,540
Dilutive effect of stock options, RSUs and PSUs	**2,639,113**	2,341,589	**2,508,677**	3,294,847
Weighted average common shares outstanding – diluted	**225,141,726**	206,141,261	**224,309,271**	199,962,387
Net earnings (loss) per share, basic	**$ (0.67)**	$ (0.09)	**$ (0.75)**	$ 0.27
Net earnings (loss) per share, diluted	**$ (0.67)**	$ (0.09)	**$ (0.75)**	$ 0.26

22. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at December 31, 2013:

Operating:

	2014	2015	2016	2017	2018	Thereafter
Office lease rentals	$12,288	$12,491	$12,901	$30,710	$30,797	$315,330
Diluent purchases	120,546	16,305	16,305	16,305	16,305	85,590
Transportation and storage	135,897	127,614	147,599	238,061	207,197	2,832,426
Other commitments	13,686	10,597	5,039	4,517	4,502	49,485
Commitments	$282,417	$167,007	$181,844	$289,593	$258,801	$3,282,831

Capital:

As part of normal operations, the Corporation has entered into a total of $153.0 million in capital commitments to be made in periods through 2018.

(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.

Reserves and Resources

The Corporation has identified two projects on its oil sands leases, Christina Lake and Surmont. The Christina Lake project consists of 80 contiguous square miles of oil sands leases. Thirty miles north of Christina Lake, MEG holds 32 square miles of oil sands leases at Surmont. Outside of Christina Lake and Surmont, MEG also holds over 800 sections of oil sands leases that the Corporation refers to as the Growth Properties. The Growth Properties are currently in the resource definition stage of development and provide significant additional development opportunities.

GLJ, an independent reservoir engineering firm, was commissioned by MEG to evaluate the reserves and resources of the Corporation's oil sands leases. GLJ evaluated Christina Lake, Surmont and a portion of the Growth Properties. Collectively 453 sections of MEG's 970 sections of oil sands leases were evaluated. GLJ's reserves and resources report is effective as of December 31, 2013.

GLJ prepared estimates of reserves and resources in accordance with National Instrument 51-101 of the Canadian Securities Administrators entitled Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), as well as the Canadian Oil and Gas Evaluation Handbook, or COGE Handbook, prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society). MEG's complete annual disclosure required under NI 51-101 will be contained within MEG's annual information form to be filed on or before March 31, 2014.

The information set forth below relating to the Corporation's reserves and resources constitutes forward-looking information which is subject to certain risks and uncertainties. See "Forward-Looking Information" for important information regarding the Corporation's reserves and resources.

According to GLJ, MEG's proved reserves (1P) are 1,446 million barrels of bitumen. The Corporation's proved-plus-probable (2P) reserves are 2,897 million barrels and its best estimate contingent resources (2C) are 3,653 million barrels. It is estimated that Christina Lake can support over 200,000 barrels per day of sustained production for 30 years and that Surmont can support over 100,000 barrels per day of sustained production for over 20 years. These production capacities are based on the GLJ estimates of 2P reserves and 2C resources as of December 31, 2013.

In addition to the reported reserves, Christina Lake, Surmont and the Growth Properties also have "resources", which are quantities of recoverable bitumen that have not met the reserves requirements at this time. Some of these resources are classified as contingent resources, pending further delineation drilling, development planning, project design and regulatory submissions or approvals. The contingent resources values set out below should be considered indicative in nature only, pending further project design work to confirm project economics, development timing and capital estimates.

GLJ assigned contingent resources (best estimate) totalling 3,653 million barrels for the MEG leases it evaluated which consists of 946 million barrels for Christina Lake, 404 million barrels for Surmont and 2,303 million barrels for the Growth Properties. See footnotes three, four and five of the table below for further information regarding the meaning of contingent resources (best estimate).

The table below summarizes the proved and probable reserves and contingent resources (best estimate) volumes and values based on GLJ's evaluation.

Bitumen Reserves and Contingent Resources As at December 31 Bitumen Reserves (millions of barrels, before royalties)	2013	2012	% Change
Proved (1P) Reserves(1)	1,446	1,284	12.6
Probable Reserves(2)	1,451	1,360	6.7
Proved Plus Probable (2P) Reserves(1)(2)	2,897	2,644	9.6
Bitumen Contingent Resources (millions of barrels, before royalties)			
Best Estimate Contingent Resources (2C)(3)(4)(5)	3,653	3,420	6.8

Pre-tax 10% Present Value of Future Net Cash Flows(6) As at December 31 Bitumen Reserves ($ millions)	2013	2012	% Change
Proved (1P) Reserves(1)(6)	13,521	10,484	29.0
Probable Reserves(2)(6)	7,501	6,354	18.1
Proved Plus Probable (2P) Reserves(2)(6)	21,022	16,838	24.8
Bitumen Contingent Resources ($ millions)			
Best Estimate Contingent Resources (2C)(3)(4)(5)	14,008	10,265	36.5

(1) *"Proved Reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Proved Reserves are also referred to as "1P Reserves".*

(2) *"Probable Reserves" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Proved-plus-probable reserves are also referred to as "2P Reserves".*

(3) *"Contingent Resources" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Such contingencies include further reservoir delineation, additional facility and reservoir design work, submission of regulatory applications and the receipt of corporate approvals. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.*

(4) *There are three categories in evaluating Contingent Resources: Low Estimate, Best Estimate and High Estimate. The resource numbers presented all refer to the Best Estimate category. Best Estimate is a classification of resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate. Best Estimate Contingent Resources are also referred to as "2C Resources".*

(5) *These volumes are the arithmetic sums of the Best Estimate Contingent resources for Christina Lake, Surmont and Growth Properties.*

(6) *The estimated future net cash flows do not represent the fair market values of MEG's reserves or resources.*

GLJ Forecast Pricing (as utilized in the GLJ 2013 Report)					
Forecast	Light and Medium Crude Oil	Exchange Rate	Bitumen Wellhead Current	Natural Gas	Inflation Rate
	WTI at Cushing, Oklahoma (US$/bbl)	US$/Cdn$	(Cdn$/bbl)	AECO Spot (Cdn$/mmcf)	%/year
2014	97.50	0.95	64.89	4.03	2%
2015	97.50	0.95	74.29	4.26	2%
2016	97.50	0.95	72.30	4.50	2%
2017	97.50	0.95	68.12	4.74	2%
2018	97.50	0.95	69.00	4.97	2%
2019	97.50	0.95	73.50	5.21	2%
2020	98.54	0.95	72.93	5.33	2%
2021	100.51	0.95	72.92	5.44	2%
2022	102.52	0.95	74.63	5.55	2%
2023	104.57	0.95	76.36	5.66	2%
2024+	+2%/year	0.95	+2%/year	+2%/yr	2%