CALGARY / FEBRUARY 3, 2011

MEG Energy announces 2010 fourth quarter financial and operating results and December 31, 2010 reserve and resource estimates

MEG Energy Corp. ("MEG" or the "Corporation") reported fourth quarter 2010 net earnings of $46.5 million ($0.24 per share, diluted) compared to a net loss of $16.0 million (loss of $0.11 per share) in the fourth quarter of 2009. Operating earnings in the fourth quarter 2010 were $19.5 million ($0.10 per share) compared to an operating loss of $13.9 million (loss of $0.09 per share) in the fourth quarter of 2009.

Cash flow from operations for the fourth quarter of 2010 was $74.1 million ($0.38 per share) compared to a cash flow deficiency of $11.7 million (deficiency of $0.08) per share in the fourth quarter of 2009.

The increase in earnings and cash flow during the fourth quarter was primarily due to higher production and lower operating costs. During the fourth quarter of 2010 production averaged 27,744 barrels of bitumen per day, approximately 10% above the nominal design capacity of the facilities. The steam to oil ratio ("SOR") in the fourth quarter of 2010 was 2.3, compared with a design SOR of 2.8. In the fourth quarter 2009 Christina Lake Phase 2 had just commenced operations and production averaged 5,933 barrels of bitumen per day. Operating costs during the fourth quarter of 2010 averaged $14.22 per barrel, including non-energy costs of $9.35 per barrel.

"I am very proud of what we have accomplished in the fourth quarter and the full year. Christina Lake continues to exceed our expectations both from production and operating cost perspectives. Considerable momentum has been developed as we enter 2011," said Bill McCaffrey, Chairman, President and CEO.

MEG also reported that GLJ Petroleum Consultants Ltd. ("GLJ"), a leading independent reservoir engineering firm, has completed an evaluation of the Corporation's reserves and recoverable resources effective as of December 31, 2010. The estimates of reserves and resources were prepared in accordance with National Instrument 51-101. Proved bitumen reserves increased to 606 million barrels, an increase of 10% compared with December 31, 2009, while proved plus probable reserves increased by 13% to 1,919 million barrels. The pre-tax present value of the future net cash flows of the proved reserves and proved plus probable reserves, discounted at 10% per annum, were $5.4 billion and $12.1 billion, respectively. The best estimate of contingent resources remained substantially unchanged at 3,716 million barrels. A summary of GLJ's report follows the unaudited financial statements in this news release.

The strong finish to the year reinforces the production and operating cost guidance for 2011. Production volumes are expected to average between 25,000 and 27,000 bbls/day taking into account the anticipated plant turnaround in September 2011. Non-energy operating costs are budgeted to continue to trend downward with the guidance for 2011 being in the $9 to $11/bbl range.

Capital investment for 2011 is budgeted to be approximately $900 million with the majority being invested towards MEG's strategic plan of growing bitumen production capacity to 260,000 bbls/day by 2020.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

The following table summarizes selected financial and operational information of the Corporation as at and for the periods indicated:

	Three months ended December 31		Year ended December 31	
($000 except per share amounts and as noted)	2010	2009	2010	2009
Bitumen production – bbls/d	27,744	5,933	21,257	3,467
Bitumen realization - $/bbl	51.43	51.70	51.76	45.01
Operating costs:				
Energy	4.87	18.89	6.47	12.18
Non-energy	9.35	33.15	14.39	43.62
Total operating costs - $/bbl	14.22	52.04	20.86	55.80
Steam to oil ratio	2.3	4.9	2.5	3.9
Operating earnings (loss)[1]	19,456	(13,940)	13,117	(39,944)
Per share, diluted[1]	0.10	(0.09)	0.07	(0.28)
Net income (loss)	46,498	(16,028)	40,097	51,176
Per share, basic	0.25	(0.11)	0.23	0.37
Per share, diluted	0.24	(0.11)	0.22	0.36
Cash flow from operations [1]	74,119	(11,695)	161,846	(32,461)
Per share, diluted [1]	0.38	(0.08)	0.88	(0.23)
Capital investment	147,438	64,140	494,630	351,342

(1) *Operating earnings, cash flow from operations and the related per share amounts do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. The Corporation uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the Corporation's ability to internally fund future growth expenditures. These "Non-GAAP Measurements" are reconciled to net income (loss) in accordance with Canadian GAAP under the heading "Non-GAAP Measurements".*

Bitumen production increased to 27,744 barrels per day for the three months ended December 31, 2010 compared to 5,933 barrels per day for the three months ended December 31, 2009. For the year ended December 31, 2010 bitumen production averaged 21,257 barrels per day compared to 3,467 barrels per day in 2009. The increase in production is due to the increased volumes from the ramp up of Phase 2 of the Christina Lake Project.

Operating costs for the three months ended December 31, 2010 were $14.22 per barrel compared to $52.04 per barrel for the same period in 2009. For the year ended December 31, 2010 operating costs were $20.86 per barrel compared to $55.80 per barrel in 2009. Operating costs per barrel decreased primarily as a result of the increase in production as a result of the ramp-up of the Christina Lake Phase 2 facility.

The average SOR for the three months ended December 31, 2010 was 2.3 compared to an SOR of 4.9 for the three months ended December 31, 2009. For the year ended December 31, 2010 the average SOR was 2.5 compared to an average SOR of 3.9 in 2009. The SOR has decreased throughout 2010 as the Phase 2 well pairs have quickly progressed through the circulation phase and entered into normal operations. The early success of the production ramp-up, and improved SOR, has enabled the Corporation to performance test the integrated Phase 1 and 2 facilities and exceed the plant design production capacity.

Operating earnings for the three months ended December 31, 2010 were $19.5 million compared to an operating loss of $13.9 million for the three months ended December 31, 2009, an increase of $33.4 million. Operating earnings of $13.1 million for the year ended December 31, 2010 represent an increase of $53.0 million from a $39.9 million loss for the same period in 2009. The increase in operating earnings primarily resulted from higher production volumes related to the ramp-up of the Christina Lake Phase 2 operations.

Net income for the fourth quarter of 2010 was $46.5 million compared to a net loss of $16.0 million for the fourth quarter of 2009. Net income for the year ended December 31, 2010 was $40.1 million compared to $51.2 million in 2009. This change was primarily 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. During the fourth quarter of 2010 there was an unrealized $35.3 million gain for the translation of the debt compared to an $18.5 million unrealized gain during the same period in 2009. For the year ended December 31, 2010 there was an unrealized foreign exchange gain of $52.2 million for the translation of the debt compared to a $127.3 million unrealized gain in 2009. The reduction in the foreign exchange gains compared to 2009 is offset by the fact that net income during the three months and year ended December 31, 2009 only included one month of income from operations. Effective December 1, 2009, the Corporation commenced planned principal operations and ceased capitalizing blend revenue, operating costs and interest costs for Phases 1 and 2 of the Christina Lake Project.

Cash flow from operations for the three months ended December 31, 2010 was $74.1 million, an increase of $85.8 million from the same period in 2009. Cash flow from operations for the year ended December 31, 2010 totalled $161.8 million, an increase of $194.3 million from 2009. The increase was the result of cash flows generated from the Phase 2 bitumen production.

Capital investment during the fourth quarter of 2010 increased by $83.3 million compared to the fourth quarter of 2009 to $147.4 million. This increase is due mainly to increased investment on Christina Lake Phase 2B horizontal drilling and facilities engineering. Capital investment for the year ended December 31, 2010 increased from $351.3 million in 2009 to $494.6 million. The increase is due to increased investment on Christina Lake Phase 2B as well as the $42.5 million purchase of lands and assets associated with the Stonefell Terminal tank farm construction project and the $54.9 million purchase of undeveloped lands in the Surmont area.

Non-GAAP Measurements

The following table reconciles the non-GAAP measurements "Operating earnings (loss)" and "Cash flow from operations" and "Cash operating netbacks" to "Net income (loss)", the nearest Canadian GAAP measure. Operating earnings (loss) is defined as net income (loss) as reported excluding the after-tax gains and losses on foreign exchange, risk management, loss on modification of long-term debt, and change in fair value of other assets. Cash flow from operations excludes realized risk management and foreign exchange losses and the net change in non-cash operating working capital while the Canadian GAAP measurement "Cash from operating activities" includes these items. Cash operating netback is comprised of petroleum and power sales less royalties, operating costs, cost of diluents and transportation and selling costs. Prior to December 1, 2009 these items were capitalized as the Corporation had not commenced planned principal operations.

	Three months ended December 31		Year ended December 31	
Non-GAAP Measurements ($000)	2010	2009	2010	2009
Net income (loss)	46,498	(16,028)	40,097	51,176
Add (deduct):				
Foreign exchange gains, net of tax[1]	(30,122)	(15,883)	(43,316)	(116,817)
Risk management losses, net of tax[2]	3,080	2,007	16,336	7,577
Change in fair value of other assets, net of tax[3]	-	-	-	2,156
Loss on modification of long-term debt, net of tax[4]	-	15,964	-	15,964
Operating earnings (loss)	19,456	(13,940)	13,117	(39,944)
Add (deduct) non-cash items:				
Stock-based compensation	4,794	2,941	14,439	12,912
Depletion, depreciation and accretion	41,688	2,592	124,801	3,103
Other	30	119	170	336
Future income taxes, operating	8,151	(3,407)	9,319	(8,868)
Cash flow from operations	74,119	(11,695)	161,846	(32,461)
Add (deduct):				
Net operating loss capitalized	-	680	-	(21,010)
Interest income	(3,764)	(367)	(7,933)	(2,572)
General and administrative	10,761	5,266	36,427	24,295
Research and development	817	1,625	5,384	4,690
Interest expense	11,074	3,306	44,591	4,183
Cash operating netback	93,007	(1,185)	240,315	(22,875)

(1) *Foreign exchange gains result primarily from the translation of US dollar denominated long-term debt and debt service reserve to period-end exchange rates.*

(2) *Risk management losses result from the Corporation's interest rate swaps entered into to fix a portion of its variable rate long-term debt.*

(3) *Change in fair value of other assets results from fair value changes in certain long-term investments.*

(4) *Loss on modification of long-term debt results from modifications to the Corporation's senior secured credit facility on December 23, 2009.*

SUMMARY OF QUARTERLY RESULTS

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

	2010				2009			
($ millions, except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue, net of royalties	246.3	155.0	210.5	126.4	23.8	0.4	0.5	1.3
Net income (loss)	46.5	25.7	(31.7)	(0.4)	(16.0)	44.1	56.7	(33.6)
Per share – basic	0.25	0.14	(0.19)	0.00	(0.11)	0.31	0.41	(0.26)
Per share – diluted	0.24	0.14	(0.19)	0.00	(0.11)	0.30	0.40	(0.26)

Revenue for the first 11 months in 2009 was primarily from interest earned on the investment of surplus cash. Commencing December 2009, revenues also include the revenue from the sale of bitumen blend and power. Effective December 1, 2009, the Corporation commenced planned principal operations and ceased capitalizing blend revenue, operating costs and interest costs for Phases 1 and 2 of the Christina Lake Project.

Net income (loss) during the periods noted were 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, risk management activities for interest rate swaps, and costs for modification of long-term debt. The net income (loss) was also positively impacted by the inclusion of blend revenue, operating costs and interest costs for Phases 1 and 2 of the Christina Lake Project as planned principal operations commenced December 1, 2009 and the Corporation ceased capitalizing these items.

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

	Year ended December 31		2010				2009			
	2010	2009	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Commodity Prices (Average Prices)										
Crude oil prices										
West Texas Intermediate (WTI) US$/bbl	79.52	61.80	85.13	76.20	78.03	78.71	76.19	68.30	59.62	43.08
Western Canadian Select (WCS) CDN$/bbl	67.23	58.66	67.87	62.94	65.60	72.51	67.66	63.74	60.64	42.60
Differential – WTI/WCS (CDN$/bbl)	14.69	11.89	18.35	16.24	14.59	9.42	12.82	11.21	8.95	11.05
Differential – WTI/WCS (%)	18.0%	17.0%	21.0%	20.5%	18.2%	11.5%	15.9%	15.0%	12.9%	20.6%
Natural gas prices										
AECO (CDN$/mcf)	4.11	4.12	3.56	3.70	3.84	5.33	4.21	3.01	3.64	5.61
Electric power prices										
Alberta Power Pool average price (CDN$/MW)	50.91	47.80	45.95	35.77	81.15	40.78	46.06	49.49	32.30	63.35
Foreign exchange rates										
Average Canadian / U.S. dollar exchange rate	1.0301	1.1415	1.0128	1.0391	1.0276	1.0409	1.0563	1.0974	1.1672	1.2453
Corporation results										
Blend Sales (CDN$/bbl)	63.03	53.40	63.95	60.84	60.94	68.06	61.11	58.36	55.37	33.22
Differential – WTI//Blend (CDN$/bbl)	18.88	17.14	22.27	18.33	19.25	13.88	19.37	16.59	14.21	20.43
Differential – WTI/Blend (%)	23.0%	24.3%	25.8%	23.2%	24.0%	16.9%	24.1%	22.1%	20.4%	38.1%
Diluent cost (CDN$/bbl)	87.27	73.56	89.95	83.46	86.20	88.56	83.79	74.52	65.78	59.10
Bitumen sales (CDN$/bbl)	51.76	45.01	51.43	51.73	48.73	58.10	51.70	52.08	50.95	21.94
Bitumen sales (bbls/d) (1)	21,292	3,416	27,648	19,376	24,562	13,447	5,920	2,493	2,136	3,093

(1) *The Corporation completed a planned plant turnaround in the third quarter of 2010*.

RESULTS OF OPERATIONS

Since the commencement of Phase 2 steaming operations in August 2009 production at the integrated Phase 1 and Phase 2 facilities has increased to average 27,744 bbls/d during the fourth quarter of 2010, exceeding the design capacity of 25,000 bbls/d. The average SOR for the three months ended December 31, 2010 was 2.3 compared to an SOR of 4.9 for the three months ended December 31, 2009. For the year ended December 31, 2010 the average SOR was 2.5 compared to an average SOR of 3.9 in 2009. SOR is an important efficiency indicator which measures the amount of steam that is injected into the reservoir in relation to bitumen produced. A lower SOR indicates a more efficient steam assisted gravity drainage ("SAGD") process. SORs are higher in the start-up period than in steady state operations due to the initial steam circulation period and lower initial production rates during ramp-up.

The Corporation's 85 MW cogeneration facility produces approximately 70% of the steam for Phase 1 and 2 SAGD operations and is operating near capacity. MEG's processing facility is utilizing the heat produced by the cogeneration facility and approximately 8 – 12 MW of the power generated. Beginning in October 2009, surplus power has been sold into the Alberta Power Pool electricity grid.

The following table summarizes the Corporation's results of operations for the periods indicated:

Operating Summary

	Three months ended December 31		Year ended December 31	
Cash operating netback ($000)	2010	2009	2010	2009
Blend sales[1]	241,020	47,089	717,610	94,295
Cost of diluent[2]	(110,199)	(18,932)	(315,350)	(38,180)
Bitumen sales	130,821	28,157	402,260	56,115
Transportation and other selling costs	(3,197)	(3,832)	(12,480)	(12,767)
Royalties	(5,777)	(1,136)	(16,521)	(1,705)
Net bitumen revenue	121,847	23,189	373,259	41,643
Operating costs – energy	(12,384)	(10,289)	(50,288)	(15,183)
Operating costs – non-energy	(23,786)	(18,056)	(111,853)	(54,383)
Power sales	7,330	3,971	29,197	5,048
Cash operating netback[3]	93,007	(1,185)	240,315	(22,875)
Less capitalized[4]	-	680	-	(21,010)
Cash operating netback in statement of operations[4]	93,007	(1,865)	240,315	(1,865)

	Three months ended December 31		Year ended December 31	
Production and Sales Volume Summary (bbls/d)	2010	2009	2010	2009
Blend sales[1]	40,964	8,376	31,192	4,838
Diluents[2]	(13,316)	(2,456)	(9,900)	(1,422)
Bitumen sales	27,648	5,920	21,292	3,416
(Increase) decrease in inventory	96	13	(35)	51
Total bitumen production	27,744	5,933	21,257	3,467
Power sales (MWh)	163,198	89,434	585,476	98,914
Power realization (CDN$/MWh)	44.91	44.40	49.87	51.97

	Three months ended December 31		Year ended December 31	
Cash operating netback ($ per barrel)	2010	2009	2010	2009
Bitumen sales	51.43	51.70	51.76	45.01
Transportation and other selling costs	(1.26)	(7.04)	(1.61)	(10.24)
Royalties	(2.27)	(2.09)	(2.13)	(1.37)
Net bitumen revenue	47.90	42.57	48.02	33.40
Operating costs – energy	(4.87)	(18.89)	(6.47)	(12.18)
Operating costs – non-energy	(9.35)	(33.15)	(14.39)	(43.62)
Power sales	2.88	7.29	3.76	4.05
Cash Operating Netback[3]	36.56	(2.18)	30.92	(18.35)

(1) *Bitumen produced at the Christina Lake Project is mixed with purchased diluent and sold as bitumen blend. Diluent is a light hydrocarbon that improves the marketing and transportation quality of bitumen.*

(2) *Diluent volumes purchased and sold have been deducted in calculating bitumen production revenue and production volumes sold.*

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

(4) *Effective December 1, 2009, the Corporation commenced planned principal operations and ceased capitalizing net operating costs.*

Bitumen sales in the three months ended December 31, 2010 were $130.8 million compared to $28.2 million for the same period in 2009. The increase of $102.6 million is primarily due to higher production volumes from the ramp-up of Christina Lake Phase 2 operations. WTI averaged US$85.13 per barrel (C$86.22/bbl) in the fourth quarter of 2010 compared to US$76.19 per barrel (C$80.48/bbl) in the same period in 2009. Revenue for the Corporation's blend of bitumen and diluent averaged $63.95 per barrel during the three months ended December 31, 2010 compared to $61.11 per barrel for the same period in 2009.

Bitumen sales in the year ended December 31, 2010 were $402.3 million compared to $56.1 million for the same period in 2009. The increase of $346.2 million is due to higher production volumes from the start up of Christina Lake Phase 2 and higher selling prices. WTI averaged US$79.52 per barrel (C$81.91/bbl) in 2010 compared to US$61.80 per barrel (C$70.54/bbl) in 2009. Blend revenue averaged $63.03 per barrel for the year ended December 31, 2010 compared to $53.40 per barrel in 2009.

Energy operating costs represent the cost of gas purchased to operate the Corporation's once through steam generators and the cogeneration facility. Non-energy operating costs represent all other non-natural gas related operating expenses. Energy operating costs have decreased from $18.89 per barrel for the fourth quarter of 2009 to $4.87 per barrel for the fourth quarter of 2010 and from $12.18 per barrel for the year ended December 31, 2009 to $6.47 per barrel for the year ended December 31, 2010. Non-energy operating costs were $9.35 per barrel for the fourth quarter of 2010 compared to $33.15 per barrel for the fourth quarter of 2009 and $14.39 per barrel for the year ended December 31, 2010 compared to $43.62 per barrel for the year ended December 31, 2009. Operating costs per barrel have decreased in 2010 primarily as a result of the increase in production from the ramp-up of Christina Lake Phase 2.

Power sales for the three months ended December 31, 2010 were $7.3 million compared to $4.0 million for the same period in 2009. During the fourth quarter of 2010 the Corporation realized an average price of $44.91 per megawatt hour compared to the Alberta Pool average of $45.95. Power sales for the year ended December 31, 2010 were $29.2 million compared to $5.0 million in 2009. During the year ended December 31, 2010 the Corporation realized a price of $49.87 per megawatt hour compared to the Alberta Pool average price of $50.91 per megawatt hour. There will be variances to the Alberta Pool average price benchmark as it is based on the average daily price while power sales are priced on an hourly basis and can vary significantly each hour during the day.

During commissioning and start up it takes time for the reservoir to respond and for operations to work through the normal processing and treating issues associated with a new facility. Since Phase

1 was a pilot plant and Phase 2 was ramping-up production through 2009 and into 2010, current operating netback per barrel does not yet reflect the economies associated with a steady state facility operating at its design capacity. Operating cost per barrel has decreased in 2010 compared to 2009 as fixed costs are spread over the higher production volumes during this period. The Corporation anticipated volatility in operating results with the start up of Phase 2 but expects the volatility to become less pronounced as steady-state operations are achieved.

General and Administrative Costs

	Three months ended December 31		Year ended December 31	
($000)	2010	2009	2010	2009
G&A Expense	10,737	5,266	36,403	24,295
Capitalized G&A	2,952	1,993	11,258	9,576
Total G&A Costs	13,689	7,259	47,661	33,871

General and administrative costs for the three months ended December 31, 2010 totalled $13.7 million, compared with $7.3 million for the same period in 2009. General and administrative costs for the year ended December 31, 2010 totalled $47.7 million, compared with $33.9 million in 2009. The increase in costs primarily resulted from the planned growth in the Corporation's professional staff and costs to support the operations and development of its oil sands assets. The head office employee headcount grew from 147 as of December 31, 2009 to 184 at December 31, 2010. For the year ended December 31, 2010 the Corporation capitalized salaries related to capital investment of $11.3 million (2009 – $9.6 million).

Stock-based Compensation

Stock-based compensation expense for the three months ended December 31, 2010 was $4.8 million compared to $2.9 million for the same period in 2009. Stock-based compensation expense for the year ended December 31, 2010 was $14.4 million compared to $12.9 million for the same period in 2009. For the year ended December 31, 2010 the Corporation capitalized $3.7 million (2009 – $3.8 million) of stock-based compensation to property, plant and equipment.

Foreign Exchange Loss (Gain)

	Three months ended December 31		Year ended December 31	
($000)	2010	2009	2010	2009
Long-term debt	(35,268)	(18,529)	(52,186)	(127,258)
Debt service reserve	913	-	2,195	3,832
US$ denominated cash and cash equivalents	457	811	1,445	4,843
Other	(416)	(55)	(509)	(1,524)
Foreign exchange loss (gain)	(34,314)	(17,773)	(49,055)	(120,107)

US$ - Canadian $ exchange rate As at December 31,	2010	2009	2008
C$ equivalent of 1 US dollar	0.9946	1.0466	1.2246

The net foreign exchange gains for the three months and year ended December 31, 2010 were primarily due to the strengthening of the Canadian dollar with respect to the US dollar and higher US dollar debt outstanding in 2010.

In December 2009, the Corporation increased its senior secured term loan by US$300 million. In the fourth quarter of 2010 the Canadian dollar strengthened against the US dollar by $0.03 while in the same period of 2009 it strengthened by $0.02. For the year ended December 31, 2010 the Canadian dollar strengthened against the US dollar by $0.05 while in 2009 it strengthened by $0.18.

Risk Management Loss

	Three months ended December 31		Year ended December 31	
($000)	2010	2009	2010	2009
Realized loss on interest rate swaps	8,625	4,945	34,412	17,180
Unrealized fair value gain on interest rate swaps	(8,763)	(4,266)	(32,671)	(14,753)
Amortization of unrealized loss on interest rate swaps from accumulated other comprehensive income	4,246	1,997	20,041	7,676
Total risk management loss	4,108	2,676	21,782	10,103

The Corporation realized an increase in interest costs due to the interest rate swaps which have been charged to operations as risk management loss. The Corporation hedged, until December 31, 2010, the interest rate on US$700 million of its floating rate debt by swapping LIBOR for an average fixed rate of 5.05%. For the three months ended December 31, 2010, the average LIBOR rate was 0.29% which was consistent with the average rate for the same period in 2009. For the year ended December 31, 2010 the average LIBOR rate was 0.35% compared to 0.89% for the year ended December 31, 2009.

The unrealized fair value gain on the interest rate swaps is due to the change in the fair value of the interest swaps. In the fourth quarter of 2010 the fair value of the interest rate swap liability decreased $8.8 million compared to $4.3 million for the same period in 2009. For the year ended December 31, 2010 the fair value of the interest rate swap liability decreased by $32.7 million compared to $14.8 million for the same period in 2009. The fair value of the interest rate swaps declined over the periods noted due to the shorter term to expiry of the contracts. As at December 31, 2010 the interest rate swap contracts have expired and there is no further liability associated with the contracts.

The amortization of the unrealized loss on interest rate swaps from accumulated other comprehensive income is a result of the Corporation previously applying hedge accounting to its interest rate swap contracts. Hedge accounting was subsequently discontinued as the hedges were no longer effective. As at December 31, 2010, all amounts remaining in accumulated other comprehensive income related to these swaps have been amortized into earnings.

Interest Expense

	Three months ended December 31		Year ended December 31	
($000)	2010	2009	2010	2009
Total interest expense	16,315	10,228	65,484	44,607
Capitalized to property, plant and equipment	(5,187)	(6,803)	(20,699)	(40,088)
Interest expense	11,128	3,425	44,785	4,519

Total interest expense in the three months and year ended December 31, 2010 increased compared to the same periods in 2009 primarily as a result of higher outstanding debt and higher interest rates on the Corporation's long-term debt. In December 2009 the Corporation increased its senior secured term loan by US$300.0 million.

Effective December 1, 2009 the Corporation commenced planned principal operations and ceased capitalizing interest on the development of Phases 1 and 2 of the Christina Lake Project. Interest on the US$300 million incremental portion of the senior secured term loan associated with the development of Phase 2B of the Christina Lake Project continues to be capitalized.

Depletion, Depreciation and Accretion

Depletion of the Christina Lake Project developed assets commenced December 1, 2009 and was calculated using the unit-of-production method based on total estimated proved reserves. This equated to $16.01 per barrel of production for the three months ended December 31, 2010 and $15.76 per barrel of production for the year ended December 31, 2010. Prior to December 2009, there was no depletion and depreciation expense related to Phases 1 and 2 of the Christina Lake Project as planned principal operations had not yet commenced.

Income Taxes

Future income tax expense for the three months ended December 31, 2010 was $11.3 million, an increase of $18.8 million from the same period in 2009. Future income tax expense for the year ended December 31, 2010 was $9.6 million compared to a future income tax recovery of $14.1 million in 2009.

The Corporation's effective income tax rate is primarily impacted by permanent differences and variances in valuation reserves. The significant permanent differences are:

- The non-taxable portion of capital foreign exchange gains and losses on the translation of the US dollar denominated debt. For the year ended December 31, 2010 the non-taxable foreign exchange gain was $26.1 million compared to $60.4 million for the year ended December 31, 2009.

- The non-taxable portion of stock-based compensation. For the year ended December 31, 2010, non-taxable stock-based compensation was $14.4 million compared to $12.9 million for the year ended December 31, 2009.

The Corporation is not currently taxable. As of December 31, 2010, the Corporation had approximately $3.1 billion of available tax pools and had recognized a net future tax liability of $22.2 million. In addition, at December 31, 2010 the Corporation had $247.2 million of capital investment in respect of incomplete projects which will be added to available tax pools upon completion of the projects.

CAPITAL INVESTING

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

Summary of capital investment ($000)	Three months ended December 31 2010	Three months ended December 31 2009	Year ended December 31 2010	Year ended December 31 2009
Christina Lake Project:				
Resource exploration and delineation	2,591	1,341	25,836	$ 6,305
Horizontal drilling	36,910	3,586	36,910	6,867
Facilities, procurement and construction	80,705	44,945	241,621	255,328
Other	145	283	8,653	1,908
Total Christina Lake Project	120,351	50,155	313,020	270,408
Surmont and Growth Properties	2,306	605	15,253	1,812
Land and other acquisitions	833	3	100,961	136
Capitalized interest and fees	4,635	6,362	18,633	37,790
Other	15,302	5,086	36,728	33,729
Total cash investments	143,427	62,211	484,595	343,875
Non-cash investments	4,011	1,929	10,035	7,467
Total capital investment	147,438	64,140	494,630	351,342

The Corporation invested cash of $143.4 million during the fourth quarter of 2010 compared to $62.2 million during the fourth quarter of 2009. During 2010, the Corporation invested cash totalling $484.6 million compared with $343.9 million in the same period in 2009. Capital investment in 2010 was focused on Christina Lake Project Phase 2B development and resource delineation at Christina Lake and on the Growth Properties.

Christina Lake Project

During the year ended December 31, 2010 the Corporation drilled 66 core holes and six observation wells to assist in the determination of Phase 2B horizontal wells placement and further delineation of resources in the Christina Lake leases. The Phase 2B horizontal drilling program was initiated in the fourth quarter of 2010. Facilities investment in 2010 was directed towards Phase 2B detailed engineering and commencing the purchase of major equipment, installation of electric submersible pumps, and maintenance and reliability of the Phase 2 facility. As at December 31, 2010, the detailed engineering of Phase 2B was 41% complete and capital commitments for 90% of all equipment orders were in place. On November 30, 2010, the Corporation's board of directors approved the 35,000 bpd Phase 2B expansion with a cost estimate of $1.4 billion.

Effective December 1, 2009 management determined that planned principal operations at Christina Lake had commenced. The Corporation therefore ceased capitalizing net operating and interest costs associated with Phases 1 and 2 as of December 1, 2009. Net operating costs for the eleven months ended November 30, 2009 totalled $21.0 million and have been capitalized as they were incurred prior to the commencement of planned principal operations. (For further details, see the tables under the subheading "Operating Summary").

Surmont and Growth Properties

The Corporation invested $15.3 million during the year ended December 31, 2010 to drill 24 core holes on the Growth Properties for increased resource definition and to evaluate source water quality near Surmont.

Land and Other Acquisitions

During 2010 the Corporation invested $42.5 million to purchase lands and assets associated with a tank farm construction project (the "Stonefell Terminal"), located east of the Access Pipeline Sturgeon Terminal. Once construction of the Stonefell Terminal is complete, it is anticipated to have a storage capacity of 900,000 barrels. The Corporation also acquired an additional 8,320 acres (13 square miles) of undeveloped oil sands leases in the Surmont area for $54.9 million.

Non-Cash

Non-cash capital investment is comprised of capitalized financing transaction costs, capitalized stock based-compensation and amounts capitalized in respect of asset retirement obligations.

Forward-Looking Information

This news release may contain forward-looking information including but not limited to: expectations of future production, revenues, cash flow, operating costs, steam-oil-ratios, 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, production capacities and performance of the Access Pipeline, the Stonefell Terminal, the future phases and expansions of the Christina Lake project, the Surmont project and MEG's other properties and facilities; and the anticipated sources of funding for operations and capital investments. Such forward-looking information is based on management's expectations 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. Such forward-looking information also 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 financial market volatility, the risks associated with the oil and gas industry (e.g. operational risks in development; exploration and production; delays or changes in plans with respect to exploration or development projects or capital investments; access to markets and to transportation infrastructure, the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and expenses; health, safety and environmental risks; the risk of legislative and regulatory changes to, amongst other things, taxes, land use, royalties and environmental laws), the risk of commodity price and foreign exchange rate fluctuations; 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 release is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this release is made as of February 3, 2011 and the Corporation assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by applicable securities laws.

Statements in this release relating to reserves and resources are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the described reserves and resources, as the case may be, exist in the quantities predicted or estimated, and can be profitably produced in the future. Additional information regarding forward-looking information and the classification of MEG's reserves and resources is contained within the Corporation's public disclosure documents on file with Canadian securities regulatory authorities. In particular, for more information regarding forward-looking information see "Risk Factors" and "Industry Regulation" within MEG's supplemented prospectus dated July 28, 2010 (the "Prospectus") and for more information regarding the classification of MEG's estimated reserves and resources see "Independent Reserve and Resource Evaluation" within the Prospectus. MEG's public disclosure documents may be accessed through the SEDAR website (www.sedar.com), at MEG's website (www.megenergy.com) or by contacting MEG's investor relations department.

Non-GAAP Financial Measures

This news release includes references to financial measures commonly used in the crude oil and natural gas industry, such as net bitumen revenue, operating earnings, cash flow from operations and cash operating netback. These financial measures are not defined by Canadian generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Corporation may not be comparable to similar measures presented by other companies. The Corporation uses these non-GAAP measures to help evaluate its performance. Management considers net bitumen revenue, operating earnings and cash operating netback important measures as they indicate profitability relative to current commodity prices. Management uses cash flow from operations to measure the Corporation's ability to generate funds to finance capital expenditures and repay debt. These non-GAAP measures should not be considered as an alternative to or more meaningful than net income (loss), as determined in accordance with Canadian GAAP, as an indication of the Corporation's performance. The non-GAAP operating earnings, cash flow from operations and cash operating netback measures are reconciled to net income (loss), as determined in accordance with Canadian GAAP, under the heading "Non-GAAP Measurements" earlier in this news release.

MEG ENERGY CORP.
Balance Sheet
(Unaudited)

As at December 31 ($ 000s)		2010		2009
Assets				
Current assets:				
Cash and cash equivalents (note 13)	$	1,224,446	$	963,018
Short-term investments (note 2)		167,406		-
Accounts receivable and other (note 3)		96,964		33,662
Inventories		6,173		5,560
Debt service reserve (note 4)		-		102,359
		1,494,989		1,104,599
Restricted cash (note 5)		-		12,810
Other assets (note 6)		7,492		7,743
Property, plant and equipment (note 7)		3,515,150		3,144,341
	$	5,017,631	$	4,269,493
Liabilities and shareholders' equity				
Current liabilities:				
Accounts payable and accrued payables	$	144,378	$	71,842
Current portion of deferred lease inducements (note 8)		292		-
Risk management liability (note 12)		-		32,671
Current portion of long-term debt (note 10)		10,065		10,593
		154,735		115,106
Deferred lease inducements (note 8)		3,185		-
Long-term debt (note 10)		969,933		1,029,687
Asset retirement obligations (note 9)		16,793		14,297
Future income tax liability		22,238		14,290
		1,166,884		1,173,380
Commitments and contingencies (note 14)				
Shareholders' equity:				
Share capital (note 11)		3,821,579		3,137,696
Contributed surplus (note 11)		71,464		55,841
Deficit		(42,296)		(82,393)
Accumulated other comprehensive loss		-		(15,031)
		3,850,747		3,096,113
	$	5,017,631	$	4,269,493

See accompanying notes to financial statements.

MEG ENERGY CORP.
Statement of Operations and Deficit
(Unaudited)

	Three months ended December 31		Year ended December 31	
($ 000s except per share amounts)	2010	2009	2010	2009
Revenues:				
Petroleum sales	$ 241,020	$ 21,380	$ 717,610	$ 21,380
Royalties	(5,777)	(573)	(16,521)	(573)
Power sales	7,330	2,615	29,197	2,615
Interest	3,764	367	7,933	2,572
	246,337	23,789	738,219	25,994
Operating expenses:				
Operating costs	36,170	14,072	162,141	14,072
Cost of diluent	110,199	9,004	315,350	9,004
Transportation and selling costs	3,197	2,211	12,480	2,211
General and administrative	10,737	5,266	36,403	24,295
Stock-based compensation (note 11)	4,794	2,941	14,439	12,912
Research and development	817	1,625	5,384	4,690
Interest expense	11,128	3,425	44,785	4,519
Depletion, depreciation and accretion (notes 7 and 9)	41,688	2,592	124,801	3,103
	218,730	41,136	715,783	74,806
Revenues less operating expenses	27,607	(17,347)	22,436	(48,812)
Other (gain) loss:				
Foreign exchange gain, net	(34,314)	(17,773)	(49,055)	(120,107)
Risk management loss (note 12)	4,108	2,676	21,782	10,103
Loss on modification of long-term debt	-	21,286	-	21,286
Change in fair value of other assets	-	-	-	2,875
	(30,206)	6,189	(27,273)	(85,843)
Income (loss) before income taxes	57,813	(23,536)	49,709	37,031
Future income tax expense (recovery)	11,315	(7,508)	9,612	(14,145)
Net income (loss)	46,498	(16,028)	40,097	51,176
Deficit, beginning of period	(88,794)	(66,365)	(82,393)	(133,569)
Deficit, end of period	$ (42,296)	$ (82,393)	$ (42,296)	$ (82,393)
Earnings (loss) per share (note 13)				
Basic	$ 0.25	$ (0.11)	$ 0.23	$ 0.37
Diluted	$ 0.24	$ (0.11)	$ 0.22	$ 0.36

See accompanying notes to financial statements.

MEG ENERGY CORP.

Statement of Other Comprehensive Income
(Unaudited)

		Three months ended December 31				Year ended December 31		
($ 000s)		2010		2009		2010		2009
Net income (loss)	$	46,498	$	(16,028)	$	40,097	$	51,176
Other comprehensive income, net of tax								
Gains (losses) on cash flow hedges (note 12)								
Unrealized loss on derivatives designated as cash flow hedges, net of taxes(1)		-		(219)		-		(1,532)
Realized loss gain on derivatives designated as cash flow hedges capitalized, net of taxes(2)		-		3,048		-		12,226
Amortization of balance in AOCI(3)		3,185		1,498		15,031		5,757
Other comprehensive income		3,185		4,327		15,031		16,451
Total comprehensive income (loss)	$	49,683	$	(11,701)	$	55,128	$	67,627

Statement of Accumulated Other Comprehensive Loss
(Unaudited)

		Three months ended December 31				Year ended December 31		
($ 000s)		2010		2009		2010		2009
Balance, beginning of period	$	(3,185)	$	(19,358)	$	(15,031)	$	(31,482)
Other comprehensive income, net of tax		3,185		4,327		15,031		16,451
Balance, end of period	$	-	$	(15,031)	$	-	$	(15,031)

(1) Net income tax expense, three months ended December 31, 2010 - nil, year ended December 31, 2010 - nil (three months ended December 31, 2009 – $73 benefit, year ended December 31, 2009 - $511 benefit)

(2) Net income tax expense, three months ended December 31, 2010 - nil, year ended December 31, 2010 - nil (three months ended December 31, 2009 – $1,016 year ended December 31, 2009 - $4,075)

(3) Net income tax expense, three months ended December 31, 2010 - $1,061 year ended December 31, 2010 – $5,010 (three months ended December 31, 2009 – $499, year ended December 31, 2009 – $1,919)

See accompanying notes to financial statements.

MEG ENERGY CORP.
Statement of Cash Flows
(Unaudited)

	Three months ended December 31		Year ended December 31	
($ 000s)	2010	2009	2010	2009
Cash provided by (used in):				
Operations:				
Net income (loss)	$ 46,498	$ (16,028)	$ 40,097	$ 51,176
Items not involving cash:				
Stock-based compensation	4,794	2,941	14,439	12,912
Depletion, depreciation and accretion	41,688	2,592	124,801	3,103
Unrealized net gain on foreign exchange	(34,811)	(17,718)	(50,741)	(122,415)
Unrealized gain on risk management	(4,517)	(2,269)	(12,630)	(7,077)
Loss on modification of long-term debt	-	11,009	-	11,009
Future income tax expense (recovery)	11,315	(7,508)	9,612	(14,145)
Other	30	119	170	3,211
Net change in non-cash operating working capital items (note 13)	(45,551)	3,121	(50,143)	2,022
	19,446	(23,741)	75,605	(60,204)
Investing:				
Purchase of property, plant and equipment	(143,427)	(62,211)	(484,595)	(343,875)
Lease inducement (note 8)	3,501	-	3,501	-
Change in debt service reserve	26,565	(105,813)	102,359	(50,146)
Decrease (increase) in restricted cash (note 5)	-	1,529	12,810	(12,810)
Payments received on commercial paper and other	111	3,506	21	1,061
Net change in non-cash investing working capital items (note 13)	(133,086)	2,470	(108,642)	(21,398)
	(246,336)	(160,519)	(474,546)	(427,168)
Financing:				
Issue of shares	5,183	542,308	672,170	889,922
Issue of long-term debt	-	298,907	-	332,945
Repayment of long-term debt	(2,516)	(2,648)	(10,356)	(8,780)
	2,667	838,567	661,814	1,214,087
Foreign exchange loss on cash and cash equivalents held in foreign currency	(457)	(811)	(1,445)	(4,843)
Increase (decrease) in cash and cash equivalents	(224,680)	653,496	261,428	721,872
Cash and cash equivalents, beginning of period	1,449,126	309,522	963,018	241,146
Cash and cash equivalents, end of period (note 13)(1)	$ 1,224,446	$ 963,018	$ 1,224,446	$ 963,018

(1) Excludes$167,406 of short term investments as at December 31, 2010.

See accompanying notes to financial statements.

Year ended December 31, 2010. Tabular amounts are expressed in $ 000 unless otherwise noted.

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 800 sections of oil sands leases in the Athabasca 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 includes co-ownership of Access Pipeline ("Access"), 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.

1. BASIS OF PRESENTATION:

These statements have been prepared in accordance with Canadian generally accepted accounting principles and reflect the same accounting policies and methods of computation as the financial statements for the year ended December 31, 2009. The disclosure herein is incremental to that included with the annual financial statements. The interim financial statements should be read in conjunction with the financial statements and the notes thereto for the year ended December 31, 2009.

2. SHORT-TERM INVESTMENTS:

Short-term investments consist of commercial paper, money market deposits or similar instruments with a maturity of between 91 and 180 days from the date of purchase.

3. ACCOUNTS RECEIVABLE AND OTHER:

As at December 31		2010		2009
Accounts receivable	$	94,170	$	28,524
Deposits and advances		2,794		5,138
	$	96,964	$	33,662

4. DEBT SERVICE RESERVE:

Investments were held in a US dollar debt service reserve account to fund interest and principal payments associated with the senior secured credit facilities. As of December 31, 2010 the Corporation is no longer required to maintain a debt service reserve account.

The US dollar denominated debt service account was translated into Canadian dollars at the period end exchange rate. The foreign exchange loss on the debt service reserve was $0.9 million for the three months ended December 31, 2010 and $2.0 million for the year ended December 31, 2010 (three months ended December 31, 2009 – $0.4 million gain, year ended December 31, 2009 - $3.4 million loss), and has been recognized in operations through foreign exchange.

5. RESTRICTED CASH:

Restricted cash consisted of cash on deposit to collateralize letters of credit issued by the Corporation. In the second quarter of 2010 letters of credit previously issued were cancelled and replaced by letters of credit issued under the Corporation's US$185 million revolving credit facility (note 10).

Year ended December 31, 2010. Tabular amounts are expressed in $ 000 unless otherwise noted.

6. OTHER ASSETS:

As at December 31		2010		2009
MAV Notes (formerly asset-backed commercial paper)	$	4,707	$	4,769
US Auction Rate Securities		2,785		2,974
	$	7,492	$	7,743

7. PROPERTY, PLANT AND EQUIPMENT:

December 31, 2010		Cost		Accumulated depletion and depreciation		Net book value
Oil sands properties and equipment	$	3,624,092	$	125,839	$	3,498,253
Corporate assets		18,647		1,750		16,897
	$	3,642,739	$	127,589	$	3,515,150

December 31, 2009						
Oil sands properties and equipment	$	3,144,945	$	3,270	$	3,141,675
Corporate assets		4,155		1,489		2,666
	$	3,149,100	$	4,759	$	3,144,341

Effective December 1, 2009, planned principal operations of the Corporation's Christina Lake Project commenced and the Corporation began depleting the developed oil sands properties and equipment costs, excluding pipeline line fill costs of $40.2 million. Prior to the commencement of principal operations, operating costs net of revenues, were capitalized. The cost of undeveloped properties not subject to depletion as at December 31, 2010 was $1,371.5 million (December 31, 2009 - $1,194.6 million).

In 2010 the Corporation capitalized $11.3 million (2009 - $9.6 million) of general and administrative expenses, $3.7 million (2009 – $3.8 million) of stock-based compensation costs and $20.7 million (2009 - $40.1 million) of interest and debt service costs relating to oil sands exploration and development activities.

Year ended December 31, 2010. Tabular amounts are expressed in $ 000 unless otherwise noted.

8. DEFERRED LEASE INDUCEMENTS:

Lease inducements applicable to the Calgary office lease are deferred and amortized as a reduction of general and administrative costs on a straight-line basis over the lease term.

As at December 31		2010
Deferred lease inducements, beginning of year	$	-
Additions		3,501
Amortization of deferred lease inducements		(24)
Deferred lease inducements, end of year	$	3,477
Less current portion of deferred lease inducements		(292)
Non-current portion of deferred lease inducements	$	3,185

9. ASSET RETIREMENT OBLIGATIONS:

The following table presents the obligation associated with the retirement of oil sands and natural gas properties:

As at December 31		2010		2009
Asset retirement obligation, beginning of year	$	14,297	$	12,907
Liabilities incurred		1,746		570
Liabilities settled		(299)		(75)
Accretion		1,049		895
Asset retirement obligation, end of year	$	16,793	$	14,297

The estimated future undiscounted asset retirement obligation is $85.1 million (December 31, 2009 - $80.2 million), which has been discounted using an average credit-adjusted risk free rate of 6.32%. This obligation is estimated to be settled in periods up to 2057.

10. LONG-TERM DEBT:

As at December 31		2010		2009
Senior secured term loan B (US$41.5 million; 2009-US$41.9 million)	$	41,240	$	43,836
Senior secured term loan D (US$957.9 million; 2009-US$967.6 million)		952,775		1,012,741
Financing transaction costs		(14,017)		(16,297)
		979,998		1,040,280
Less current portion of senior secured term loan B		(417)		(439)
Less current portion of senior secured term loan D		(9,648)		(10,154)
	$	969,933	$	1,029,687

Year ended December 31, 2010. Tabular amounts are expressed in $ 000 unless otherwise noted.

The Corporation's senior secured credit facilities are comprised of US$999.4 million in term loans and a three year US$185.0 million revolving credit facility. The US$41.5 million term loan B matures on April 3, 2013 and the US$957.9 million term loan D matures on April 3, 2016. The term loan B bears a floating interest rate based on either US prime or the London Interbank Offered Rate ("LIBOR"), at the Corporation's option, plus a credit spread of 100 or 200 basis points, respectively. The term loan D bears a floating interest rate based on either US prime or LIBOR, at the Corporation's option, plus a credit spread of 300 or 400 basis points, respectively. In addition, the term loan D bears an interest rate floor of 325 basis points based on US prime and an interest rate floor of 200 basis points based on LIBOR. As at December 31, 2010, $8.3 million of the revolving credit facility was utilized to support letters of credit. The US dollar denominated debt is translated into Canadian dollars at the period end exchange rate of $1 US = $0.9946 CDN (December 31, 2009 – $1 US = $1.0466 CDN).

11. SHARE CAPITAL:

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

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

As at December 31	2010			2009		
	Number of shares		Amount	Number of shares		Amount
Balance, beginning of year	169,130,053	$	3,137,696	128,123,287	$	2,243,618
Stock options exercised	745,098		11,406	341,017		2,387
Shares issued for cash	20,000,000		700,000	40,665,749		975,978
Share issue costs, net of taxes of $9,174 (2009 – $3,698)			(27,523)			(84,287)
Balance, end of year	189,875,151	$	3,821,579	169,130,053	$	3,137,696

During the year ended December 31, 2010, a total of 745,098 options were exercised at a weighted average price of $11.90 per share.

On August 6, 2010, the Corporation completed its initial public offering and issued 20,000,000 common shares to the public at a price of $35.00 per share.

Year ended December 31, 2010. Tabular amounts are expressed in $ 000 unless otherwise noted.

(c) Stock options:

Effective June 9, 2010, the Corporation's board of directors approved a new option plan ("the 2010 Option Plan") as a replacement for the Corporation's existing stock option plan ("2003 Option Plan"). The 2010 Option Plan allows for the granting of options to directors, officers or employees and consultants of the Corporation. Options granted under the 2010 Option Plan are generally fully exercisable after three years and expire seven years after the grant date. Prior to June 9, 2010, the Corporation issued options to employees and directors under a previous option plan and under stand alone option agreements (collectively, the "Old Option Plan"). No additional options will be granted under the Old Option Plan. The Corporation has reserved 18,987,515 common shares (10% of the outstanding common shares, subject to certain restrictions) for issuance pursuant to the 2010 Option Plan and the restricted share unit plan ("the RSU Plan").

As at December 31	2010			2009		
	Options		Weighted average exercise price per share	Options		Weighted average exercise price per share
Balance, beginning of year	12,609,407	$	19.89	10,892,674	$	18.86
Granted	1,208,170		33.48	2,206,500		24.00
Forfeited	(152,633)		29.35	(148,750)		38.24
Exercised	(745,098)		11.90	(341,017)		5.65
Balance, end of year	12,919,846	$	21.51	12,609,407	$	19.89

(d) Restricted share units:

Effective June 9, 2010, the Corporation's Board of Directors approved the RSU Plan. The RSU Plan allows for the granting of Restricted Share Units ("RSUs") to directors, officers or employees and consultants of the Corporation. An RSU represents the right for the holder to receive a cash payment 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. The value of an RSU is determined based on the share price of the Corporation's common shares on the date of grant with the resulting expense recognized in earnings over the three year vesting term.

As at December 31	2010
RSUs	
Balance, beginning of year	-
Granted	407,610
Forfeited	(2,665)
Balance, end of year	404,945

Year ended December 31, 2010. Tabular amounts are expressed in $ 000 unless otherwise noted.

(e) Contributed surplus:

As at December 31		2010		2009
Balance, beginning of year	$	55,841	$	39,614
Stock based compensation - expensed		14,439		12,912
Stock based compensation - capitalized		3,723		3,775
Stock options exercised		(2,539)		(460)
Balance, end of year	$	71,464	$	55,841

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT:

The financial instruments recognized in the balance sheet are comprised of cash and cash equivalents, short-term investments, accounts receivable, debt service reserve, restricted cash, other assets, accounts payable and accrued liabilities, risk management liability and long-term debt.

The carrying value of cash and cash equivalents, short-term investments, accounts receivable, debt service reserve, restricted cash and accounts payable and accrued liabilities approximates their fair value due to the short-term maturity of these instruments. Other assets and risk management liability are considered to be held-for-trading and are recorded at fair value. At December 31, 2010 the estimated fair value of long-term debt was $921.2 million. The fair value of long-term debt and the risk management liability were determined based on quoted prices from financial institutions. The Corporation has applied a discounted cash flow valuation in determining the fair value of other assets.

To mitigate a portion of the risk of interest rate increases on long-term debt the Corporation had entered into interest rate swap contracts to fix the interest rate on US$700 million of the US$999.4 million total debt. The Corporation had the following interest rate swap contracts which expired on December 31, 2010:

Amount ($ million)	Remaining term	Fixed rate	Floating rate
US$350	Oct 2010 – Dec 2010	5.29%	LIBOR(1)
US$60	Oct 2010 – Dec 2010	4.85%	LIBOR(1)
US$55	Oct 2010 – Dec 2010	4.83%	LIBOR(1)
US$235	Oct 2010 – Dec 2010	4.80%	LIBOR(1)

(1) London Interbank Offered Rate

Year ended December 31, 2010. Tabular amounts are expressed in $ 000 unless otherwise noted.

The Corporation had previously applied hedge accounting to its interest rate swap contracts which was subsequently discontinued as the hedges were no longer effective. As at December 31, 2010, all amounts remaining in accumulated other comprehensive income related to these swaps have been amortized into earnings.

As at December 31		2010		2009
Risk management liability, beginning of year	$	32,671	$	61,683
Decrease in liability fair value recognized in earnings		(32,671)		(14,753)
Decrease in liability fair value recognized in OCI		-		(14,259)
Risk management liability, end of year	$	-	$	32,671

	Three months ended December 31				Year ended December 31			
Risk management expense		2010		2009		2010		2009
Realized loss on interest rate swaps	$	8,625	$	4,945	$	34,412	$	17,180
Unrealized fair value gain on interest rate swaps		(8,763)		(4,266)		(32,671)		(14,753)
Amortization of unrealized loss on interest rate swaps from AOCI		4,246		1,997		20,041		7,676
	$	4,108	$	2,676	$	21,782	$	10,103

Year ended December 31, 2010. Tabular amounts are expressed in $ 000 unless otherwise noted.

13. SUPPLEMENTARY INFORMATION:

(a) Supplemental cash flow disclosures:

	Three months ended December 31		Year ended December 31	
	2010	2009	2010	2009
Changes in non-cash working capital items:				
Accounts receivable and other	$ (75,738)	$ (19,883)	$ (63,302)	$ (19,853)
Short-term investments	(160,444)	-	(167,406)	-
Inventories	12,234	8,870	(613)	2,226
Accounts payable	45,311	16,604	72,536	(1,749)
	(178,637)	5,591	(158,785)	(19,376)
Changes in non-cash working capital relating to:				
Operations	$ (45,551)	$ 3,121	$ (50,143)	$ 2,022
Investing	(133,086)	2,470	(108,642)	(21,398)
	(178,637)	5,591	(158,785)	(19,376)

Cash and cash equivalents[(1)]:		
Cash	$ 18,857	$ 107,074
Cash equivalents	1,205,589	855,944
	$ 1,224,446	$ 963,018

[(1)] Excludes $167,406 of short term investments as at December 31, 2010.

(b) Per share amounts:

	Three months ended December 31		Year ended December 31	
	2010	2009	2010	2009
Weighted average common shares outstanding	189,774,757	147,078,485	177,476,449	138,953,495
Dilutive effect of stock options and RSUs	6,369,708	4,234,716	5,778,675	4,557,334
Weighted average common shares outstanding – diluted	196,144,465	151,313,201	183,255,124	143,510,829

Year ended December 31, 2010. Tabular amounts are expressed in $ 000 unless otherwise noted.

14. COMMITMENTS AND CONTINGENCIES:

(a) Commitments

The Corporation had the following commitments as at December 31, 2010.

Operating:

	2011	2012	2013	2014	2015	Thereafter
Office lease rentals	$ 4,031	$ 4,031	$ 4,031	$ 4,031	$ 4,060	$ 20,961
Diluent purchases	341,972	-	-	-	-	-
Other commitments	2,647	1,630	3,255	1,562	-	-
Annual commitments	$ 348,650	$ 5,661	$ 7,286	$ 5,593	$ 4,060	$ 20,961

Capital:

As part of normal operations, the Corporation has entered into a total of $177.4 million in capital commitments to be made in periods through 2015.

(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.

15. COMPARATIVE FIGURES:

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

Reserves and Resources

The Corporation has identified two commercial 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 700 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 412 sections of MEG’s 864 sections of oil sands leases were evaluated. GLJ’s Reserves and Resources Report is effective as of December 31, 2010.

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, 2011.

The information set forth below relating to the Corporation’s reserves and resources constitute 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 606 million barrels of bitumen. The Corporation’s proved-plus-probable (2P) reserves are 1,919 million barrels and its best estimate contingent resources (2C) are 3,716 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 100,000 barrels per day of sustained production for over 20 years. These production capacities are based on the GLJ estimate of 2P reserves and 2C resources as of December 31, 2010.

Reserves

GLJ has prepared estimates of the various producing and non-producing reserve types: proved reserves (1P) and proved-plus-probable reserves (2P). All of the Corporation's reserves are at Christina Lake due to the advanced stage of development of the Christina Lake Project.

GLJ has used a two-step process to determine and allocate reserves. First, GLJ utilized the pay thickness and well density for reserve categorization. GLJ assigned 1P reserves to portions of MEG’s leases where continuous bitumen pay of greater than ten metres was identified with a minimum density of one well per 80 acres plus 3D seismic coverage. GLJ assigned 2P reserves to portions of the leases where continuous bitumen pay of greater than nine metres was identified with a minimum density of one well per 160 acres.

The second step was to determine whether these reserves will be produced within 50 years and whether the necessary regulatory approvals are in place or submissions have been made. The reserves identified in this step are termed “marketable reserves” by GLJ. In order to be classified as marketable proved reserves, the necessary regulatory approvals must have been obtained and significant capital spending to develop the project must occur within three years. In order to be classified as marketable probable reserves, all the necessary regulatory applications must have been submitted with no significant outstanding issues and significant capital spending to develop the project must occur within five years. The proved and probable reserves shown in the table below have been classified by GLJ as marketable proved reserves and marketable probable reserves, respectively.

Resources

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 provided three estimates for the contingent resources category: “low estimate” (high certainty), “best estimate” (most likely) and “high estimate” (low certainty). GLJ identified a total of best estimate contingent resource of 3,716 million barrels for MEG which consists of 1,061 million barrels for Christina Lake, 837 million barrels for Surmont and 1,818 million barrels for the Growth Properties.

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)	2010	2009	% Change
Proved (1P) Reserves (1)	606	549	10
Probable Reserves(2)	1,313	1,143	15
Proved Plus Probable (2P) Reserves(1) (2)	1,919	1,692	13
Best Estimate of Contingent Resources (2C)(3) (4) (5)	3,716	3,724	0

Pre-tax 10% Present Value of Future Net Cash Flows As at December 31 ($ millions)	2010	2009	% Change
Proved (1P) Reserves (1)	5,388	4,387	23
Probable Reserves(2)	6,743	3,779	78
Proved Plus Probable (2P) Reserves(1) (2)	12,131	8,167	49
Best Estimate of Contingent Resources (2C)(3) (4) (5)	13,265	11,559	15

(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. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. 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.*

GLJ Forecast Pricing (as utilized in the GLJ 2010 Report)

Forecast	Light and Medium Crude Oil	Exchange Rate	Bitumen Wellhead Current	Natural Gas	Inflation Rate
	WTI at Cushing Oklahoma (US$/bbl)	US$/Cdn$	(Cdn$/bbl)	Alberta Spot (Cdn$/mmbtu)	%/year
2011	88.00	0.980	61.03	4.02	0%
2012	89.00	0.980	61.14	4.61	2%
2013	90.00	0.980	60.36	5.16	2%
2014	92.00	0.980	62.13	5.62	2%
2015	95.17	0.980	64.51	6.07	2%
2016	97.55	0.980	66.24	6.38	2%
2017	100.26	0.980	68.23	6.60	2%
2018	102.74	0.980	70.03	6.75	2%
2019	105.45	0.980	72.02	6.90	2%
2020	107.56	0.980	73.56	7.05	2%
2021+	+2%/yr	0.980	+2%/yr	+2%/yr	2%

For further information:

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