SECOND QUARTER 2013

Report to Shareholders for the period ended June 30, 2013

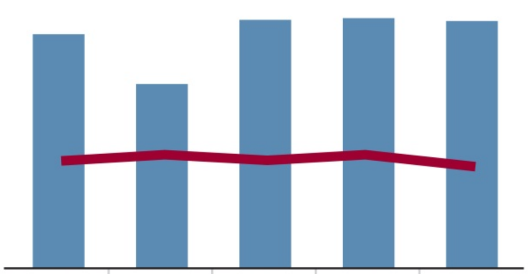
MEG Energy Corp. reported second quarter 2013 operational and financial results on July 30, 2013. Highlights include:

- Phase 2B water treatment and steam generation facilities are mechanically complete, with commissioning underway and steaming set to begin later in the third quarter, with first oil planned in the fourth quarter;
- Near-record quarterly production volumes of 32,144 barrels of bitumen per day (bpd);
- A highly efficient steam-oil ratio of 2.3, reflecting continued deployment of MEG's eMSAGP technology;
- Net operating costs of $8.85 per barrel;
- Strong cash operating netbacks at $41.93 per barrel, primarily due to narrowing light-heavy crude oil differentials;
- Revolving credit facility increased from US$1 billion to US$2 billion (which remains undrawn) and maturity extended to 2018.

MEG's production during the second quarter of 2013 increased by 6% to an average 32,144 bpd, from a second quarter 2012 production average of 30,429 bpd. For the first six months of 2013, production increased by 10% to 32,337 bpd from 29,411 bpd in the first half of 2012.

"We're very pleased with our performance this quarter, especially considering the impact of maintenance and tie-in work that took place in May," said Bill McCaffrey, President and Chief Executive Officer. "As we continue to roll out the RISER initiative, and with plans to start up Phase 2B later this year, we're set for a very strong second half." MEG is targeting 2013 exit rates of 37,000 to 43,000 bpd and annual average production volumes of 32,000 to 35,000 bpd.

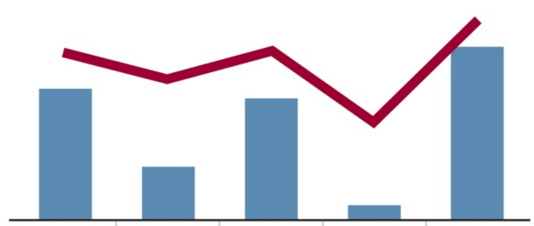
Operational Performance



	Q2/12	Q3/12*	Q4/12	Q1/13	Q2/13*
Production (bpd)	30,429	23,941	32,292	32,531	32,144
SOR	2.4	2.5	2.4	2.5	2.3

* Scheduled annual plant maintenance

Financial Performance



	Q2/12	Q3/12*	Q4/12	Q1/13	Q2/13*
Cash flow from operations ($mm)	60.0	24.4	56.1	7.1	79.2
Cash operating netback ($/bbl)	34.17	27.85	34.44	17.90	41.93

* Scheduled annual plant maintenance

Net operating costs, which include natural gas energy costs and revenues from electricity sales, were $8.85 per barrel in the second quarter of 2013 compared to $8.55 in the second quarter of 2012. Second quarter 2013 non-energy operating costs averaged $10.00 per barrel and remain within 2013 guidance of $9 to $11 per barrel.

High production volumes, low operating costs and stronger price realizations in the second quarter of 2013 generated cash flow of $79.2 million ($0.35 per share, diluted), compared to cash flow of $60.0 million ($0.30 per share, diluted) in the second quarter of 2012.

Operating earnings, which are adjusted for items that are not indicative of operating performance, were $13.6 million ($0.06 per share, diluted) in the second quarter of 2013 compared to $11.1 million ($0.06 per share, diluted) in the same period of 2012, reflecting the same factors that impacted cash flow from operations.

MEG recorded a $62.3 million net loss ($0.28 per share, diluted) in the second quarter of 2013, compared to a net loss of $29.5 million ($0.15 per share, diluted) in the second quarter of 2012. The net loss in the second quarter of 2013 is primarily due to an unrealized foreign exchange loss of $82.4 million (before tax) on the translation of the company's U.S. dollar denominated debt, net of U.S. dollar cash and cash equivalents, as the Canadian dollar lost value relative to the U.S. dollar.

Capital and Growth Strategy

MEG's management believes the company has the financial resources in place, including working capital of $731 million and an undrawn US$2.0 billion revolving credit facility, to execute its plans to increase production to 80,000 bpd by early 2015.

"Increased production is expected to drive a substantial increase in cash flow, which enables a larger portion of future capital spending to be internally funded," said McCaffrey.

As part of RISER, in the second quarter MEG tied-in 13 new infill wells in the Phase 2 area that are expected to ramp up through the second half of 2013 and into early 2014 with the continued deployment of eMSAGP technology.

Phase 2B water treatment and steam generating facilities are now mechanically complete and in the commissioning process, with start-up of steaming planned for late in the third quarter. Completion of oil treating facilities and first oil are expected in the fourth quarter. Phase 2B has a design capacity of 35,000 bpd at a conservative steam-oil ratio of 2.8. However, with many of the elements of the RISER initiative already built into the plant's design, MEG anticipates that we will be able to increase throughput beyond the base design level.

Marketing Strategy

In addition to growing its production base, MEG continues to pursue strategies to expand the company's reach to higher-value crude oil markets. MEG now has all 18 of its leased barges available for use, as needed, to move products along the U.S. Inland Waterway system to the Gulf Coast. MEG also expects connections between its Stonefell Terminal and an Edmonton-area rail loading facility, which is scheduled for operation later this year, to provide further transportation options.

“While we’ve seen differentials between Western Canadian heavies and WTI narrow significantly this quarter, we are taking a longer-term view with the goal of significantly mitigating that differential volatility from our future revenues,” said McCaffrey. “Having a full suite of market options will help move us toward world pricing and support greater price stability, regardless of short-term market swings.

Forward-Looking Information and Non-IFRS Financial Measures

This quarterly report contains forward-looking information and financial measures that are not defined by IFRS and should be read in conjunction with the "Forward-Looking Information" and Non-IFRS Financial Measures" sections of this quarter's Management's Discussion and Analysis.

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three and six months ended June 30, 2013 is dated July 29, 2013. This MD&A should be read in conjunction with the Corporation's MD&A for the year ended December 31, 2012, the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2012 and the unaudited condensed consolidated interim financial statements and notes thereto for the period ended June 30, 2013. All tabular amounts are stated in thousands of Canadian dollars ($ or C$) unless indicated otherwise.

MD&A – Table of Contents

1. OVERVIEW

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

MEG owns a 100% working interest in over 900 sections of oil sands leases. In a report (the "GLJ Report") dated as at December 31, 2012, GLJ Petroleum Consultants Ltd. ("GLJ") estimated that the oil sands leases it had evaluated contained 2.6 billion barrels of proved plus probable bitumen reserves and 3.4 billion barrels of contingent bitumen resources (best estimate).

The Corporation has identified two commercial SAGD projects; the Christina Lake project and the Surmont project. MEG believes, as supported by estimates in the GLJ Report, that the Christina Lake project can support an average of over 210,000 barrels per day ("bpd") of sustained production for 30 years and that the Surmont project can support an average of 120,000 bpd of sustained production for 20 years. In addition, the Corporation holds additional leases (the “Growth Properties”) that are in the resource definition stage and that could provide significant additional development opportunities.

MEG is currently focused on the phased development of the Christina Lake project. MEG's first two production phases at the Christina Lake project, Phases 1 and 2, commenced production in 2008 and 2009, respectively, with an initial combined design production capacity of 25,000 bpd. Phase 2B, an expansion with an initial design production capacity of 35,000 bpd, is anticipated to commence initial production late in the fourth quarter of 2013. In 2012, the Corporation announced the RISER initiative and now expects to reach a total production target from Christina Lake Phases 1, 2, and 2B of approximately 80,000 bpd by early 2015. Phase 3 is expected to be developed in a number of sub-phases. Once Phase 3 is complete, the design production capacity at the Christina Lake Project is expected to reach 210,000 bpd. MEG received regulatory authorization to proceed with Phase 3, following approvals issued by the Energy Resources and Conservation Board and by Alberta Environment and Sustainable Development in 2012.

MEG’s Surmont project, which is situated along the same geological trend as Christina Lake, has an anticipated design production capacity of approximately 120,000 bpd over multiple phases. MEG filed a regulatory application for the project in September 2012. The proposed project will use SAGD technology and include multi-well production pads, electricity and steam cogeneration and other facilities similar to MEG’s current Christina Lake project. The project is located approximately 80 kilometers south of Fort McMurray and approximately 50 kilometers north of the Corporation’s Christina Lake operations. This area has been extensively explored and developed for natural gas projects, and more recently for oil sands resources. Other thermal recovery projects are already operating in this area.

MEG also holds a 50% direct interest in the Access Pipeline, a strategic dual pipeline system that connects the Christina Lake project to a regional upgrading, refining, diluent supply and transportation hub in the Edmonton, Alberta area.

In addition to the Access Pipeline, MEG owns the Stonefell Terminal, a terminal and storage facility currently under construction near Edmonton, Alberta. When complete in the fourth quarter of 2013, the Stonefell Terminal will be connected to the Access Pipeline and provide approximately 900,000 bbls of strategic storage capacity. The Stonefell Terminal is also expected to provide MEG with access to a variety of markets and with access to multiple sources of diluent.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

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

	Three months ended June 30		Six months ended June 30	
	2013	**2012**	**2013**	**2012**
Bitumen production – bpd	32,144	30,429	32,337	29,411
Steam to oil ratio (SOR)	2.3	2.4	2.4	2.4
West Texas Intermediate (WTI) US$/bbl	94.22	93.49	94.30	98.21
Differential – Blend vs WTI - %	27.1%	31.6%	34.7%	31.4%
Bitumen realization - $/bbl	53.98	45.59	42.04	47.81
Net operating costs(1) - $/bbl	8.85	8.55	9.65	8.25
Cash operating netback(2) - $/bbl	41.93	34.17	29.94	36.62
Capital cash investment - $000	653,827	339,077	1,322,759	703,939
Net income (loss) - $000	(62,312)	(29,534)	(133,606)	23,835
Per share, diluted	(0.28)	(0.15)	(0.60)	0.12
Operating earnings (loss) - $000(3)	13,612	11,134	(23,100)	34,663
Per share, diluted(3)	0.06	0.06	(0.10)	0.18
Cash flow from operations - $000(3)	79,184	59,975	86,255	131,966
Per share, diluted(3)	0.35	0.30	0.39	0.67
Cash, cash equivalents and short-term investments - $000	1,203,457	1,111,150	1,203,457	1,111,150
Long-term debt - $000	2,923,382	1,751,522	2,923,382	1,751,522

(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 production and power revenues, on a per barrel basis. Please refer to note 3 of the Cash Operating Netbacks table within "RESULTS OF OPERATIONS."*

(3) *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.*

Bitumen production for the three months ended June 30, 2013 averaged 32,144 bpd compared to 30,429 bpd for the same period in 2012. During the second quarter of 2013, production was constrained for approximately two weeks due to work on the provincial electrical grid. The Corporation used this two week period to perform its annual plant maintenance activities, that have in the past been carried out during the third quarter. Production for the first half of 2013 averaged 32,337 bpd compared to 29,411 bpd for the first half of 2012. The increase in production is the result of expanded steam generation capacity and reservoir efficiency measures that have allowed additional wells to be placed into production.

Bitumen realizations increased in the second quarter of 2013 compared to the second quarter of 2012, as the price of WTI increased and the differential between WTI and the Corporation's blend sales price decreased. The price of West Texas Intermediate ("WTI") increased to an average of US$94.22 per barrel during the second quarter of 2013 from US$93.49 per barrel during the second quarter of 2012. The differential between the price of WTI and the Corporation's blend sales price was 27.1% in the second quarter of 2013, compared to 41.9% in the first quarter of 2013 and 31.6% for the second quarter of 2012. Bitumen realizations for the first half of 2013 were lower than the comparable period in 2012, as the price of WTI decreased and the differential between WTI and the Corporation's blend sales increased. The price of WTI averaged US$94.30 per barrel during the first six months of 2013 compared to $98.21 per barrel during the same period in 2012. For the six months ended June 30, 2013 the differential between WTI and the Corporation's blend sales price was 34.7% compared to a differential of 31.4% for the six months ended June 30, 2012.

Net operating costs for the three months ended June 30, 2013 were $8.85 per barrel, compared to $8.55 per barrel for the three months ended June 30, 2012. Net operating costs for the six months ended June 30, 2013 were $9.65 per barrel compared to $8.25 per barrel for the six months ended June 30, 2012. The increase in net operating costs was the result of:

- an increase in energy operating costs, primarily as a result of higher natural gas prices, which increased from an average of $1.89 per mcf during the second quarter of 2012, to $3.51 per mcf during the second quarter of 2013, and from $2.01 per mcf during the first half of 2012 to $3.35 per mcf for first half of 2013; and

- an increase in non-energy operating costs, as a result of higher camp and labor costs, and the scheduled plant maintenance that was performed in the second quarter of 2013 to coincide with outages imposed by the electrical grid operator.

Energy and non-energy operating costs were partially offset by power sales. Power sales had the effect of offsetting 124% of energy operating costs during the second quarter of 2013 compared to 71% of energy operating costs during the second quarter of 2012. Power sales had the effect of offsetting 95% of energy operating costs during the first half of 2013 compared to 91% of energy operating costs during the first half of 2012. Numerous Alberta power plant outages during the second quarter of 2013, combined with an increase in demand, led to a substantial increase in average realized power prices.

Cash operating netback for the three months ended June 30, 2013 was $41.93 per barrel compared to $34.17 per barrel for the same period in 2012. The increase in cash operating netback for the second quarter of 2013 was due largely to the increase in bitumen realizations as compared to the second quarter of 2012. Cash operating netback for the first six months of 2013 was $29.94 per barrel compared to $36.62 per barrel for the first six months of 2012. Cash operating netbacks for the first half of 2013 were negatively impacted by a decrease in the Corporation's bitumen realizations compared to the first half of 2012, primarily as a result of higher differentials in the first quarter of 2013.

Capital investment was $653.8 million during the second quarter of 2013 compared to $339.1 million during the second quarter of 2012. Capital investment for the first six months of 2013 was $1.3 billion compared to $0.7 billion for the first six months of 2012. Capital investment during 2013 has focused on the completion of Phase 2B, front-end engineering and design for Phase 3A, delineation drilling at Christina Lake and Surmont, the RISER initiative, construction of the Stonefell Terminal, and expansion of the Access Pipeline.

The Corporation recognized a net loss for the second quarter of 2013 of $62.3 million compared to a net loss of $29.5 million for the second quarter of 2012, largely due to a net foreign exchange loss of $84.0 million in the second quarter of 2013. The foreign exchange loss primarily results from the net effect of translation of the Corporation's U.S. dollar denominated debt and U.S. dollar cash and cash equivalents. This compared to a net foreign exchange loss of $34.4 million in the second quarter of 2012. The net loss for the six months ended June 30, 2013 was $133.6 million compared to net income of $23.8 million for the six months ended June 30, 2012. Net income (loss) for the six months ended June 30, 2013 included a net foreign exchange loss of $126.2 million compared to a net foreign exchange loss of $5.8 million for the six months ended June 30, 2012. Net income (loss) for the first half of 2013 has also been impacted by lower bitumen realizations during the first three months of 2013 and higher net operating costs in 2013 compared to 2012.

Operating earnings for the three months ended June 30, 2013 were $13.6 million compared to operating earnings of $11.1 million for the three months ended June 30, 2012. The increase in operating earnings for the second quarter of 2013 compared to the second quarter of 2012 is due mainly to the increase in bitumen realizations and the increase in production. The Corporation recognized an operating loss for the first half of 2013 of $23.1 million compared to operating earnings of $34.7 million for the first half of 2012. The decrease in operating earnings in the first half of 2013 compared to the first half of 2012 is primarily due to the decrease in bitumen realizations during the first three months of 2013.

Cash flow from operations was $79.2 million for the second quarter of 2013, compared to $60.0 million for the second quarter of 2012. Cash flow from operations was $86.3 million for the six months ended June 30, 2013, compared to $132.0 million for the six months ended June 30, 2012. Cash flow from operations was impacted by the same factors that impacted operating earnings.

The Corporation's cash, cash equivalents and short-term investments balance was $1.2 billion as at June 30, 2013 compared to $1.1 billion as at June 30, 2012. Long-term debt increased to $2.9 billion as at June 30, 2013, from $1.8 billion as at June 30, 2012. On July 19, 2012, the Corporation issued US$800.0 million in aggregate principal amount of 6.375% senior unsecured notes due January 30, 2023. On December 28, 2012, the Corporation issued 24.2 million common shares at a price of $33.00 per share for net proceeds of $774.8 million. 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 million. In addition, the Corporation reduced the interest rate on the term loan by 0.25 percent.

As at June 30, 2013, the Corporation's capital resources included $1.2 billion of cash, cash equivalents and short-term investments. In addition, on May 24, 2013, the Corporation expanded its undrawn senior secured revolving credit facility from US$1.0 billion to US$2.0 billion and extended the maturity by one year to May 24, 2018.

3. OUTLOOK

The Corporation anticipates that annual bitumen production volumes for 2013 will be in the 32,000 to 35,000 bpd range. Following the start-up of Christina Lake Phase 2B, production is expected to ramp-up toward a year-end exit rate of 37,000 to 43,000 bpd. Annual non-energy operating costs are anticipated to be in the range of $9 to $11 per barrel.

The construction of the Phase 2B project is now substantially complete. The water treatment and steam generating facilities for Phase 2B are mechanically complete and the oil treating facilities are nearing completion. The Corporation is now focused on commissioning these facilities, with plans to commence steam generation and steam injection to Phase 2B well pairs late in the third quarter of 2013. The Stonefell Terminal is also anticipated to be mechanically complete in the third quarter of 2013 and commissioned in the fourth quarter of 2013. The Corporation's remaining budgeted 2013 capital investment totals approximately $0.7 billion, and will be directed towards:

- the RISER initiative, which is focused on increasing production and throughput capacity from Christina Lake Phases 1, 2, and 2B to 80,000 bpd by early 2015;
- completion, commissioning and start-up of Phase 2B;
- drilling and completion of an inventory of stand-by wells to take advantage of freed-up steam from the implementation of enhanced Modified Steam and Gas Push (eMSAGP);
- engineering, long lead items and site preparation for Phase 3A; and
- infrastructure investments to expand the jointly-owned Access Pipeline and to complete the 900,000 barrel Stonefell Terminal.

4. BUSINESS ENVIRONMENT

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

	Six months ended June 30		2013		2012			
	2013	2012	Q2	Q1	Q4	Q3	Q2	Q1
Commodity Prices (Averages)								
Crude oil prices								
West Texas Intermediate (WTI) US$/bbl	94.30	98.21	94.22	94.37	88.18	92.22	93.49	102.92
Western Canadian Select (WCS) C$/bbl	69.91	76.50	76.82	63.01	69.47	70.06	71.34	81.66
Differential – WTI vs WCS (C$/bbl)	25.90	22.27	19.60	32.20	17.94	21.67	23.10	21.39
Differential – WTI vs WCS (%)	27.0%	22.5%	20.3%	33.8%	20.5%	23.6%	24.5%	20.8%
Natural gas prices								
AECO (C$/mcf)	3.35	2.01	3.51	3.18	3.20	2.27	1.89	2.14
Electric power prices								
Alberta power pool (C$/MWh)	94.34	50.07	123.41	65.26	78.73	78.09	40.03	60.10
Foreign exchange rates								
C$ equivalent of 1 US$ - average	1.0161	1.0057	1.0233	1.0089	0.9913	0.9948	1.0102	1.0012
C$ equivalent of 1 US$ - period end	1.0512	1.0191	1.0512	1.0156	0.9949	0.9837	1.0191	0.9991

The price of WTI is an important 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 second quarter of 2013 was US$94.22 per barrel compared to US$93.49 per barrel for the second quarter of 2012. The WTI price averaged US$94.30 per barrel for the first six months of 2013 compared to US$98.21 per barrel for the first six months of 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 and condensate. WCS trades at a differential below the WTI benchmark price. During the second quarter of 2013, the WTI/WCS differential averaged 20.3% compared to 24.5% during the second quarter of 2012. The WTI/WCS differential averaged 27.0% for the first half of 2013 compared to 22.5% for the same period in 2012.

Production of both light crude oil and heavier crudes has increased more quickly than pipeline transportation additions, resulting in pipeline congestion between the mid-continent and coastal markets. This congestion, coupled with refinery outages in the U.S. Midwest, has led to a discount of Canadian crude oil prices relative to world oil prices during 2012 and early 2013. Recent pipeline additions connecting west Texas to the U.S. Gulf Coast and refinery modifications in the U.S. Midwest have begun to relieve some of this price pressure. Incrementally, planned initiatives to access additional markets, including the completion of the TransCanada Gulf Coast Pipeline in late 2013 and the completion of the Flanagan South pipeline and Seaway expansion in mid-2014, should help realign Canadian crude prices with international crude oil benchmarks over the next 12 to 18 months.

Bitumen the Corporation produces is mixed with purchased diluent and the end product is marketed as a heavy crude oil blend known as Access Western Blend (“AWB” or “blend”). It is shipped through the Access Pipeline to the Edmonton-area refining and transportation hub.

MEG’s marketing objective is to receive world prices for its products. To do this, a strategy has been implemented which will enable MEG to bypass markets which are not paying world prices and access markets which are. This strategy includes the option to move bitumen blend by rail, barge or pipeline to enable MEG to get the highest value for its products and mitigate the effects of the volatility of differentials. The railing and barging options will be available in the second half of 2013 and the pipeline capacity to the US Gulf Coast will be available in mid-2014.

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 facility. The benchmark AECO natural gas price averaged $3.51 per mcf during the three months ended June 30, 2013, compared to $1.89 per mcf during the same period in 2012. During the six months ended June 30, 2013, the AECO natural gas price averaged $3.35 per mcf compared to $2.01 per mcf for the six months ended June 30, 2012. Natural gas storage levels in the U.S. ended the quarter 17% below levels as of the end of the second quarter of 2012 and 2% below the five year average.

The Alberta power pool price averaged $123.41 per megawatt hour for the three months ended June 30, 2013, compared to $40.03 per megawatt hour for the same period in 2012. During the first half of 2013, the Alberta power pool price averaged $94.34 per megawatt hour compared to an average price of $50.07 per megawatt hour for the first half of 2012. Numerous Alberta coal plant outages, both scheduled and unscheduled, coupled with strong demand, contributed to very strong power prices in the second quarter of 2013. Year to date average power prices are well above last year as a result of the same factors.

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, and 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 June 30, 2013, the Canadian dollar, at a rate of 1.0512, had decreased in value by approximately 6% against the U.S. dollar compared to its value as at December 31, 2012, when the rate was 0.9949.

5. RESULTS OF OPERATIONS

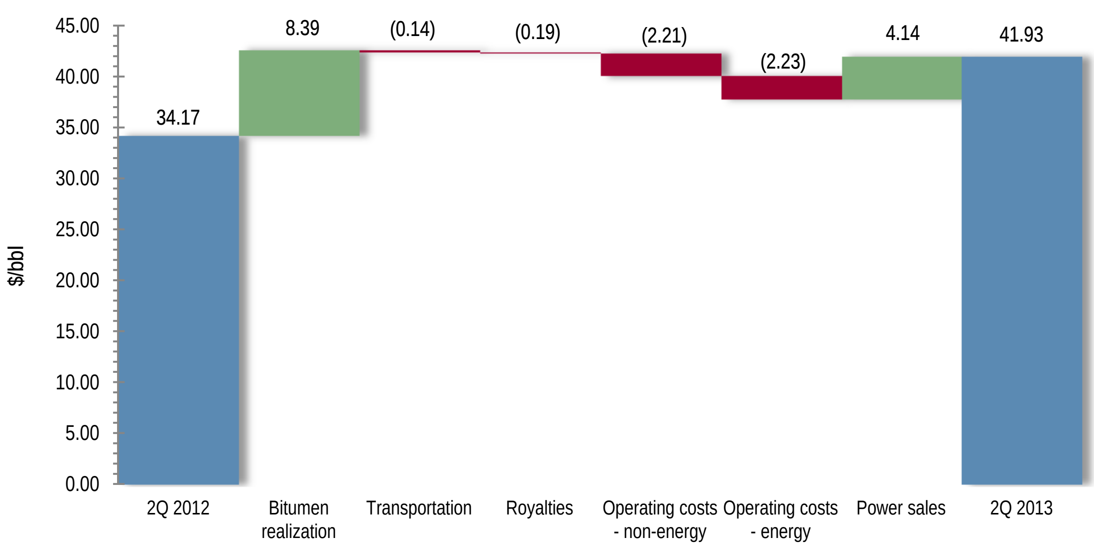
	Three months ended June 30		Six months ended June 30	
	2013	2012	2013	2012
Bitumen production – bpd	32,144	30,429	32,337	29,411
Steam to oil ratio (SOR)	2.3	2.4	2.4	2.4

Production

Production averaged 32,144 bpd for the second quarter of 2013, compared to 30,429 bpd for the second quarter of 2012. Production for the six months ended June 30, 2013 averaged 32,337 bpd compared to 29,411 bpd for the six months ended June 30, 2012. The increase in production is the result of the implementation of RISER, which has expanded steam generation capacity and improved reservoir efficiency and thereby enabled additional wells to be placed into production. Production has increased in 2013 compared to 2012, despite approximately two weeks of production restrictions as a result of scheduled plant maintenance, which was performed in the second quarter of 2013.

The SOR for the second quarter of 2013 was 2.3, compared to an SOR of 2.4 for the second quarter of 2012. For the six months ended June 30, 2013, the SOR was 2.4, consistent with the six months ended June 30, 2012. 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 amount of steam that is injected into the reservoir per barrel of bitumen produced.

Cash Operating Netback – Three Months Ended June 30, 2013 versus June 30, 2012:



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

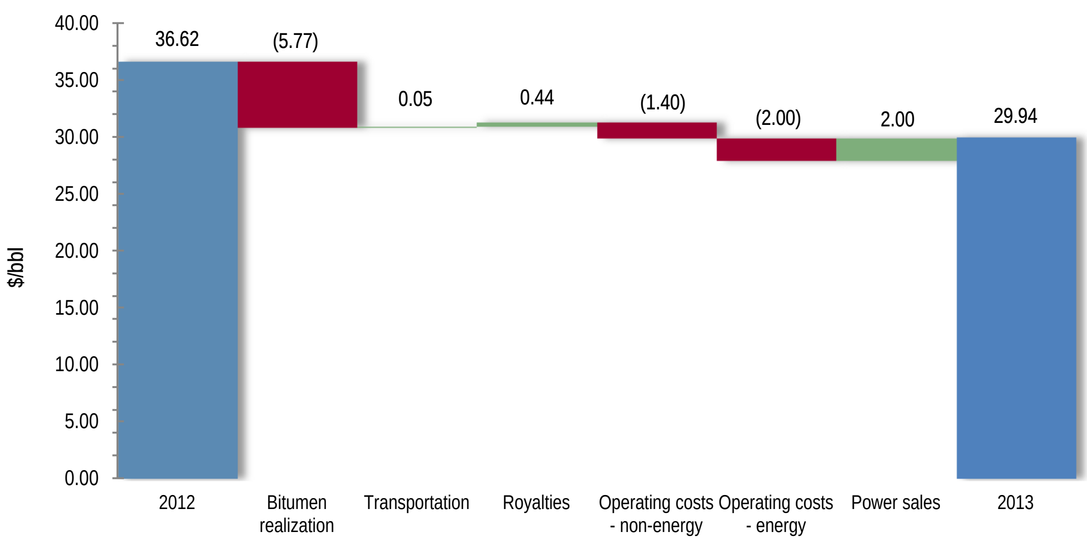
	2013		2012	
	$000	**$ per bbl**	**$000**	**$ per bbl**
Bitumen realization[(1)]	158,039	53.98	125,415	45.59
Transportation[(2)]	(499)	(0.17)	(96)	(0.03)
Royalties	(8,867)	(3.03)	(7,800)	(2.84)
Net bitumen revenue	**148,673**	**50.78**	**117,519**	**42.72**
Operating costs – non-energy	(29,287)	(10.00)	(21,427)	(7.79)
Operating costs – energy	(14,207)	(4.85)	(7,211)	(2.62)
Power sales	17,555	6.00	5,127	1.86
Net operating costs	**(25,939)**	**(8.85)**	**(23,511)**	**(8.55)**
Cash operating netback[(3)]	**122,734**	**41.93**	**94,008**	**34.17**

(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 production 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."*

Cash Operating Netback – Six Months Ended June 30, 2013 versus June 30, 2012:



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

	2013		2012	
	$000	**$ per bbl**	**$000**	**$ per bbl**
Bitumen realization[(1)]	245,628	42.04	255,796	47.81
Transportation[(2)]	(859)	(0.15)	(1,049)	(0.20)
Royalties	(13,469)	(2.30)	(14,635)	(2.74)
Net bitumen revenue	**231,300**	**39.59**	**240,112**	**44.87**
Operating costs – non-energy	(54,969)	(9.41)	(42,845)	(8.01)
Operating costs – energy	(28,566)	(4.89)	(15,475)	(2.89)
Power sales	27,171	4.65	14,152	2.65
Net operating costs	**(56,364)**	**(9.65)**	**(44,168)**	**(8.25)**
Cash operating netback[(3)]	**174,936**	**29.94**	**195,944**	**36.62**

(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 production 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 sold as bitumen blend. Bitumen realization as discussed in this MD&A represents the Corporation's realized revenues, net of the cost of diluent.

	Three months ended June 30		Six months ended June 30	
($000)	**2013**	**2012**	**2013**	**2012**
Blend sales – proprietary	296,300	258,890	538,100	533,186
Cost of diluent	(138,261)	(133,475)	(292,472)	(277,390)
Bitumen realization	158,039	125,415	245,628	255,796

Blend sales for the three months ended June 30, 2013 were $296.3 million compared to $258.9 million for the three months ended June 30, 2012. The increase in blend sales for the second quarter of 2013 compared to the second quarter of 2012 is due to an increase in the average realized price combined with a 5% increase in sales volumes. Blend sales averaged $70.25 per barrel for the second quarter of 2013, compared to $55.24 per barrel in the first quarter of 2013 and $64.62 per barrel for the second quarter of 2012. Blend sales for the six month ended June 30, 2013 were $538.1 million compared to $533.2 million for the six months ended June 30, 2012. The increase in blend sales for the first six months of 2013 compared to the same period in 2012 is due to a 9% increase in sales volumes offset by a decrease in the average realized price. Blend sales averaged $62.61 per barrel during the first half of 2013 compared to $67.72 per barrel for the same period in 2012.

The cost of diluent was $138.3 million for the three months ended June 30, 2013, compared to $133.5 million for the same period in 2012. On a per barrel basis, the Corporation's cost of diluent increased to

$107.17 per barrel for the second quarter of 2013, from $106.29 per barrel for the second quarter of 2012. The cost of diluent for the six months ended June 30, 2013 was $292.5 million compared to $277.4 million for the six months ended June 30, 2012. On a per barrel basis, the Corporation's average cost of diluent was $106.29 per barrel during the first half of 2013 compared to an average cost of $109.97 per barrel during the first half of 2012. The total cost of diluent increased mainly due to higher volumes of diluent purchased as a result of increased bitumen production.

Transportation

Transportation costs, which primarily consist of MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries, were $0.5 million for the three months ended June 30, 2013 compared to $0.1 million for the three months ended June 30, 2012. In the second quarter of 2013, the Corporation recognized third-party recoveries of $5.8 million compared to $3.4 million in the second quarter of 2012. On a per barrel basis, transportation costs increased to an average of $0.17 per barrel during the three months ended June 30, 2013, from $0.03 per barrel during the three months ended June 30, 2012. Transportation costs for the six months ended June 30, 2013 were $0.9 million compared to $1.0 million for the six months ended June 30, 2012, net of $11.1 million and $6.5 million in recoveries, respectively. Transportation costs decreased to an average of $0.15 per barrel for the six months ended June 30, 2013 compared to $0.20 per barrel for the six months ended June 30, 2012. The decrease in transportation costs in the first six months of 2013 compared to the first six months of 2012 is due to the increase in recoveries from diluent transportation arrangements.

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 $8.9 million for the second quarter of 2013 compared to $7.8 million for the second quarter of 2012, or an average of $3.03 per barrel for the second quarter of 2013, compared to $2.84 per barrel for the second quarter of 2012. The increase in royalties for the three months ended June 30, 2013 compared to the three months ended June 30, 2012 is attributable to the increase in bitumen realizations. Royalties were $13.5 million for the six months ended June 30, 2013 compared to $14.6 million for the six months ended June 30, 2012. Royalties averaged $2.30 per barrel during the first half of 2013 compared to $2.74 per barrel for first half of 2012. The decrease in royalties for the first half of 2013 compared to the first half of 2012 is attributable to the decrease in bitumen realizations in the first quarter of 2013.

Operating Costs

Non-energy operating costs were $29.3 million for the three months ended June 30, 2013, compared to $21.4 million for the three months ended June 30, 2012. Non-energy operating costs increased to an average of $10.00 per barrel in the second quarter of 2013, from $7.79 per barrel in the second quarter of 2012. For the six months ended June 30, 2013, non-energy operating costs were $55.0 million compared to $42.8 million for the six months ended June 30, 2012. Non-energy operating costs averaged $9.41 per barrel for the six months ended June 30, 2013 compared to $8.01 per barrel for the same period in 2012. The increase in non-energy related operating costs is primarily attributable to scheduled plant maintenance, and higher materials, camp and labor costs, which were partially offset on a per barrel basis by the increase in production. The increase in plant maintenance and material costs in 2013 compared to 2012 is primarily attributable to the scheduled plant maintenance that was performed in the second quarter of 2013. In contrast, maintenance activities occurred during the third quarter of 2012.

Energy related operating costs were $14.2 million for the three months ended June 30, 2013 compared to $7.2 million for the three months ended June 30, 2012. On a per barrel basis, energy operating costs were $4.85 per barrel for the three months ended June 30, 2013 compared to $2.62 per barrel for the same period in 2012. Energy related operating costs were $28.6 million for the first six months of 2013 compared to $15.5 million for the first six months of 2012. On a per barrel basis, energy related operating costs were $4.89 per barrel for the first half of 2013 compared to $2.89 per barrel for the first half of 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 $3.51 per mcf for the second quarter of 2013, compared to $1.89 per mcf for the second quarter of 2012. The benchmark AECO natural gas price averaged $3.35 per mcf during the first six months of 2013 compared to $2.01 per mcf for the first six months of 2012. The increase in natural gas prices in 2013 is largely due to a decrease in U.S. natural gas storage levels in 2013 compared to 2012.

Power Sales

The Corporation's 85 megawatt cogeneration facility produces approximately 70% of the steam for current SAGD operations. MEG's Christina Lake facilities utilize the heat produced by the cogeneration facility and approximately 11 to 13 megawatts of the power generated. Surplus power is sold into the Alberta power pool.

Power sales were $17.6 million for the three months ended June 30, 2013, compared to $5.1 million for the three months ended June 30, 2012. The Corporation realized an average power price of $138.96 per megawatt hour for the three months ended June 30, 2013, compared to $36.85 per megawatt hour for the three months ended June 30, 2012. Power sales were $27.2 million for the six months ended June 30, 2013, compared to $14.2 million for the six months ended June 30, 2012. The average realized power price for the first six months of 2013 was $94.74 per megawatt hour compared to $48.13 per megawatt hour for the first six months of 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. The increase in power prices is largely attributable to numerous power plant outages in the second quarter of 2013, combined with an increase in demand.

6. NON-IFRS MEASUREMENTS

The following tables reconcile the non-IFRS measurements "Operating earnings" 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 is defined as net income (loss) as reported, excluding the after-tax unrealized foreign exchange gains and losses and unrealized gains and losses on derivative financial liabilities. 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 June 30		Six months ended June 30	
($000)	**2013**	**2012**	**2013**	**2012**
Net income (loss)	(62,312)	(29,534)	(133,606)	23,835
Add (deduct):				
Unrealized foreign exchange loss, net of tax[(1)]	87,024	34,587	124,834	5,591
Unrealized (gain) loss on derivative financial liabilities, net of tax[(2)]	(11,100)	7,219	(14,328)	6,375
Unrealized fair value (gain) on other assets, net of tax[(3)]	-	(1,138)	-	(1,138)
Operating earnings (loss)	13,612	11,134	(23,100)	34,663
Add (deduct):				
Interest income	(6,225)	(4,345)	(11,496)	(9,894)
Depletion and depreciation	44,252	36,020	88,667	70,806
General and administrative	24,298	17,675	47,065	32,406
Stock-based compensation	9,563	5,221	16,518	10,555
Research and development	787	1,797	2,070	3,091
Interest expense	24,783	18,938	49,872	38,645
Accretion	1,186	903	2,262	1,737
Gain on disposition of asset	-	-	-	(3,075)
Realized (gain) loss on foreign exchange	1,617	(113)	2,845	(480)
Realized loss on derivative financial liabilities	1,182	1,154	2,283	2,213
Net marketing activity	74	-	307	-
Deferred income tax expense (recovery), operating	7,605	5,624	(2,357)	15,277
Cash operating netback	122,734	94,008	174,936	195,944

(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 $4,610 for the three months ended June 30, 2013 and $1,503 for the six months ended June 30, 2013 (deferred tax expense of $105 for the three months ended June 30, 2012 and a deferred tax recovery of $657 for the six months ended June 30, 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 $3,700 for the three months ended June 30, 2013 and $4,776 for the six months ended June 30, 2013 (deferred tax recovery of $2,407 for the three months ended June 30, 2012 and $2,125 for the six months ended June 30, 2012).*

(3) *Unrealized fair value gain on other assets results from the fair market valuation of other assets held at June 30, 2012, net of a deferred tax expense of $380 for the three and six month periods ended June 30, 2012.*

	Three months ended June 30		Six months ended June 30	
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	46,704	104,344	21,712	145,902
Add:				
Net change in non-cash operating working capital items	32,480	(44,369)	64,543	(13,936)
Cash flow from operations	79,184	59,975	86,255	131,966

Depletion and Depreciation

Depletion and depreciation expense was $44.3 million for the three months ended June 30, 2013, compared to $36.0 million for the same period in 2012. For the six months ended June 30, 2013, depletion and depreciation expense was $88.7 million compared to $70.8 million for the six months ended June 30, 2012. The increase is primarily due to higher production 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. Production volumes increased by approximately 6% in the second quarter, and 10% in the first half of 2013, as compared to the same periods in 2012. The future development costs are a key element of the rate determination. The depletion and depreciation rate for the three and six month periods ended June 30, 2013 was $15.13 per barrel, and $15.14 per barrel, respectively. This compared to a depletion and depreciation rate of $13.01 per barrel for the three months ended June 30, 2012 and $13.23 per barrel for the six months ended June 30, 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 assets are depreciated on a straight-line basis over their estimated useful lives.

General and Administrative Costs

	Three months ended June 30		**Six months ended June 30**	
($000)	**2013**	**2012**	**2013**	**2012**
General and administrative costs	30,599	22,310	59,246	41,455
Capitalized general and administrative costs	(6,301)	(4,635)	(12,181)	(9,049)
General and administrative expense	24,298	17,675	47,065	32,406

General and administrative expense for the three months ended June 30, 2013 was $24.3 million, compared to $17.7 million for the same period in 2012. General and administrative expense for the six months ended June 30, 2013 was $47.1 million compared to $32.4 million for the six months ended June 30, 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

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 $9.6 million for the three months ended June 30, 2013, compared to $5.2 million for the three months ended June 30, 2012. For the six months ended June 30, 2013, stock-based compensation expense was $16.5 million compared to $10.6 million for the six months ended June 30, 2012. The increase in stock-based compensation for the periods ended June 30, 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 $2.2 million of stock-based compensation to property, plant and equipment during the three months ended June 30, 2013, compared to $1.4 million during the three months ended June 30, 2012. The Corporation capitalized $3.9 million of stock-based compensation during the first half of 2013 compared to $2.9 million during the first half of 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 $0.8 million for the three months ended June 30, 2013, compared to $1.8 million for the three months ended June 30, 2012. For the six months ended June 30, 2013, research and development expenditures were $2.1 million compared to $3.1 million for the six months ended June 30, 2012.

Net Finance Expense

	Three months ended June 30		Six months ended June 30	
($000)	**2013**	**2012**	**2013**	**2012**
Total interest expense	42,994	25,148	81,717	49,399
Less capitalized interest	(18,211)	(6,210)	(31,845)	(10,754)
Net interest expense	24,783	18,938	49,872	38,645
Accretion on decommissioning provision	1,186	903	2,262	1,737
Unrealized fair value (gain) loss on embedded derivative financial liabilities	(9,828)	2,895	(12,903)	437
Unrealized fair value (gain) loss on interest rate swaps	(4,973)	6,731	(6,202)	8,063
Realized loss on interest rate swaps	1,182	1,154	2,283	2,213
Unrealized fair value (gain) on other assets	-	(1,518)	-	(1,518)
Net finance expense	12,350	29,103	35,312	49,577

Total interest expense was $43.0 million for the three months ended June 30, 2013, compared to $25.1 million for the three months ended June 30, 2012. For the six months ended June 30, 2013, total interest expense increased to $81.7 million compared to $49.4 million for the six months ended June 30, 2012. Total interest expense increased primarily as a result of the increased debt outstanding. Effective July 19, 2012, the Corporation issued US$800.0 million of 6.375% senior unsecured notes. Effective February 25, 2013, the Corporation increased its senior secured term loan by US$300 million to US$1.3 billion.

The Corporation recognized an unrealized gain on embedded derivative financial liabilities of $9.8 million during the second quarter of 2013, compared to a loss of $2.9 million during the second quarter of 2012. The Corporation recognized an unrealized gain on embedded derivative financial liabilities of $12.9 million for the six months ended June 30, 2013 compared to an unrealized loss of $0.4 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 fix the interest rate at approximately 4.3% 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 for the three months ended June 30, 2013 and a loss of $2.3 million for the six months ended June 30, 2013. This compared to a realized loss of $1.2 million for the three months ended June 30, 2012 and a loss of $2.2 million for the six months ended June 30, 2012. In addition, the Corporation recognized unrealized gains of $5.0 million and $6.2 million for the three and six month periods ended June 30, 2013, respectively, compared to unrealized losses of $6.7 million and $8.1 million during the same periods in 2012.

Net Foreign Exchange Loss

	Three months ended June 30		Six months ended June 30	
($000)	**2013**	**2012**	**2013**	**2012**
Foreign exchange gain (loss) on:				
Long-term debt	(100,889)	(34,900)	(150,145)	(3,620)
US$ denominated cash and cash equivalents	18,476	418	26,815	(2,628)
Other	(1,618)	113	(2,846)	480
Net foreign exchange loss	(84,031)	(34,369)	(126,176)	(5,768)

C$-US$ exchange rate as at	**June 30, 2013**	**March 31, 2013**	**December 31, 2012**	**June 30, 2012**	**March 31, 2012**	**December 31, 2011**
C$ equivalent of 1 US$	1.0512	1.0156	0.9949	1.0191	0.9991	1.0170

The net foreign exchange loss for the three months ended June 30, 2013 was $84.0 million in comparison to a net foreign exchange loss of $34.4 million for the three months ended June 30, 2012. For the six months ended June 30, 2013, the net foreign exchange loss was $126.2 million compared to a net loss of $5.8 million for the six months ended June 30, 2012. The Canadian dollar weakened by approximately 4% during the second quarter of 2013, while it weakened by approximately 2% during the second quarter of 2012. During the first six months of 2013, the Canadian dollar weakened in value compared to the U.S. dollar by approximately 6%, while it remained relatively stable during the same period in 2012.

Net Marketing Activity

	Three months ended June 30		Six months ended June 30	
($000)	**2013**	**2012**	**2013**	**2012**
Sales of purchased product	13,621	-	19,399	-
Purchased product and storage	(13,695)	-	(19,706)	-
Net marketing activity	(74)	-	(307)	-

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

Income Taxes

The Corporation recognized a deferred income tax expense of $15.9 million for the three months ended June 30, 2013, compared to a deferred income tax expense of $3.7 million for the three months ended June 30, 2012. Deferred income tax expense was $3.9 million for the six months ended June 30, 2013 compared to $12.9 million for the six months ended June 30, 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 June 30, 2013, the non-taxable loss was $50.4 million compared to a non-taxable loss of $17.5 million for the same period in 2012. For the six months ended June 30, 2013, the non-taxable loss was $75.1 million compared to $1.8 million for the six months ended June 30, 2012.

- As at June 30, 2013, the Corporation had not recognized the tax benefit related to $54.3 million in unrealized taxable capital foreign exchange losses.

- Non-taxable stock-based compensation expense was $9.6 million for the second quarter of 2013, in comparison to $5.2 million for the second quarter of 2012. For the six months ended June 30, 2013, non-taxable stock-based compensation expense was $16.5 million compared to $10.6 million for the six months ended June 30, 2012.

The Corporation is not currently taxable. As of June 30, 2013, the Corporation had approximately $4.5 billion of available tax pools and had recognized a deferred income tax liability of $75.4 million. In addition, at June 30, 2013, the Corporation had $2.1 billion of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

7. SUMMARY OF QUARTERLY RESULTS

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

	2013		2012				2011	
($ millions, except per share amounts)	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Revenue	324.4	258.0	297.6	213.7	259.7	279.6	326.5	175.9
Net income (loss)	(62.3)	(71.3)	(18.7)	47.5	(29.5)	53.4	91.1	(115.2)
Per share – basic	(0.28)	(0.32)	(0.09)	0.24	(0.15)	0.28	0.47	(0.60)
Per share – diluted	(0.28)	(0.32)	(0.09)	0.24	(0.15)	0.27	0.46	(0.60)

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 third quarters of 2012 and 2011 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:

- 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 estimated future development costs;

- higher general and administrative expense as a result of the planned increase in office staff to support growth;
- an increase in interest expense as a result of the increase in long-term debt; and
- scheduled annual plant maintenance activities performed in May 2013, September 2012 and September 2011.

8. CAPITAL INVESTING

	Three months ended June 30		Six months ended June 30	
Summary of capital investment ($000)	**2013**	**2012**	**2013**	**2012**
Christina Lake Phase 2B	58,138	149,525	159,412	323,400
Christina Lake Phase 3A	72,099	10,803	165,003	14,754
RISER and other enhancements	245,016	41,066	359,408	60,758
Inventory wells	27,426	9,748	78,002	11,712
Delineation drilling and seismic	1,537	11,023	84,018	98,968
Regulatory	2,007	411	2,397	3,700
Other	32,280	10,098	50,600	16,489
Growth	**438,503**	**232,674**	**898,840**	**529,781**
Access Pipeline	47,640	16,377	138,656	48,790
Stonefell Terminal	44,358	24,322	107,150	35,920
Field infrastructure	34,490	20,924	53,248	31,133
Infrastructure related to growth	**126,488**	**61,623**	**299,054**	**115,843**
Sustaining	26,515	34,901	37,017	40,380
Capitalized interest	18,211	6,210	31,845	10,754
Land and other	44,110	3,669	56,003	7,181
Total cash capital investment	**653,827**	**339,077**	**1,322,759**	**703,939**
Non-cash	20,749	2,763	33,688	8,995
Total capital investment	**674,576**	**341,840**	**1,356,447**	**712,934**

MEG's capital investment for the three months ended June 30, 2013 totalled $674.6 million, compared to $341.8 million invested during the three months ended June 30, 2012. For the six months ended June 30, 2013, capital investment was $1.4 billion in comparison to $0.7 billion for the six months ended June 30, 2012. Capital investment included $438.5 million in growth focused investment during the second quarter of 2013 and $898.8 million for the first half of 2013, compared to $232.7 million and $529.8 million in the same periods of 2012.

MEG invested $58.1 million on Phase 2B of the Christina Lake project during the second quarter of 2013, and $159.4 million during the first half of 2013. The construction of the Phase 2B project is now substantially complete. The water treatment and steam generating facilities for Phase 2B are mechanically complete and the oil treating facilities are nearing completion. The Corporation is now focused on commissioning these facilities, with plans to commence steam generation and steam injection to Phase 2B well pairs late in the third quarter of 2013.

The Corporation invested $72.1 million for the three months ended, and $165.0 million for the six months ended June 30, 2013 on engineering, purchasing of long-lead equipment and materials, and site preparation activity for Phase 3A.

MEG invested $245.0 million during the second quarter of 2013 and $359.4 million during the first half of 2013 on RISER. The investment is to accommodate the implementation of RISER on Phases 1 and 2 and to prepare Phase 2B for the first stage of adoption. With RISER fully implemented on Phases 1 and

2, and Phase 2B achieving its initial design capacity, the Corporation expects production to reach 80,000 bpd by early 2015. Approximately $128.1 million of the $359.4 million 2013 RISER capital investment is associated with RISER initatives related to Phase 2B.

The Corporation invested $27.4 million for the drilling of inventory wells at the Christina Lake project during the second quarter of 2013, and $78.0 million during the first half of 2013. These inventory wells will be placed on production as freed-up steam becomes available from the implementation of enhanced Modified Steam and Gas Push (eMSAGP).

The Corporation invested $1.5 million during the second quarter of 2013 on delineation drilling and seismic and $84.0 million during the six months ended June 30, 2013. The Corporation drilled 131 stratigraphic wells, one water observation well and four water source wells to support horizontal well placement and to further delineate the resource base at Christina Lake. A total of 24 stratigraphic wells, one water source well and three water test wells were completed at Surmont.

A total of $126.5 million was invested in the Corporation's growth-related infrastructure during the second quarter of 2013 and $299.1 million during the first half of 2013. Of this total, during the first six months of 2013 the Corporation invested $138.7 million, primarily 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 80 kilometers of the 300 kilometer pipeline have been installed. Investment in the Stonefell Terminal was $107.2 million during the first half of 2013. The Stonefell Terminal is a 900,000 barrel tank farm, connected to the Access Pipeline and is anticipated to be mechanically complete in the third quarter of 2013 and commissioned in the fourth quarter of 2013. The Corporation invested a total of $53.2 million in support infrastructure for current and future operations at Christina Lake.

The Corporation capitalizes interest associated with qualifying assets. During the three months ended June 30, 2013, $18.2 million of interest was capitalized, in comparison to $6.2 million during the three months ended June 30, 2012. A total of $31.8 million in interest was capitalized during the six months ended June 30, 2013 compared to $10.8 million during the six months ended June 30, 2012.

Land and other investments in 2013 include $39.0 million for land acquired northeast of Edmonton, Alberta, amounts paid to maintain the right to participate in a potential pipeline project and investments in administrative assets.

Non-cash capital investment included $18.5 million for future reclamation and decommissioning of the Corporation’s property, plant and equipment and $2.2 million in capitalized stock-based compensation for the three months ended June 30, 2013. Non-cash capital investment for the six months ended June 30, 2013 included $29.8 million for future reclamation and decommissioning of the Corporation’s property, plant and equipment and $3.9 million in capitalized stock-based compensation.

9. LIQUIDITY AND CAPITAL RESOURCES

	As at June 30	
($000, except as noted)	**2013**	**2012**
Cash, cash equivalents and short-term investments	1,203,457	1,111,150
Senior secured term loan (June 30, 2013 - US$1.3 billion; June 30, 2012 – US$992.5 million; due 2020)	1,346,587	1,011,457
US$2.0 billion revolver due 2018	-	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	788,400	764,325
6.375% senior unsecured notes (US$800.0 million; due 2023)	840,960	-
Total debt[(1)]	2,975,947	1,775,782
Shareholders' equity	4,771,616	4,027,652
Total book capitalization[(2)]	7,747,563	5,803,434
Total debt/book capitalization[(2)]	38.4%	30.6%

(1) *Total debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The Corporation uses this non-IFRS measurement to analyze leverage and liquidity. Total debt less the current portion of the senior secured term loan, unamortized financial derivative liability discount and unamortized deferred debt issue costs is equal to long term debt as reported in the Corporation's consolidated financial statements as at June 30, 2013 and 2012.*

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

Capital Resources

As at June 30, 2013, the Corporation's capital resources included $0.7 billion of working capital and an additional undrawn US$2.0 billion revolving credit facility. As at June 30, 2013, $60 million of the revolving credit facility was utilized to support letters of credit. Working capital is comprised of $1.2 billion of cash, cash equivalents and short-term investments, offset by a non-cash working capital deficiency of $0.5 billion.

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary. The Corporation's cash flow and the development of projects are dependent on factors discussed in the "RISK FACTORS" section below.

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

On February 25, 2013, the Corporation re-priced, increased and extended its US$987.5 million senior secured term loan. The Corporation extended the maturity date to March 31, 2020 and increased its borrowing under the senior secured term loan by US$300 million. In addition, the Corporation reduced the interest rate on the term loan by 25 basis points. The amended term loan bears a floating interest rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 175 or 275 basis points, respectively, and an interest rate floor of 200 basis points based on U.S. Prime or 100 basis points based on LIBOR. The term loan is being repaid in quarterly installments of US$3.25 million, which commenced March 28, 2013, with the balance due March 31, 2020. The $7.2 million cost of the transaction has been deferred and is being amortized over the term of the revolving credit facility.

On December 28, 2012, the Corporation issued 24.2 million common shares at a price of $33.00 per share for net proceeds of $774.8 million.

On July 19, 2012, the Corporation issued US$800.0 million in aggregate principal amount of 6.375% senior unsecured notes, with interest paid semi-annually. The notes are due on January 30, 2023. The $13.6 million cost of the transaction has been deferred and is being amortized over the life of the notes.

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. The Corporation has entered into interest rate swap contracts to fix the interest rate at approximately 4.3% on US$748.0 million of the US$1.3 billion senior secured term loan until September 30, 2016.

The Corporation's cash is held in high interest savings accounts with a diversified group of highly-rated financial institutions. The Corporation has also invested in high grade, liquid, short-term instruments such as government, commercial and bank paper as well as term deposits. To date, the Corporation has experienced no material loss or lack of access to its cash in operating accounts, invested cash or cash equivalents. However, the Corporation can provide no assurance that access to its invested cash and cash equivalents will not be impacted by adverse conditions in the financial markets. While the Corporation monitors the cash balances in its operating and investment accounts according to its investment policy and adjusts the cash balances as appropriate, these cash balances could be impacted if the underlying financial institutions or corporations fail or are subject to other adverse conditions in the financial markets.

Cash Flows Summary

	Three months ended June 30		Six months ended June 30	
($000)	**2013**	**2012**	**2013**	**2012**
Net cash provided by (used in):				
Operating activities	46,704	104,344	21,712	145,902
Investing activities	(676,835)	(449,813)	(757,161)	(621,441)
Financing activities	(6,897)	(1,251)	300,049	(4,362)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	18,476	418	26,815	(2,628)
Change in cash and cash equivalents	(618,552)	(346,302)	(408,585)	(482,529)

Cash Flows - Operating Activities

Net cash provided by operating activities during the three months ended June 30, 2013 was $46.7 million compared to net cash provided by operating activities of $104.3 million during the three months ended June 30, 2012. The decrease in cash flows from operating activities is primarily due to the $76.9 million decrease in non-cash working capital partially offset by the increase in cash operating netback for the second quarter of 2013 compared to the second quarter of 2012. Net cash provided by operating activities during the six months ended June 30, 2013 was $21.7 million compared to $145.9 million for the six months ended June 30, 2012. The decrease in cash flows from operating activities is primarily due to the $78.4 million decrease in non-cash working capital combined with lower bitumen realizations, higher operating expenses, higher general and administrative expense and higher interest expense, partially offset by the increase in production.

Cash Flows - Investing Activities

Net cash used for investing activities during the second quarter of 2013 primarily consists of $653.8 million in cash capital investment (refer to the "CAPITAL INVESTING" section of this MD&A for further details) and a $21.2 million decrease in non-cash investing working capital. Net cash used for investing activities during the six months ended June 30, 2013 consists of $1.3 billion in cash capital investment offset by a $0.6 billion increase in non-cash investing working capital. The majority of the change in non-cash working capital for the six months ended June 30, 2013 relates to the decrease in short-term investments from $533.0 million at December 31, 2012 to $137.2 million at June 30, 2013.

Net cash used for investing activities during the second quarter of 2012 primarily consisted of $339.1 million in cash capital investment and a $109.8 million increase in non-cash working capital. Net cash used for investing activities for the six months ended June 30, 2012 primarily consisted of $703.9 million in cash capital investment, $7.5 million in proceeds from the disposition of assets and a $76.2 million decrease in non-cash working capital.

Cash Flows - Financing Activities

Net cash provided by financing activities for the three months ended June 30, 2013 primarily consists of $4.9 million in proceeds received from the exercise of stock options offset by $3.4 million in debt principal repayment on the senior secured term loan and $8.4 million in financing costs. Net cash provided by financing activities for the six months ended June 30, 2013 primarily consists of $308.0 million of proceeds from the increase in the senior secured term loan and $14.3 million of proceeds received from the exercise of stock options. These amounts were partially offset by $6.7 million in debt principal repayments and $15.5 million in fees primarily associated with the amendments to the senior secured term loan and the revolving credit facility.

Financing activities during the three months ended June 30, 2012 included $2.5 million of debt principal repayment on the senior secured term loan, partially offset by $1.0 million in proceeds received from the exercise of stock options. Net cash used for financing activities for the six months ended June 30, 2012 consisted of $5.0 million in debt principal repayments and $5.6 million in fees associated with the revolving credit facility amendments, partially offset by $6.3 million in proceeds received from the exercise of stock options.

10. SHARES OUTSTANDING

As at June 30, 2013, the Corporation had the following share capital instruments outstanding:

Common shares	221,828,872
Convertible securities	
Stock options outstanding – exercisable and unexercisable	9,501,642
Restricted share units outstanding	2,379,957
Performance share units outstanding	145,498

As at July 19, 2013, the Corporation had 221,836,722 common shares, 9,499,350 stock options, 2,376,369 restricted share units and 145,498 performance share units outstanding.

11. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

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

($000)	Total	< 1 year	1 – 3 years	4 – 5 years	More than 5 years
Long-term debt[1]	2,975,947	13,666	27,331	27,331	2,907,619
Interest on long-term debt[1]	1,221,648	155,098	308,658	306,608	451,284
Decommissioning obligation[2]	236,920	2,068	3,439	-	231,413
Transportation and storage[3]	2,416,233	109,000	266,227	291,693	1,749,313
Contracts and purchase orders[4]	1,297,925	1,050,565	79,972	33,149	134,239
Operating leases[5]	417,947	12,207	24,925	48,294	332,521
	8,566,620	1,342,604	710,552	707,075	5,806,389

(1) *This represents the scheduled principal repayment of the senior secured credit facility and the senior unsecured notes and associated interest payments based on interest rates in effect on June 30, 2013.*

(2) *This represents the undiscounted future obligation associated with the decommissioning of the Corporation's oil and gas properties and facilities.*

(3) *This represents transportation and storage commitments from 2013 to 2028.*

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

(5) *This represents the future commitment for the Calgary corporate office.*

12. NEW 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 International Accounting Standard ("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 (amended in 2011). 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.

13. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Property, Plant and Equipment

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

Exploration and Evaluation Assets

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

Impairments

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

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

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

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

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

Bitumen Reserves

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

Decommissioning Provision

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

Deferred Income Taxes

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

Stock-based Compensation

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

Derivative Financial Instruments

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

14. OFF-BALANCE SHEET ARRANGEMENTS

At June 30, 2013 and December 31, 2012, the Corporation did not have any off-balance sheet arrangements.

15. RISK FACTORS

The Corporation's primary focus is on the ongoing development and operation of its oil sands assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including the risks which have been categorized and described in the Corporation’s MD&A for the year ended December 31, 2012. In addition, MEG is also subject to other risks and uncertainties which are described in the Corporation’s Annual Information Form dated February 27, 2013 under the heading “Regulatory Matters” and “Risk Factors”.

16. DISCLOSURE CONTROLS AND PROCEDURES

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

17. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

18. ADVISORY

Forward-Looking Information

This MD&A may contain forward-looking information including but not limited to: expectations of future production, revenues, 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 MD&A is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this MD&A 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 MD&A 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 MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as net bitumen revenue, operating earnings, cash flow from operations and cash operating netback. These financial measures are not defined by IFRS as issued by the International Accounting Standards Board and therefore are referred to as non-IFRS measures. The non-IFRS measures used by the Corporation may not be comparable to similar measures presented by other companies. The Corporation uses these non-IFRS measures to help evaluate its performance.

Management considers net bitumen revenue, operating earnings and cash operating netback important measures as they indicate profitability relative to current commodity prices. Management uses cash flow from operations to measure the Corporation's ability to generate funds to finance capital expenditures and repay debt. These non-IFRS measures should not be considered as an alternative to or more meaningful than net income (loss) or net cash provided by (used in) operating activities, as determined in accordance with IFRS, as an indication of the Corporation's performance. The non-IFRS operating earnings and cash operating netback measures are reconciled to net income (loss), while cash flow from operations is reconciled to net cash provided by (used in) operating activities.

19. 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.

20. QUARTERLY SUMMARIES

	2013		2012				2011	
Unaudited	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
FINANCIAL ($000 unless specified)								
Net income (loss)	(62,312)	(71,294)	(18,740)	47,474	(29,534)	53,369	91,118	(115,196)
Per share, diluted	(0.28)	(0.32)	(0.09)	0.24	(0.15)	0.27	0.46	(0.60)
Operating earnings (loss)	13,612	(36,712)	(538)	(12,883)	11,134	23,529	57,833	(5,917)
Per share, diluted	0.06	(0.16)	0.00	(0.07)	0.06	0.12	0.29	(0.03)
Cash flow from operations	79,184	7,071	56,106	24,442	59,975	71,991	121,608	25,478
Per share, diluted	0.35	0.03	0.27	0.12	0.30	0.36	0.61	0.13
Capital investment	674,576	681,871	500,223	406,526	341,840	371,094	319,897	243,226
Cash, cash equivalents and short-term investments	1,203,457	1,803,338	2,007,841	1,607,036	1,111,150	1,402,390	1,647,069	1,831,937
Working capital	731,290	1,298,955	1,655,915	1,307,325	902,424	1,183,628	1,475,245	1,619,557
Long-term debt	2,923,382	2,823,207	2,488,609	2,461,676	1,751,552	1,718,474	1,751,539	1,791,695
Shareholders' equity	4,771,616	4,817,253	4,870,534	4,092,556	4,027,652	4,049,633	3,984,104	3,879,415
BUSINESS ENVIRONMENT								
West Texas Intermediate (WTI) US$/bbl	94.22	94.37	88.18	92.22	93.49	102.92	94.06	89.76
C$ equivalent of 1US$ - average	1.0233	1.0089	0.9913	0.9948	1.0102	1.0012	1.0231	0.9802
Differential – WTI vs blend ($/bbl)	26.17	39.96	26.13	29.54	29.83	32.10	17.47	23.53
Differential – WTI vs blend (%)	27.1%	41.9%	29.9%	32.2%	31.6%	31.2%	18.2%	26.7%
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bpd	32,144	32,531	32,292	23,941	30,429	28,446	30,032	20,945
Diluent usage – bpd	14,176	16,239	14,810	9,466	13,800	13,919	14,223	8,229
Blend sales – bpd	46,351	48,632	47,532	33,342	44,029	42,486	44,491	28,820
Blend sales	70.25	55.24	61.29	62.19	64.62	70.95	78.76	64.46
Cost of diluent	(16.27)	(25.20)	(15.62)	(15.70)	(19.03)	(20.80)	(10.77)	(12.67)
Bitumen realization	53.98	30.04	45.67	46.49	45.59	50.15	67.99	51.79
Transportation – net	(0.17)	(0.12)	(0.05)	(0.93)	(0.03)	(0.37)	(1.19)	(1.93)
Royalties	(3.03)	(1.58)	(2.23)	(2.10)	(2.84)	(2.63)	(3.66)	(2.82)
Operating costs – non-energy	(10.00)	(8.81)	(8.70)	(15.23)	(7.79)	(8.24)	(8.55)	(17.20)
Operating costs – energy	(4.85)	(4.93)	(4.65)	(3.22)	(2.62)	(3.18)	(4.61)	(5.05)
Power sales	6.00	3.30	4.40	2.84	1.86	3.47	4.66	5.13
Cash operating netback	**41.93**	**17.90**	**34.44**	**27.85**	**34.17**	**39.20**	**54.64**	**29.92**
Power sales price (C$/MWh)	138.96	59.92	79.62	57.99	36.85	58.25	78.91	93.33
Power sales (MW/h)	58	74	75	49	64	71	74	47
Depletion and depreciation rate	15.13	15.16	14.98	13.39	13.01	13.44	12.60	12.51
COMMON SHARES								
Shares outstanding, end of period (000)	221,829	221,256	220,190	195,248	194,326	193,986	193,472	192,978
Volume traded (000)	43,789	28,495	20,370	13,578	21,560	18,230	16,083	16,706
Common share price ($)								
High	32.98	35.67	38.74	41.90	43.96	47.11	48.48	52.90
Low	25.50	30.89	30.25	35.20	32.92	36.73	32.26	36.96
Close (end of period)	28.83	32.61	30.44	37.39	36.49	38.46	41.57	38.76

Interim Financial Statements

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

As at	Note		June 30, 2013		December 31, 2012
Assets					
Current assets					
Cash and cash equivalents	19	**$**	**1,066,258**	$	1,474,843
Short-term investments			**137,199**		532,998
Trade receivables and other	6		**147,478**		110,823
Inventories			**20,277**		17,536
			1,371,212		2,136,200
Non-current assets					
Property, plant and equipment	7		**6,527,231**		5,267,885
Exploration and evaluation assets	8		**553,344**		554,349
Other intangible assets	9		**55,472**		46,033
Other assets	10		**20,486**		14,212
Total assets		**$**	**8,527,745**	$	8,018,679
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	11	**$**	**610,161**	$	463,077
Current portion of long-term debt	12		**13,666**		9,949
Current portion of provisions and other liabilities	13		**16,095**		7,259
			639,922		480,285
Non-current liabilities					
Long-term debt	12		**2,909,716**		2,478,660
Provisions and other liabilities	13		**131,042**		117,756
Deferred income tax liability			**75,449**		71,444
Total liabilities			**3,756,129**		3,148,145
Commitments and contingencies	21				
Shareholders' equity					
Share capital	14		**4,727,949**		4,694,378
Contributed surplus	14		**103,239**		102,219
Retained earnings (deficit)			**(59,694)**		73,912
Accumulated other comprehensive income			**122**		25
Total shareholders' equity			**4,771,616**		4,870,534
Total liabilities and shareholders' equity		**$**	**8,527,745**	$	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 June 30		Six months ended June 30	
	Note	**2013**	2012	**2013**	2012
Petroleum revenue, net of royalties	15	**$ 301,054**	$ 251,090	**$ 544,030**	$ 518,551
Other revenue	16	**23,306**	8,567	**38,299**	20,681
		324,360	259,657	**582,329**	539,232
Diluent and transportation	17	**144,512**	137,011	**304,460**	284,968
Purchased product and storage		**13,695**	-	**19,706**	-
Operating expenses		**43,494**	28,638	**83,535**	58,320
Depletion and depreciation	7, 9	**44,252**	36,020	**88,667**	70,806
General and administrative		**24,298**	17,675	**47,065**	32,406
Stock-based compensation	14	**9,563**	5,221	**16,518**	10,555
Research and development		**787**	1,797	**2,070**	3,091
		280,601	226,362	**562,021**	460,146
Revenues less expenses		**43,759**	33,295	**20,308**	79,086
Other income (expense)					
Interest and other income		**6,225**	4,345	**11,496**	9,894
Gain on disposition of asset		**-**	-	**-**	3,075
Foreign exchange loss, net		**(84,031)**	(34,369)	**(126,176)**	(5,768)
Net finance expense	18	**(12,350)**	(29,103)	**(35,312)**	(49,577)
		(90,156)	(59,127)	**(149,992)**	(42,376)
Income (loss) before income taxes		**(46,397)**	(25,832)	**(129,684)**	36,710
Deferred income tax expense		**(15,915)**	(3,702)	**(3,922)**	(12,875)
Net income (loss)		**(62,312)**	(29,534)	**(133,606)**	23,835
Other comprehensive income					
Foreign currency translation adjustment		**45**	-	**97**	-
Comprehensive income (loss) for the period		**$ (62,267)**	$ (29,534)	**$ (133,509)**	$ 23,835

Earnings (loss) per share					
Basic	20	**$ (0.28)**	$ (0.15)	**$ (0.60)**	$ 0.12
Diluted	20	**$ (0.28)**	$ (0.15)	**$ (0.60)**	$ 0.12

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

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

	Note	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (AOCI)	Total Shareholders' Equity
Balance at January 1, 2013		**$ 4,694,378**	**$ 102,219**	**$ 73,912**	**$ 25**	**$ 4,870,534**
Share issue costs, net of tax		**332**				**332**
Stock options exercised	14	**18,038**	**(4,154)**			**13,884**
RSUs vested and released	14	**15,201**	**(15,201)**			**-**
Stock-based compensation	14		**20,375**			**20,375**
Net loss				**(133,606)**		**(133,606)**
Other comprehensive income					**97**	**97**
Balance at June 30, 2013		**$ 4,727,949**	**$ 103,239**	**$ (59,694)**	**$ 122**	**$ 4,771,616**
Balance at January 1, 2012		$ 3,877,193	$ 85,568	$ 21,343	$ -	$ 3,984,104
Stock options exercised		8,063	(1,757)			6,306
RSUs vested and released		8,875	(8,875)			-
Stock-based compensation			13,407			13,407
Net income				23,835		23,835
Balance at June 30, 2012		$ 3,894,131	$ 88,343	$ 45,178	$ -	$ 4,027,652

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 June 30		Six months ended June 30	
	Note	**2013**	2012	**2013**	2012
Cash provided by (used in):					
Operating activities					
Net income (loss)		**$ (62,312)**	$ (29,534)	**$ (133,606)**	$ 23,835
Adjustments for:					
Depletion and depreciation		**44,252**	36,020	**88,667**	70,806
Stock-based compensation		**9,563**	5,221	**16,518**	10,555
Unrealized loss on foreign exchange		**82,413**	34,482	**123,330**	6,248
Unrealized (gain) loss on derivative financial liabilities	18	**(14,801)**	9,626	**(19,105)**	8,500
Deferred income tax expense		**15,915**	3,702	**3,922**	12,875
Other		**4,154**	458	**6,529**	(853)
Net change in non-cash operating working capital items	19	**(32,480)**	44,369	**(64,543)**	13,936
Net cash provided by operating activities		**46,704**	104,344	**21,712**	145,902
Investing activities					
Capital investments		**(653,827)**	(339,077)	**(1,322,759)**	(703,939)
Proceeds on disposition of assets		**-**	-	**-**	7,456
Other		**(1,767)**	(978)	**(3,655)**	(1,130)
Net change in non-cash investing working capital items	19	**(21,241)**	(109,758)	**569,253**	76,172
Net cash used in investing activities		**(676,835)**	(449,813)	**(757,161)**	(621,441)
Financing activities					
Issue of shares		**4,870**	966	**14,327**	6,306
Issue of long-term debt		**-**	-	**307,950**	-
Repayment of long-term debt		**(3,406)**	(2,548)	**(6,707)**	(5,046)
Financing costs		**(8,361)**	331	**(15,521)**	(5,622)
Net cash provided by (used in) financing activities		**(6,897)**	(1,251)	**300,049**	(4,362)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**18,476**	418	**26,815**	(2,628)
Change in cash and cash equivalents		**(618,552)**	(346,302)	**(408,585)**	(482,529)
Cash and cash equivalents, beginning of period		**1,684,810**	1,358,904	**1,474,843**	1,495,131
Cash and cash equivalents, end of period		**$ 1,066,258**	$1,012,602	**$ 1,066,258**	$1,012,602

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 development also includes co-ownership of 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. 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, composed 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 (amended in 2011). 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, other assets, accounts payable and accrued liabilities, derivative financial liabilities and long-term debt. As at June 30, 2013, short-term investments, 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 other assets, derivative financial liabilities and long-term debt

			Fair value measurements using		
As at June 30, 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	**$ 7,616**	**$ 7,616**	**$ -**	**$ -**	**$ 7,616**
Financial liabilities					
Derivative financial liabilities	**31,132**	**31,132**	**-**	**31,132**	**-**
Long-term debt	**2,975,947**	**2,928,693**	**2,928,693**	**-**	**-**

			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	2,524,559	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 asset-backed commercial paper that were restructured into MAV notes and US auction rate securities ("ARS"). The Corporation estimated the fair value of the MAV notes and the ARS based on the following: (i) the underlying structure of the notes and the securities; (ii) the present value of future principal and interest payments discounted at rates considered to reflect current market conditions for similar securities; and (iii) consideration of the probabilities of default, based on the quoted credit rating for the respective notes and securities. These estimated fair values could change significantly based on future market conditions.

The Corporation recognizes transfers into and transfers out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer. There were no transfers between levels of the fair value hierarchy during the period ended June 30, 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 fix the interest rate on US$748.0 million of the US$1.3 billion senior secured term loan. At June 30, 2013, there was an unrealized loss on the interest rate swaps of $6.2 million (December 31, 2012 - $12.4 million).

Amount	**Effective date**	**Remaining term**	**Fixed rate**	**Floating rate**
US$300 million	September 30, 2011	Jul 2013-Sept 2016	4.436%	3 month LIBOR(1)
US$150 million	December 31, 2011	Jul 2013-Sept 2016	4.376%	3 month LIBOR(1)
US$150 million	January 12, 2012	Jul 2013-Sept 2016	4.302%	3 month LIBOR(1)
US$148 million	January 27, 2012	Jul 2013-Sept 2016	4.218%	3 month LIBOR(1)

(1) *London Interbank Offered Rate*

6. TRADE RECEIVABLES AND OTHER

		June 30, 2013		December 31, 2012
Trade receivables	**$**	**136,043**	$	104,008
Deposits and advances		**8,154**		4,757
Current portion of deferred financing costs		**3,281**		2,058
	$	**147,478**	$	110,823

7. 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 8)	478,347	-	-	478,347
Balance as at December 31, 2012	$ 4,799,595	$ 793,671	$ 33,597	$ 5,626,863
Additions	1,042,163	297,469	5,293	1,344,925
Transfer from exploration and evaluation assets (note 8)	-	2,513	-	2,513
Balance as at June 30, 2013	**$ 5,841,758**	**$ 1,093,653**	**$ 38,890**	**$ 6,974,301**

	Crude oil	Transportation and storage	Corporate assets	Total
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	81,861	4,005	2,226	88,092
Balance as at June 30, 2013	**$ 411,417**	**$ 26,836**	**$ 8,817**	**$ 447,070**

	Crude oil	Transportation and storage	Corporate assets	Total
Carrying Amounts				
As at December 31, 2012	$ 4,470,039	$ 770,840	$ 27,006	$ 5,267,885
As at June 30, 2013	**$ 5,430,341**	**$ 1,066,817**	**$ 30,073**	**$ 6,527,231**

During the six months ended June 30, 2013, the Corporation capitalized $12.2 million (six months ended June 30, 2012 - $9.0 million) of general and administrative costs and $3.9 million (six months ended June 30, 2012 - $2.9 million) of stock-based compensation costs relating to oil sands exploration and development activities. In addition, $31.8 million of interest and finance charges related to the development of capital projects were capitalized during the six months ended June 30, 2013 (six months ended June 30, 2012 - $10.8 million).

8. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2011	$	991,805
Additions		40,891
Transfer to property, plant and equipment (note 7)		(478,347)
Balance as at December 31, 2012	$	554,349
Additions		1,508
Transfer to property, plant and equipment (note 7)		(2,513)
Balance as at June 30, 2013	**$**	**553,344**

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 June 30, 2013, no impairment has been recognized on these assets.

9. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2011	$	38,186
Additions		9,303
Balance as at December 31, 2012	$	47,489
Additions		10,014
Balance as at June 30, 2013	**$**	**57,503**

Accumulated depreciation		
Balance as at December 31, 2011	$	894
Depreciation		562
Balance as at December 31, 2012	$	1,456
Depreciation		575
Balance as at June 30, 2013	**$**	**2,031**

Carrying Amounts		
As at December 31, 2012	$	46,033
As at June 30, 2013	**$**	**55,472**

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.

10. OTHER ASSETS

		June 30, 2013		December 31, 2012
MAV Notes[(a)]	**$**	**5,391**	$	5,475
ARS[(b)]		**2,225**		2,106
Deferred financing costs[(c)]		**16,151**		8,689
		23,767		16,270
Less current portion of deferred financing costs		**(3,281)**		(2,058)
	$	**20,486**	$	14,212

(a) The Corporation's investment in MAV Notes that mature between 2016 and 2056 are classified as held-for-trading which requires them to be measured at fair value at each period end with changes in fair value included in net finance expense in the period in which they arise.

(b) The investment in ARS is considered an illiquid asset and is recorded at its fair value based on a discounted cash flow valuation using observable information with changes in fair value included in net finance expense in the period in which they arise.

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

11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

		June 30, 2013		December 31, 2012
Trade payables	**$**	**108,512**	$	51,651
Accrued liabilities		**460,614**		370,431
Interest payable		**39,741**		36,848
Other payables		**1,294**		4,147
	$	**610,161**	$	463,077

12. LONG-TERM DEBT

		June 30, 2013		December 31, 2012
Senior secured term loan (June 30, 2013 – US$1.3 billion; December 31, 2012 - US$987.5 million)[(a)]	**$**	**1,346,587**	$	982,464
6.5% senior unsecured notes (US$750 million)[(b)]		**788,400**		746,175
6.375% senior unsecured notes (US$800 million)[(c)]		**840,960**		795,920
		2,975,947		2,524,559
Less current portion of senior secured term loan		**(13,666)**		(9,949)
Less unamortized financial derivative liability discount		**(21,479)**		(10,324)
Less unamortized deferred debt issue costs		**(31,086)**		(25,626)
	$	**2,909,716**	$	2,478,660

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.0512 (December 31, 2012 - US$1 = C$0.9949).

(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 June 30, 2013, $60.3 million (December 31, 2012 - $2.6 million) of the revolving credit facility was utilized to support letters of credit. As at June 30, 2013, no amount had been drawn under the revolving credit facility.

The senior secured credit facilities are comprised of a US$1.281 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, and 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$3.250 million beginning on March 28, 2013, with the balance due on March 31, 2020. Interest is paid quarterly. The Corporation has deferred the associated remaining debt issue costs of $6.5 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 $11.8 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 $12.7 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

13. PROVISIONS AND OTHER LIABILITIES

		June 30, 2013		December 31, 2012
Derivative financial liabilities[a]	**$**	**31,132**	$	37,195
Decommissioning provision[b]		**110,559**		82,087
Deferred lease inducements[c]		**5,446**		5,733
Provisions and other liabilities		**147,137**		125,015
Less current portion		**(16,095)**		(7,259)
Non-current portion	**$**	**131,042**	$	117,756

(a) Derivative financial liabilities

		June 30, 2013		December 31, 2012
1% interest rate floor	**$**	**24,946**	$	24,807
Interest rate swaps		**6,186**		12,388
Derivative financial liabilities		**31,132**		37,195
Less current portion		**(13,265)**		(6,509)
Non-current portion	**$**	**17,867**	$	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 June 30, 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:

		June 30, 2013		December 31, 2012
Decommissioning provision, beginning of period	**$**	**82,087**	$	65,360
Changes in discount rates		**(3,579)**		(3,846)
Liabilities incurred		**33,408**		18,218
Liabilities settled		**(3,619)**		(1,315)
Accretion		**2,262**		3,670
Decommissioning provision, end of period		**110,559**		82,087
Less current portion		**(2,068)**		-
Non-current portion	**$**	**108,491**	$	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 $110.6 million as at June 30, 2013 (December 31, 2012 - $82.1 million) based on an undiscounted total future liability of $282.1 million (December 31, 2012 - $228.1 million) and a credit-adjusted rate of 5.9% (December 31, 2012 – 5.7%). This obligation is estimated to be settled in periods up to 2057.

(c) Leasehold inducements were received when the Corporation entered into the corporate office lease. These inducements are recognized as a deferred liability and amortized over the life of the lease.

14. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

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

	Six months ended June 30, 2013		Year ended December 31, 2012	
	Number of shares	**Amount**	Number of shares	Amount
Balance, beginning of period	**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	**-**	**332**	-	(18,988)
Issued upon exercise of stock options	**1,246,552**	**18,038**	2,243,319	26,520
Issued upon vesting and release of RSUs	**392,236**	**15,201**	228,848	9,528
Balance, end of period	**221,828,872**	**$ 4,727,949**	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.

	Six months ended June 30, 2013		Year ended December 31, 2012	
	Stock options	**Weighted average exercise price per share**	Stock options	Weighted average exercise price per share
Outstanding, beginning of period	**9,147,404**	**$ 32.50**	10,190,103	$ 27.12
Granted	**1,668,949**	**30.81**	1,456,537	35.67
Exercised	**(1,246,552)**	**11.14**	(2,243,319)	9.21
Forfeited	**(68,159)**	**40.01**	(255,917)	40.29
Outstanding, end of period	**9,501,642**	**$ 34.95**	9,147,404	$ 32.50

(d) Restricted share units outstanding:

The Restricted Share Unit Plan allows for the granting of Restricted Share Units ("RSUs") to directors, officers, employees and consultants of the Corporation. An RSU 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. RSUs granted under the Restricted Share Unit Plan generally vest annually over a three year period.

	Six months ended June 30, 2013	Year ended December 31, 2012
	RSUs	RSUs
Outstanding, beginning of period	**953,804**	554,362
Granted	**1,845,724**	664,796
Vested and released	**(392,236)**	(228,848)
Forfeited	**(27,335)**	(36,506)
Outstanding, end of period	**2,379,957**	953,804

(e) Performance share units outstanding:

Effective June 13, 2013, the Corporation's Board of Directors amended the Restricted Share Unit Plan to clarify its application in respect of RSUs having performance criteria attached to them. The Restricted Share Unit Plan allows for the granting of Performance Share Units ("PSUs") to directors, officers, employees and consultants of the Corporation. 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. PSUs become eligible to vest if the Corporation satisfies certain performance criteria within a target range identified by the Corporation's Board of Directors. A pre-determined multiplier is then applied to PSUs that have become eligible to vest depending on the point in the target range to which such performance criteria are satisfied. PSUs granted under the Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that the holder remains actively employed, a director or a consultant with the Corporation on the vesting date. At June 30, 2013, there were 145,498 PSUs outstanding.

(f) 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 June 30, 2013, there were 8,874 DSUs outstanding.

(g) Contributed Surplus:

	Six months ended June 30, 2013	Year ended December 31, 2012
Balance, beginning of period	**$ 102,219**	$ 85,568
Stock-based compensation - expensed	**16,518**	25,246
Stock-based compensation - capitalized	**3,857**	6,796
Stock options exercised	**(4,154)**	(5,863)
RSUs vested and released	**(15,201)**	(9,528)
Balance, end of period	**$ 103,239**	$ 102,219

15. PETROLEUM REVENUE

	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Petroleum sales:				
Proprietary	**$ 296,300**	$ 258,890	**$ 538,100**	$ 533,186
Third party	**13,621**	-	**19,399**	-
	309,921	258,890	**557,499**	533,186
Royalties	**(8,867)**	(7,800)	**(13,469)**	(14,635)
Petroleum revenue	**$ 301,054**	$ 251,090	**$ 544,030**	$ 518,551

16. OTHER REVENUE

	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Power revenue	**$ 17,555**	$ 5,127	**$ 27,171**	$ 14,152
Transportation revenue	**5,751**	3,440	**11,128**	6,529
Other revenue	**$ 23,306**	$ 8,567	**$ 38,299**	$ 20,681

17. DILUENT AND TRANSPORTATION

	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Diluent	**$ 138,261**	$ 133,475	**$ 292,472**	$ 277,390
Transportation	**6,251**	3,536	**11,988**	7,578
Diluent and transportation	**$ 144,512**	$ 137,011	**$ 304,460**	$ 284,968

18. NET FINANCE EXPENSE

	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Total interest expense	**$ 42,994**	$ 25,148	**$ 81,717**	$ 49,399
Less capitalized interest	**(18,211)**	(6,210)	**(31,845)**	(10,754)
Net interest expense	**24,783**	18,938	**49,872**	38,645
Accretion on decommissioning provision	**1,186**	903	**2,262**	1,737
Unrealized fair value (gain) loss on embedded derivative liabilities	**(9,828)**	2,895	**(12,903)**	437
Unrealized fair value (gain) loss on interest rate swaps	**(4,973)**	6,731	**(6,202)**	8,063
Realized loss on interest rate swaps	**1,182**	1,154	**2,283**	2,213
Unrealized fair value gain on other assets	**-**	(1,518)	**-**	(1,518)
Net finance expense	**$ 12,350**	$ 29,103	**$ 35,312**	$ 49,577

19. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Changes in non-cash working capital				
Operating activities:				
Trade receivables and other	**$ (14,455)**	$ 4,063	**$ (36,460)**	$ 29,836
Inventories	**555**	8,873	**(2,741)**	(176)
Accounts payable and accrued liabilities	**(18,580)**	31,433	**(25,342)**	(15,724)
Change in operating non-cash working capital	**$ (32,480)**	$ 44,369	**$ (64,543)**	$ 13,936
Investing activities:				
Short-term investments	**$ (18,671)**	$ (55,062)	**$ 395,798**	$ 53,390
Accounts payable and accrued liabilities	**(2,570)**	(54,696)	**173,455**	22,782
Change in investing non-cash working capital	**$ (21,241)**	$ (109,758)	**$ 569,253**	$ 76,172
Change in total non-cash working capital	**$ (53,721)**	$ (65,389)	**$ 504,710**	$ 90,108
Cash and cash equivalents:				
Cash	**$ 421,382**	$ 39,957	**$ 421,382**	$ 39,957
Cash equivalents	**644,876**	972,645	**644,876**	972,645
	$ 1,066,258	$ 1,012,602	**$ 1,066,258**	$ 1,012,602

20. EARNINGS PER COMMON SHARE

	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Net income (loss)	**$ (62,312)**	$ (29,534)	**$ (133,606)**	$ 23,835
Weighted average common shares outstanding	221,484,529	194,132,517	**221,266,813**	194,009,461
Dilutive effect of stock options, RSUs and PSUs	2,833,271	3,511,736	**2,267,009**	3,787,335
Weighted average common shares outstanding – diluted	224,317,800	197,644,253	**223,533,822**	197,796,796
Earnings (loss) per share, basic	**$ (0.28)**	$ (0.15)	**$ (0.60)**	$ 0.12
Earnings (loss) per share, diluted	**$ (0.28)**	$ (0.15)	**$ (0.60)**	$ 0.12

21. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at June 30, 2013:

Operating:

	2013	2014	2015	2016	2017	Thereafter
Office lease rentals	$ 6,103	$ 12,208	$ 12,411	$ 12,820	$ 30,504	$ 343,901
Diluent purchases	403,012	71,765	16,115	16,115	16,115	100,708
Transportation and storage	41,842	134,315	126,129	145,881	145,685	1,822,381
Other commitments	14,949	16,875	8,164	4,794	4,259	35,852
Commitments	$ 465,906	$ 235,163	$ 162,819	$ 179,610	$196,563	$ 2,302,842

Capital:

As part of normal operations, the Corporation has entered into a total of $589.2 million in capital commitments to be made in periods through 2017.

(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.