CALGARY/ AUGUST 9, 2010

MEG Energy Corp. announces 2010 Second Quarter Results and Successful Ramp-up of Production at Christina Lake

- Christina Lake bitumen production averaged 24,412 barrels per day ("bbls/d") in the second quarter of 2010 and averaged over 26,000 bbls/d in the month of June 2010.
- The steam oil ratio ("SOR"), a key measure of steam assisted gravity drainage ("SAGD") efficiency, dropped to 2.4 in May and June.
- Cash flow from operations increased to $45.3 million in the second quarter of 2010, compared with a use of cash of $14.0 million in the second quarter of 2009.
- On August 6, 2010 MEG closed its initial public offering of 20 million common shares generating net proceeds of over $660 million. Including these proceeds, June 30, 2010 pro-forma cash and cash equivalents is over $1.4 billion, providing the capital to fund the Corporation's 35,000 bbls/d expansion of its Christina Lake Project.

"This is an exciting time for MEG's shareholders and employees," stated Bill McCaffrey, the Corporation's Chairman, President and Chief Executive Officer. "Production volumes from our commercial operations at Christina Lake, which commenced in August 2009, have safely ramped-up more rapidly than any other SAGD project that we are aware of, and with one of the lowest SORs. This demonstrates both the quality of our oil sands reservoir and the high performance of our team."

"The very positive results of our operations at Christina Lake, combined with the closing of MEG's initial public offering, give us the confidence and financial strength to more than double our production to 60,000 bbls/d at Christina Lake," McCaffrey continued. "MEG is well positioned to grow and to increase shareholder value."

Operational and Financial Highlights

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

	Three months ended June 30		Six months ended June 30	
($000 except as noted and per share amounts)	**2010**	**2009**	**2010**	**2009**
Bitumen production – bbls/d	24,412	2,136	18,935	2,612
Bitumen realization - $/bbl	48.73	50.95	52.02	33.87
Revenue, net of royalties	210,534	515	336,888	1,835
Net (loss) income	(31,658)	56,712	(32,143)	23,127
Per share, basic	(0.19)	0.41	(0.19)	0.17
Per share, diluted	(0.19)	0.40	(0.19)	0.17
Cash flow from operations[1]	45,319	(14,012)	35,735	(22,697)
Per share, basic[1]	0.27	(0.39)	$0.21	(0.47)
Per share, diluted[1]	0.26	(0.39)	$0.20	(0.47)
Capital investment	158,378	91,564	250,187	216,444

(1) *Cash flow from operations and cash flow from operations per share do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("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. The reconciliation "Cash Flow from Operations" presented in Management's Discussion and Analysis lists certain non-cash items that are included in the Corporation's financial results.*

MEG Energy Corp. (the "Corporation") (TSX: "MEG") is an oil sands company focused on sustainable *in situ* oil sands development and production in the southern Athabasca region of Alberta, Canada. The Corporation is actively developing enhanced oil recovery projects that utilize SAGD extraction methods.

Christina Lake Operations

Christina Lake Phase 1, MEG's 3,000 bbls/d pilot facility, commenced production in 2008 and has been integrated with the 22,000 bbls/d Phase 2 facility that commenced operations in August 2009. Combined design capacity of 25,000 bbls/d was exceeded in June 2010, when bitumen production averaged 26,412 bbls/d from 29 horizontal well pairs. Importantly, the SOR for June was 2.4 and for the second quarter as a whole averaged 2.5, one of the lowest in the Alberta *in situ* oil sands industry. Phase 2 was engineered with a design SOR of 2.8. As the SOR is already lower, MEG commenced circulation of steam into two additional horizontal well pairs in the second quarter and plans to convert these wells to production in the third quarter of 2010.

The ramp-up in production volumes over the past year has been better than planned. Bitumen sales over the past four quarters have been as follows:

2009 third quarter	2,493 bbls/d
2009 fourth quarter	5,920 bbls/d
2010 first quarter	13,447 bbls/d
2010 second quarter	24,562 bbls/d

Production volumes are anticipated to stabilize in the range of 24,000 to 27,000 bbls/d. Commercial operations at Christina Lake are at an early stage, and production volumes may be volatile as experience shows that unexpected situations often arise during the start-up of SAGD operations. Also note that a planned plant turnaround is scheduled for two to three weeks in September, during which there will be no production. If plant issues are found during this important inspection and maintenance period, operations may be interrupted for a longer period of time than currently scheduled.

Christina Lake Expansion

Christina Lake Phase 2B, a 35,000 bbls/d expansion, received regulatory approvals in 2009. Detailed engineering and the procurement of major equipment is underway. Field construction and the drilling of horizontal well pairs is planned to commence late this year or early in 2011. Phase 2B is being designed to more than double our production capacity to 60,000 bbls/d and is planned to commence steaming operations in 2013.

MEG's Christina Lake Phase 3 regulatory application, for a total of an additional 150,000 bbls/d of bitumen production, was filed with Alberta provincial regulatory authorities in 2008. MEG received a completeness decision in May 2010 from Alberta Environment in respect of its Phase 3 Environmental Impact Assessment application and made a formal request to the Energy Resources Conservation Board for a decision regarding the project application in June 2010. MEG anticipates the receipt of approvals late in 2010 or 2011.

Financial Results

Prior to December 1, 2009, the financial results from operations were capitalized as commercial production had not commenced. Therefore, revenue prior to December 1, 2009 consisted primarily of interest earned on cash balances. Effective December 1, 2009, the Corporation commenced planned principal operations and ceased capitalizing petroleum and power sales, operating costs and interest costs for the Christina Lake Project.

As a result of the commencement of commercial operations, revenue, net of royalties, increased to $210.5 million in the second quarter of 2010, compared with $0.5 million in the second quarter of 2009. Cash flow from operations for the three months ended June 30, 2010 totaled $45.3 million, an increase of $59.3 million from the same period in 2009.

MEG's long-term debt of US$1.0 billion is denominated in US dollars. At the end of each reporting period, the loans are translated into Canadian dollars at the period-end exchange rate. The effect of exchange rate changes is recorded as a gain, if the Canadian dollar strengthens, or a loss, if the Canadian dollar weakens compared with the previous period. Exchange rate fluctuations can have a large impact on net income each quarter, but are not considered by management to be indicative of operating results. The Cdn/US$ exchange rate was 1.0606 on June 30 2010, compared with 1.0156 on March 31, 2010, 1.1625 on June 30, 2009 and 1.2602 on March 31, 2009. As a result, the foreign exchange loss on the translation of US dollar denominated debt, net of US dollar denominated cash and our debt service reserve, was $37.5 million in the second quarter of 2010, compared with a gain of $64.9 million in the second quarter of 2009. The net loss for the second quarter of 2010 was $31.7 million compared with net income of $56.7 million in the same period in 2009.

Please refer to the following Management's Discussion and Analysis and to the Consolidated Financial Statements for the three and six months ended June 30, 2010 for details concerning MEG's financial results, forward looking information, non-GAAP financial measures, and risk factors.

A conference call will be held to review the financial statements at 7:00 a.m. Mountain Time (9:00 a.m. Eastern Time) on Tuesday, August 10, 2010. The U.S./Canada toll-free conference call number is 1 (888) 231-8191. The international/local conference call number is (647) 427-7450. A recording of the call will be available from 10:00 a.m. Mountain Time (noon Eastern Time) on August 10, 2010 until 10:00 p.m. Mountain Time (midnight Eastern Time) on September 3, 2010. To access the recording dial toll-free 1 (800) 642-1687 or local (416) 849-0833 and enter the conference password 92858120.

For further information, please contact:

Dale J. Hohm, CA
Chief Financial Officer
MEG Energy Corp.

(403) 770-5337
dale.hohm@megenergy.com

Management's Discussion and Analysis

The following discussion of financial condition and performance is dated August 9, 2010 and should be read in conjunction with the management's discussion and analysis "MD&A" for the year ended December 31, 2009, the audited consolidated financial statements for the year ended December 31, 2009 and the unaudited consolidated financial statements for the period ended June 30, 2010. All tabular amounts are stated in thousands of Canadian dollars unless indicated otherwise.

Forward-Looking Information

This report of MEG Energy Corp. ("MEG" or the "Corporation") may contain forward-looking information including but not limited to expectations of future production, revenues, cash flow, profitability and capital investments, anticipated reductions in operating costs as a result of optimization of certain operations, development of additional oil sands resources, and 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; 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, 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. 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. The forward-looking information included in this report is expressly qualified in its entirety by the foregoing cautionary statements. The forward-looking information included in this report is made as of August 9, 2010 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 relating to reserves and recoverable 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.

Non-GAAP Financial measures

The management's discussion and analysis includes references to financial measures commonly used in the crude oil and natural gas industry, such as net bitumen revenue, 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 and cash operating netback important measures as it indicates 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 cash flow from operations and cash operating netback measures are reconciled to net income (loss), as determined in accordance with Canadian GAAP, under the headings "Operational and Financial Highlights" and "Results of Operations" below.

Overview

The Corporation is an oil sands company focused on sustainable in situ oil sands development and production in the southern Athabasca region of Alberta, Canada. The Corporation is actively developing enhanced oil recovery projects that utilize steam assisted gravity drainage ("SAGD") extraction methods.

The Corporation owns a 100% working interest in over 800 sections of oil sands leases. At December 31, 2009, GLJ Petroleum Consultants Ltd. ("GLJ"), an independent reservoir engineering firm, estimated that the Corporation's oil sands leases it had evaluated contained 1.7 billion barrels of proved and probable bitumen reserves and 3.7 billion barrels of contingent bitumen resources (best estimate). The Corporation has identified two commercial SAGD projects, the Christina Lake Project and the Surmont Project. The Corporation believes, supported by GLJ estimates, that the Christina Lake Project and the Surmont Project (assuming an initial 50,000 barrels per day ("bbls/d") project size) combined will support 260,000 bbls/d of sustained bitumen production for over 30 years. In addition, the Corporation holds other leases at the Growth Properties that are still in the resource definition stage and that provide significant additional development opportunities.

The Corporation also holds a 50% interest in a dual pipeline system, which connects the Christina Lake Project to a large regional upgrading, refining and transportation hub in the Edmonton area (the "Access Pipeline"). The Access Pipeline and its associated blending facilities are in operation and provide the Corporation with the ability to transport diluents to the Christina Lake Project and a blend of bitumen and condensate (called dilbit) from Christina Lake to Edmonton, Alberta to supply a range of North American and global refining markets.

Christina Lake Project

The Christina Lake Project is situated on 51,200 contiguous acres (80 square miles) of oil sands leases in the southern Athabasca region of Alberta, adjacent to the Christina Lake project operated by Cenovus Energy Inc. and northeast of the Jackfish project operated by Devon ARL Corporation. At December 31, 2009, GLJ estimated the Christina Lake Project to contain 1.7 billion barrels of proved and probable reserves and 1.4 billion barrels of contingent resources (best estimate). The Corporation has a staged growth plan to reach 210,000 bbls/d of bitumen production at Christina Lake by 2020, which the Corporation believes, supported by GLJ estimates, would be sustainable for over 30 years.

Phases 1 and 2 of the Christina Lake Project, with designed production capacity totaling 25,000 bbls/d of bitumen, are complete and on production. The 3,000 bbls/d Phase 1 bitumen pilot plant commenced production in 2008 and has now been integrated with Phase 2. Phase 2, which is designed to produce an incremental 22,000 bbls/d of bitumen, commenced steaming in August 2009.

MEG has received regulatory approvals for a 35,000 bbls/d facility expansion of Phase 2, called Phase 2B. The Corporation has commenced detailed facilities engineering and the equipment procurement process, and plans to commence site construction in early 2011 with first production scheduled for 2013. Phase 2B is designed to increase production capacity of the Christina Lake Project to 60,000 bbls/d.

The regulatory application for Phase 3 of the Christina Lake Project was filed with regulatory authorities in 2008, and covers the remaining 37,120 acres (58 square miles) of the Christina Lake Project. This application is for phased development totaling an incremental 150,000 bbls/d. The Corporation received a completeness decision in May 2010 from Alberta Environment in respect of its Phase 3 Environmental Impact Assessment application and has made a formal request to the Energy Resources Conservation Board (the "ERCB") for a decision regarding the project application. The ERCB has deemed the application to be technically complete, and the Corporation anticipates the receipt of approvals late in 2010 or 2011. Subject to, amongst other things, the receipt of regulatory approvals, a 50,000 bbls/d expansion known as Phase 3A could commence production in 2016, followed by two subsequent 50,000 bbls/d expansions (Phases 3B and 3C) in two to three year intervals.

Surmont Project

The Surmont Project, approximately 30 miles north of Christina Lake, comprises 20,480 acres (32 square miles) of 100%-owned oil sands leases. The Corporation's project is directly adjacent to *in situ* oil sands leases operated by ConocoPhillips Canada. The report of GLJ dated effective December 31, 2009 with respect to the proved and probable reserves and contingent resources of the Corporation (the "GLJ Report") assigned 647 million barrels of contingent resources (best estimate) to the 12,160 acres (19 square miles) of oil sands leases that the Corporation held at December 31, 2009. In the second quarter of 2010, the Corporation acquired an additional 8,320 acres (13 square miles) of oil sands leases in the Surmont area.

A detailed environmental impact assessment for the Surmont Project is substantially complete and the Corporation is currently preparing a regulatory application for a 100,000 bbls/d project, to be developed in several phases. The Corporation plans to file the regulatory application in 2011. The Corporation currently plans to construct a facility for the initial phase with the capacity to produce 50,000 bbls/d of bitumen which, subject to the receipt of regulatory approvals and other factors, could commence production in 2018. At 50,000 bbls/d, management anticipates that the Surmont Project will support sustained bitumen production for approximately 30 years, supported by GLJ's estimate of 647 million barrels of contingent resources (best estimate). The Corporation plans to connect the Surmont Project to the Access Pipeline, which management anticipates will offer similar diluent supply and marketing advantages to those realized at the Christina Lake Project. In addition, the Corporation expects to incorporate cogeneration into the project design.

Growth Properties

The Growth Properties, located west of Christina Lake and Surmont, comprise 471,040 acres (736 square miles) of 100%-owned oil sands leases, including several large contiguous blocks, that the Corporation believes could support stand-alone commercial enhanced oil recovery projects. GLJ has evaluated 186,880 acres (292 square miles) of the Growth Properties and assigned contingent resources (best estimate) to those leases of 1.7 billion barrels. The Corporation plans to connect the Growth Properties to the Access Pipeline, which management anticipates will offer similar diluent supply and transportation advantages to those realized at the Christina Lake Project.

Access Pipeline

The Corporation and Devon each own a 50% interest in the Access Pipeline, a strategic 215-mile dual pipeline system. The Access Pipeline includes a 16-inch diluent line from the Edmonton area to the Christina Lake Project and a 24-inch blend line to transport dilbit from the Christina Lake Project to a blending and storage facility northeast of Edmonton, Alberta, called the Sturgeon Terminal, that is also part of the Access Pipeline.

The Access Pipeline began operating in March 2007 and has a capacity of 156,000 bbls/d of blended bitumen and 70,000 bbls/d of condensate. With the addition of incremental pumping stations, capacity can be increased to 394,000 bbls/d of blended bitumen and 206,000 bbls/d of condensate. The Corporation's share of existing Access Pipeline capacity is 78,000 bbls/d of bitumen blend and 35,000 bbls/d of condensate. The Corporation's share of the fully-powered capacity is 197,000 bbls/d of bitumen blend and 103,000 bbls/d of condensate, which the Corporation expects to be sufficient to market its combined production from Phases 1, 2, 2B and 3A of the Christina Lake Project. In addition, there is an ability to loop segments of the blend line, which involves the installation of another pipeline in the same rights of way, to accommodate the anticipated volumes of blended bitumen produced from Phases 3B and 3C of the Christina Lake Project, from the Surmont Project and from the Corporation's other planned projects. The looping of segments of the blend line would enable the existing segments to be converted to condensate service, thereby increasing condensate transportation capacity.

Development of the Christina Lake future phases and other projects is discretionary, and there can be no assurance that development will be completed as currently planned. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. There is no certainty that it will be commercially viable to produce any portion of the Corporation's contingent resources.

Operational and Financial Highlights

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

	Three months ended June 30		Six months ended June 30	
($000 except as noted and per share amounts)	2010	2009	2010	2009
Bitumen production - bbls/d	24,412	2,136	18,935	2,612
Bitumen realization - $/bbl	48.73	50.95	52.02	33.87
Revenue, net of royalties	210,534	515	336,888	1,835
Net (loss) income	(31,658)	56,712	(32,143)	23,127
Per share, basic	(0.19)	0.41	(0.19)	0.17
Per share, diluted	(0.19)	0.40	(0.19)	0.17
Cash flow from operations[1]	45,319	(14,012)	35,735	(22,697)
Per share, basic[1]	0.27	(0.39)	$0.21	(0.47)
Per share, diluted[1]	0.26	(0.39)	$0.20	(0.47)
Capital investment	158,378	91,564	250,187	216,444

(1) *Cash flow from operations and cash flow from operations per share 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. The reconciliation "Cash Flow from Operations" presented below lists certain non-cash items that are included in the Corporation's financial results.*

Revenue prior to December 1, 2009, consisted primarily of interest earned on the cash balances. The inclusion of bitumen blend and power sales in total revenue effective December 1, 2009 is the primary reason for the increase in revenue from 2009. 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 loss for the first six months of 2010 of $32.1 million increased by $55.3 million compared to the same period in 2009. The increase in the loss was primarily attributable to the fluctuations in the rate of exchange between the Canadian and U.S. dollar in translating the Corporation's U.S. dollar-denominated debt. For the six months ended June 30, 2010 there was a foreign exchange loss of $14.0 million for the translation of the debt compared to a $44.3 million gain in the same period of 2009.

Cash flow from operations for the six months ended June 30, 2010 totaled $35.7 million, an increase of $58.4 million from the same period in 2009. The increase was the result of cash flows generated from the Phase 2 bitumen production.

The following table reconciles the non-GAAP measurement "Cash Flow from Operations" to "Net (loss) income" being the nearest Canadian GAAP measure.

	Three months ended June 30		Six months ended June 30	
Cash Flow from Operations ($000)	2010	2009	2010	2009
Net (loss) income	(31,658)	56,712	(32,143)	23,127
Non-cash items:				
Stock-based compensation	2,911	2,161	6,540	4,347
Depletion, depreciation and accretion	35,592	165	54,661	353
Unrealized net (gain) loss on foreign exchange	40,038	(67,533)	13,879	(42,937)
Unrealized (gain) loss on risk management	(2,977)	(3,257)	(4,829)	(3,038)
Future income taxes	1,360	(2,358)	(2,461)	(4,647)
Other	53	98	88	98
Cash flow from operations	45,319	(14,012)	35,735	(22,697)

Summary of Quarterly Results

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

	2010		2009				2008(1)	
($ millions, except per share amounts)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenue, net of royalties	210.5	126.4	23.8	0.4	0.5	1.3	2.9	4.1
Net (loss) income	(31.7)	0.5	(16.0)	44.1	56.7	(33.6)	(129.5)	(29.2)
Per share – basic	(0.19)	0.00	(0.11)	0.31	0.41	(0.26)	(1.01)	(0.23)
Per share – diluted	(0.19)	0.00	(0.11)	0.30	0.40	(0.26)	(1.01)	(0.23)

(1) The Corporation adopted new accounting policies effective January 1, 2009 that required the retroactive restatement of prior periods.

Revenue during the periods from the third quarter of 2008 to the third quarter of 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 (loss) income during the periods noted were impacted by foreign exchange gains and losses attributable to the 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 foreign exchange call options, and modification of long-term debt. The net (loss) income was also 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 benchmark information on a quarterly basis to assist in understanding the impact of commodity prices and foreign exchange rates on the Corporation's financial results:

	2010		2009				2008	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Benchmarks								
Crude oil prices								
West Texas Intermediate (WTI) US$/bbl	78.03	78.71	76.19	68.30	59.62	43.08	58.73	117.98
Western Canadian Select (WCS) CDN$/bbl	65.60	72.51	67.66	63.74	60.64	42.60	47.73	103.92
Differential – WTI/WCS (CDN$/bbl)	14.59	9.42	12.82	11.21	8.95	11.05	23.49	19.00
Differential – WTI/WCS (%)	18.2%	11.5%	15.9%	15.0%	12.9%	20.6%	33.0%	15.5%
Natural gas prices								
AECO (CDN$/mcf)	3.84	5.33	4.21	3.01	3.64	5.61	6.75	9.20
Electric power prices								
Alberta Power Pool average price (CDN$/MW)	81.15	40.78	46.06	49.49	32.30	63.35	95.14	$80.21
Foreign exchange rates								
Average Canadian / U.S. dollar exchange rate	1.0276	1.0409	1.0563	1.0974	1.1672	1.2453	1.2125	1.0418
Corporation results								
Blend Sales (CDN$/bbl)	60.94	68.06	61.11	58.36	55.37	33.22	29.32	91.08
Differential – WTI//Blend (CDN$/bbl)	19.25	13.88	19.37	16.59	14.21	20.43	41.89	31.83
Differential – WTI/Blend (%)	24.0%	16.9%	24.1%	22.1%	20.4%	38.1%	58.8%	25.9%
Diluent cost (CDN$/bbl)(1)	86.20	88.56	83.79	74.52	65.78	59.10	98.52	108.87
Bitumen sales (CDN$/bbl)	48.73	58.10	51.70	52.08	50.95	21.94	2.63	84.34
Bitumen sales (bbls/d)	24,562	13,447	5,920	2,493	2,136	3,093	2,427	2,312

(1) Cost of diluent is the average inventory value used in blending. The June 2010 average purchase price was $80.36 per barrel.

Results of Operations

Phase 1 operations started on March 20, 2008. Steam was circulated into well pairs to gradually warm up the reservoir in preparation for SAGD production. After two months of circulation, three well pairs were converted to production in late May of 2008. Phase 1 reached designed production capacity of 3,000 bbls/d by the end of 2008.

First steam for Phase 2 was achieved in August 2009 and production has increased to an average of approximately 26,400 bbls/d in the month of June 2010 for the integrated Phase 1 and Phase 2 facilities, exceeding the design capacity of 25,000 bbls/d. As of June 30, 2010 there were 29 well pairs, including the three Phase 1 well pairs, on SAGD production and an additional 2 well pairs were circulating steam. During the first six months of 2010, the Corporation converted 14 well pairs from steam circulation to SAGD production and plans to convert the remaining well pairs currently on steam circulation to SAGD production in the third quarter of 2010. It is anticipated that production volumes may be volatile for several quarters as the Corporation works through the plant reliability issues associated with a new facility.

Steam to oil ratio ("SOR") is an important efficiency indicator. It measures the amount of steam that is injected into the reservoir for each barrel of bitumen produced, the lower the SOR, the more efficient the 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 average SOR for the integrated facilities for the three months ended June 30, 2010 was 2.5 compared to an SOR of 3.1 for the three months ended March 31, 2010.

The 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 all of 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 June 30		Six months ended June 30	
Cash operating netback ($000)	2010	2009	2010	2009
Blend sales[1]	202,061	15,339	324,445	28,617
Cost of diluent[2]	(93,147)	(5,435)	(145,219)	(12,605)
Bitumen sales	108,914	9,904	179,226	16,012
Transportation and other selling costs	(3,273)	(2,967)	(7,027)	(6,423)
Royalties	(4,190)	(176)	(7,292)	(212)
Net bitumen revenue	101,451	6,761	164,907	9,377
Operating costs	(42,022)	(11,255)	(89,236)	(28,069)
Power sales	11,714	-	18,027	-
Cash operating netback[3]	71,143	(4,494)	93,698	(18,692)
Cash operating netback capitalized[4]	-	(4,494)	-	(18,692)
Cash operating netback in statement of operations[4]	71,143	-	93,698	-

	Three months ended June 30		Six months ended June 30	
Production and Sales Volume Summary (bbls/d)	2010	2009	2010	2009
Blend sales[1]	36,436	3,044	28,253	3,739
Diluents[2]	(11,874)	(908)	(9,218)	(1,127)
Bitumen sales	24,562	2,136	19,035	2,612
Decrease in inventory	(150)	-	(100)	-
Total bitumen production	24,412	2,136	18,935	2,612
Power sales (MWh)	149,956	-	313,614	-
Power realization (CDN$/MWh)	78.12	-	57.48	-

	Three months ended June 30		Six months ended June 30	
Cash operating netback ($ per barrel)	2010	2009	2010	2009
Bitumen sales	48.73	50.95	52.02	33.87
Transportation and other selling costs	(1.46)	(15.26)	(2.04)	(13.59)
Royalties	(1.87)	(0.91)	(2.12)	(0.45)
Net bitumen revenue	45.40	34.78	47.86	19.83
Operating costs	(18.80)	(57.90)	(25.90)	(59.37)
Power sales	5.24	-	5.23	-
Netback[3]	31.84	(23.12)	27.19	(39.54)

(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 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 below to "net income (loss)", 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 June 30, 2010 were $108.9 million compared to $9.9 million for the same period in 2009. The increase of $99.0 million is due to higher production volumes resulting from Phase 2 commencing production in October 2009 and higher selling prices. WTI averaged US$78.03 (C$80.19) in the second quarter of 2010 compared to US$59.62 (C$69.59) in the same period of 2009. Blend revenue for the Corporation's Access Western Blend ("AWB"), a blend of bitumen and diluent, averaged $60.94 in the three months ended June 30, 2010.

Bitumen sales in the six months ended June 30, 2010 were $179.2 million compared to $16.0 million for the same period in 2009. The increase of $163.2 million is due to higher production volumes resulting from Phase 2 commencing production in October 2009 and higher selling prices. WTI averaged US$78.37 (C$81.06) in the first six months of 2010 compared to US$51.35 (C$61.62) in the same period of 2009. Blend revenue for the Corporation's AWB, a blend of bitumen and diluent, averaged $63.44 in the first six months of 2010. The Corporation's blend product has sold at a discount to WCS due to lower quantities of AWB being produced, higher TAN (Total Acid Number) and sulphur content in AWB. The discount to WCS has narrowed over the past two years as quantities of AWB have increased and refineries have become more familiar with AWB qualities and yields. Pipeline specifications require product to contain less than 0.5% of basic sediments and water and in the six months ended June 30, 2010 1.5% of the blend product produced did not meet this specification and was sold at a discount.

Power sales for the first six months of 2010 were $18.0 million with a realized price of $57.48 per megawatt hour compared to the Alberta Pool average price of $60.96 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. Beginning in October 2009, surplus power has been sold into the Alberta Power Pool electricity grid.

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 is ramping up production through 2009 and 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 the first six months of 2010 compared to the same period in 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 and expects the volatility to continue through 2010.

	Three months ended June 30		Six months ended June 30	
Reconciliation of operating cash netback to net (loss) income ($000)	2010	2009	2010	2009
Operating cash netback, as above	71,143	(4,494)	93,698	(18,692)
Net operating results capitalized(1)	-	4,494	-	18,692
Interest income	949	515	1,708	1,835
General and administrative	(8,731)	(6,386)	(17,343)	(12,441)
Stock-based compensation	(2,911)	(2,161)	(6,540)	(4,347)
Research and development	(906)	(1,072)	(2,539)	(2,409)
Net foreign exchange (loss) gain	(37,470)	64,877	(14,048)	41,605
Risk management loss	(5,679)	(696)	(12,564)	(4,828)
Interest expense	(11,101)	(558)	(22,315)	(582)
Depreciation, depletion and accretion(1)	(35,592)	(165)	(54,661)	(353)
Income taxes	(1,360)	2,358	2,461	4,647
Net (loss) income	(31,658)	56,712	(32,143)	23,127

(1) *Effective December 1, 2009 the Corporation commenced planned principal operations, ceased capitalizing net operating costs and commenced depletion of oil sands and natural gas properties and equipment.*

Interest Income

For the three months ended June 30, 2010, interest income increased to $0.9 million from $0.5 million for the same period in 2009. The increase was due to higher interest rates in 2010 and an increase in average investment balances. The average yield on three month Bank of Canada treasury bills increased from 0.25% in the three months ended June 30, 2009 to 0.41% in the same period of 2010.

For the six months ended June 30, 2010, interest income decreased to $1.7 million from $1.8 million for the same period in 2009. The decrease was due to lower interest rates in 2010 partially offset by an increase in average investment balances. The average yield on three month Bank of Canada treasury bills declined from 0.45% in the first six months of 2009 to 0.30% in the same period of 2010.

General and administrative costs

	Three months ended June 30		Six months ended June 30	
($000)	2010	2009	2010	2009
G&A Expense	8,731	6,386	17,343	12,441
Capitalized G&A	2,695	2,617	5,160	5,089
Total G&A Costs	11,426	9,003	22,503	17,530

General and administrative costs for the three months ended June 30, 2010 totaled $11.4 million, compared with $9.0 million for the same period in 2009. General and administrative costs for the six months ended June 30, 2010 totaled $22.5 million, compared with $17.5 million for the same period 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 135 as of June 30, 2009 to 163 at June 30, 2010. For the six months ended June 30, 2010 the Corporation capitalized salaries related to capital investment of $5.2 million (2009 – $5.1 million).

Stock-based Compensation

Stock-based compensation for the three months ended June 30, 2010 was $2.9 million compared to $2.2 million for the same period in 2009. Stock-based compensation for the six months ended June 30, 2010 was $6.5 million compared to $4.3 million for the same period in 2009. For the six months ended June 30, 2010 the Corporation capitalized $1.7 million (six months ended June 30, 2009 – $1.5 million) of stock-based compensation to property, plant and equipment.

Effective June 9, 2010, the Corporation's Board of Directors approved the 2010 Option Plan and approved the Restricted Share Unit Plan ("RSU Plan"). The 2010 Option Plan allows for the granting of options to directors, officers or employees and consultants of the Corporation. As at June 30, 2010, no options had been granted under the 2010 Option 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. As at June 30, 2010, no RSUs had been granted under the RSU Plan.

Prior to June 9, 2010, the Corporation issued options to employees and directors under a previous option plan ("2003 Option Plan") and no additional options will be granted under the 2003 Option Plan.

The Corporation recognizes the fair value of compensation associated with granting stock options to employees and directors in its financial statements. Fair value is determined using the Black-Scholes option pricing model. As of June 30, 2010, 12,653,107 options under the 2003 Option Plan and under standalone option agreements that preceded such plan were outstanding with a weighted average exercise price of $20.13 per option.

Research and Development

Research and development expenditures relate to the Corporation's research of greenhouse gas management, upgrading and related technologies and have been expensed. For the three months ended June 30, 2010 research and development expenditures were $0.9 million compared to $1.1 million for the same period in 2009. Research and development expenditures were $2.5 million for the six months ended June 30, 2010 compared to $2.4 million for the same period in 2009.

Foreign Exchange Loss (Gain)

	Three months ended June 30		Six months ended June 30	
($000)	2010	2009	2010	2009
Long-term debt	45,315	(68,740)	14,020	(44,272)
Debt service reserve	(3,247)	3,371	(204)	1,751
US$ denominated cash and cash equivalents	(5,277)	1,211	(140)	1,338
Other	679	(719)	372	(422)
Foreign exchange loss (gain)	37,470	(64,877)	14,048	(41,605)

US$ - Canadian $ exchange rate	June 30, 2010	December 31, 2009	June 30, 2009	December 31, 2008
C$ equivalent of 1 US dollar	1.0606	1.0466	1.1625	1.2246

The net foreign exchange loss for the three and six months ended June 30, 2010 was primarily due to the weakening of the Canadian dollar with respect to US dollar and higher US dollar debt outstanding in 2010. In the second quarter of 2010 the Canadian dollar weakened against the U.S. dollar by $0.05 while in the same period of 2009 it strengthened by $0.10. For the six months ended June 30, 2010 the Canadian dollar weakened against the US dollar by $0.01 while in the same period of 2009 it strengthened by $0.06.

Risk Management

	Three months ended June 30		Six months ended June 30	
($000)	2010	2009	2010	2009
Realized loss on interest rate swaps	8,656	3,953	17,393	7,866
Unrealized fair value gain on interest rate swaps	(8,273)	(5,172)	(15,841)	(6,958)
Amortization of unrealized loss on interest rate swaps from accumulated other comprehensive income	5,296	1,915	11,012	3,920
Total risk management loss	5,679	696	12,564	4,828

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 has hedged, until December 31, 2010, US$700 million of its floating rate debt at an average LIBOR rate of 5.05%. For the three months ended June 30, 2010 the average LIBOR rate was 0.30% compared to 1.22% for the same period in 2009. For the six months ended June 30, 2010 the average LIBOR rate was 0.28% compared to 1.34% for the same period in 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 second quarter of 2010 the fair value of the interest rate swaps decreased $8.3 million compared to $5.2 million for the same period in 2009. For the six months ended June 30, 2010 the fair value of the interest rate swaps decreased by $15.8 million compared to $7.0 million for the same period in 2009. The fair value of the interest rate swaps have declined over the periods noted due to the shorter term to expiry of the contracts.

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 June 30, 2010, there was $9.0 million, before income taxes, remaining in accumulated other comprehensive income related to these swaps which will be amortized into earnings over the remaining term of the contracts.

Interest Expense

	Three months ended June 30		Six months ended June 30	
($000)	2010	2009	2010	2009
Total interest	16,290	11,748	32,543	23,843
Capitalized to property, plant and equipment	(5,189)	(11,190)	(10,228)	(23,261)
Interest expense	11,101	558	22,315	582

Total interest expense in the second quarter of 2010 and the six months ended June 30, 2010 increased compared to the same periods in 2009 primarily as a result of higher outstanding 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 associated with the development of Phase 2B of the Christina Lake Project is being capitalized.

Depletion, Depreciation and Amortization

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 $15.67 per barrel of production. Depletion is based on invested capital to the end of June 2010 and the forecast of future development costs required to develop the current proved reserves. The future development costs and proved reserves are from the December 2009 GLJ reserve report. The $15.67 is comprised of approximately $3.66 of depletion on invested capital, $8.21 of depletion on future development cost in 2010 dollars and $3.80 of depletion on the inflation on the future development costs. Prior to December 2009, there was no depletion and depreciation expense related only to MEG's corporate assets.

Income Taxes

Future income tax expense for the three months ended June 30, 2010 was $1.4 million, an increase of $3.7 million from the same period in 2009. Future income tax recovery for the six months ended June 30, 2010 was $2.5 million, a decrease of $2.2 million from the same period in 2009.

The Corporation's unrealized foreign exchange gains or losses on the translation of its US dollar debt are capital in nature and only 50% of the gain or loss is taxable. At December 31, 2008 the Corporation had $46.5 million of unrealized taxable foreign exchange losses and recognized a valuation allowance against this future tax asset. In 2009 the Corporation reversed this valuation allowance to offset most of the unrealized foreign exchange gains during this period. In the first six months of 2010 there was a $14.0 million unrealized foreign exchange loss and the Corporation has recognized a valuation allowance against this future tax asset.

The Corporation is not currently taxable and as of June 30, 2010, the Corporation had approximately $3.1 billion of available tax pools, comprised of approximately $221.8 million of Canadian development expense, $309.8 million of Canadian exploration expense, $1,477.1 million of non capital losses ($212.6 million expiring in 2026, $253.9 million expiring in 2027, $341.4 million expiring in 2028, $528.7 million expiring in 2029 and $140.6 million expiring in 2030) and $1,080.8 million of other tax pools. In addition, at June 30, 2010 the Corporation had $117.9 million of capital investment in incomplete accounts which will be added to available tax pools upon completion of the projects. As of June 30, 2010, the Corporation had recognized a net future tax liability of $14.6 million.

CAPITAL INVESTING

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

Summary of capital investment ($000)	Three months ended June 30 2010	Three months ended June 30 2009	Six months ended June 30 2010	Six months ended June 30 2009
Christina Lake Project:				
Resource exploration & delineation	1,831	837	22,867	4,438
Horizontal drilling	-	1,205	-	2,001
Facilities, procurement & construction	45,470	71,259	89,779	163,936
Other	2,260	311	2,605	1,131
Total Christina Lake Project	49,561	73,612	115,251	171,506
Surmont and Growth Properties	560	63	12,236	1,111
Land and other acquisitions	97,366	22	97,366	136
Capitalized interest and fees	4,654	10,572	9,260	22,041
Other	4,422	5,738	12,934	18,501
Total cash investments	156,563	90,007	247,047	213,295
Non-cash	1,815	1,557	3,140	3,149
Total capital investment	158,378	91,564	250,187	216,444

During the first six months ended June 30, 2010, the Corporation invested cash totaling $247.1 million compared with $213.3 million in the same period in 2009. Capital investment in the first six months of 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 six months ended June 30, 2010 the Corporation drilled 65 core holes and 6 observation wells to assist in the determination of Phase 2B horizontal wells placement and further delineation of the Christina Lake lands. Facilities investment in the first six months of 2010 was directed towards maintenance and reliability of the Phase 2 facility, installation of electric submersible pumps, Phase 2B detailed engineering and commencing the purchase of major equipment for the Phase 2B expansion. The Corporation anticipates the completion of the authorization for expenditure estimate for the expansion in late 2010 for board approval.

Management determined that the Corporation is no longer in the pre-production stage and effective December 1, 2009 planned principal operations 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 six months ended June 30, 2009 totaled $18.7 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 $10.4 million during the first six months of 2010 to drill 24 core holes in the Growth Properties to increase the resource definition and to drill a water source well in Surmont.

Land and Other Acquisitions

During the second quarter of 2010 the Corporation invested $42.5 million to purchase lands and assets associated with a tank farm construction project east of the Access Pipeline Sturgeon Terminal. Once construction of the tank farm 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.

Capitalized Interest and Fees

The Corporation capitalizes interest expense and amortization of deferred finance charges for undeveloped property acquisitions and major development projects. Interest associated with the development of Phase 2B is being capitalized commencing December 1, 2009. During the six months ended June 30, 2010 the Corporation capitalized $9.3 million of interest and fees (six months ended June 30, 2009 - $22.0 million). Capitalization of interest for Phase 1 and 2 was discontinued effective December 1, 2009 due to the commencement of planned principal operations.

Other

Other costs include the costs to maintain the right to participate in a potential pipeline project, capitalized salaries and consulting costs and investment in tangible assets for the Corporation's offices.

Non-Cash

The composition of the non-cash investment is summarized in the following table:

	Three months ended June 30		Six months ended June 30	
Summary of non-cash capital investment ($000)	2010	2009	2010	2009
Financing transaction costs	535	619	969	1,221
Stock based compensation	805	699	1,696	1,470
Asset retirement obligation	475	239	475	458
Total non-cash investments	1,815	1,557	3,140	3,149

SHARES OUTSTANDING

As at August 9, 2010, the Corporation had 189,255,970 common shares outstanding and 12,607,857 options outstanding. The Corporation has reserved 18,925,597 common shares (10% of the outstanding common shares subject to certain restrictions) for issuance pursuant to options granted under the 2010 Option Plan less the number of common shares issuable pursuant to all other security-based compensation arrangements of the Corporation. No additional options under the 2003 Option Plan will be granted.

OUTLOOK FOR 2010

MEG is utilizing a phased approach to development of its Christina Lake Project. Phases 1 and 2 are complete and currently operating. The Corporation anticipated volatility in operating results with the start up of Phase 2 and cautions the volatility could continue through 2010. The Corporation's 2010 capital budget of $439 million was increased to $629 million on June 9, 2010. The 2010 budget will be directed towards detailed engineering and major equipment purchases for Phase 2B, maintenance and reliability capital for the Phase 2 facility, and continued resource definition of Christina Lake, Surmont and Growth Properties. The construction of Phase 2B is subject to the approval of the board of directors. Included in the revised 2010 capital investment was the $42.4 million to purchase lands and assets associated with a tank farm construction project east of the Access Pipeline Sturgeon Terminal and $54.9 million to acquire undeveloped oil sands leases in the Surmont area.

LIQUIDITY AND CAPITAL RESOURCES

Historically, the Corporation has used the net cash generated from its debt and equity financing activities to fund the net operating expenses and the capital investments related to seismic and drilling, expanding the resource base through the acquisition of additional oil sands properties, developing the Christina Lake Project and constructing the Access Pipeline.

The Corporation believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the 2010 capital program and the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not become necessary.

In addition to funding the capital investments described above, the Corporation anticipates that it will be required to maintain existing letters of credit and provide further letters of credit to support its operational and marketing activities. As at June 30, 2010 the Corporation has utilized US$7.9 million of its US$185.0 million revolving credit facility to support letters of credit.

As of June 30, 2010, the Corporation's capital resources included $780.6 million of working capital, excluding risk management and debt service reserve. Working capital is comprised of $766.2 million of cash and short-term investments and non-cash working capital of $14.4 million made up of accounts receivable and inventories less accounts payable and accrued liabilities. The US$46.3 million debt service reserve is to fund principal and interest payments on the amended senior secured credit facility until December 31, 2010.

On August 6, 2010, the Corporation completed its initial public offering and received estimated net proceeds of approximately $661.8 million. (For further details, see the section "Subsequent Events").

Other assets include $13.4 million of floating rate notes received on the restructuring of Canadian non-bank commercial paper and US$3.2 million of US Auction Rated Securities ("ARS"). The ARS were previously held in the Corporation's debt service reserve account and could not be liquidated due to the breakdown of the ARS market. Due to the illiquidity of these assets the Corporation has classified them as a long-term investment. The investments are recorded at fair value determined on a discounted cash flow valuation using observable information regarding the timing of payments and the credit rating of the securities. These investments are classified as held-for-trading which requires them to be measured at fair value at each period end with changes in fair value included in the consolidated statement of operations in the period in which they arise. In May 2009 the Corporation received a $1.0 million payment on these notes and has applied it against the estimated amounts to be recovered. As at June 30, 2010 an impairment provision of $7.9 million has been recorded on the floating rate notes and ARS investments.

The Corporation's cash and cash equivalents are held in accounts managed by third party financial institutions and consist of invested cash and cash in the Corporation's operating accounts. The invested cash is invested in high grade liquid short term debt such as commercial and bank paper. To date, the Corporation has experienced no loss or lack of access to its cash in operating accounts, invested cash or cash equivalents other than the investment in the restructured floating rate notes and the ARS that were held in the debt service reserve. However, the Corporation can provide no assurance that access to its invested cash and cash equivalents will not be impacted by adverse conditions in the financial markets. While the Corporation monitors daily the cash balances in its operating accounts and adjusts the cash balances as appropriate, these cash balances could be impacted if the underlying financial institutions or corporations fail or are subject to other adverse conditions in the financial markets.

Cash Flows Summary

	Three months ended June 30		Six months ended June 30	
($000)	2010	2009	2010	2009
Net cash provided by (used in)				
Operating activities	40,759	(8,301)	(9,768)	(12,830)
Investing activities	(131,142)	(106,372)	(182,643)	(210,596)
Financing activities	(2,146)	262,293	(4,588)	261,121
Foreign exchange losses on cash and cash equivalents held in foreign currency	5,278	(1,208)	141	(1,336)
Increase (decrease) in cash and cash equivalents	(87,251)	146,412	(196,858)	36,359

Operating Activities

The Corporation was considered to be a development stage company prior to December 1, 2009 as cash flows were primarily comprised of financing activities net of investment made in the Corporation's development. The completion of Phase 2 and the ramp-up of bitumen production volumes and associated revenues have resulted in management determining that planned principal operations have commenced effective December 1, 2009. Cash provided by or used in operations after this date also includes product and power sales net of operating expenses.

Investing Activities

Net cash used for investing activities in the six months ended June 30, 2010 decreased $28.0 million compared to the same six month period in 2009. Capital investments in the six months ended June 30, 2010 decreased $33.7 million compared to the same period in 2009. Refer to the "Capital Investing" section of this MD&A for further details.

Financing Activities

Financing activities during the periods noted above consists of principal payments on the Corporation's long term debt and proceeds received from the exercise of stock options. In the first six months of 2009 the Corporation also exercised its rights under a standby purchase agreement with WP X LuxCo S.a.r.l. ("WPX Luxco") that required them to purchase 10,416,666 common shares at a price of $24.00 per share for an aggregate purchase price of approximately $250.0 million. In consideration for the standby commitment, the Corporation paid WPX Luxco a fee equal to 7.5% of the standby commitment upon exercise of the Corporation's rights. Refer to the "Transactions with Related Parties" section of this MD&A for further details.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

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

($ 000)	Total	< 1 year	1 – 3 years	4 - 5 years	More than 5 years
Long-term debt[(1)]	1,065,343	10,734	21,357	63,552	969,700
Interest on long-term debt[(1)]	360,285	62,156	144,107	96,071	57,951
Asset retirement obligation[(2)]	82,451	181	-	663	81,607
Contracts and purchase orders[(3)]	306,432	268,147	34,134	3,489	662
Operating leases[(4)]	47,417	3,595	8,938	8,940	25,944
Other commitments[(5)]	3,000	3,000	-	-	-
	1,864,928	347,813	208,536	172,715	1,135,864

(1) This represents the scheduled principal repayment of the senior secured credit facility and associated interest payments based on interest rates in effect on June 30, 2010.

(2) This represents the undiscounted obligation associated with the retirement of oil and gas properties.

(3) This represents the future commitments associated with the construction of the Christina Lake Project Phase 2 facility, capital equipment maintenance and purchases, diluent purchases and horizontal well drilling rig.

(4) This represents the future commitments for the Calgary corporate office space.

(5) The Corporation has committed to pay $3.0 million for the right to participate in a potential pipeline project.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's unaudited consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2009. The critical accounting estimates remain unchanged from those disclosed in the 2009 annual consolidated financial statements.

TRANSACTIONS WITH RELATED PARTIES

For the six months ended June 30, 2010 the Corporation did not have any related party transactions. In 2009 the Corporation had the following transactions with related parties:

- The Corporation entered into two standby purchase agreements with WPX Luxco, an affiliate of Warburg Pincus LLC, a New York limited liability company ("WP LLC"), which manages various entities that indirectly own entities that legally and/or beneficially own more than 20% of the common shares and which has nominated three members of the Board. Pursuant to the agreements, provided that certain conditions were met, the Corporation had the right to require WPX Luxco to purchase up to an aggregate of 13,246,398 common shares at a price of $24.00 per share for an aggregate purchase price of approximately $317.9 million. In consideration for each standby commitment, the Corporation agreed to pay WPX Luxco a fee equal to 7.5% of the standby commitment upon exercise of the Corporation's rights. The transactions were not considered to be in the normal course of operations and were measured at the exchange amount based on a $24.00 price per share. The Corporation exercised its rights under the standby purchase agreements, and thereby received gross proceeds of $317.9 million and paid WPX Luxco fees totaling $23.8 million, equal to 7.5% of the commitments. As additional consideration for the first standby commitment, the Corporation entered into the Investor Rights Agreement between MEG and WPX Luxco dated May 15, 2009.

- The Corporation entered into two standby purchase agreements with CNOOC Belgium BVBA ("CNOOC"), a shareholder of the Corporation, and which has nominated a member of the Board. Pursuant to the agreements, provided that certain conditions were met, the Corporation had the right to require CNOOC to purchase up to an aggregate of 11,461,933 common shares at a price of $24.00 per share for an aggregate purchase price of approximately $275.1 million. In consideration for each standby commitment, the Corporation agreed to pay CNOOC a fee equal to 7.5% of the standby commitment upon exercise of the Corporation's rights. The transactions were not considered to be in the normal course of operations and were measured at the exchange amount based on a $24.00 price per share. The Corporation exercised its rights under the standby purchase agreements, and thereby received gross proceeds of $275.1 million and paid CNOOC fees totaling $20.6 million, equal to 7.5% of the commitments.

These transactions were entered into in order to provide funding for the Corporation's capital program.

OFF-BALANCE SHEET ARRANGEMENTS

At June 30, 2010 and December 31, 2009, the Corporation did not have any off-balance sheet arrangements.

NEW ACCOUNTING POLICIES

There are no new accounting policies for the Corporation in the six months ended June 30, 2010.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards ("IFRS")

In February 2008, the Canadian Accounting Standards Board confirmed that the use of IFRS will be required for interim and annual financial statements of publicly accountable enterprises effective for fiscal years beginning on or after January 1, 2011. The Corporation has established a project plan and timeline for the implementation of IFRS which consists of three phases; initiation, detailed assessment and design and implementation.

The Corporation has completed the initiation phase which involved the completion of a high level review of the major differences between current Canadian GAAP and IFRS, the development of a timeline for addressing these differences in subsequent phases and an initial assessment of the impact on the Corporation's financial systems. Discussions with the Corporation's external auditors have commenced and will continue throughout the subsequent phases. Regular reporting is provided to the Corporation's Audit Committee of the Board of Directors. The Corporation has determined that the most significant impacts of IFRS conversion will be the following:

Property, Plant and Equipment ("PP&E")

IFRS does not prescribe specific oil and gas accounting guidance other than for costs associated with the exploration and evaluation phase. The Corporation currently follows full cost accounting as prescribed by Canadian GAAP and has identified the following significant differences; the treatment of pre-exploration costs, exploration and evaluation costs and depletion, depreciation and amortization

Pre-exploration costs are costs incurred before the Corporation obtains the legal right to explore an area. Under Canadian GAAP, these costs are capitalized, while under IFRS, these costs must be expensed. At this time, it is not anticipated that this accounting policy difference will have a significant impact on the consolidated financial statements.

During the exploration and evaluation phase ("E&E"), the Corporation capitalizes costs incurred for these projects under Canadian GAAP. Under IFRS, the Corporation has the alternative to either continue capitalizing these costs until technical feasibility and commercial viability of the project has been determined, or expensing these costs as incurred. The Corporation anticipates that it will capitalize these costs until technical feasibility and commercial viability of the project has been determined. If technically feasible and commercially viable reserves are not established for a new area, the costs must be expensed.

Canadian GAAP prescribes that PP&E for producing oil and gas properties are depleted on a unit-of-production method using remaining proved reserves. The requirement to use proved reserves does not exist under IFRS and the Corporation is evaluating whether depletion based on proved and probable reserves more accurately reflects the usage of the properties economic benefits.

IFRS 1 "First-time Adoption of International Financial Reporting Standards" includes a transition exemption for oil and gas companies following full cost accounting under their previous GAAP. The transition exemption allows full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes without requiring retroactive adjustment. The Corporation is not planning on adopting this exemption and will continue to measure PP&E at cost.

Impairment of Assets

Canadian GAAP generally uses a two-step approach to impairment testing: first comparing asset carrying values with undiscounted future cash flows to determine whether impairment exists; and then measuring any impairment by comparing asset carrying values with fair values. International Accounting Standard ("IAS") 36, "Impairment of Assets", uses a one-step approach for both testing for and measurement of impairment, with asset carrying values compared directly with the higher of fair value less costs to sell and value in use (which uses discounted future cash flows). This may result in more write-downs where carrying values of assets were previously supported under Canadian GAAP on an undiscounted cash flow basis, but could not be supported on a discounted cash flow basis.

However, an impairment loss is reversed if there has been an increase in the estimated recoverable amount of a previously impaired asset. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or depletion, if no impairment loss had been recognized. Canadian GAAP prohibits reversal of impairment losses. The impact of this change has not been determined.

Provisions (Including Asset Retirement Obligations)

IAS 37, "Provisions, Contingent Liabilities and Contingent Assets", requires a provision to be discounted using a current pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The timing and amount of future expenditures are reviewed regularly, together with the interest rate used in discounting the cash flows and the carrying amount of the provision is adjusted accordingly. Under Canadian GAAP a provision previously recognized is not revised for subsequent changes in interest rates. Also, for those provisions that are required to be discounted there is a difference in the rate applied as Canadian GAAP uses a credit-adjusted risk free rate while IAS 37 does not specify the use of a credit-adjusted risk free rate. The Corporation does not anticipate that this accounting policy difference will have a significant impact on the consolidated financial statements.

Income Taxes

IAS 12, "Income Taxes", does not recognize a deferred tax liability/asset if it arises from initial recognition of an asset or liability outside a business combination and there is no impact in profit or loss at the time of the transaction. Also, the income tax balances will be directly impacted by tax effects resulting from the changes required by some of the above IFRS accounting policy differences. The impact of these changes has not been determined.

The Corporation is currently engaged in the detailed assessment and design phase of the project. The detailed assessment and design phase involves completing a comprehensive analysis of the impact of the IFRS differences identified in the initial scoping assessment. In addition, an initial evaluation of IFRS 1 "First-Time Adoption of International Financial Reporting Standards" which provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions, in certain areas, to the general requirement for full retrospective application of IFRS has been performed. The Corporation is analyzing the various accounting policy choices available and will implement those determined to be most appropriate in our circumstances. The Corporation has substantially completed the detailed assessment and design phase of the project and has commenced working on the IFRS opening balance sheet.

In conjunction with the detailed assessment and design phase of the project the Corporation completed an assessment of its information systems and based on this review does not expect any significant changes to the information systems to be required as part of the IFRS conversion process. In addition, the Corporation assessed its initial IFRS training requirements and training of key finance staff involved in the IFRS conversion process was delivered in 2009. Further training requirements for other members of the Corporation will be assessed during the implementation phase of the project.

During the implementation phase, the Corporation will implement the required changes in business processes, accounting policies and internal controls over financial reporting. All necessary changes in business processes, accounting policies and internal controls identified during the implementation phase will be implemented during the fourth quarter of 2010 and will be in place as of January 1, 2011.

RISK FACTORS

The Corporation's primary focus is on the ongoing development and operation of its oil sands assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including the risks which have been described in the MD&A for the year ended December 31, 2009.

For additional information regarding the risks and uncertainties to which the Corporation and its business are subject, please see information under the headings "Forward-looking Statements" and "Risk Factors" in the Corporation's prospectus dated July 28, 2010, which is available on the SEDAR website at www.sedar.com.

SUBSEQUENT EVENTS

On August 6, 2010, pursuant to an underwriting agreement and a prospectus each dated July 28, 2010, the Corporation completed its initial public offering (the "IPO") and issued 20,000,000 common shares to the public for estimated proceeds of approximately $661.8 million, net of commissions and other estimated costs relating to the issue aggregating approximately $38.2 million. The Corporation has also granted an over-allotment option to the underwriters of the IPO, for the issue of up to an additional 3,000,000 common shares exercisable within 30 days from the date of closing of the public financing.

ADDITIONAL INFORMATION

Additional information relating to MEG Energy Corp. is available on SEDAR at www.sedar.com.

MEG ENERGY CORP.
Consolidated Balance Sheet

($ 000s, unaudited)	As at June 30, 2010	As at December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 766,160	$ 963,018
Accounts receivable and other (note 2)	86,987	33,662
Inventories	5,967	5,560
Debt service reserve (note 3)	49,152	102,359
	908,266	1,104,599
Restricted cash (note 4)	-	12,810
Other assets (note 5)	7,730	7,743
Property, plant and equipment (note 6)	3,340,459	3,144,341
	$ 4,256,455	$ 4,269,493
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued payables	$ 78,577	$ 71,842
Risk management liability (note 10)	16,830	32,671
Current portion of long-term debt (note 8)	10,734	10,593
	106,141	115,106
Long-term debt (note 8)	1,039,386	1,029,687
Asset retirement obligations (note 7)	15,235	14,297
Future income tax liability	14,557	14,290
Commitments and contingencies (note 12)		
Shareholders' equity:		
Share capital (note 9)	3,138,598	3,137,696
Contributed surplus (note 9)	63,846	55,841
Deficit	(114,536)	(82,393)
Accumulated other comprehensive loss	(6,772)	(15,031)
	3,081,136	3,096,113
	$ 4,256,455	$ 4,269,493

See accompanying notes to consolidated financial statements.

MEG ENERGY CORP.
Consolidated Statement of Operations and Deficit

	Three months ended June 30		Six months ended June 30	
($ 000s except per share amounts, unaudited)	2010	2009	2010	2009
Revenue:				
Petroleum sales	$ 202,061	$ -	$ 324,445	$ -
Royalties	(4,190)	-	(7,292)	-
Power sales	11,714	-	18,027	-
Interest	949	515	1,708	1,835
	210,534	515	336,888	1,835
Operating expenses:				
Operating costs	42,022	-	89,236	-
Cost of diluent	93,147	-	145,219	-
Transportation and selling costs	3,273	-	7,027	-
General and administrative	8,731	6,386	17,343	12,441
Stock-based compensation (note 9)	2,911	2,161	6,540	4,347
Research and development	906	1,072	2,539	2,409
Interest expense	11,101	558	22,315	582
Depletion, depreciation and accretion (notes 6 and 7)	35,592	165	54,661	353
	197,683	10,342	344,880	20,132
Revenue less operating expenses	12,851	(9,827)	(7,992)	(18,297)
Other (gain) loss:				
Foreign exchange (gain) loss, net	37,470	(64,877)	14,048	(41,605)
Risk management loss (note 10)	5,679	696	12,564	4,828
	43,149	(64,181)	26,612	(36,777)
(Loss) income before income taxes	(30,298)	54,354	(34,604)	18,480
Future income tax expense (recovery)	1,360	(2,358)	(2,461)	(4,647)
Net (loss) income	(31,658)	56,712	(32,143)	23,127
Deficit, beginning of period	(82,878)	(167,154)	(82,393)	(133,569)
Deficit, end of period	$ (114,536)	$ (110,442)	$ (114,536)	$ (110,442)
Earnings per share (note 11)				
Basic	$ (0.19)	$ 0.41	$ (0.19)	$ 0.17
Diluted	$ (0.19)	$ 0.40	$ (0.19)	$ 0.17

See accompanying notes to consolidated financial statements.

MEG ENERGY CORP.

Consolidated Statement of Other Comprehensive Income (Loss)

		Three months ended June 30				Six months ended June 30		
($ 000s, unaudited)		2010		2009		2010		2009
Net (loss) income	$	(31,658)	$	56,712	$	(32,143)	$	23,127
Other comprehensive income, net of tax								
Gains (losses) on cash flow hedges (note 10)								
Unrealized gain (loss) on derivatives designated as cash flow hedges, net of taxes[1]		-		915		-		(681)
Realized gain on derivatives designated as cash flow hedges capitalized, net of taxes[2]		-		2,965		-		5,900
Amortization of balance in AOCI[3]		3,973		1,436		8,259		2,940
Other comprehensive income		3,973		5,316		8,259		8,159
Total comprehensive (loss) income	$	(27,685)	$	62,028	$	(23,884)	$	31,286

Consolidated Statement of Accumulated Other Comprehensive Loss

		Three months ended June 30				Six months ended June 30		
($ 000s, unaudited)		2010		2009		2010		2009
Balance, beginning of period	$	(10,745)	$	(28,639)	$	(15,031)	$	(31,482)
Other comprehensive income, net of tax		3,973		5,316		8,259		8,159
Balance, end of period	$	(6,772)	$	(23,323)	$	(6,772)	$	(23,323)

(1) Net income tax expense, three months ended June 30, 2010 – nil, six months ended June 30, 2010 -nil (three months ended June 30, 2009 – $304 expense, six months ended June 30, 2009 - $227 benefit)

(2) Net income tax expense, three months ended June 30, 2010 – nil, six months ended June 30, 2010 - nil (three months ended June 30, 2009 – $988, six months ended June 30, 2009 - $1,967)

(3) Net income tax expense, three months ended June 30, 2010 - $1,324, six months ended June 30, 2010 – $2,753 (three months ended June 30, 2009 – $479, six months ended June 30, 2009 - $980)

See accompanying notes to consolidated financial statements.

MEG ENERGY CORP.
Consolidated Statement of Cash Flows

	Three months ended June 30		Six months ended June 30	
($ 000s, unaudited)	2010	2009	2010	2009
Cash provided by (used in):				
Operations:				
Net (loss) income	$ (31,658)	$ 56,712	$ (32,143)	$ 23,127
Items not involving cash:				
Stock-based compensation	2,911	2,161	6,540	4,347
Depletion, depreciation and accretion	35,592	165	54,661	353
Other	53	98	88	98
Unrealized net (gain) loss on foreign exchange	40,038	(67,533)	13,879	(42,937)
Unrealized gain on risk management	(2,977)	(3,257)	(4,829)	(3,038)
Future income tax expense (recovery)	1,360	(2,358)	(2,461)	(4,647)
Net change in non-cash operating working capital items (note 11)	(4,560)	5,711	(45,503)	9,867
	40,759	(8,301)	(9,768)	(12,830)
Investing:				
Purchase of property, plant and equipment	(156,563)	(90,007)	(247,047)	(213,295)
Changes in debt service reserve	24,085	15,738	53,207	27,932
Decrease (increase) in restricted cash (note 4)	12,810	(15,898)	12,810	(15,898)
Other	(234)	993	(118)	993
Net change in non-cash investing working capital items (note 11)	(11,240)	(17,198)	(1,495)	(10,328)
	(131,142)	(106,372)	(182,643)	(210,596)
Financing:				
Issue of shares	537	230,292	646	231,324
Issue of long-term debt	-	34,033	-	34,033
Repayment of long-term debt (note 8)	(2,683)	(2,032)	(5,234)	(4,236)
	(2,146)	262,293	(4,588)	261,121
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	5,278	(1,208)	141	(1,336)
(Decrease) increase in cash and cash equivalents	(87,251)	146,412	(196,858)	36,359
Cash and cash equivalents, beginning of period	853,411	131,093	963,018	241,146
Cash and cash equivalents, end of period (note 11)	$ 766,160	$ 277,505	$ 766,160	$ 277,505

See accompanying notes to consolidated financial statements.

MEG Energy Corp. (the "Corporation") was incorporated under the Alberta Business Corporations Act on March 9, 1999. 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 in the Corporation's annual report for the year ended December 31, 2009.

2. ACCOUNTS RECEIVABLE AND OTHER:

		June 30, 2010		December 31, 2009
Accounts receivable	$	85,659	$	28,524
Deposits and advances		1,328		5,138
	$	86,987	$	33,662

3. DEBT SERVICE RESERVE:

On December 23, 2009, as part of the modifications to the Corporation's senior secured credit facilities (note 8) the Corporation placed US$97.8 million in the debt service reserve to fund principal and interest payments through December 31, 2010. Investments are held in a US dollar debt service account and are comprised of high grade liquid short-term debt such as commercial, government, and bank paper.

The US dollar denominated debt service account is translated into Canadian dollars at the period end exchange rate. The foreign exchange gain on the restricted investments was $3.2 million for the three months ended June 30, 2010 and $0.2 million for the six months ended June 30, 2010 (three months ended June 30, 2009 – $3.4 million loss, six months ended June 30, 2009 - $1.8 million loss), and has been recognized in operations through foreign exchange.

4. RESTRICTED CASH:

Restricted cash consists of cash on deposit which collateralizes letters of credit issued by the Corporation. Prior to June 30, 2010, US$28.2 million was held as collateral for the issuance of letters of credit in a US dollar denominated cash collateral account. During the three months ended June 30, 2010, the $12.8 million in 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 8).

5. OTHER ASSETS:

		June 30, 2010		December 31, 2009
MAV Notes (formerly asset-backed commercial paper)	$	4,708	$	4,769
US Auction Rate Securities		3,022		2,974
	$	7,730	$	7,743

6. PROPERTY, PLANT AND EQUIPMENT:

June 30, 2010		Cost		Accumulated depletion and depreciation		Net book value
Oil sands and natural gas properties and equipment	$	3,393,391	$	56,968	$	3,336,423
Corporate assets		5,895		1,859		4,036
	$	3,399,286	$	58,827	$	3,340,459
December 31, 2009						
Oil sands and natural gas 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 and natural gas 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 June 30, 2010 was $1,332.6 million (December 31, 2009 - $1,194.6 million).

During the six months ended June 30, 2010 the Corporation capitalized $5.2 million (June 30, 2009 - $5.1 million) of general and administrative expenses, $1.7 million (June 30, 2009 – $1.5 million) of stock-based compensation costs and $10.2 million (June 30, 2009 - $23.3 million) of interest and debt service costs relating to oil sands exploration and development activities.

7. ASSET RETIREMENT OBLIGATIONS:

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

		June 30, 2010		December 31, 2009
Asset retirement obligation, beginning of period	$	14,297	$	12,907
Changes in estimated future cash flows		475		-
Liabilities incurred		-		570
Liabilities settled		(130)		(75)
Accretion		593		895
Asset retirement obligation, end of period	$	15,235	$	14,297

The estimated future undiscounted asset retirement obligation is $82.5 million (December 31, 2009 - $80.2 million), which has been discounted using an average credit-adjusted risk free rate of 6.26%. This obligation is estimated to be settled in periods up to 2057.

8. LONG-TERM DEBT:

		June 30, 2010		December 31, 2009
Senior secured term loan B (US$41.7 million; 2009-US$41.9 million)	$	44,200	$	43,836
Senior secured term loan D (US$962.8 million; 2009-US$967.6 million)		1,021,142		1,012,741
Financing transaction costs		(15,222)		(16,297)
		1,050,120		1,040,280
Less current portion of senior secured term loan B		(445)		(439)
Less current portion of senior secured term loan D		(10,289)		(10,154)
	$	1,039,386	$	1,029,687

The Corporation's senior secured credit facilities are comprised of US$1,012.1 million in term loans and a three year US$185.0 million revolving credit facility. The term loans are comprised of the US$42.0 million term loan B which matures on April 3, 2013 and the US$970.1 million term loan D which 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 June 30, 2010, $8.3 million of the revolving credit facility was utilized to support letters of credit. Under the terms of the credit facility agreement $102.4 million was deposited in the debt service reserve account on December 31, 2009 and is being used to fund required principal and interest payments on the senior secured credit facilities through December 31, 2010. The US dollar denominated debt is translated into Canadian dollars at the period end exchange rate of $1 CAD = $1.0606 US (December 31, 2009 – $1 CAD = $1.0466 US).

9. SHARE CAPITAL:

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

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

	Six months ended June 30, 2010			Year ended December 31, 2009		
	Number of shares		Amount	Number of shares		Amount
Balance, beginning of period	169,130,053	$	3,137,696	128,123,287	$	2,243,618
Stock options exercised	100,917		977	341,017		2,387
Shares issued for cash	-		-	40,665,749		975,978
Share issue costs, net of taxes of $25 (2009 – $3,698)			(75)			(84,287)
Balance, end of period	169,230,970	$	3,138,598	169,130,053	$	3,137,696

During the six months ended June 30, 2010, 100,917 options were exercised at a weighted average price of $7.40 per share.

(c) Stock options:

Effective June 9, 2010, the Corporation's Board of Directors approved the 2010 Option Plan as a replacement for the Corporation's existing stock option plan ("2003 Option Plan") and also approved the Restricted Share Unit Plan ("RSU Plan"). The 2010 Option Plan allows for the granting of New Options to directors, officers or employees and consultants of the Corporation. As at June 30, 2010, no New Options had been granted under the 2010 Option 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. As at June 30, 2010, no RSUs had been granted under the RSU Plan.

Prior to June 9, 2010, the Corporation issued options to employees and directors under the 2003 Option Plan. No additional options under the 2003 Option Plan will be granted. The Corporation has reserved 18,925,597 common shares (10% of the outstanding common shares subject to certain restrictions) for issuance pursuant to options granted under the 2010 Option Plan.

2003 Option Plan	June 30, 2010		December 31, 2009	
	Options	Weighted average exercise price per share	Options	Weighted average exercise price per share
Balance, beginning of period	12,609,407	$ 19.89	10,892,674	$ 18.86
Granted	237,000	30.82	2,206,500	24.00
Forfeited	(92,383)	27.48	(148,750)	38.24
Exercised	(100,917)	7.40	(341,017)	5.65
Balance, end of period	12,653,107	$ 20.13	12,609,407	$ 19.89

(d) Contributed Surplus:

	June 30, 2010	December 31, 2009
Balance, beginning of period	$ 55,841	$ 39,614
Stock based compensation - expensed	6,540	12,912
Stock based compensation - capitalized	1,696	3,775
Stock options exercised	(231)	(460)
Balance, end of period	$ 63,846	$ 55,841

10. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT:

The financial instruments recognized in the balance sheet are comprised of cash and cash equivalents, 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, 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 June 30, 2010 the estimated fair value of long-term debt was $966.1 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 has entered into interest rate swap contracts to fix the interest rate on US$700 million of the US$1,004.5 million total debt. At June 30, 2010 the Corporation had the following interest rate swap contracts outstanding:

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

[1] London Interbank Offered Rate

The Corporation has two counterparties to the interest rate swap contracts which the Corporation had designated as cash flow hedges and they are recorded at fair value. The effective portion of the change in fair value was recognized in Other Comprehensive Income. Any gain or loss in fair value relating to the ineffective portion is recognized immediately in the statement of income. Effective October 1, 2008 the Corporation discontinued applying hedge accounting to the interest rate swap contracts held by one of the counterparties as they filed for bankruptcy protection and the requirements to apply hedge accounting were no longer met. As a result, the change in the fair value of the related contracts from October 1, 2008 is recognized in earnings. As at June 30, 2010 $1.2 million after-tax (December 31, 2009 - $2.9 million) remains in accumulated other comprehensive income related to these swaps which will be amortized into earnings over the remaining term of the contracts.

Effective December 23, 2009 the Corporation discontinued applying hedge accounting to the remaining interest rate swap contracts. Amendments made to the Corporation's senior secured credit facility resulted in the hedge no longer being effective and the Corporation has elected to discontinue applying hedge accounting to the swaps. As a result, the change in the fair value of the related contracts from December 23, 2009 onward has been recognized in earnings. As at June 30, 2010 $5.6 million after-tax (December 31, 2009 - $12.1 million) remains in accumulated other comprehensive income related to these swaps which will be amortized into earnings over the remaining term of the contracts.

	June 30, 2010	December 31, 2009
Risk management liability, beginning of period	$ 32,671	$ 61,683
Decrease in liability fair value recognized in earnings	(15,841)	(14,753)
Decrease in liability fair value recognized in OCI	-	(14,259)
Risk management liability, end of period	$ 16,830	$ 32,671

Risk management expense	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Realized loss on interest rate swaps	$ 8,656	$ 3,953	$ 17,393	$ 7,866
Unrealized fair value gain on interest rate swaps	(8,273)	(5,172)	(15,841)	(6,958)
Amortization of unrealized loss on interest rate swaps from AOCI	5,296	1,915	11,012	3,920
	$ 5,679	$ 696	$ 12,564	$ 4,828

11. SUPPLEMENTARY INFORMATION:

(a) Supplemental cash flow disclosures:

	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Changes in non-cash working capital items:				
Accounts receivable and other	$ (14,008)	$ 11,646	$ (53,325)	$ (7,726)
Inventories	6,632	(5,495)	(407)	(3,224)
Accounts payable	(8,424)	(17,638)	6,734	10,489
	(15,800)	(11,487)	(46,998)	(461)
Changes in non-cash working capital relating to:				
Operations	$ (4,560)	$ 5,711	$ (45,503)	$ 9,867
Investing	(11,240)	(17,198)	(1,495)	(10,328)
	(15,800)	(11,487)	(46,998)	(461)
Cash and cash equivalents:				
Cash			$ 38,939	$ 33,592
Short-term investments			727,221	243,913
			$ 766,160	$ 277,505

(b) Per share amounts:

	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Weighted average common shares outstanding	169,208,355	137,023,448	169,180,727	132,624,672
Dilutive effect of stock options	-	4,715,111	-	4,755,134
Weighted average common shares outstanding – diluted	169,208,355	141,738,559	169,180,727	137,379,806

The Corporation's stock options outstanding were anti-dilutive to the earnings per share calculation for the three and six months ended June 30, 2010.

12. COMMITMENTS AND CONTINGENCIES:

(a) Commitments

The Corporation had the following commitments as at June 30, 2010.

Operating:

	2010	2011	2012	2013	2014	Thereafter
Office lease rentals	$ 1,361	$ 4,469	$ 4,469	$ 4,469	$ 4,469	$ 28,180
Diluent purchases	174,515	75,181	-	-	-	-
Other commitments	5,456	523	528	534	28	-
Annual commitments	$ 181,332	$ 80,173	$ 4,997	$ 5,003	$ 4,497	$ 28,180

Capital:

As part of normal operations, the Corporation has entered into a total of $52.7 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.

13. COMPARATIVE FIGURES:

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

14. SUBSEQUENT EVENTS:

On August 6, 2010, pursuant to an underwriting agreement and a prospectus each dated July 28, 2010, the Corporation completed its initial public offering (the "IPO") and issued 20,000,000 common shares to the public for estimated proceeds of approximately $661.8 million, net of commissions and other estimated costs relating to the issue aggregating approximately $38.2 million. The Corporation has also granted an over-allotment option to the underwriters of the IPO, for the issue of up to an additional 3,000,000 common shares exercisable within 30 days from the date of closing of the public financing.