MEG Energy

FOURTH QUARTER 2012

Report to Shareholders for the period ended December 31, 2012

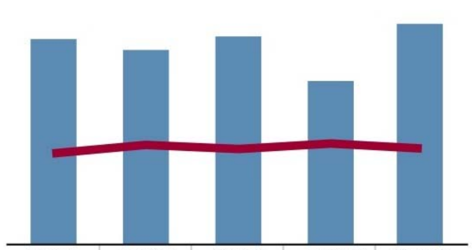
MEG Energy Corp. ("MEG" or the "Corporation") reported fourth quarter and full-year 2012 operational and financial results on January 31, 2013. Highlights included:

- Record annual and exit production volumes, exceeding 2012 guidance;
- Record quarterly production and low operating costs contribute to very strong fourth quarter netbacks;
- Agreements in place to enable substantial volumes to be transported by rail and barge to high-value markets, providing the option to bypass congested pipeline infrastructure;
- Fabrication and delivery to site of all major components of the Christina Lake Phase 2B project, with start-up scheduled in the second half of 2013;
- Regulatory approval for deployment of proprietary eMSAGP production technology to additional well-pads as part of the RISER production enhancement initiative; and
- Independent evaluation increased proved reserves by more than 80% year-over-year, as project developments and resource definition advanced.

“Record production levels and low operating costs contributed to a netback of $34.44, which we believe places MEG among the best in the industry for the value we get out of every barrel,” said Bill McCaffrey, MEG President and Chief Executive Officer. “To further build on that strong performance, we are taking major strategic steps in 2013 to both increase production and improve market access. Starting mid-year, we expect to market volumes to the U.S. Gulf Coast through agreements already in place for rail and barge transportation, allowing us to directly access these higher-value markets.”

Production during the fourth quarter of 2012 was 32,292 barrels per day (bpd), MEG's highest quarterly volume to date. Comparative fourth quarter 2011 production averaged 30,032 bpd. Annual production for 2012 averaged 28,773 bpd, an increase of 8% over 2011 volumes of 26,605 bpd, marking MEG’s fourth consecutive year of production gains.

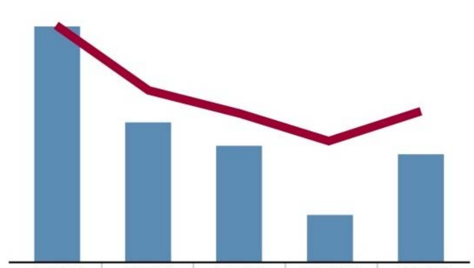
Operational Performance



	Q4/11	Q1/12	Q2/12	Q3/12*	Q4/12
Production (bpd)	30,032	28,446	30,429	23,941	32,292
SOR	2.3	2.5	2.4	2.5	2.4

*Planned plant turnaround

Financial Performance



	Q4/11	Q1/12	Q2/12	Q3/12*	Q4/12
Cash flow from operations ($mm)	121.6	72.0	60.0	24.4	56.1
Cash operating netback ($/bbl)	54.64	39.20	34.17	27.85	34.44

*Planned plant turnaround

Net operating costs for the fourth quarter of 2012 were $8.95 per barrel, expected to be among the lowest in the industry for the period. Comparable fourth quarter 2011 results, the best in MEG's history, were $8.50 per barrel. The difference in net operating costs is primarily due to lower per barrel power sales and higher non-energy operating costs during the fourth quarter of 2012 compared to the fourth quarter of 2011. Non-energy operating costs for 2012 were $9.71 per barrel, beating MEG's 2012 target of $10 to $12 per barrel.

Cash flow from operations for the fourth quarter of 2012 was $56.1 million ($0.27 per share, diluted) compared to cash flow of $121.6 million ($0.61 per share, diluted) in the fourth quarter of 2011. The decrease was primarily due to lower bitumen realizations, higher general and administrative expense and higher interest expense, partially offset by higher production.

MEG recorded a net loss of $18.7 million ($0.09 per share, diluted) for the fourth quarter of 2012 compared to net income of $91.1 million ($0.46 per share, diluted) in the fourth quarter of 2011. Fourth quarter 2012 results included a net foreign exchange loss of $21.1 million, primarily arising from the translation of MEG's U.S. dollar denominated debt and U.S. dollar cash and cash equivalents. For the comparable period in 2011, there was a net foreign exchange gain of $33.7 million.

Operating earnings, which are adjusted to exclude items that are not indicative of operating performance, were recorded as a loss of $0.5 million in the fourth quarter of 2012 ($0.00 per share, diluted) compared to earnings of $57.8 million ($0.29 per share, diluted) in the same period of 2011. Operating earnings were impacted by the same factors that affected cash flow from operations.

Capital and growth strategy

Full-year capital investment for 2012 was approximately $1.6 billion, slightly below MEG's forecast of $1.75 billion due to a shift in timing of capital investments. The majority of the 2012 budget was invested in MEG's strategic plan to support increasing production capacity tenfold to 260,000 bpd in 2020.

Investments in 2012 were focused primarily on the RISER initiative ($234.3 million) to drive near-term production increases and Christina Lake Phase 2B ($631.5 million), which is targeted to more than double MEG's production capacity in the second half of 2013. All materials and project modules associated with Phase 2B have been delivered, with on-site construction continuing. With the continuing deployment of RISER and the planned completion of Phase 2B in the second half of 2013, MEG is targeting a 16% increase in annual production to approximately 32,000 to 35,000 bpd, with investments this year supporting longer-term targets of 80,000 bpd in early 2015.

In addition to ongoing investments in growth initiatives, MEG has also targeted investments to improve market access with the goal of mitigating differentials to drive higher sales prices and related cash flow in the near term. MEG has recently entered into agreements for rail terminal capacity accessible by direct pipeline connections to the company's Stonefell Terminal, as well as leasing agreements for barges to provide transportation to high-value markets throughout the U.S. Gulf Coast via US inland waterways.

These market access options are expected to allow MEG to begin bypassing U.S. pipeline congestion and shift product pricing from the discounted Edmonton and mid-continent markets to higher value markets on the east coast and U.S. Gulf Coast. Contracted capacity on rail terminals and barges are expected to accommodate MEG's mid-2013 production levels. Additional contracted capacity on the Flanagan South pipeline, providing further U.S. Gulf Coast access, is expected to be available in mid-2014. This combination of pipeline access, along with continuing options for rail and barge transportation, is expected to provide MEG with reliable access to the best available pricing as the company's production grows.

Financial Condition and Liquidity

The Corporation's cash and short-term investment balance was $2.0 billion as at December 31, 2012 compared to $1.6 billion as at December 31, 2011. Long-term debt increased to $2.5 billion as at December 31, 2012 from $1.8 billion as at December 31, 2011. 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. 12.1 million common shares were issued through a public bought deal financing while the remaining 12.1 million common shares were issued on a private placement basis.

"The December equity issue adds significant strength to our financial foundation, with the proceeds largely going toward the deployment of RISER to Phases 2 and 2B," said McCaffrey. "In combination with well-structured debt, the added cash flow we expect to generate will help fund a meaningful portion of our future growth."

In addition to MEG's $2.0 billion in cash and short-term investments as at December 31, 2012, MEG's capital resources also include an undrawn US$1.0 billion revolving credit facility.

Reserves update

GLJ Petroleum Consultants Ltd. ("GLJ"), an independent reservoir engineering firm, has completed an evaluation of MEG's bitumen reserves and resources effective as of December 31, 2012. Proved bitumen reserves increased more than 80% to an estimated 1.3 billion barrels from approximately 700 million barrels at December 31, 2011, while proved plus probable reserves increased to 2.6 billion barrels from 2.1 billion barrels. GLJ's estimate of contingent resources (on a best estimate basis) was approximately 3.4 billion barrels, compared to 3.8 billion barrels a year earlier, reflecting the continued de-risking of MEG's assets through the conversion of contingent resources to the reserves category.

"MEG's large, high-quality resource base is the foundation of our growth strategy," said McCaffrey. "This most recent evaluation, supported by our ongoing project development, places MEG among the largest holders of proved and proved-plus-probable reserves in the Canadian oil industry."

The pre-tax net present value of the future net cash flows of the proved reserves and of the proved plus probable reserves, discounted at 10% per annum, were $10.5 billion and $16.8 billion, respectively. A summary of GLJ's report, along with important information regarding net present value calculations and the classification of reserves and contingent resources is included under the heading "Reserves and Resources".

OPERATIONAL AND FINANCIAL HIGHLIGHTS

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

	Three months ended December 31		Year ended December 31	
	2012	2011	2012	2011
Bitumen production – bpd	32,292	30,032	28,773	26,605
Steam to oil ratio	2.4	2.3	2.4	2.4
West Texas Intermediate (WTI) US$/bbl	88.18	94.06	94.21	95.12
Differential – WTI/Blend %	29.9%	18.2%	31.2%	23.5%
Bitumen realization - $/bbl	45.67	67.99	46.93	58.74
Net operating costs(1) - $/bbl	8.95	8.50	9.98	10.96
Cash operating netback(2) - $/bbl	34.44	54.64	34.18	43.15
Capital cash investment - $000	494,916	268,814	1,598,514	928,921
Net income (loss) - $000	(18,740)	91,118	52,569	63,837
Per share, diluted	(0.09)	0.46	0.26	0.32
Operating earnings (loss) - $000(3)	(538)	57,833	21,242	109,255
Per share, diluted(3)	0.00	0.29	0.11	0.55
Cash flow from operations - $000(3)	56,106	121,608	212,514	304,627
Per share, diluted(3)	0.27	0.61	1.06	1.54
Cash and short-term investments - $000	2,007,841	1,647,069	2,007,841	1,647,069
Long-term debt - $000	2,488,609	1,751,539	2,488,609	1,751,539
Bitumen Reserves and Contingent Resources (millions of barrels, before royalties)				
Proved (1P) Reserves(4)			1,284	708
Probable Reserves(5)			1,360	1,352
Proved Plus Probable (2P) Reserves(4)(5)			2,644	2,060
Best Estimate Contingent Resources (2C)(6)(7)(8)			3,420	3,818

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

(2) *Cash operating netbacks are calculated by deducting the related royalties and diluents, transportation, operating costs and realized gains/losses on financial derivatives from bitumen sales revenues, on a per barrel basis. Please refer to note 3 of the Cash Operating Netbacks table within "RESULTS OF OPERATIONS."*

(3) *Operating earnings (loss), 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.*

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

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

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

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

[8] *These volumes are the arithmetic sums of the Best Estimate Contingent Resources for Christina Lake, Surmont and the Growth Properties.*

Production for the three months ended December 31, 2012 averaged 32,292 bpd compared to 30,032 bpd for the same period in 2011. Bitumen production for the year ended December 31, 2012 averaged 28,773 bpd compared to 26,605 bpd for the year ended December 31, 2011. The increase in production results from increased steam generation capabilities in 2012 compared to 2011. There were 41 SAGD well pairs and two infill wells on production as at December 31, 2012 compared to 35 SAGD well pairs on production as at December 31, 2011. With respect to the six SAGD well pairs added during 2012, one was brought into production during the first quarter, two were added in the second quarter, one well pair was brought into production during the third quarter and two well pairs were added in the fourth quarter. The two infill wells were brought into production during the first quarter of 2012.

Bitumen realizations were impacted by market conditions as WTI prices decreased to an average of US$88.18 per barrel in the fourth quarter of 2012 compared to US$94.06 per barrel during the fourth quarter of 2011. For the year ended December 31, 2012, WTI prices averaged US$94.21 per barrel compared to US$95.12 per barrel during 2011. Bitumen realizations were also impacted by higher differentials between WTI and the Corporation's blend sales. The differential increased to 29.9% during the fourth quarter of 2012, from 18.2% during the fourth quarter of 2011. For the year ended December 31, 2012, the differential between WTI price and the Corporation's blend sales increased to 31.2% from 23.5% during 2011. Increases in production of both light crude oil and heavier crudes have put downward pressure on both light and heavy oil prices in the U.S. mid-continent. Pipeline congestion and refinery outages in the U.S. Midwest have added to this pressure which led to a higher discount for Canadian crude in 2012.

Net operating costs for the three months ended December 31, 2012 were $8.95 per barrel, compared to $8.50 per barrel during the same period in 2011. The increase in net operating costs is primarily due to lower per barrel power sales and higher non-energy operating costs during the fourth quarter of 2012 compared to the fourth quarter of 2011. For the year ended December 31, 2012, net operating costs were $9.98 per barrel, compared to $10.96 per barrel during the same period in 2011. The decrease in net operating costs was the result of:

- a reduction in energy operating costs, primarily as a result of lower natural gas prices; and
- a decline in annual non-energy operating costs on a per barrel basis, which has largely been driven by higher production volumes. Efficient plant utilization enabled the Corporation to spread relatively fixed operating costs over higher production volumes.

Energy and non-energy operating costs are partially offset by power sales which were lower in 2012 compared to 2011 due to a decrease in realized power prices. Primarily as a result of lower natural gas prices, MEG's power sales had the effect of offsetting 95% of energy operating costs in the fourth quarter of 2012 and 92% for the year ended December 31, 2012.

Cash operating netback for the fourth quarter of 2012 was $34.44 per barrel compared to $54.64 per barrel for the fourth quarter of 2011. Cash operating netback for the year ended December 31, 2012 was $34.18 per barrel compared to $43.15 for 2011. Cash operating netbacks were negatively impacted by the decrease in the Corporation's bitumen realizations due to the wider differentials to WTI on both a quarter over quarter basis and a year over year basis in 2012 compared to 2011. The decreases were partially offset by an increase in production during the fourth quarter and the year and a reduction in energy operating costs for the year ended December 31, 2012.

Capital investment increased to $494.9 million during the fourth quarter of 2012 from $268.8 million during the fourth quarter of 2011. Capital investment increased to $1.6 billion for the year ended December 31, 2012 from $928.9 million for the year ended December 31, 2011. Capital investment in 2012 has focused on the construction of Phase 2B, delineation drilling and seismic programs at Christina Lake and Surmont, the RISER production enhancement program, construction of the Stonefell Terminal, and expansion of the Access Pipeline.

Net loss for the fourth quarter of 2012 was $18.7 million compared to net income of $91.1 million for the fourth quarter of 2011. Net loss during the fourth quarter included a net foreign exchange loss of $21.1 million primarily arising from the translation of the Corporation's U.S. dollar denominated debt and U.S. dollar cash and cash equivalents. For the comparable period in 2011, there was a net foreign exchange gain of $33.7 million. Net income for the year ended December 31, 2012 was $52.6 million compared to $63.8 million for the year ended December 31, 2011. Net income for year ended December 31, 2012 included a net foreign exchange gain of $36.6 million compared to a net foreign exchange loss of $35.7 million for year ended December 31, 2011. Net income was also impacted by lower realized bitumen prices and higher production volumes in 2012, compared to the corresponding comparative periods of 2011.

The operating loss for the three months ended December 31, 2012 was $0.5 million compared to operating earnings of $57.8 million for the same period in 2011. The decrease in operating earnings for the fourth quarter of 2012 compared to the fourth quarter of 2011 is due to lower bitumen realizations combined with higher general and administrative expense, interest expense and operating costs partially offset by an increase in production. Operating earnings for the year ended December 31, 2012 were $21.2 million compared to $109.3 million for the year ended December 31, 2011. The decrease in operating earnings for 2012 compared to 2011 is due to lower bitumen realizations, higher general and administrative expense and higher interest expense, partially offset by higher production and lower operating costs.

Cash flow from operations for the three months ended December 31, 2012 was $56.1 million compared to $121.6 million for the three months ended December 31, 2011. Cash flow from operations was $212.5 million for the year ended December 31, 2012 compared to $304.6 million for the same period in 2011. Cash flow from operations was impacted by the same factors that impacted operating earnings.

The Corporation's cash and short-term investments balance was $2.0 billion as at December 31, 2012 compared to $1.6 billion as at December 31, 2011. Long-term debt increased to $2.5 billion as at December 31, 2012 from $1.8 billion as at December 31, 2011. 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. 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. 12.1 million of the common shares were issued through a public bought deal financing while the remaining 12.1 million common shares were issued on a private placement basis.

As at December 31, 2012, the Corporation's capital resources included $2.0 billion of cash and short-term investments and an undrawn US$1.0 billion revolving credit facility. During the first quarter of 2012, MEG expanded its undrawn senior secured revolving credit facility from US$500.0 million to US$1.0 billion and extended the maturity to March 2017.

BUSINESS ENVIRONMENT

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

	Year Ended December 31		2012				2011			
	2012	2011	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Commodity Prices (Average Prices)										
Crude oil prices										
West Texas Intermediate (WTI) US$/bbl	94.21	95.12	88.18	92.22	93.49	102.92	94.06	89.76	102.56	94.10
Western Canadian Select (WCS) C$/bbl	73.13	77.15	69.47	70.06	71.34	81.66	85.53	70.68	82.17	70.23
Differential – WTI/WCS (C$/bbl)	21.01	16.95	17.94	21.67	23.10	21.39	10.70	17.31	17.08	22.55
Differential – WTI/WCS	22.3%	18.0%	20.5%	23.6%	24.5%	20.8%	11.1%	19.7%	17.2%	24.3%
Natural gas prices										
AECO (C$/mcf)	2.39	3.66	3.04	2.18	1.83	2.50	3.45	3.70	3.72	3.76
Electric power prices										
Alberta power pool average price (C$/MWh)	64.24	76.17	78.73	78.09	40.03	60.10	76.05	94.69	51.90	82.03
Foreign exchange rates										
C$ equivalent of 1 US$ - average	0.9994	0.9893	0.9913	0.9948	1.0102	1.0012	1.0231	0.9802	0.9676	0.9860
C$ equivalent of 1 US$ - period end	0.9949	1.0170	0.9949	0.9837	1.0191	0.9991	1.0170	1.0389	0.9643	0.9718

WTI price 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 benchmark WTI price averaged US$88.18 per barrel during the fourth quarter of 2012 compared to US$94.06 per barrel during the fourth quarter of 2011. The average WTI price for the year ended December 31, 2012 was US$94.21 per barrel compared to US$95.12 per barrel during the same period in 2011.

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 discount to the WTI benchmark price. For the three months ended December 31, 2012 the WTI/WCS differential averaged 20.5% compared to 11.1% during the same period of 2011. For the year ended December 31, 2012, the WTI/WCS differential averaged 22.3% compared to 18.0% during 2011.

Increases in production of both light crude oil and heavier crudes have put pressure on both light and heavy oil prices in the U.S. mid-continent. Pipeline congestion and refinery outages in the U.S. Midwest added to this pressure which led to a larger discount for Canadian crude in 2012. A number of initiatives to access additional markets, including the expansion in capacity of the Seaway pipeline in early 2013, completion of the 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 those of other crude oil benchmarks over the next 18 to 24 months.

The bitumen the Corporation produces at the Christina Lake property is mixed with purchased diluents. The end product is marketed as a bitumen blend known as Access Western Blend ("AWB" or "blend"). It is shipped through the Access Pipeline to the Edmonton-area refining and transportation hub. During the fourth quarter of 2012, the differential between WTI and MEG's blend sales widened to an average of 29.9%, from 18.2% in the fourth quarter of 2011. On a full year basis, the WTI/AWB differential widened to 31.2% in 2012 from 23.5% during 2011. The completion of MEG's Stonefell Terminal combined with the initiation of rail and barging alternatives in mid-2013 are expected to enable MEG to avoid pipeline bottlenecks and shift product pricing from the discounted Edmonton and mid-continent markets to higher value markets on the east coast and U.S. Gulf Coast. In addition, the Corporation has secured strategic pipeline capacity commencing in mid-2014 along with opportunities to move products to a wider range of markets. These include pipeline connections to rail loading facilities at Bruderheim, Alberta and the acquisition of barges for use on the U.S. Inland Waterways, both of which, along with the Stonefell Terminal, are expected to become available for use in mid-2013.

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 $3.04 per thousand cubic feet ("mcf") for the fourth quarter of 2012, in comparison to $3.45 per mcf during the fourth quarter of 2011. During the year ended December 31, 2012, the AECO natural gas price averaged $2.39 per mcf, compared to $3.66 per mcf during the year ended December 31, 2011. Natural gas prices have trended lower over the past three years as a result of strong supply growth throughout North America.

The Alberta power pool price averaged $78.73 per megawatt hour during the fourth quarter of 2012. This compares to $76.05 per megawatt hour in the fourth quarter of 2011. During the year ended December 31, 2012, the Alberta power pool price averaged $64.24 per megawatt hour compared to $76.17 per megawatt hour during the year ended December 31, 2011. Power prices for 2012 were lower due to mild winter weather, lower natural gas prices and power supply additions to the Alberta grid.

Increases in the value of the Canadian dollar relative to the U.S. dollar have a negative impact on the Corporation's bitumen revenues, as sales prices are determined by reference to U.S. benchmarks. The negative impact on bitumen revenues is partially offset by lower principal and interest payments on the Corporation's U.S. dollar denominated debt. As at December 31, 2012, the Canadian dollar, at a rate of 0.9949, had increased by approximately $0.02 in value against the U.S. dollar compared to its value as at December 31, 2011, when the rate was 1.0170.

RESULTS OF OPERATIONS

	Three months ended December 31		**Year ended December 31**	
	2012	**2011**	**2012**	**2011**
Bitumen production – bpd	32,292	30,032	28,773	26,605
Steam to oil ratio	2.4	2.3	2.4	2.4

Production

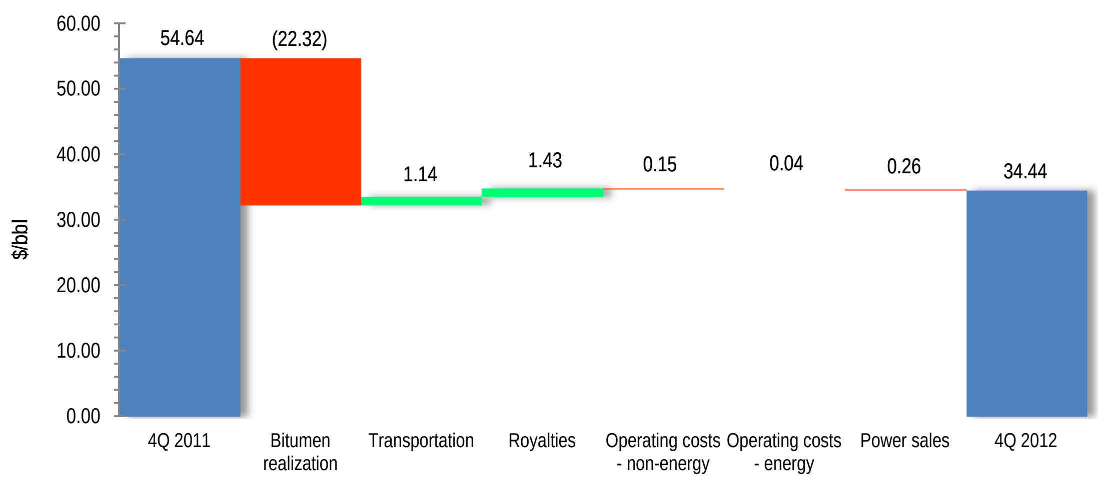
Production averaged 32,292 bpd during the fourth quarter of 2012 compared to 30,032 bpd during the same period in 2011. Production averaged 28,773 bpd for the year ended December 31, 2012 compared to 26,605 bpd for the year ended December 31, 2011.

The increase in production primarily results from increased steam generation capabilities in 2012 compared to the same periods in 2011. Plant efficiencies, combined with improvements made to the Corporation's existing steam generation system during the plant turnaround that occurred in the fourth quarter of 2011, enabled the additional six well pairs and two infill wells to be placed on production. There were 41 SAGD well pairs and two infill wells on production as at December 31, 2012, in comparison to 35 SAGD well pairs on production as at December 31, 2011.

For the three months ended December 31, 2012, the average steam to oil ratio ("SOR") was 2.4, compared to an average SOR of 2.3 during the fourth quarter of 2011. For the year ended December 31, 2012, the average SOR was 2.4, compared to an average SOR of 2.4 for the year ended December 31, 2011. 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 in relation to bitumen produced.

Cash Operating Netback

Bridge analysis of cash operating netback for the three months ended December 31, 2012 versus December 31, 2011:

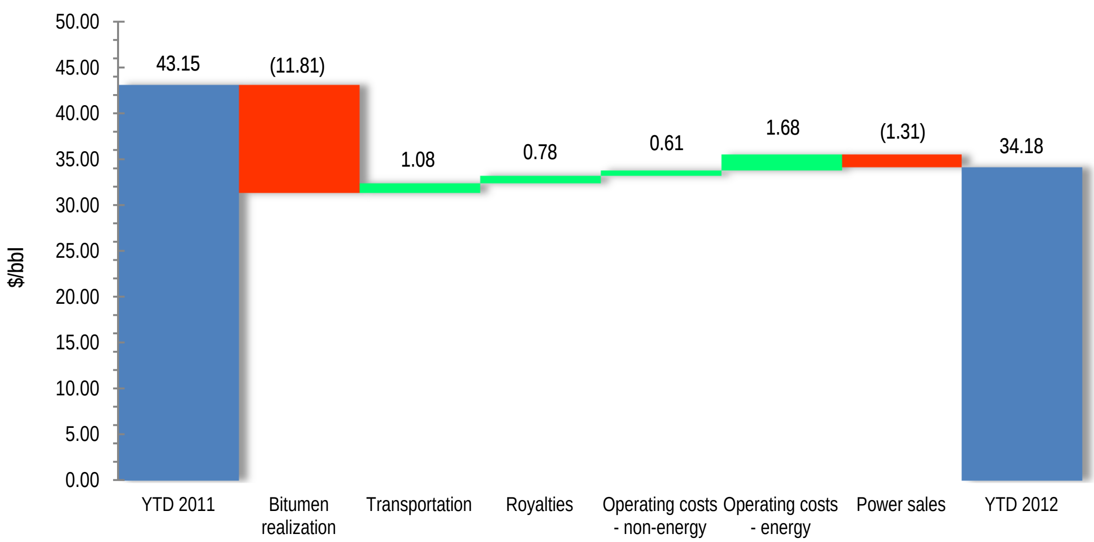


The following table summarizes the Corporation's cash operating netback for the three month periods ended:

	Three months ended December 31			
	2012		2011	
	$000	**$ per bbl**	**$000**	**$ per bbl**
Bitumen realization[(1)]	137,500	45.67	189,334	67.99
Transportation[(2)]	(144)	(0.05)	(3,307)	(1.19)
Royalties	(6,709)	(2.23)	(10,185)	(3.66)
Net bitumen revenue	**130,647**	**43.39**	**175,842**	**63.14**
Operating costs – non-energy	(26,179)	(8.70)	(23,807)	(8.55)
Operating costs – energy	(13,984)	(4.65)	(12,826)	(4.61)
Power sales	13,248	4.40	12,969	4.66
Net operating costs	**(26,915)**	**(8.95)**	**(23,664)**	**(8.50)**
Cash operating netback[(3)]	**103,732**	**34.44**	**152,178**	**54.64**

(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".*

Bridge analysis of cash operating netback for the year ended December 31, 2012 versus December 31, 2011:



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

	Year ended December 31			
	2012		2011	
	$000	$ per bbl	$000	$ per bbl
Bitumen realization[1]	495,425	46.93	570,027	58.74
Transportation[2]	(3,231)	(0.31)	(13,476)	(1.39)
Royalties	(25,959)	(2.46)	(31,438)	(3.24)
Net bitumen revenue	**466,235**	**44.16**	**525,113**	**54.11**
Operating costs – non-energy	(102,481)	(9.71)	(100,162)	(10.32)
Operating costs – energy	(36,538)	(3.46)	(49,867)	(5.14)
Power sales	33,634	3.19	43,628	4.50
Net operating costs	**(105,385)**	**(9.98)**	**(106,401)**	**(10.96)**
Cash operating netback[3]	**360,850**	**34.18**	**418,712**	**43.15**

(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 document represents the Corporation's realized revenues, net of the cost of diluent.

	Three months ended December 31		Year ended December 31	
$000	**2012**	**2011**	**2012**	**2011**
Blend sales – proprietary volumes	268,007	322,383	991,975	1,021,036
Cost of diluent	(130,507)	(133,049)	(496,550)	(451,009)
Bitumen realization	137,500	189,334	495,425	570,027

Blend sales for the three months ended December 31, 2012 were $268.0 million compared to $322.4 million for the three months ended December 31, 2011. Blend sales averaged $61.29 per barrel during the fourth quarter of 2012 compared to $78.76 per barrel in the fourth quarter of 2011. Blend sales for the year ended December 31, 2012 were $992.0 million compared to $1.0 billion for the year ended December 31, 2011. Blend sales averaged $64.78 per barrel during the year ended December 31, 2012 compared to $72.03 per barrel for the same period in 2011. The decrease in blend sales for the periods ended December 31, 2012 compared to the same periods in 2011 is due to the lower average realized prices partially offset by higher sales volumes.

The cost of diluent for the three months ended December 31, 2012 was $130.5 million compared to $133.0 million for the same period in 2011. The decrease in the cost of diluent for the fourth quarter of 2012 compared to the fourth quarter of 2011 is due to a decrease in the cost per barrel of diluent, which was substantially offset by higher volumes of diluent purchased as a result of the increase in production volumes. On a per barrel basis, the Corporation's cost of diluent for the fourth quarter of 2012 was $95.78 per barrel, compared to $101.68 per barrel for the fourth quarter of 2011. The cost of diluent for the year ended December 31, 2012 was $496.6 million compared to $451.0 million for the year ended December 31, 2011. On a per barrel basis, the Corporation's cost of diluent increased to $104.41 per barrel for the year ended December 31, 2012, from $100.87 per barrel for the same period in 2011. The cost of diluent increased for the year ended December 31, 2012 compared to the previous year due to higher volumes of diluent purchased as a result of increased production plus higher average diluent prices.

Transportation

Transportation costs, which primarily consist of MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries on diluent transportation arrangements, were $0.1 million for the three months ended December 31, 2012 compared to $3.3 million for the same period in 2011. Transportation costs averaged $0.05 per barrel during the fourth quarter of 2012 compared to $1.19 per barrel during the same period in 2011. The decrease in transportation costs in the fourth quarter of 2012 compared to the same period in 2011 is primarily due to higher recoveries on diluent transportation arrangements. In the fourth quarter of 2012, the Corporation recognized third-party recoveries of $3.7 million compared to $1.3 million for the same period in 2011. For the year ended December 31, 2012, transportation costs were $3.2 million compared to $13.5 million for 2011, net of $13.0 million and $3.4 million in third-party recoveries, respectively. On a per barrel basis, transportation costs decreased to an average of $0.31 per barrel during 2012, from $1.39 per barrel during 2011.

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 for the three months ended December 31, 2012 were $6.7 million compared to $10.2 million for the same period in 2011. Royalties averaged $2.23 per barrel during the fourth quarter of 2012 compared to $3.66 per barrel during the same period in 2011. For the year ended December 31, 2012, royalties were $26.0 million compared to $31.4 million for the same period in 2011. Royalties averaged $2.46 per barrel for the year ended December 31, 2012 compared to $3.24 per barrel during the same period in 2011. The Corporation's royalty rate for the three months ended December 31, 2012 was 4.9% of bitumen realizations compared to 5.4% during the same period in 2011. For the year ended December 31, 2012, the realized royalty rate was 5.2% compared to 5.5% for the year ended December 31, 2011. The decrease in royalties is attributable to lower bitumen realizations.

Operating Costs

Non-energy operating costs for the three months ended December 31, 2012 were $26.2 million compared to $23.8 million for the three months ended December 31, 2011. Non-energy related operating costs averaged $8.70 per barrel for the quarter compared to $8.55 per barrel for the fourth quarter of 2011. The increase in non-energy related operating costs for the fourth quarter of 2012 is attributable to higher camp and labor costs, which were largely offset on a per barrel basis by the increase in production. Non-energy related operating costs were $102.5 million for the year ended December 31, 2012 compared to $100.2 million for the same period in 2011. For the year ended December 31, 2012, non-energy operating costs decreased to an average of $9.71 per barrel from $10.32 per barrel for the comparative period in 2011. On a per barrel basis, non-energy related operating costs for the year ended December 31, 2012 decreased compared to the prior year primarily as a result of higher production, as relatively fixed components of operating costs are spread over a greater number of barrels of production.

Energy related operating costs were $14.0 million for the three month period ended December 31, 2012 compared to $12.8 million for the same period in 2011. On a per barrel basis, these costs averaged $4.65 per barrel for the fourth quarter of 2012 compared to $4.61 per barrel for the fourth quarter of 2011. Energy related operating costs were $36.5 million for the year ended December 31, 2012 compared to $49.9 million for the same period in 2011. On a per barrel basis, energy operating costs were $3.46 per barrel for the year ended December 31, 2012 compared to $5.14 for the year ended December 31, 2011. The decrease in energy related operating costs per barrel is primarily the result of lower natural gas prices. The benchmark AECO natural gas price averaged $3.04 per mcf for the fourth quarter of 2012 compared to $3.45 per mcf for the fourth quarter of 2011. The AECO benchmark decreased to $2.39 per mcf for the full year in 2012 compared to $3.66 per mcf for 2011. Natural gas prices have trended lower over the past three years as a result of strong supply growth throughout North America.

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 for the three months ended December 31, 2012 were $13.2 million compared to $13.0 million for the three months ended December 31, 2011. Power sales for the year ended December 31, 2012 were $33.6 million compared to $43.6 million for the year ended December 31, 2011. During the fourth quarter of 2012, the Corporation realized a price of $79.62 per megawatt hour compared to $78.91 per megawatt hour for the fourth quarter of 2011. The Corporation realized an average power price of $59.22 per megawatt hour during the year ended December 31, 2012 compared to $74.33 per megawatt hour during the same period in 2011. Variations in the Corporation's realized power prices during the periods are largely consistent with variations in the Alberta power pool prices during the periods noted. Power prices for 2012 were lower due to mild winter weather and additional power supply as a result of the commissioning of a 450 megawatt power plant in Alberta during September 2011. Power prices have also been affected by lower natural gas prices.

NON-IFRS MEASUREMENTS

The following tables reconcile the non-IFRS measurements "Operating earnings (loss)" and "Cash operating netback" to "Net income (loss)" the nearest IFRS measure, and also reconcile the non-IFRS measurement "Cash flow from operations" to "Net cash provided by operating activities", the nearest IFRS measure. Operating earnings (loss) is defined as net income (loss) as reported, excluding the after-tax unrealized foreign exchange gains and losses, unrealized gains and losses on derivative liabilities, unrealized fair value gains or losses on other assets and gain on modification of long-term debt. Cash flow from operations excludes debt modification costs and the net change in non-cash operating working capital, while the IFRS measurement "Net cash provided by operating activities" includes these items. Cash operating netback is comprised of proprietary petroleum and power sales less royalties, operating costs, cost of diluent and transportation costs.

	Three months ended December 31		Year ended December 31	
($000)	**2012**	**2011**	**2012**	**2011**
Net income (loss)	(18,740)	91,118	52,569	63,837
Add (deduct):				
Unrealized foreign exchange (gain) loss, net of tax[(1)]	20,136	(33,525)	(39,090)	39,383
Unrealized (gain) loss on derivative liabilities, net of tax[(2)]	(1,934)	240	9,651	8,115
Unrealized fair value gain on other assets[(3)]	-	-	(1,888)	-
Gain on modification of long-term debt, net of tax[(4)]	-	-	-	(2,080)
Operating earnings (loss)	(538)	57,833	21,242	109,255
Add (deduct):				
Interest income	(4,650)	(7,024)	(19,896)	(18,786)
Depletion and depreciation	44,593	34,803	144,950	124,327
General and administrative	22,173	16,227	70,597	55,738
Stock-based compensation	7,271	5,412	25,246	21,355
Research and development	966	2,004	5,157	6,810
Interest expense	27,600	20,198	91,816	73,647
Accretion	999	1,049	3,670	1,646
Gain on disposition of asset	-	-	(3,075)	-
Realized (gain) loss on foreign exchange	372	(40)	(796)	506
Realized loss on derivative liabilities	1,169	532	4,518	532
Net marketing activity	1,537	-	1,762	-
Deferred income taxes, operating	2,240	21,184	15,659	43,682
Cash operating netback	103,732	152,178	360,850	418,712

(1) *Unrealized foreign exchange gains and losses result primarily from the translation of U.S. dollar denominated long-term debt, cash and cash equivalents to period-end exchange rates. Unrealized foreign exchange gains and losses are presented net of a deferred tax recovery of $618 for the three month period ended December 31, 2012 and net of a deferred tax recovery of $3,269 for the year ended December 31, 2012 (deferred tax expense of $85 and $4,176 for the three and twelve month periods ended December 31, 2011).*

(2) *Unrealized losses on derivative 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 $645 for the three month period and a deferred tax recovery of $3,217 for the year ended December 31, 2012 (deferred tax recovery of $79 and $2,704 for the three and twelve month periods ended December 31, 2011).*

(3) *Unrealized fair value gain on other assets results from the fair market valuation of certain investments held at December 31, 2012, net of a deferred tax expense of $630 for the year ended December 31, 2012.*

(4) *Gain on modification of long-term debt results from modifications to the Corporation's senior secured credit facility on March 18, 2011, net of a deferred tax expense of $693 for the year ended December 31, 2011.*

Non-IFRS Measurements – Reconciliation of net cash provided by operating activities to cash flow from operations ($000)	Three months ended December 31		Year ended December 31	
	2012	**2011**	**2012**	**2011**
Net cash provided by operating activities	48,491	88,696	240,824	314,302
Add (deduct):				
Net change in non-cash operating working capital items	7,615	32,912	(28,310)	(18,098)
Debt modification costs	-	-	-	8,423
Cash flow from operations	56,106	121,608	212,514	304,627

Interest and Other Income

Interest and other income for the three months ended December 31, 2012 was $4.7 million compared to $7.0 million for the same period in 2011. The decrease in interest and other income is due to lower average cash and short-term investments balances held in the fourth quarter of 2012 compared to the fourth quarter of 2011. Interest and other income for the year ended December 31, 2012 was $19.9 million compared to $18.8 million for the same period in 2011. The increase in interest earned is mainly due to higher interest rates and income realized on cash and short-term investments held during 2012 compared to the same period in 2011.

Depletion and Depreciation

Depletion and depreciation expense totaled $44.6 million for the three months ended December 31, 2012, compared to $34.8 million for the three months ended December 31, 2011. The average depletion and depreciation rate was $14.98 per barrel for the quarter compared to $12.60 per barrel for the same quarter in 2011. Depletion and depreciation expense for the fourth quarter of 2012 has increased compared to the same period of 2011 primarily due to higher production volumes and an increase in the rate per barrel as a result of higher estimated future development costs of the producing oil sands properties. The future development costs are a key element of the rate determination. For the year ended December 31, 2012, depletion and depreciation expense was $145.0 million, compared to $124.3 million for the year ended December 31, 2011. Depletion and depreciation expense for the year ended December 31, 2012 has increased compared to the same period of 2011 primarily due to higher production volumes and an increase in the rate per barrel as a result of higher future development costs of the producing oil sands properties. Depletion and depreciation expense for the year ended December 31, 2011 included $5.3 million of capital costs associated with derecognizing a SAGD well that required replacement ($nil in 2012). The depletion and depreciation rate was $13.76 per barrel for the year ended December 31, 2012, compared to $12.81 per barrel for the year ended December 31, 2011. 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 December 31		Year ended December 31	
($000)	**2012**	**2011**	**2012**	**2011**
General and administrative costs	27,986	20,314	91,510	69,861
Capitalized general and administrative costs	(5,813)	(4,087)	(20,913)	(14,123)
General and administrative expense	22,173	16,227	70,597	55,738

General and administrative expense for the three months ended December 31, 2012 was $22.2 million, compared to $16.2 million for the three months ended December 31, 2011. General and administrative expense for the year ended December 31, 2012 was $70.6 million compared to $55.7 million for the year ended December 31, 2011. 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 and restricted share units ("RSUs") to employees, contractors and directors is recognized by the Corporation in its financial statements. Fair value is determined using the Black-Scholes option pricing model. Stock-based compensation expense for the three months ended December 31, 2012 was $7.3 million compared to $5.4 million for the three months ended December 31, 2011. Stock-based compensation expense was $25.2 million for the year ended December 31, 2012 compared to $21.4 million for the year ended December 31, 2011. The Corporation capitalizes a portion of stock-based compensation expense associated with capitalized salaries and benefits. For the three months ended December 31, 2012, the Corporation capitalized $1.9 million of stock-based compensation to property, plant and equipment, compared to $1.4 million for the three months ended December 31, 2011. For the year ended December 31, 2012, the Corporation capitalized $6.8 million of stock-based compensation, compared to $5.1 million capitalized during the year ended December 31, 2011.

Research and Development

Research and development expenditures relate to the Corporation's research of greenhouse gas management, crude quality improvement and related technologies and have been expensed. Research and development expenditures were $1.0 million for the three months ended December 31, 2012 compared to $2.0 million during the same period in 2011. For the year ended December 31, 2012 research and development expenditures were $5.2 million compared to $6.8 million for the year ended December 31, 2011.

Gain on Disposition of Assets

During the first quarter of 2012, the Corporation sold a portion of its interest in certain connections on the Access Pipeline. The Corporation’s net investment in these connections was $4.4 million and the proceeds were $7.5 million, resulting in a gain of $3.1 million.

Net Finance Expense

	Three months ended December 31		Year ended December 31	
($000)	**2012**	**2011**	**2012**	**2011**
Total interest expense	37,954	24,737	122,424	88,276
Less capitalized interest	(10,354)	(4,539)	(30,608)	(14,629)
Net interest expense	27,600	20,198	91,816	73,647
Accretion on decommissioning provision	999	1,049	3,670	1,646
Unrealized fair value (gain) loss on embedded derivative liabilities	(2,023)	(2,154)	2,953	8,346
Unrealized fair value (gain) loss on interest rate swaps	(556)	2,473	9,915	2,473
Realized loss on interest rate swaps	1,169	532	4,518	532
Unrealized fair value gain on other assets	-	-	(2,518)	-
Net finance expense	27,189	22,098	110,354	86,644

Total interest expense for the three months ended December 31, 2012 was $38.0 million, compared to $24.7 million for the same period in 2011. For the year ended December 31, 2012, total interest expense was $122.4 million compared to $88.3 million during the year ended December 31, 2011. Total interest expense increased primarily as a result of the increased debt outstanding as at December 31, 2012. Effective July 19, 2012, the Corporation issued US$800.0 million of 6.375% senior unsecured notes.

The Corporation recognized an unrealized gain on embedded derivative liabilities of $2.0 million for the three months ended December 31, 2012 compared to an unrealized gain of $2.2 million for the same period in 2011. For the year ended December 31, 2012 the Corporation recognized an unrealized loss on embedded derivative liabilities of $3.0 million compared to a loss of $8.3 million for the year ended December 31, 2011. The 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 agreement was entered into. Accordingly, the original fair value of the embedded derivative at the time the debt agreement was entered into was netted against the carrying value of the long-term debt and will be amortized over the life of the debt agreement. The fair value of the embedded derivative is included in financial derivative 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 4.6% on US$748.0 million of the US$987.5 million senior secured term loan until September 30, 2016. The Corporation realized a $1.2 million loss on interest rate swap contracts during the fourth quarter and a $4.5 million loss for the year ended December 31, 2012 compared to a realized loss of $0.5 million for the three months and year ended December 31, 2011. In addition, the Corporation recognized an unrealized gain of $0.6 million during the fourth quarter and a $9.9 million loss for the year ended December 31, 2012 compared to a $2.5 million unrealized loss for the three months and year ended December 31, 2011.

The unrealized fair value gain on other assets of $2.5 million for the year ended December 31, 2012 (three months and year ended December 31, 2011 – nil), relates to a net increase in the fair value of notes held by the Corporation. The notes are classified as held-for-trading which requires them to be measured at fair value at each period end with the resulting change in fair value recognized within net income.

Net Foreign Exchange Gain (Loss)

	Three months ended December 31		Year ended December 31	
($000)	**2012**	**2011**	**2012**	**2011**
Foreign exchange gain (loss) on:				
Long-term debt	(28,449)	38,325	48,822	(46,856)
US$ denominated cash and cash equivalents	7,695	(4,715)	(13,000)	11,649
Other	(372)	40	796	(506)
Net foreign exchange gain (loss)	(21,126)	33,650	36,618	(35,713)

Cdn$-US$ exchange rate As at	**December 31, 2012**	**September 30, 2012**	**December 31, 2011**	**September 30, 2011**	**December 31, 2010**
C$ equivalent of 1 US$	0.9949	0.9837	1.0170	1.0389	0.9946

The net foreign exchange loss for the three months ended December 31, 2012 was $21.1 million, compared to a $33.7 million net foreign exchange gain for the same period in 2011. For the year ended December 31, 2012, the net foreign exchange gain was $36.6 million in comparison to a net foreign exchange loss of $35.7 million during the year ended December 31, 2011. The Canadian dollar weakened by approximately $0.01 during the fourth quarter of 2012 while it strengthened by approximately $0.02 over the course of 2012. In comparison, the Canadian dollar strengthened by approximately $0.02 during the fourth quarter of 2011 and weakened by approximately $0.02 during 2011.

Net Marketing Activity

	Three months ended December 31		Year ended December 31	
($000)	**2012**	**2011**	**2012**	**2011**
Sales of purchased product	19,323	-	37,822	-
Purchased product and storage	(20,860)	-	(39,584)	-
Net marketing activity	(1,537)	-	(1,762)	-

The Corporation is securing pipeline capacity and pursuing 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 for the three months ended December 31, 2012 of $2.3 million compared to a deferred income tax expense of $21.2 million for the three months ended December 31, 2011. Deferred income tax expense for the year ended December 31, 2012 was $9.8 million compared to deferred income tax expense of $45.8 million for the year ended December 31, 2011.

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 capital foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt is a permanent difference. For the three months ended December 31, 2012 the non-taxable loss was $14.3 million compared to a non-taxable gain of

$19.2 million for the three months ended December 31, 2011. For the year ended December 31, 2012, the non-taxable gain was $24.4 million compared to a non-taxable loss of $23.4 million for the year ended December 31, 2011.

- At the end of 2011, the Corporation had not recognized the tax benefit related to $28.5 million in unrealized taxable capital foreign exchange losses. With the strengthening of the Canadian dollar by approximately $0.02 during 2012, the Corporation was able to recognize $24.5 million of this tax benefit.

- Non-taxable stock-based compensation for the three months ended December 31, 2012 was $7.3 million compared to $5.4 million for the three months ended December 31, 2011. For the year ended December 31, 2012, non-taxable stock-based compensation was $25.2 million in comparison to $21.4 million for the year ended December 31, 2011.

The Corporation is not currently taxable. As of December 31, 2012, the Corporation had approximately $3.6 billion of available tax pools and had recognized a deferred income tax liability of $71.4 million. In addition, at December 31, 2012, the Corporation had $1.8 billion of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

SUMMARY OF QUARTERLY RESULTS

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

	2012				2011			
($ millions, except per share amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue	297.6	213.7	259.7	279.6	326.5	175.9	279.9	254.4
Net income (loss)	(18.7)	47.5	(29.5)	53.4	91.1	(115.2)	42.5	45.4
Per share – basic	(0.09)	0.24	(0.15)	0.28	0.47	(0.60)	0.22	0.24
Per share – diluted	(0.09)	0.24	(0.15)	0.27	0.46	(0.60)	0.21	0.23

Revenue for the eight most recent quarters has been impacted by an increase in production, partially offset by decreased bitumen realizations during 2012. Lower revenues in the third quarters of 2012 and 2011 were due to reduced production as the result of scheduled turnarounds at the Christina Lake facilities.

Net income 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 and short-term investments);

- Changes in the fair value of the LIBOR floor on the senior secured term loans (embedded derivative liability);

- Risk management activities for interest rate swaps;

- Net gains and losses on the modification of long-term debt;

- The scheduled plant turnarounds performed in September 2011 and September 2012;

- Higher general and administrative expense as a result of the planned increase in office staff to support growth; and
- An increase in interest expense as a result of the increase in long-term debt.

CAPITAL INVESTING

The following table summarizes the capital investments for the periods presented:

	Three months ended December 31		Year ended December 31	
Summary of capital investment ($000)	**2012**	**2011**	**2012**	**2011**
Christina Lake Phase 2B	138,535	154,919	631,495	466,341
Christina Lake Phase 3	21,737	2,687	80,288	4,327
RISER and other enhancements	127,799	19,183	234,277	76,078
Delineation drilling and seismic	27,534	10,854	127,959	87,106
Regulatory	882	1,498	5,577	2,585
Other	15,542	10,325	47,581	91,671
Growth	**332,029**	**199,466**	**1,127,177**	**728,108**
Access Pipeline	35,473	12,665	115,807	41,895
Stonefell Terminal	52,375	4,788	136,399	10,439
Field infrastructure	40,142	33,498	100,066	86,133
Infrastructure related to growth	**127,990**	**50,951**	**352,272**	**138,467**
Sustaining and maintenance	18,268	4,805	67,275	23,857
Capitalized interest and fees	10,354	4,539	30,608	14,629
Other	6,275	9,053	21,182	23,860
Total cash capital investment	**494,916**	**268,814**	**1,598,514**	**928,921**
Non-cash	5,307	51,083	21,169	55,705
Total capital investment	**500,223**	**319,897**	**1,619,683**	**984,626**

MEG's capital investment totalled $500.2 million during the three months ended December 31, 2012. During the 2011 comparative period, total capital investment totalled $319.9 million. For the year ended December 31, 2012, capital investment was $1.6 billion, compared to $984.6 million invested during the year ended December 31, 2011.

Growth-focused investment included $332.0 million in the fourth quarter of 2012 compared to $199.5 million in the fourth quarter of 2011. Full year 2012 capital investment included $1.1 billion in growth focused investment compared to $728.1 million in 2011.

MEG invested $138.5 million on Phase 2B of the Christina Lake project during the fourth quarter of 2012, and $631.5 million in 2012, which was directed towards detailed engineering, the purchase of major equipment and materials, and construction activities. As at December 31, 2012, detailed engineering was complete and all modules had been installed. All materials have been ordered and delivered, with on-site construction scheduled to continue toward targeted completion and start-up in the second half of 2013.

MEG invested $234.3 million during 2012 on RISER and other operational enhancements at the Christina Lake project, with $127.8 million of the total invested during the fourth quarter. This included the drilling of 22 infill wells and two additional SAGD well pairs which are scheduled to be brought into production during the second half of 2013. These activities are aimed at further improving the operational performance of the Corporation’s wells and facilities.

The Corporation invested $128.0 million for the year ended December 31, 2012 on delineation drilling and seismic. The Corporation drilled 113 core holes, ten observation wells and six water wells to support Phase 2B horizontal well placement and to further delineate the resource base at Christina Lake. A total of ten core holes were completed on Surmont leases. These core holes, combined with the acquisition of high resolution 3D seismic, were used to increase resource definition on the Surmont leases in regulatory applications filed in September 2012. In addition, 28 core holes were drilled on the Growth Properties with the intent of increasing resource definition and continuing to build an inventory of potentially commercial projects.

A total of $128.0 million was invested in the Corporation's growth-related infrastructure during the fourth quarter and $352.3 million in 2012. The Corporation invested $35.5 million during the quarter and $115.8 million during the year ended December 31, 2012 primarily on regulatory and engineering work and material purchases related to the expansion of the jointly-owned Access Pipeline. Regulatory approval of the pipeline expansion was received on November 30, 2012 and initial construction activities have commenced. Investment in the Stonefell Terminal amounted to $52.4 million during the fourth quarter and $136.4 million during the year ended December 31, 2012. The Stonefell Terminal is a 900,000 barrel tank farm located east of the Access Pipeline Sturgeon Terminal, and is expected to be operational in 2013. The Corporation invested a total of $40.1 million for the quarter, and $100.1 million for the year ended December 31, 2012, in support infrastructure for current operations at Christina Lake.

The Corporation capitalizes interest expense and certain finance charges associated with undeveloped property acquisitions and major development projects. Interest associated with growth capital projects, including Phase 2B, Phase 3 and certain infrastructure projects are capitalized. During the fourth quarter of 2012, the Corporation capitalized $10.4 million of interest and finance charges compared to $4.5 million during the fourth quarter of 2011. During the year ended December 31, 2012 $30.6 million was capitalized, in comparison to $14.6 million during the year ended December 31, 2011.

Other investments include amounts paid to maintain the right to participate in a potential pipeline project and investment in administrative assets.

Non-cash capital investment for the three months and year ended December 31, 2012 included $5.3 million (three months ended December 31, 2011, - $51.1 million) and $21.2 million (year ended December 31, 2011 - $55.7 million), respectively, for future decommissioning of the Corporation's facilities under construction.

ADVISORY

Forward-Looking Information

This document 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, capacities and performance of the Access Pipeline expansion, the RISER initiative, the Stonefell Terminal, third party barging and rail facilities, the future phases and expansions of the Christina Lake project, the Surmont project and potential projects on the Growth Properties; and the anticipated sources of funding for operations and capital investments. Such forward-looking information is based on management's expectations and assumptions regarding future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), plans for and results of drilling activity, environmental matters, business prospects and opportunities. By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: risks associated with the oil and gas industry (e.g. operational risks and delays in the development, exploration or production associated with MEG's projects; the securing of adequate supplies and access to markets and transportation infrastructure; the availability of capacity on the electrical transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and revenues; health, safety and environmental risks; risks of legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws), assumptions regarding and the volatility of commodity prices and foreign exchange rates; and risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the continued expansion of the Christina Lake project and the development of the Corporation's other projects and facilities. Although MEG believes that the assumptions used in such forward-looking information are reasonable, there can be no assurance that such assumptions will be correct. Accordingly, readers are cautioned that the actual results achieved may vary from the forward-looking information provided herein and that the variations may be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive. The forward-looking information included in this document is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this document is made as of the date of this document and the Corporation assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law. For more information regarding forward-looking information see “Notice Regarding Forward Looking Information”, "Risk Factors" and "Regulatory Matters" within MEG’s Annual Information Form dated March 28, 2012 (the “AIF”) along with MEG's other public disclosure documents. Copies of the AIF and MEG's other public disclosure documents are available through the SEDAR website (www.sedar.com) or by contacting MEG's investor relations department.

Estimates of Reserves and Resources

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

Non-IFRS Financial Measures

This document includes references to financial measures commonly used in the crude oil and natural gas industry, such as net bitumen revenue, operating earnings (loss), 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 (loss) 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 or net cash provided by operating activities, as determined in accordance with IFRS, as an indication of the Corporation's performance. The non-IFRS operating earnings (loss) and cash operating netback measures are reconciled to net income (loss), while cash flow from operations is reconciled to net cash provided by operating activities.

QUARTERLY SUMMARIES (Unaudited)

	2012				2011			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
FINANCIAL ($000 unless specified)								
Net income (loss)	(18,740)	47,474	(29,534)	53,369	91,118	(115,196)	42,537	45,378
Per share, diluted	(0.09)	0.24	(0.15)	0.27	0.46	(0.60)	0.21	0.23
Operating earnings (loss)	(538)	(12,883)	11,134	23,529	57,833	(5,917)	36,474	20,865
Per share, diluted	0.00	(0.07)	0.06	0.12	0.29	(0.03)	0.18	0.11
Cash flow from operations	56,106	24,442	59,975	71,991	121,608	25,478	88,204	69,337
Per share, diluted	0.27	0.12	0.30	0.36	0.61	0.13	0.45	0.35
Capital investment	500,223	406,526	341,840	371,094	319,897	243,226	209,627	211,876
Cash and short-term investments	2,007,841	1,607,036	1,111,150	1,402,390	1,647,069	1,831,937	1,926,429	2,034,526
Working capital	1,655,915	1,307,325	902,424	1,183,628	1,475,245	1,619,557	1,806,881	1,921,382
Long-term debt	2,488,609	2,461,676	1,751,552	1,718,474	1,751,539	1,791,695	1,660,445	1,673,194
Shareholders' equity	4,870,534	4,092,556	4,027,652	4,049,633	3,984,104	3,879,415	3,983,825	3,921,147
BUSINESS ENVIRONMENT								
West Texas Intermediate (WTI) US$/bbl	88.18	92.22	93.49	102.92	94.06	89.76	102.56	94.10
C$ equivalent of 1US$ - average	0.9913	0.9948	1.0102	1.0012	1.0231	0.9802	0.9676	0.9860
Differential – WTI/blend ($/bbl)	26.13	29.54	29.83	32.10	17.47	23.53	22.88	27.17
Differential – WTI/blend	29.9%	32.2%	31.6%	31.2%	18.2%	26.7%	23.1%	29.3%
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bpd	32,292	23,941	30,429	28,446	30,032	20,945	27,826	27,653
Diluent usage – bpd	14,810	9,466	13,800	13,919	14,223	8,229	12,647	14,037
Blend sales – bpd	47,532	33,342	44,029	42,486	44,491	28,820	40,507	41,703
Blend sales	61.29	62.19	64.62	70.95	78.76	64.46	76.37	65.61
Cost of diluent	(15.62)	(15.70)	(19.03)	(20.80)	(10.77)	(12.67)	(13.59)	(16.04)
Bitumen realization	45.67	46.49	45.59	50.15	67.99	51.79	62.78	49.57
Transportation – net	(0.05)	(0.93)	(0.03)	(0.37)	(1.19)	(1.93)	(1.18)	(1.42)
Royalties	(2.23)	(2.10)	(2.84)	(2.63)	(3.66)	(2.82)	(3.69)	(2.64)
Operating costs – non-energy	(8.70)	(15.23)	(7.79)	(8.24)	(8.55)	(17.20)	(8.74)	(8.68)
Operating costs – energy	(4.65)	(3.22)	(2.62)	(3.18)	(4.61)	(5.05)	(5.39)	(5.54)
Power sales	4.40	2.84	1.86	3.47	4.66	5.13	2.77	5.59
Cash operating netback	**34.44**	**27.85**	**34.17**	**39.20**	**54.64**	**29.92**	**46.55**	**36.88**
Power sales price (C$/MWh)	79.62	57.99	36.85	58.25	78.91	93.33	46.95	82.40
Power sales (MW/h)	75	49	64	71	74	47	68	78
Depletion and depreciation rate	14.98	13.39	13.01	13.44	12.60	12.51	12.37	13.71
COMMON SHARES								
Shares outstanding, end of period (000)	220,190	195,248	194,326	193,986	193,472	192,978	192,767	191,304
Volume traded (000)	20,370	13,578	21,560	18,230	16,083	16,706	34,428	38,566
Common share price ($)								
High	38.74	41.90	43.96	47.11	48.48	52.90	52.68	50.35
Low	30.25	35.20	32.92	36.73	32.26	36.96	46.25	40.90
Close (end of period)	30.44	37.39	36.49	38.46	41.57	38.76	50.32	49.06

Interim Financial Statements

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

As at	Note	December 31, 2012	December 31, 2011
Assets			
Current assets			
Cash and cash equivalents	16	**$ 1,474,843**	$ 1,495,131
Short-term investments		**532,998**	151,938
Trade receivables and other	5	**110,823**	135,545
Inventories		**17,536**	9,207
		2,136,200	1,791,821
Non-current assets			
Property, plant and equipment	6	**5,267,885**	3,368,819
Exploration and evaluation assets	7	**554,349**	991,805
Other intangible assets	8	**46,033**	37,292
Other assets		**14,212**	11,312
Total assets		**$ 8,018,679**	$ 6,201,049
Liabilities			
Current liabilities			
Trade payables	9	**$ 463,077**	$ 301,626
Current portion of long-term debt	10	**9,949**	10,145
Current portion of provisions and other liabilities	11	**7,259**	4,805
		480,285	316,576
Non-current liabilities			
Long-term debt	10	**2,478,660**	1,741,394
Provisions and other liabilities	11	**117,756**	91,006
Deferred income tax liability		**71,444**	67,969
Total liabilities		**3,148,145**	2,216,945
Commitments and contingencies	18		
Shareholders' equity			
Share capital	12	**4,694,378**	3,877,193
Contributed surplus	12	**102,219**	85,568
Retained earnings		**73,912**	21,343
Accumulated other comprehensive income		**25**	-
Total shareholders' equity		**4,870,534**	3,984,104
Total liabilities and shareholders' equity		**$ 8,018,679**	$ 6,201,049

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

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

		Three months ended December 31		Year ended December 31	
	Note	**2012**	2011	**2012**	2011
Petroleum revenue, net of royalties	13	**$ 280,621**	$ 312,198	**$1,003,838**	$ 989,598
Other revenue	14	**16,957**	14,284	**46,666**	47,015
		297,578	326,482	**1,050,504**	1,036,613
Diluent and transportation		**134,360**	137,671	**512,814**	467,872
Purchased product and storage		**20,860**	-	**39,584**	-
Operating expenses		**40,163**	36,633	**139,019**	150,029
Depletion and depreciation	6, 8	**44,593**	34,803	**144,950**	124,327
General and administrative		**22,173**	16,227	**70,597**	55,738
Stock-based compensation	12	**7,271**	5,412	**25,246**	21,355
Research and development		**966**	2,004	**5,157**	6,810
		270,386	232,750	**937,367**	826,131
Revenues less operating expenses		**27,192**	93,732	**113,137**	210,482
Other income (expense)					
Interest and other income		**4,650**	7,024	**19,896**	18,786
Gain on disposition of asset		**-**	-	**3,075**	-
Gain on debt modification		**-**	-	**-**	2,773
Foreign exchange gain (loss), net		**(21,126)**	33,650	**36,618**	(35,713)
Net finance expense	15	**(27,189)**	(22,098)	**(110,354)**	(86,644)
		(43,665)	18,576	**(50,765)**	(100,798)
Income (loss) before income taxes		**(16,473)**	112,308	**62,372**	109,684
Deferred income tax expense		**2,267**	21,190	**9,803**	45,847
Net income (loss)		**(18,740)**	91,118	**52,569**	63,837
Other comprehensive income					
Foreign currency translation adjustment		**25**	-	**25**	-
Comprehensive income (loss) for the period		**$(18,715)**	$ 91,118	**$ 52,594**	$ 63,837

Earnings (loss) per share					
Basic	17	**$ (0.09)**	$ 0.47	**$ 0.27**	$ 0.33
Diluted	17	**$ (0.09)**	$ 0.46	**$ 0.26**	$ 0.32

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

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

	Note	Share Capital	Contributed Surplus	Retained Earnings (Deficit) (Note 11(b))	Accumulated Other Comprehensive Income (AOCI)	Total Shareholders' Equity
Balance at January 1, 2012		**$ 3,877,193**	**$ 85,568**	**$ 21,343**	**$ -**	**$ 3,984,104**
Shares issued		**800,125**				**800,125**
Share issue costs, net of tax		**(18,988)**				**(18,988)**
Stock options exercised	12	**26,520**	**(5,863)**			**20,657**
RSU's vested and released	12	**9,528**	**(9,528)**			**-**
Stock-based compensation	12		**32,042**			**32,042**
Net income				**52,569**		**52,569**
Other comprehensive income					**25**	**25**
Balance at December 31, 2012		**$ 4,694,378**	**$ 102,219**	**$ 73,912**	**$ 25**	**$ 4,870,534**
Balance at January 1, 2011		$ 3,820,446	$ 76,172	$ (42,494)	$ -	$ 3,854,124
Stock options exercised		52,037	(12,320)			39,717
RSU's vested and released		4,710	(4,710)			-
Stock-based compensation			26,426			26,426
Net income				63,837		63,837
Balance at December 31, 2011		$ 3,877,193	$ 85,568	$ 21,343	$ -	$ 3,984,104

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)

	Note	Three months ended December 31		Year ended December 31	
		2012	2011	**2012**	2011
Cash provided by (used in):					
Operating activities					
Net income (loss)		**$ (18,740)**	$ 91,118	**$ 52,569**	$ 63,837
Adjustments for:					
Depletion and depreciation		**44,593**	34,803	**144,950**	124,327
Stock-based compensation		**7,271**	5,412	**25,246**	21,355
Unrealized (gain) loss on foreign exchange		**20,753**	(33,610)	**(35,822)**	35,207
Unrealized (gain) loss on derivative financial liabilities	11	**(2,579)**	319	**12,868**	(378)
Deferred income tax expense		**2,267**	21,190	**9,803**	45,847
Other		**2,541**	2,376	**2,900**	6,009
Net change in non-cash operating working capital items	16	**(7,615)**	(32,912)	**28,310**	18,098
Net cash provided by operating activities		**48,491**	88,696	**240,824**	314,302
Investing activities					
Capital investments		**(494,916)**	(268,814)	**(1,598,514)**	(928,921)
Proceeds on disposition of assets		**-**	-	**7,456**	-
Other		**899**	1,773	**1,176**	965
Net change in non-cash investing working capital items	16	**(143,200)**	(69,754)	**(230,638)**	114,173
Net cash used in investing activities		**(637,217)**	(336,795)	**(1,820,520)**	(813,783)
Financing activities					
Issue of shares		**781,176**	6,739	**795,466**	39,717
Issue of long-term debt		**-**	-	**792,552**	1,708,188
Financing costs		**-**	-	**(5,622)**	(3,025)
Repayment of long-term debt		**(2,489)**	(2,542)	**(9,988)**	(986,363)
Net cash provided by financing activities		**778,687**	4,197	**1,572,408**	758,517
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**7,695**	(4,715)	**(13,000)**	11,649
Change in cash and cash equivalents		**197,656**	(248,617)	**(20,288)**	270,685
Cash and cash equivalents, beginning of period		**1,277,187**	1,743,748	**1,495,131**	1,224,446
Cash and cash equivalents, end of period		**$1,474,843**	$ 1,495,131	**$ 1,474,843**	$ 1,495,131

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 Corporation's 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, 2011. 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, 2011. These interim consolidated financial statements should be read in conjunction with the Corporation's audited financial statements for the year ended December 31, 2011, which are included in the Corporation's 2011 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. PRINCIPLES OF CONSOLIDATION

The interim consolidated financial statements of the Corporation comprise the Corporation and its wholly-owned subsidiary, MEG Energy (U.S.) Inc., that was incorporated on June 26, 2012. All intercompany transactions and balances are eliminated on consolidation.

4. 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, trade payables, derivative financial liabilities and long-term debt. As at December 31, 2012, 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 trade payables were classified as other financial liabilities. Long-term debt was carried at amortized cost.

(a) Fair value measurement

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

The fair value of long-term debt is derived from quoted prices from financial institutions. At December 31, 2012 the fair value of long-term debt was $2,612.8 million (December 31, 2011 - $1,789.9 million).

(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$987.5 million senior secured term loan. At December 31, 2012, there was an unrealized loss on the interest rate swaps of $12.4 million (December 31, 2011 - $2.5 million).

Amount	Effective date	Remaining term	Fixed rate	Floating rate
US$300 million	September 30, 2011	Jan 2013-Sept 2016	4.686%	3 month LIBOR[1]
US$150 million	December 31, 2011	Jan 2013-Sept 2016	4.626%	3 month LIBOR[1]
US$150 million	January 12, 2012	Jan 2013-Sept 2016	4.552%	3 month LIBOR[1]
US$148 million	January 27, 2012	Jan 2013-Sept 2016	4.468%	3 month LIBOR[1]

(1) London Interbank Offered Rate

5. TRADE RECEIVABLES AND OTHER

	December 31, 2012	December 31, 2011
Trade receivables	**$ 104,008**	$ 124,341
Deposits and advances	**4,757**	10,034
Current portion of deferred financing costs	**2,058**	1,170
	$ 110,823	$ 135,545

6. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Corporate assets	Total
Cost			
Balance as at December 31, 2010	$ 2,647,682	$ 16,868	$ 2,664,550
Additions	915,615	10,742	926,357
Disposals	(5,540)	-	(5,540)
Balance as at December 31, 2011	$ 3,557,757	$ 27,610	$ 3,585,367
Additions	1,563,502	5,987	1,569,489
Disposals	(6,340)	-	(6,340)
Transfer from exploration and evaluation assets (note 7)	478,347	-	478,347
Balance as at December 31, 2012	**$ 5,593,266**	**$ 33,597**	**$ 5,626,863**

Accumulated depletion and depreciation			
Balance as at December 31, 2010	$ 96,906	$ 1,170	$ 98,076
Depletion and depreciation for the year	121,861	2,151	124,012
Disposals	(5,540)	-	(5,540)
Balance as at December 31, 2011	$ 213,227	$ 3,321	$ 216,548
Depletion and depreciation for the year	141,118	3,270	144,388
Disposals	(1,958)	-	(1,958)
Balance as at December 31, 2012	**$ 352,387**	**$ 6,591**	**$ 358,978**

Carrying Amounts			
As at December 31, 2011	$ 3,344,530	$ 24,289	$ 3,368,819
As at December 31, 2012	**$ 5,240,879**	**$ 27,006**	**$ 5,267,885**

During the year ended December 31, 2012, the Corporation capitalized $20.9 million (year ended December 31, 2011 - $14.1 million) of general and administrative costs and $6.8 million (year ended December 31, 2011 - $5.1 million) of stock-based compensation costs relating to oil sands exploration and development activities. In addition, $30.6 million of interest and finance charges related to the development of growth capital projects, including Christina Lake Phase 2B and Phase 3, were capitalized during the year ended December 31, 2012 (year ended December 31, 2011 - $14.6 million).

7. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2010	$	937,986
Additions		53,819
Balance as at December 31, 2011	$	991,805
Additions		40,891
Transfer to property, plant and equipment (note 6)		(478,347)
Balance as at December 31, 2012	**$**	**554,349**

Exploration and evaluation assets were transferred to property, plant and equipment – crude oil assets following the determination of technical feasibility and commercial viability of the Surmont project.

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. These assets are not subject to depletion, as they are in the exploration and evaluation stage, but are reviewed on a quarterly basis for any indication of impairment. As of December 31, 2012, no impairment has been recognized on these assets.

8. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2010	$	33,738
Additions		4,448
Balance as at December 31, 2011	$	38,186
Additions		9,303
Balance as at December 31, 2012	**$**	**47,489**

Accumulated depreciation		
Balance as at December 31, 2010	$	580
Depreciation		314
Balance as at December 31, 2011	$	894
Depreciation		562
Balance as at December 31, 2012	**$**	**1,456**

Carrying Amounts		
As at December 31, 2011	$	37,292
As at December 31, 2012	**$**	**46,033**

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.

9. TRADE PAYABLES

		December 31, 2012		December 31, 2011
Trade payables	**$**	**51,651**	$	26,939
Accruals		**370,431**		256,215
Interest payable		**36,848**		14,674
Other payables		**4,147**		3,798
	$	**463,077**	$	301,626

10. LONG-TERM DEBT

		December 31, 2012		December 31, 2011
Senior secured term loan (December 31, 2012 – US$987.5 million; December 31, 2011 - US$997.5 million)[(a)]	**$**	**982,464**	$	1,014,458
6.5% senior unsecured notes (December 31, 2012 and 2011 - US$750 million)[(b)]		**746,175**		762,750
6.375% senior unsecured notes (December 31, 2012 US$800 million; December 31, 2011 - nil)[(c)]		**795,920**		-
		2,524,559		1,777,208
Less current portion of senior secured term loan		**(9,949)**		(10,145)
Less unamortized financial derivative liability discount		**(10,324)**		(12,130)
Less unamortized deferred debt issue costs		**(25,626)**		(13,539)
	$	**2,478,660**	$	1,741,394

The U.S. dollar denominated debt was translated into Canadian dollars at the year-end exchange rate of US$1 = C$0.9949 (December 31, 2011 - US$1 = C$1.0170).

(a) The senior secured credit facilities are comprised of a US$987.5 million term loan and a five year US$1.0 billion revolving credit facility. The US$987.5 million 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 200 or 300 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 0.25% of the original outstanding balance beginning on December 31, 2011, with the balance due on March 18, 2018. Interest is paid quarterly.

Effective March 21, 2012, the Corporation agreed to amend, extend and increase its revolving credit facility from US$500.0 million to US$1.0 billion with a maturity date of March 21, 2017. As at December 31, 2012, $2.6 million (December 31, 2011 - $0.8 million) of the revolving credit facility was utilized to support letters of credit. As at December 31, 2012, no amount had been drawn under the revolving credit facility.

(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 $12.2 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

(c) Effective July 19, 2012, the Corporation issued US$800.0 million in aggregate principal amount of 6.375% Senior Unsecured Notes, with a maturity date of January 30, 2023. Interest is paid semi-annually on January 30 and July 30. No principal payments are required until January 30, 2023. The Corporation has deferred the associated remaining debt issue costs of $13.4 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

11. PROVISIONS AND OTHER LIABILITIES

		December 31, 2012		December 31, 2011
Derivative financial liabilities[(a)]	**$**	**37,195**	$	24,326
Decommissioning provision[(b)]		**82,087**		65,360
Deferred lease inducements		**5,733**		6,125
Provisions and other liabilities		**125,015**		95,811
Less current portion of derivative financial liabilities		**(6,509)**		(4,056)
Less current portion of deferred lease inducements		**(750)**		(749)
Non-current portion of provisions and other liabilities	**$**	**117,756**	$	91,006

(a) Derivative financial liabilities

		December 31, 2012		December 31, 2011
1% interest rate floor	**$**	**24,807**	$	21,853
Interest rate swaps		**12,388**		2,473
Derivative financial liabilities		**37,195**		24,326
Less current portion of derivative financial liabilities		**(6,509)**		(4,056)
Non-current portion of derivative financial liabilities	**$**	**30,686**	$	20,270

The interest rate floor 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 through income or loss.

The Corporation is exposed to interest rate risk in relation to interest income earned on cash and cash equivalents and short-term investments and in relation to interest expense on floating rate long-term debt. To mitigate a portion of the risk of interest rate increases on long-term debt, the Corporation periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. As of December 31, 2012, the Corporation had entered into interest rate swaps on US$748.0 million (note 4(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 retirement of crude oil properties:

		December 31, 2012		December 31, 2011
Decommissioning provision, beginning of year	$	65,360	$	12,557
Changes in estimated future cash flows		-		24,876
Changes in discount rates		(3,846)		-
Liabilities acquired		-		1,522
Liabilities incurred		18,218		25,471
Liabilities settled		(1,315)		(712)
Accretion		3,670		1,646
Decommissioning provision, end of year	$	82,087	$	65,360

The total decommissioning provision is based on the estimated costs to reclaim and abandon the Corporation's crude oil properties 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 $82.1 million as at December 31, 2012 (December 31, 2011 - $65.4 million) based on an undiscounted total future liability of $228.1 million (December 31, 2011 - $179.1 million) and a credit-adjusted rate of 5.7% (December 31, 2011 – 5.4%). This obligation is estimated to be settled in periods up to 2057.

In the fourth quarter of 2011, the Corporation changed its accounting policy from using a risk-free rate, to a credit-adjusted rate to calculate the discounted value of the estimated future cash outflows required to settle the decommissioning obligation. The change was applied retrospectively, and on the transition to IFRS at January 1, 2010, resulted in a $3.9 million decrease to the decommissioning provision and a $2.9 million decrease in the deficit, net of $1.0 million in deferred taxes (December 31, 2010 - $10.6 million decrease to the decommissioning provision, $7.9 million decrease in the deficit, net of $2.7 million in deferred taxes).

12. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

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

	Year ended December 31, 2012			Year ended December 31, 2011	
	Number of shares		Amount	Number of shares	Amount
Balance, beginning of year	193,471,705	$	3,877,193	189,875,151	$ 3,820,446
Shares issued	24,246,212		800,125	-	-
Share issue costs, net of tax	-		(18,988)	-	-
Issued upon exercise of stock options	2,243,319		26,520	3,462,840	52,037
Issued upon vesting and release of RSUs	228,848		9,528	133,714	4,710
Balance, end of year	220,190,084	$	4,694,378	193,471,705	$ 3,877,193

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. 12,125,000 of the common shares were issued through a public bought deal financing while the remaining 12,121,212 common shares were issued on a private placement basis.

(c) Stock options outstanding:

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

	Year ended December 31, 2012		Year ended December 31, 2011	
	Stock options	**Weighted average exercise price per share**	Stock options	Weighted average exercise price per share
Outstanding, beginning of year	**10,190,103**	**$ 27.12**	12,919,846	$ 21.51
Granted	**1,456,537**	**35.67**	810,682	50.52
Exercised	**(2,243,319)**	**9.21**	(3,462,840)	11.47
Forfeited	**(255,917)**	**40.29**	(77,585)	37.41
Outstanding, end of year	**9,147,404**	**$ 32.50**	10,190,103	$ 27.12

(d) Restricted share units outstanding:

The RSU 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 (subject to the consent of the Corporation and its Board of Directors) or its equivalent in fully-paid common shares equal to the fair market value of the Corporation's common shares calculated at the date of such payment. RSUs granted under the RSU Plan generally vest annually over a three year period.

	Year ended December 31, 2012	Year ended December 31, 2011
	RSUs	RSUs
Outstanding, beginning of year	**554,362**	404,945
Granted	**664,796**	301,273
Vested and released	**(228,848)**	(133,714)
Forfeited	**(36,506)**	(18,142)
Outstanding, end of year	**953,804**	554,362

(e) Contributed Surplus:

	Year ended December 31, 2012	Year ended December 31, 2011
Balance, beginning of year	**$ 85,568**	$ 76,172
Stock-based compensation - expensed	**25,246**	21,356
Stock-based compensation - capitalized	**6,796**	5,070
Stock options exercised	**(5,863)**	(12,320)
RSUs vested and released	**(9,528)**	(4,710)
Balance, end of year	**$ 102,219**	$ 85,568

13. PETROLEUM REVENUE

	Three months ended December 31		Year ended December 31	
	2012	2011	**2012**	2011
Petroleum sales:				
Proprietary	**$ 268,007**	$ 322,383	**$ 991,975**	$ 1,021,036
Third party	**19,323**	-	**37,822**	-
	287,330	322,383	**1,029,797**	1,021,036
Royalties	**(6,709)**	(10,185)	**(25,959)**	(31,438)
Petroleum revenue	**$ 280,621**	$ 312,198	**$ 1,003,838**	$ 989,598

14. OTHER REVENUE

	Three months ended December 31		Year ended December 31	
	2012	2011	**2012**	2011
Power revenue	**$ 13,248**	$ 12,969	**$ 33,634**	$ 43,628
Transportation revenue	**3,709**	1,315	**13,032**	3,387
Other revenue	**$ 16,957**	$ 14,284	**$ 46,666**	$ 47,015

15. NET FINANCE EXPENSE

	Three months ended December 31		Year ended December 31	
	2012	2011	**2012**	2011
Total interest expense	**$ 37,954**	$ 24,737	**$ 122,424**	$ 88,276
Less capitalized interest	**10,354**	4,539	**30,608**	14,629
Net interest expense	**27,600**	20,198	**91,816**	73,647
Accretion on decommissioning provision	**999**	1,049	**3,670**	1,646
Unrealized fair value (gain) loss on embedded derivative liabilities	**(2,023)**	(2,154)	**2,953**	8,346
Unrealized fair value (gain) loss on interest rate swaps	**(556)**	2,473	**9,915**	2,473
Realized loss on interest rate swaps	**1,169**	532	**4,518**	532
Unrealized fair value (gain) on other assets	**-**	-	**(2,518)**	-
Net finance expense	**$ 27,189**	$ 22,098	**$ 110,354**	$ 86,644

16. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended December 31		Year ended December 31	
	2012	2011	**2012**	2011
Cash provided by (used in):				
Short-term investments	**$ (203,149)**	$ (63,749)	**$ (381,060)**	$ 15,468
Trade receivables and other	**(61,525)**	(104,956)	**25,610**	(37,411)
Inventories	**(1,893)**	20,423	**(8,329)**	(3,034)
Trade payables	**115,752**	45,616	**161,451**	157,248
	$ (150,815)	$ (102,666)	**$ (202,328)**	$ 132,271
Changes in non-cash working capital relating to:				
Operations	**$ (7,615)**	$ (32,912)	**$ 28,310**	$ 18,098
Investing	**(143,200)**	(69,754)	**(230,638)**	114,173
	$ (150,815)	$ (102,666)	**$ (202,328)**	$ 132,271
Cash and cash equivalents:				
Cash	**$ 224,241**	$ 29,519	**$ 224,241**	$ 29,519
Cash equivalents	**1,250,602**	1,465,612	**1,250,602**	1,465,612
	$1,474,843	$ 1,495,131	**$1,474,843**	$ 1,495,131
Cash interest paid	**$ 10,290**	$ 10,283	**$ 86,939**	$ 66,554

17. EARNINGS PER COMMON SHARE

	Three months ended December 31		Year ended December 31	
	2012	2011	**2012**	2011
Net income (loss)	**$ (18,740)**	$ 91,118	**$ 52,569**	$ 63,837
Weighted average common shares outstanding	**203,799,672**	193,333,018	**196,667,540**	192,298,562
Dilutive effect of stock options and restricted share units	**2,341,589**	4,449,349	**3,294,847**	5,475,942
Weighted average common shares outstanding – diluted	**206,141,261**	197,782,367	**199,962,387**	197,774,504
Earnings (loss) per share, basic	**$ (0.09)**	$ 0.47	**$ 0.27**	$ 0.33
Earnings (loss) per share, diluted	**$ (0.09)**	$ 0.46	**$ 0.26**	$ 0.32

18. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at December 31, 2012:

Operating:

	2013	2014	2015	2016	2017	Thereafter
Office lease rentals	$ 10,986	$ 10,986	$ 11,159	$ 11,554	$ 11,554	$ 67,231
Diluent purchases	405,202	33,055	-	-	-	-
Pipeline transportation	984	30,905	30,413	60,992	60,826	1,217,514
Other commitments	25,375	32,629	11,767	5,540	4,645	35,476
Annual commitments	$ 442,547	$ 107,575	$ 53,339	$ 78,086	$ 77,025	$1,320,221

Capital:

As part of normal operations, the Corporation has entered into a total of $491.9 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.

19. COMPARATIVE FIGURES

Certain of the comparative figures have been reclassified to conform to the presentation adopted in the current year.

Reserves and Resources

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

GLJ, an independent reservoir engineering firm, was commissioned by MEG to evaluate the reserves and resources of the Corporation's oil sands leases. GLJ evaluated Christina Lake, Surmont and a portion of the Growth Properties. Collectively 417 sections of MEG's 934 sections of oil sands leases were evaluated. GLJ's reserves and resources report is effective as of December 31, 2012.

GLJ prepared estimates of reserves and resources in accordance with National Instrument 51-101 of the Canadian Securities Administrators entitled Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), as well as the Canadian Oil and Gas Evaluation Handbook, or COGE Handbook, prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society). MEG's complete annual disclosure required under NI 51-101 will be contained within MEG's annual information form to be filed on or before March 31, 2013.

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

According to GLJ, MEG's proved reserves (1P) are 1,284 million barrels of bitumen. The Corporation's proved-plus-probable (2P) reserves are 2,644 million barrels and its best estimate contingent resources (2C) are 3,420 million barrels. It is estimated that Christina Lake can support over 200,000 barrels per day of sustained production for 30 years and that Surmont can support over 100,000 barrels per day of sustained production for over 20 years. These production capacities are based on the GLJ estimates of 2P reserves and 2C resources as of December 31, 2012.

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

GLJ assigned contingent resources (best estimate) totalling 3,420 million barrels for the MEG leases it evaluated which consists of 979 million barrels for Christina Lake, 327 million barrels for Surmont and 2,114 million barrels for the Growth Properties. See footnotes three, four and five of the table below for further information regarding the meaning of contingent resources (best estimate).

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

Bitumen Reserves and Contingent Resources As at December 31 (Millions of barrels, before royalties)	2012	2011	% Change
Proved (1P) Reserves[(1)]	1,284	708	81
Probable Reserves[(2)]	1,360	1,352	1
Proved Plus Probable (2P) Reserves[(1)(2)]	2,644	2,060	28
Best Estimate Contingent Resources (2C)[(3)(4)(5)]	3,420	3,818	-10

Pre-tax 10% Present Value of Future Net Cash Flows[(6)] As at December 31 ($ millions)	2012	2011	% Change
Proved (1P) Reserves[(1)(6)]	10,484	6,797	54
Probable Reserves[(2)(6)]	6,354	6,705	-5
Proved Plus Probable (2P) Reserves[(2)(6)]	16,838	13,502	25
Best Estimate Contingent Resources (2C)[(3)(4)(5)]	10,265	13,790	-26

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

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

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

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

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

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

GLJ Forecast Pricing (as utilized in the GLJ 2012 Report)					
Forecast	Light and Medium Crude Oil	Exchange Rate	Bitumen Wellhead Current	Natural Gas	Inflation Rate
	WTI at Cushing, Oklahoma (US$/bbl)	US$/Cdn$	Christina Lake (Cdn$/bbl)	AECO Spot (Cdn$/mmbtu)	%/year
2013	90.00	1.000	52.70	3.38	2%
2014	92.50	1.000	58.69	3.83	2%
2015	95.00	1.000	64.15	4.28	2%
2016	97.50	1.000	66.60	4.72	2%
2017	97.50	1.000	67.43	4.95	2%
2018	97.50	1.000	67.39	5.22	2%
2019	98.54	1.000	68.26	5.32	2%
2020	100.51	1.000	69.72	5.43	2%
2021	102.52	1.000	71.22	5.54	2%
2022	104.57	1.000	72.74	5.64	2%
2023+	+2%/yr	1.000	+2%/yr	+2%/yr	2%