

Anderson Energy Announces 2010 First Quarter Results

Calgary, Alberta, May 13, 2010 - Anderson Energy Ltd. ("Anderson Energy" or the "Company") (TSX:AXL) is pleased to announce its operating and financial results for the three months ended March 31, 2010.

HIGHLIGHTS:

- In the first quarter of 2010, three gross (2.25 net) Cardium horizontal oil wells were drilled. All three wells have been completed and are on production. The Company's working interest share of initial production from these three wells is 700 BOPD of light oil.
- Second quarter production is estimated to be approximately 8,500 BOED, with the production peaking in the quarter at 9,200 BOED. The Company's guidance for 2010 is 8,000 to 8,500 BOED. The percentage of oil and NGL production included in this guidance has increased from 11% to 18% with the additional Cardium oil volumes. By the fourth quarter of 2010, oil and NGL production is estimated to be 20% of total production and will make up over 35% of total revenue at currently forecast prices.
- Drilling of an additional 5 gross (3.2 net) Cardium horizontal oil wells is expected to commence in May 2010.
- The Company has increased its Cardium prospective land to 92 gross (52 net) sections. Based on a drilling density of three wells per section, the drilling inventory is possibly 276 gross (156 net) Cardium horizontal oil wells. The Company's exposure in the Cardium oil horizontal play has the potential to significantly increase future oil production.
- In the first quarter of 2010, two 100% working interest Rock Creek wells were drilled in Westpem. These wells came on stream on April 2, 2010 and their combined current production is 300 BOED.
- The Company has completed its planned Edmonton Sands winter drilling program and the spring well tie-in and plant construction program is nearing completion. The Company estimates that as a result of the fit for purpose facilities being constructed, this new Edmonton Sands production will be brought on stream at less than \$3.50 per BOE starting in the second quarter of 2010.
- In February 2010, a financing for net proceeds of \$29.8 million was completed by issuing 21.9 million common shares at a price of \$1.45 per share. The Company's net debt at March 31, 2010 is \$65.8 million, which is \$65.2 million less than at March 31, 2009.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended March 31		% Change
<i>(thousands of dollars, unless otherwise stated)</i>	2010	2009	
Oil and gas revenue before royalties	\$ 23,265	\$ 24,429	(5%)
Funds from operations	\$ 10,635	\$ 8,792	21%
Funds from operations per share			
Basic	\$ 0.06	\$ 0.10	(40%)
Diluted	\$ 0.06	\$ 0.10	(40%)
Loss	\$ (5,953)	\$ (10,159)	41%
Loss per share			
Basic	\$ (0.04)	\$ (0.12)	67%
Diluted	\$ (0.04)	\$ (0.12)	67%
Capital expenditures, including acquisitions net of dispositions	\$ 33,427	\$ 13,545	147%
Debt, net of working capital	\$ 65,753	\$ 130,971	(50%)
Shareholders' equity	\$ 357,475	\$ 299,949	19%
Average shares outstanding <i>(thousands)</i>			
Basic	163,811	87,300	88%
Diluted	163,811	87,300	88%
Ending shares outstanding <i>(thousands)</i>	172,400	87,300	97%
Average daily sales			
Natural gas <i>(Mcf)</i>	35,221	42,344	(17%)
Liquids <i>(bpd)</i>	1,130	1,448	(22%)
Barrels of oil equivalent <i>(BOED)</i>	7,000	8,505	(18%)
Average prices			
Natural gas <i>(\$/Mcf)</i>	\$ 5.22	\$ 5.15	1%
Liquids <i>(\$/bbl)</i>	\$ 62.43	\$ 38.69	61%
Barrels of oil equivalent <i>(\$/BOE) *</i>	\$ 36.93	\$ 31.91	16%
Royalties <i>(\$/BOE)</i>	\$ 5.39	\$ 5.79	(7%)
Operating costs <i>(\$/BOE)</i>	\$ 10.91	\$ 10.81	1%
Operating netback <i>(\$/BOE)</i>	\$ 20.63	\$ 15.31	35%
General and administrative <i>(\$/BOE)</i>	\$ 2.73	\$ 2.62	4%
Wells drilled <i>(gross)</i>	26	11	136%

* Includes royalty and other income classified with oil and gas sales.

OPERATIONS:

Cardium Horizontal Oil. In the first quarter of 2010, the Company drilled three gross (2.25 net) Cardium horizontal oil wells. In March and April, these three wells were completed. All three of the wells commenced production in May and the Company's working interest share of initial production from the wells is 700 BOPD of light oil. The Company is planning on operating the drilling of five gross (3.2 net) locations in the second and third quarters of 2010 at Garrington, Willesden Green and Pembina to allow the Company to further delineate areas for near term development. The Company has increased its Cardium prospective land inventory to 92 gross (52 net) sections. Based on a development drilling density of three wells per section, it could potentially drill 276 gross (156 net) Cardium horizontal wells. The Company's exposure in the Cardium oil horizontal play has the potential to significantly increase future production.

Edmonton Sands. On January 30, 2009, the Company announced a significant farm-in transaction which more than doubled its land and prospective Edmonton Sands drilling inventory. The Company is committed to drill 200 wells by December 31, 2010 and has an option to drill a minimum of 100 additional wells prior to April 30, 2012 to earn additional lands. In this winter's drilling program, the Company drilled 126 gross (96.1 net) Edmonton Sands wells. The Company achieved significant cost savings in this winter program, with average drilling and completion costs of \$215,000 per well as compared to \$313,000 per well in the fourth quarter of 2008. Completion test rate results averaged 40% higher than the previous winter's drilling program. The Company will be drilling 74 additional wells in the last half of 2010 to complete its 200 well commitment. The Company has completed construction of its new Leedale compressor station. The startup of the Medicine River compressor station has been delayed to approximately July 1, 2010. Various other well tie-in projects have been completed in the Gilby, Buck Lake and Sylvan Lake areas. New production from the winter drilling program has started to come on stream in the second quarter of 2010. These projects will make up approximately 20% of production for the remaining three quarters of the year, and the associated operating expenses are expected to be less than \$3.50 per BOE.

Whitemud Horizontal Gas. The Company drilled and completed two Whitemud horizontal gas wells in the first quarter of 2010. Both wells were recently completed and the Company will be conducting flow-back operations to determine a stabilized rate for these wells when ground conditions permit. The Whitemud Sands are at 600 meters vertical depth and the horizontal wells traverse 1,000 to 1,200 meters through the formation. The Whitemud Sands has on average 2.5 Bcf per section of initial gas in place. Currently, the Company has 200 sections of land that it owns or controls in this play.

Deeper Drilling. The Company drilled two Westpem Rock Creek liquids rich gas wells in the first quarter of 2010. These wells came on stream on April 2, 2010 and their combined current production is 300 BOED. The Company is planning on drilling four gross (2.9 net) deeper targets in Westpem targeting Rock Creek and in Willesden Green targeting Ellerslie in the remainder of the year. All of these operations are liquids rich gas targets.

PRODUCTION

For the quarter ended March 31, 2010, the Company averaged 7,000 BOED, which was similar to the fourth quarter of 2009. Low commodity prices and the need to conserve funds for the farm-in drilling program in the winter resulted in new wells not being drilled and brought on production in

2009 to offset natural production declines. However, this winter's drilling program has brought on stream significant new production additions in the second quarter of 2010. The Company estimates production in the second quarter of 2010 to be 8,500 BOED. Production in the second quarter of 2010 peaked at 9,200 BOED in early May.

The Company's annual production guidance is 8,000 to 8,500 BOED. Of significance is the percentage of oil and NGL which has increased from 11% to 18% on an annual basis. Oil and NGL is estimated to be 20% of the Company's production by the fourth quarter of 2010, and will make up over 35% of total revenue at currently forecast prices.

FINANCIAL RESULTS

Capital expenditures, net of dispositions and drilling incentive credits, were \$33.4 million in the first quarter of 2010 with \$17.0 million spent on drilling and completions before drilling incentive credits and \$20.7 million spent on facilities. This compares to capital expenditures of \$13.5 million in the first quarter of 2009.

The Company's funds from operations were \$10.6 million in the first quarter of 2010 compared to \$8.8 million in the first quarter of 2009. The Company's average natural gas sales price was \$5.22 per Mcf in the first quarter of 2010 compared to \$5.15 per Mcf in first quarter of 2009. Based on prices to date, the Company's average natural gas sales price in the second quarter of 2010 is estimated to be approximately \$3.60 per Mcf. The Company had entered into fixed price contracts for approximately 19 MMcfd of natural gas production in the first quarter of 2010 at an average AECO price of \$5.71 per Mcf. The Company realized a gain on the contracts of \$1.3 million for the three months ended March 31, 2010. The 2010 gas price before the gain was \$4.81 per Mcf. The Company's average crude oil and natural gas liquids sales price in the first quarter of 2010 was \$62.43 per barrel compared to \$38.69 per barrel in the first quarter of 2009. WTI oil prices averaged US\$78.71 per barrel in the first quarter of 2010 and are expected to be similar in the second quarter based on prices to date. The Company's operating netback was \$20.63 per BOE in the first quarter of 2010 compared to \$15.31 per BOE in the first quarter of 2009. The increase in the operating netback was primarily due to the increase in commodity prices, including the gains on fixed price natural gas contracts. Operating expenses in 2010 were \$10.91 per BOE, which was slightly higher than the first quarter of 2009 of \$10.81 per BOE. The new production from the Edmonton Sands winter drilling program is expected to make up approximately 20% of total average production for the last three quarters of the year and is projected to come on stream at an average operating expense of less than \$3.50 per BOE as compared to a historical operating expense of \$9.00 per BOE.

FINANCING

In February 2010, the Company completed a financing for net proceeds of \$29.8 million by issuing 21.9 million common shares at an issue price of \$1.45 per share. This financing was put in place to expand the Company's Cardium oil horizontal drilling program. The Company has 172.4 million outstanding common shares as of March 31, 2010. The Company has credit facilities of \$100 million with three Canadian banks. The Company's net debt at March 31, 2010 was \$65.8 million compared to \$131.0 million at March 31, 2009.

OUTLOOK

Natural gas prices have been weak to date in the second quarter of 2010. Warmer weather in the summer and the return of winter should strengthen natural gas prices. The Company has been increasing its focus on Cardium light oil horizontal well drilling programs and is rebalancing its overall product mix to include a higher proportion oil and NGL, with an estimated 20% of the product mix being liquids production by the fourth quarter of 2010.

The Alberta government has made important changes to their fiscal incentives program which benefit the Company. The 5% one year royalty program has now been made permanent. This benefits all of the Company's Cardium horizontal oil, Edmonton Sands and deep drilling programs. The Alberta government has indicated that it will be reducing the oil and gas royalty curves before the end of May 2010. To date, they have indicated that the maximum gas royalty will be reduced from 50% to 36% and the maximum oil royalty will be reduced from 50% to 40%. The oil royalty curve adjustment is expected to be a significant benefit to the Company's current and planned Cardium horizontal oil program.

Completion test rate results from the Edmonton Sands farm-in program averaged 40% higher than results achieved in the previous winter's drilling program. The Company expects similar results for the next fall/winter drilling program. This winter, the locations drilled were predominantly on Crown land that did not require mineral subsurface poolings or have any surface access restrictions. Next winter, the Company will be drilling more freehold lands and lands where subsurface poolings have been completed. Many of the new locations to be drilled next winter will connect to the new plant infrastructure built this winter.

In 2009, the Company had excellent finding, development and acquisition costs, at less than \$8.00 per BOE, and is continuing its low capital cost and low operating cost Edmonton Sands program for the upcoming winter. The Company is continuing to evaluate its Cardium oil acreage position with the horizontal drill bit.

PEOPLE

David Sandmeyer has been nominated to join the Board of Directors at the May 2010 annual meeting of shareholders. David is a professional engineer and a corporate director, and former President and Chief Executive Officer of Freehold Royalty Trust and Rife Resources Ltd. He was also a founding Governor of the Canadian Association of Petroleum Producers serving several terms and active on a number of committees.

The Company has hired Ian Kerr into the newly created position of Edmonton Sands Business Unit Manager. Previously, Mr. Kerr worked as the Asset Team Leader for Petro Canada's shallow gas project at Medicine Hat. Mr. Kerr has over 25 years of industry experience and we welcome him to Anderson Energy.

The Company invites its shareholders to attend the annual meeting on May 13, 2010 at the Metropolitan Centre in Calgary at 2:00 pm MDT and encourages anyone interested in further details on the Company to visit the Company's website at www.andersonenergy.ca.

Brian H. Dau
President & Chief Executive Officer
May 13, 2010

Management's Discussion and Analysis

FOR THE THREE MONTHS ENDED MARCH 31, 2010 AND 2009

The following discussion and analysis of financial results should be read in conjunction with the unaudited interim consolidated financial statements of Anderson Energy Ltd. ("Anderson Energy" or the "Company") for the three months ended March 31, 2010 and the audited consolidated financial statements and management's discussion and analysis of Anderson Energy for the years ended December 31, 2009 and 2008 and is based on information available as of May 12, 2010.

The following information is based on financial statements prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). Production and reserves numbers are stated before deducting Crown or lessor royalties.

Included in the discussion and analysis are references to terms commonly used in the oil and gas industry such as funds from operations, finding, development and acquisition ("FD&A") costs, operating netback and barrels of oil equivalent ("BOE"). Funds from operations as used in this report represent cash from operating activities before changes in non-cash working capital and asset retirement expenditures. See "Review of Financial Results – Funds from Operations" for details of this calculation. Funds from operations represent both an indicator of the Company's performance and a funding source for on-going operations. FD&A costs measure the cost of reserves additions and are an indicator of the efficiency of capital expended in the period. Operating netback is calculated as oil and gas revenues less royalties and operating expenses and is a measure of the profitability of operations before administrative and financing expenditures. Production volumes and reserves are commonly expressed on a BOE basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants. These terms are not defined by Canadian GAAP and therefore are referred to as non-GAAP measures.

All references to dollar values are to Canadian dollars unless otherwise stated.

The abbreviations used in this discussion and analysis are located on the last page of this document.

REVIEW OF FINANCIAL RESULTS

Overview. For the three months ended March 31, 2010, funds from operations were \$10.6 million, up 16% from the fourth quarter of 2009 due to increases in commodity prices and gains on fixed price natural gas contracts in the first quarter of 2010. Sales volumes for the three months ended March 31, 2010 averaged 7,000 BOED, 1% lower than the fourth quarter of 2009.

Capital expenditures, net of dispositions, were \$33.4 million for the three months ended March 31, 2010. During the first quarter of 2010, the Company drilled 26 gross (21.1 net) wells with an 85% success rate. The Company tied in 57 gross (43.7 net) Edmonton Sands wells and 2 gross (2.0 net) Rock Creek wells in the first three months of 2010. The Company has tied in 3 gross

(2.25 net) Cardium oil wells to date in the second quarter of 2010. The Company also completed construction of a new fit for purpose Edmonton Sands facility at Leedale, which became operational in March 2010.

Debt, net of working capital, was \$65.8 million at March 31, 2010, \$6.8 million lower than at December 31, 2009 as a result of a bought deal share financing in February 2010 that raised \$29.8 million in net proceeds and was initially used pay down bank debt. The availability created in the credit facilities through the equity issuance was used to increase the Company's 2010 capital budget from \$75 million to \$87 million in order to expand its Cardium horizontal light oil drilling program.

Revenue and Production. Gas sales comprised 84% of Anderson Energy's total oil and gas sales volumes for the three months ended March 31, 2010, consistent with the fourth quarter of 2009.

Gas sales volumes for the three months ended March 31, 2010 increased slightly to 35.2 MMcfd from 34.9 MMcfd in the fourth quarter of 2009. The increase is a result of production from new wells coming on stream in March 2010. Gas sales volumes decreased 17% from the first quarter of 2009 as a result of a poor commodity price environment in 2009 where new wells were not drilled and brought on production to offset natural production decline.

Oil sales for the three months ended March 31, 2010 averaged 345 bpd compared to 351 bpd in the fourth quarter of 2009 and 443 bpd for the first quarter of 2009. The decrease in 2010 volumes is due to natural production decline and workovers being deferred due to the low price environment in 2009. New capital initiatives for oil did not commence until the first quarter of 2010. The Company drilled three gross (2.25 net) Cardium wells in the first quarter of 2010, which did not come on stream until the second quarter of 2010. There were no oil wells drilled in 2009.

Natural gas liquids sales for the three months ended March 31, 2010 averaged 785 bpd compared to 906 bpd in the fourth quarter of 2009 and 1,005 bpd for the first quarter of 2009. Natural gas liquids volumes were affected by natural production decline.

The following tables outline production revenue, volumes and average sales prices for the period ended March 31, 2010 and 2009.

OIL AND NATURAL GAS REVENUE

	<i>Three months ended March 31</i>	
<i>(thousands of dollars)</i>	<i>2010</i>	<i>2009</i>
Natural gas	\$ 15,259	\$ 19,638
Gain on fixed price natural gas contracts	1,302	-
Oil	2,346	1,714
NGL	4,003	3,328
Royalty and other	355	(251)
Total	\$ 23,265	\$ 24,429

PRODUCTION

	Three months ended March 31	
	2010	2009
Natural gas (Mcf)	35,221	42,344
Oil (bpd)	345	443
NGL (bpd)	785	1,005
Total (BOED)	7,000	8,505

PRICES

	Three months ended March 31	
	2010	2009
Natural gas (\$/Mcf) ⁽¹⁾	\$ 5.22	\$ 5.15
Oil (\$/bbl)	75.47	42.97
NGL (\$/bbl)	56.68	36.80
Total (\$/BOE) ⁽²⁾	\$ 36.93	\$ 31.91

(1) Includes gain on fixed price natural gas contracts in 2010.

(2) Includes royalty and other income classified with oil and gas sales.

Anderson Energy's average natural gas sales price was \$5.22 per Mcf for the three months ended March 31, 2010, 22% higher than the fourth quarter of 2009 price of \$4.28 per Mcf and 1% higher than the first quarter of 2009 price of \$5.15 per Mcf. The natural gas price in the first quarter of 2010 includes a gain of \$1.3 million on the Company's fixed price natural gas contracts. The 2010 gas price before the gain was \$4.81 per Mcf. Gas prices were significantly affected by increased supply and lower industrial consumption of natural gas in the United States. Natural gas prices started to improve in the last quarter of 2009, but have declined throughout the first quarter of 2010 as marketplace volatility continues.

Historically, Anderson Energy has sold most of its gas at Alberta spot market prices. The Company is currently selling gas production that is not under fixed price contracts at the average daily index price. The Company has classified all transportation costs as an offset to gas sales revenue as title transfers prior to transport on the applicable sales pipelines and transportation is being held by and charged by the gas purchasers. The Company has arranged firm service transportation agreements covering approximately 27 MMcf of natural gas sales for various terms ranging from one to ten years.

Fixed Price Contracts. In December 2009, as part of its risk management program, the Company entered into fixed price natural gas contracts to manage commodity price risk. The Company entered into physical contracts to sell 20,000 GJ per day of natural gas for each of January, February and March 2010 at an average AECO price of \$5.41 per GJ. The Company realized a gain on fixed price natural gas contracts of \$1.3 million for the three months ended March 31, 2010. The Company has no fixed price contracts in place as at March 31, 2010.

Royalties. Royalties were 15% of revenue for the three months ended March 31, 2010 compared to 9% for the fourth quarter of 2009 and 18% for the three months ended March 31, 2009. On January 1, 2009, the Alberta government's New Royalty Framework came into effect. While royalties increased in some areas, overall, the changes reduced royalties due to the Company's

focus on shallow gas, lower productivity wells and lower natural gas prices. In addition, when prices and corresponding revenues are lower, fixed monthly gas cost allowance provisions become more significant to the overall royalty rate. Royalties as a percentage of revenue are highly sensitive to prices and adjustments to gas cost allowance and so these rates can fluctuate from quarter to quarter. The methodology used to calculate gas cost allowance was amended as part of the New Royalty Framework in 2009 and the first set of annual adjustments are expected in June 2010 and may result in further amendments to amounts estimated by the Crown for 2009.

The Alberta government revised the royalty regime effective April 1, 2009, for new wells tied in on Crown lands. Producers will pay a reduced Crown royalty rate of 5% for the first year on up to 500 MMcf of gas production or up to 50 Mstb of oil production. In addition, the Alberta government changed the maximum royalty payable on oil from 50% to 40% and on natural gas from 50% to 36%. The new royalty curves are to be made available by May 31, 2010. At this time, the Company anticipates that the royalty curve changes will mostly benefit production from its new Cardium oil horizontal drilling program, as the royalty rates on Edmonton Sands gas are already relatively low.

	<i>Three months ended March 31</i>	
	<i>2010</i>	<i>2009</i>
Royalties (%)	15%	18%
Royalties (\$/BOE)	\$ 5.39	\$ 5.79

Operating Expenses. Operating expenses were \$10.91 per BOE for the three months ended March 31, 2010 compared to \$10.49 per BOE in the last quarter of 2009 and \$10.81 per BOE in the first quarter of 2009. Operating expenses in the first quarter of 2010 were affected by workovers previously deferred due to market conditions, a casing repair and compressor maintenance. The Company is completing construction of additional fit for purpose Edmonton Sands facilities at Leedale and Medicine River. These projects, combined with other new Edmonton Sands tie ins, particularly at Gilby and Willesden Green should help to reduce the operating expenses per BOE in subsequent quarters.

OPERATING NETBACK

	<i>Three months ended March 31</i>	
<i>(thousands of dollars)</i>	<i>2010</i>	<i>2009</i>
Revenue	\$ 23,265	\$ 24,429
Royalties	(3,394)	(4,434)
Operating expenses	(6,876)	(8,272)
	\$ 12,995	\$ 11,723
Sales (MBOE)	630.0	765.5
Per BOE		
Revenue	\$ 36.93	\$ 31.91
Royalties	(5.39)	(5.79)
Operating expenses	(10.91)	(10.81)
	\$ 20.63	\$ 15.31

General and Administrative Expenses. General and administrative expenses were \$1.7 million or \$2.73 per BOE for the three months ended March 31, 2010 compared to \$1.9 million or \$2.94 per BOE in the fourth quarter of 2009 and \$2.0 million or \$2.62 per BOE for the three months ended March 31, 2009. The decrease in general and administrative expenses from the comparable quarter of 2009 is largely the result of a staff reduction that occurred at the end of March 2009.

<i>(thousands of dollars)</i>	<i>Three months ended March 31,</i>	
	<i>2010</i>	<i>2009</i>
General and administrative (gross)	\$ 3,026	\$ 3,503
Overhead recoveries	(447)	(392)
Capitalized	(860)	(1,104)
General and administrative (net)	\$ 1,719	\$ 2,007
General and administrative <i>(\$/BOE)</i>	\$ 2.73	\$ 2.62
% Capitalized	28%	32%

Capitalized general and administrative costs are limited to salaries and associated office rent of staff involved in capital activities.

Stock-Based Compensation. The Company accounts for stock-based compensation plans using the fair value method of accounting. Stock-based compensation costs were \$0.4 million for the first quarter of 2010 (\$0.2 million net of amounts capitalized) versus \$0.5 million (\$0.3 million net of amounts capitalized) in the first quarter of 2009. The minimal decrease is a result of options reaching their full vesting terms.

Interest Expense. Interest expense was \$0.7 million for the first quarter of 2010, compared to \$0.8 million in the fourth quarter of 2009 and \$1.0 million in the first quarter of 2009. The decrease in interest expense is due to the lower debt levels. Bank loans, including the current portion, were \$38.8 million at March 31, 2010 compared to \$62.4 million at December 31, 2009 and \$110.8 million at March 31, 2009. The average effective interest rate on outstanding bank loans was 4.5% for the three months ended March 31, 2010 compared to 4.4% for the three months ended March 31, 2009.

Depletion and Depreciation. Depletion and depreciation was \$28.08 per BOE or \$17.7 million for the first quarter of 2010 compared to \$26.39 per BOE, or \$17.2 million in the fourth quarter of 2009 and \$28.85 per BOE, or \$22.1 million in the first quarter of 2009. Depletion and depreciation expense is calculated based on proved reserves only. Total proved reserves increased in the fourth quarter of 2009. In addition, future development costs decreased in the 2009 reserve report, reflecting measures taken in the 2009/2010 winter drilling program to reduce drilling and completion costs. The impact of both of these changes resulted in a decrease in depletion rates per BOE and in total dollars in the fourth quarter of 2009. Depletion and depreciation rates in the first quarter of 2010 remain lower than the first quarter of 2009 for similar reasons, however they are higher than the fourth quarter of 2009 as a result of increased capital spending and lower proved reserves due to natural gas price declines.

Asset Retirement Obligation. As a result of new drilling and facility construction, the Company recorded \$0.3 million in asset retirement obligations in the first quarter of 2010. Other changes in estimates were \$0.4 million. Accretion expense was \$0.6 million for the first quarter of 2010 compared to \$0.6 million in the first quarter of 2009 and was included in depletion and depreciation expense.

Income Taxes. Anderson Energy is not currently taxable. The Company does not anticipate paying current income tax in 2010. The future income tax reduction has decreased as a percentage of pre-tax loss due to lower corporate tax rates. The Company has approximately \$335 million in tax pools at March 31, 2010.

Funds from Operations. Funds from operations for the first quarter of 2010 were \$10.6 million (\$0.06 per share), a 16% increase over the \$9.2 million (\$0.06 per share) recorded in the fourth quarter of 2009 and 21% higher than the \$8.8 million (\$0.10 per share) recorded in the same period of the prior year. The increase in funds from operations in 2010 is a result of higher commodity prices compared to the fourth quarter of 2009. In addition, the gain on fixed price natural gas contracts in the first quarter of 2010 increased funds from operations relative to the first and fourth quarters of 2009. Cash from operating activities also increased year over year for similar reasons.

<i>(thousands of dollars)</i>	<i>Three months ended March 31</i>	
	<i>2010</i>	<i>2009</i>
Cash from operating activities	\$ 12,946	\$ 9,298
Changes in non-cash working capital	(2,540)	(1,444)
Asset retirement expenditures	229	938
Funds from operations	\$ 10,635	\$ 8,792

Earnings. The Company reported a loss of \$6.0 million in the first quarter of 2010 compared to a loss of \$6.5 million for the three months ended December 31, 2009 and a loss of \$10.2 million for the first quarter of 2009. Earnings in the first quarter of 2010 continued to be impacted by low commodity prices. In addition, higher depletion and depreciation charges negatively impacted in the first three months of the year. The Company's funds from operations and earnings are highly sensitive to changes in factors that are beyond its control. An estimate of the Company's sensitivities to changes in commodity prices, exchange rates and interest rates is summarized below:

SENSITIVITIES

<i>(thousands of dollars)</i>	<i>Funds from Operations</i>		<i>Earnings</i>	
	<i>Millions</i>	<i>Per Share</i>	<i>Millions</i>	<i>Per Share</i>
\$0.50/Mcf in price of natural gas	\$ 7.2	\$ 0.06	\$ 5.1	\$ 0.04
US \$5.00/bbl in the WTI crude price	\$ 1.8	\$ 0.01	\$ 1.3	\$ 0.01
US \$0.01 in the US/Cdn exchange rate	\$ 0.7	\$ 0.01	\$ 0.5	\$ 0.00
1% in short-term interest rate	\$ 0.8	\$ 0.01	\$ 0.5	\$ 0.00

This sensitivity analysis was calculated by applying different pricing, interest rate and exchange rate assumptions to the 2009 actual results related to production, prices, royalty rates, operating costs and capital spending.

CAPITAL EXPENDITURES

The Company spent \$33.4 million on capital expenditures, net of dispositions and drilling incentive credits in the first quarter of 2010. The breakdown of expenditures is shown below:

<i>(thousands of dollars)</i>	<i>2010</i>		<i>2009</i>	
Land, geological and geophysical costs	\$	(170)	\$	89
Acquisitions, net of dispositions		(1,247)		(27)
Drilling, completion and recompletion		17,044		6,119
Drilling incentive credits		(2,614)		-
Facilities and well equipment		20,744		5,933
Capitalized G&A		860		1,104
Total finding, development & acquisition expenditures		34,617		13,218
Change in compressor and other inventory and equipment		(1,199)		307
Office equipment and furniture		9		20
Total capital expenditures		33,427		13,545
Non-cash asset retirement obligations and capitalized stock-based compensation		916		657
Total cash and non-cash capital additions	\$	34,343	\$	14,202

Drilling statistics are shown below:

	<i>Three months ended March 31</i>			
	<i>2010</i>		<i>2009</i>	
	<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>
Gas	19	16.0	11	8.3
Oil	3	2.3	-	-
Dry	4	2.8	-	-
Total	26	21.1	11	8.3
Success rate (%)	85%	87%	100%	100%

During the first quarter of 2010, the Company drilled 19 gross (14.8 net) vertical Edmonton Sands wells. The Company also completed 64 gross (49.5 net) Edmonton Sands wells and tied in 57 gross (43.7 net) Edmonton Sands wells. The Company also drilled, completed and tied in two gross (2.0 net) Rock Creek wells, drilled three gross (2.25 net) Cardium horizontal oil wells and two gross (2.0 net) Whitemud horizontal wells. Approximately \$2.5 million was spent on fit for purpose processing facilities.

In the fourth quarter of 2009, the Company accrued \$6.0 million for drilling incentive credits. Drilling credits earned are capped at 50% of crown royalties paid between April 1, 2009 and March 31, 2011 and the Company estimates that it will earn more drilling credits that it will be able to claim. These credits were earned through drilling in the fourth quarter of 2009 but are expected to be paid out between 2009 and 2011 as crown royalties are paid. The estimate is highly dependent on commodity prices, production levels, crown royalty rates and gas cost allowance earned over this period. To the extent that crown royalties paid are lower or higher, drilling credits will be lower or higher as well. As a result of the cap, no additional credits were

accrued related to drilling in the first quarter of 2010, however, the Company did receive \$2.6 million in proceeds on the sale of some of its surplus credits.

CEILING TEST

No impairment was recognized under the ceiling test at March 31, 2010. The future commodity prices used in the ceiling test were based on the commodity price forecasts of the Company's independent reserve engineers at April 1, 2010 adjusted for differentials specific to the Company's reserves. These price forecasts have declined since year end which has had the impact of reducing the available cushion under the ceiling test. Factors used in the ceiling test calculation are disclosed in note 1 of the consolidated interim financial statements for the period ended March 31, 2010.

SHARE INFORMATION

The Company's shares have been listed on the Toronto Stock Exchange since September 7, 2005 under the symbol "AXL". As of May 12, 2010, there were 172.4 million common shares outstanding and 10.5 million stock options outstanding.

	<i>Three months ended March 31,</i>	
	<i>2010</i>	<i>2009</i>
High	\$ 1.57	\$ 1.48
Low	\$ 1.10	\$ 0.75
Close	\$ 1.14	\$ 0.84
Volume	43,643,072	6,131,128
Shares outstanding at March 31	172,400,401	87,300,401
Market capitalization at March 31	\$ 196,536,457	\$ 73,332,337

The statistics above include trading on the Toronto Stock Exchange only. Shares also trade on alternative platforms like Alpha, Chi-X, Pure and Omega. Approximately 22.9 million common shares traded on these alternative exchanges in the three months ended March 31, 2010.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2010, the Company had outstanding long term bank loans of \$28.8 million and a working capital deficiency of \$36.9 million. The bank facilities have a revolving period ending on July 13, 2010, extendible at the option of the lenders, followed by a term period with three equal quarterly principal repayments commencing 180 days from the term date. The Company has classified \$10 million of the outstanding bank loan as a current liability as the normal annual review by lenders has not yet been completed. The review is currently underway and is expected to be completed by the end of May 2010. The Company has no reason to believe that the revolving period of the facilities will not be extended for another year or, therefore, that any portion of the bank loan will ultimately become payable in the next year.

The Company's current capital budget for 2010 is \$87 million of which \$33.4 million was spent in the first quarter of 2010. The Company is committed to drill 74 wells under its farm-in agreement. The Company expects to drill these wells in the fourth quarter of 2010. In addition, the Company

is planning to drill five gross (3.2 net) Cardium oil wells and four gross (2.9 net) deep, liquids rich natural gas wells starting in the second quarter of 2010.

The Company's need for capital will be both short-term and long-term in nature. Short-term capital is required to finance accounts receivable and other similar short-term assets while the acquisition and development of oil and natural gas properties requires larger amounts of long-term capital. At March 31, 2010, the Company has a \$90 million extendible revolving term credit facility and a \$10 million working capital credit facility with a syndicate of Canadian banks. Anderson Energy will prudently use its bank loan facilities to finance its operations as required. The available lending limits under the bank facilities are reviewed twice a year and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The lenders are currently conducting their annual renewal, which is expected to be completed by the end of May 2010. There can be no assurance that the amount of the available bank lines will not be adjusted. The Company will continue to fund its ongoing operations from a combination of cash flow, debt, asset dispositions and equity financing as needed.

CONTRACTUAL OBLIGATIONS

The Company enters into various contractual obligations in the course of conducting its operations. These obligations include:

- *Loan agreements* – The reserves-based credit facilities have a revolving period ending on July 13, 2010 extendible at the option of the lenders, followed by a term period with three equal quarterly principal repayments commencing 180 days from the term date.
- *Lease for office space* – This lease expires on November 30, 2012. Future minimum lease payments are expected to be \$1.8 million per year in 2010 and 2011, and \$1.6 million in 2012.
- *Firm service transportation commitments* – The Company has entered into firm service transportation agreements for approximately 27 million cubic feet per day of gas sales for various terms expiring between 2010 and 2020. Based on rate schedules announced to date, the payments in each of the next five years and thereafter are estimated to be \$1.9 million for the remainder of 2010, \$1.8 million in 2011, \$1.3 million in 2012, \$0.8 million in 2013, \$0.7 million in 2014 and \$1.0 million thereafter.
- *Farm-in* – On January 30, 2009, the Company announced a farm-in agreement with a large international oil and gas company on lands near its existing core operations. Under the farm-in agreement, the Company has access to 388 gross (205 net) sections of land. During the commitment phase of the transaction, the Company is committed to drill, complete and equip 200 wells to earn an interest in up to 120 sections. The Company drilled 126 wells under the commitment to March 31, 2010. The Company is obligated to complete the drilling of the wells on or before December 31, 2010. The commitment is subject to certain guarantees. The Company estimates that its minimum commitment to drill the remaining 74 wells is \$10 million to the end of 2010. The Company currently plans to spend a total of \$23 million in the remainder of 2010 on the farm-in project to drill and complete the remaining farm-in wells, tie-in wells drilled in the first quarter of 2010 and complete the construction of facilities.

These obligations are described further in note 8 to the consolidated financial statements for the three months ended March 31, 2010.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (“IFRS”)

In February 2008, the CICA Accounting Standards Board (“AcSB”) confirmed the changeover to IFRS from Canadian Generally Accepted Accounting Principles (“GAAP”) will be required for publicly accountable enterprises for interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011, including comparatives for 2010.

In response, the Company has completed its high-level IFRS changeover plan and established a preliminary timeline for the execution and completion of the conversion project. The changeover plan was determined following a preliminary assessment of the differences between Canadian GAAP and IFRS and the potential effects of IFRS to accounting and reporting processes, information systems, business processes and external disclosures. This assessment has provided insight into what are anticipated to be the most significant areas of difference applicable to the Company.

During the next phase of the project, the Company is performing an in-depth review of the significant areas of difference identified during the preliminary assessment, in order to identify all specific Canadian GAAP and IFRS differences and select ongoing IFRS policies. Key areas addressed will also be reviewed to determine any information technology issues, the impact on internal controls over financial reporting and the impact on business activities including the effect, if any, on covenants and compensation arrangements. External advisors have been retained and will assist management with the project on an as needed basis to ensure IFRS readiness by January 1, 2011.

Below is a summary of the Company’s preliminary views of the key areas where changes in accounting policies are expected that may impact the Company’s consolidated financial statements. The list and comments below should not be regarded as a complete list of changes that will result from the transition to IFRS. It is intended to highlight those areas the Company believes to be most significant; however, analysis of changes is still in progress and not all decisions have been made where choices of accounting policies are available. At this stage, the Company has not quantified the impacts expected on its consolidated financial statements for these differences.

Note that most adjustments required on transition to IFRS will be made retrospectively, against opening retained earnings in the first comparative balance sheet. Transitional adjustments relating to those standards where comparative figures are not required to be restated because they are applied prospectively will only be made as of the first day of the year of transition.

IFRS 1 “First-Time Adoption of International Financial Reporting Standards” 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. The Company is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate in the Company’s circumstances.

Property, Plant and Equipment. International Accounting Standard (IAS) 16 “Property, Plant & Equipment” and Canadian GAAP contain the same basic principles, however there are some differences. IFRS requires that significant parts of an asset be depreciated separately and

depreciation commences when the asset is available for use. There will be more depreciable components than the current single full cost pool. IFRS also permits property, plant equipment to be measured using the fair value model or the historical cost model. The Company is not planning on adopting the fair value measurement model for property, plant and equipment.

IFRS 1 contains an exemption whereby a company may apply IFRS prospectively by utilizing its current reserves (volumes or values) at the transition date to allocate the Company's full cost pool, with the provision that an impairment test, under IFRS standards, be conducted at the transition date. The Company intends to use this exemption and is currently evaluating the impact of allocating the net book values based on reserve volumes or values.

Provisions. Under IFRS, similar to Canadian GAAP, the Company is required to record obligations relating to the retirement of its wells and facilities where a legal or contractual obligation currently exists. Upon the adoption of IFRS, the Company will also need to evaluate if there are any constructive obligations where the decommissioning liability would also need to be recognized. Currently, the Company has not identified any constructive obligations.

Upon transition, the Company intends to apply the IFRS 1 exemption whereby the decommissioning liability provision is recalculated at January 1, 2010 using the IFRS methodology and any adjustments would be offset against opening retained earnings.

The Company is in the process of evaluating the methodology by which its decommissioning liabilities will be calculated including the future cash flows as well as the appropriateness of the discount rate. It is anticipated the liability will increase due to a lower rate being utilized.

Impairment of Assets. IAS 36 "Impairment of Assets" requires that impairments be determined based on the greater of fair value and value in use. This differs from the current two step practice where the asset's carrying value is initially compared to the estimated undiscounted future cash flows, and only if the carrying value exceeds the undiscounted future cash flows is a discounted analysis, step two, required. There is no undiscounted test under IFRS. This may result in more frequent write-downs upon transition.

In addition, under IFRS, an entity must also evaluate whether there are changes in circumstances that would support an impairment reversal, which is not allowable under full cost guidelines under GAAP.

Another difference arises in the level at which an impairment test is performed. Under IFRS, impairment testing will be performed on cash generating units. The Company has identified its cash generating units. There are more cash generating units than the current single full cost pool.

Income taxes. Under IAS 12 "Income Taxes", current and deferred tax are normally recognized in the income statement, except to the extent that tax arises from (1) an item that has been recognized directly in equity, whether in the same or a different period, (2) a business combination or (3) a share based payment transaction. If a deferred tax asset or liability is re-measured subsequent to initial recognition, the impact of re-measurement is recorded in earnings, unless it relates to an item originally recognized in equity, in which case the change

would also be recorded in equity. The practice of tracking the re-measurement of taxes back to the item which originally triggered the recognition is commonly referred to as “backwards tracing”. Canadian GAAP prohibits backwards tracing except on business combinations and financial reorganizations.

Share based payments. Under IFRS 2 “Share-Based Payments”, graded vested options are required to be separated into their vesting tranches and valued and accounted for separately. This differs from Canadian GAAP, where graded vested options may be valued as a single award at grant date and expensed using the straight line method. IFRS 1 provides an exemption on IFRS 2 for equity instruments which vested before the transition date and does not require them to be retroactively restated. All unvested options at transition date will be required to be retroactively restated with the adjustment going through opening retained earnings on transition. The Company intends to use this exemption and is currently evaluating the transitional impact.

Throughout 2010, the Company will continue to document and define its IFRS accounting policies and the Company will start to evaluate the financial impact of IFRS on its financial statements. Staff training programs will continue in 2010 and will be ongoing as the project unfolds.

The Company will also continue to monitor standards development as issued by the International Accounting Standards Board (“IASB”) and the AcSB as well as regulatory developments as issued by the Canadian Securities Administrators, which may affect the timing, nature or disclosure of its adoption of IFRS.

In the first quarter of 2010, no changes were made to the Company’s IFRS transition plan. No significant milestones were scheduled for this quarter due to the time constraints associated with year end and first quarter reporting deadlines. Implementation steps will commence again in the second quarter of 2010.

CONTROLS AND PROCEDURES

The Chief Executive Officer and the Chief Financial Officer have evaluated and tested the effectiveness of Anderson Energy’s disclosure controls and procedures as of March 31, 2010 and have concluded that such disclosure controls and procedures were effective.

The Chief Executive Officer and the Chief Financial Officer have evaluated and tested the design effectiveness of Anderson Energy’s internal controls over financial reporting during the three month ended March 31, 2010 and have concluded that, these internal controls are designed properly and are effective in the preparation of financial statements for external purposes in accordance with Canadian GAAP. There were no material changes in the Company’s internal controls over financial reporting during the three months ended March 31, 2010.

Because of inherent limitations, internal controls over financial reporting may not prevent or detect all misstatements, errors or fraud. Control systems, no matter how well designed, only provide reasonable, not absolute, assurance that the objectives of the controls systems are met.

BUSINESS RISKS

Oil and gas exploration and production is capital intensive and involves a number of business risks including, without limitation, the uncertainty of finding new reserves, the instability of commodity prices, weather and various operational risks. Commodity prices are influenced by local and worldwide supply and demand, OPEC actions, ongoing global economic concerns, the U.S. dollar exchange rate, transportation costs, political stability and seasonal and weather related changes to demand. Natural gas prices in particular have weakened on fears of reduced industrial use due to the continued U.S. recession and increased supply from U.S. natural gas shale plays. The industry is subject to extensive governmental regulation with respect to the environment. Operational risks include well performance, uncertainties inherent in estimating reserves, timing of/ability to obtain drilling licences and other regulatory approvals, ability to obtain equipment, expiration of licences and leases, competition from other producers, sufficiency of insurance, ability to manage growth, reliance on key personnel, third party credit risk and appropriateness of accounting estimates. These risks are described in more detail in the Company's Annual Information Form for the year ended December 31, 2009 filed with Canadian securities regulatory authorities on SEDAR.

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Company's revenues may decline as a result of decreased commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the present global economic concerns exposes the Company to additional access to capital risk. There can be no assurance that debt or equity financing, or funds generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Anderson Energy manages these risks by employing competent professional staff, following sound operating practices and using capital prudently. The Company generates its exploration prospects internally and performs extensive geological, geophysical, engineering, and environmental analysis before committing to the drilling of new prospects. Anderson Energy seeks out and employs new technologies where possible. With the Company's extensive drilling inventory and advance planning, the Company can manage the slower pace of regulatory approvals and the requirements for extensive landowner consultation.

The Company has a formal emergency response plan which details the procedures employees and contractors will follow in the event of an operational emergency. The emergency response plan is designed to respond to emergencies in an organized and timely manner so that the safety of employees, contractors, residents in the vicinity of field operations, the general public and the environment are protected. A corporate safety program covers hazard identification and control on the jobsite, establishes Company policies, rules and work procedures and outlines training requirements for employees and contract personnel.

The Company currently deals with a small number of buyers and sales contracts, and endeavors to ensure that those buyers are an appropriate credit risk. The Company continuously evaluates the merits of entering into fixed price or financial hedge contracts for price management.

The oil and natural gas business is subject to regulation and intervention by governments in such matters as the awarding of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights. As well, governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas. Such regulation may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas, increase the Company's costs or affect its future opportunities.

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. Such legislation may also impose restrictions and prohibitions on water use or processing in connection with certain oil and gas operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result, amongst other things in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

The Government of Alberta implemented a new oil and gas royalty framework effective January 2009. The new framework establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the new framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional oil range from 0% to 50%. Natural gas royalty rates range from 5% to 50%.

On March 3, 2009, the Government of Alberta announced a three-point incentive program. Amendments to the program were announced on June 11 and June 25, 2009. This incentive program includes a drilling credit for new oil and natural gas wells drilled between April 1, 2009 and March 31, 2011, providing a \$200 per meter drilled royalty credit to companies. The credit is limited to 50% of Crown royalties payable over the same period. There is also a new well incentive program that provides a maximum 5% royalty rate for the first 12 months of production from new wells that begin producing oil or natural gas between April 1, 2009 and March 31, 2011 to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. The province of Alberta will also invest \$30 million in a fund committed to abandonment and reclamation projects where there is no legally responsible or financially able party to deal with the clean-up of the wells.

On March 11, 2010, the Alberta government announced amendments to the new oil and gas royalty framework, which come into effect January 1, 2011. Under the most recent amendments, the maximum royalty paid was reduced from 50% to 40% on oil and from 50% to 36% on natural gas. In addition, according to the announced amendments, the new well incentive program is to become a permanent feature to the new oil and gas royalty framework.

Further refinements to the amendments are anticipated to be announced by the Government of Alberta by the end of May 2010 including, without limitation, the royalty curves that are to be utilized to determine the applicable royalty rates.

The changes to the royalty regime in the Province of Alberta are subject to certain risks and uncertainties. There may be modifications introduced to the royalty structure and such changes may be adverse to the business of the Company. There can be no assurance that the Government of Alberta or the Government of Canada will not adopt new royalty regimes which may render the Company's projects uneconomic or otherwise adversely affect the business of the Company.

BUSINESS PROSPECTS

The Company is focused on the ramp up of its Cardium oil program and the efficient development of its shallow gas play in its one core area in central Alberta.

Anderson Energy has significant exposure to multistage frac opportunities in the Cardium light oil halo play and in the middle and lower Cardium sands inside the major Cardium fields. The company has 92 gross (52 net) sections in the fairway. At a drilling density of three wells per section, the potential drilling inventory is 276 gross (156 net) Cardium locations.

The Company has drilled 596 wells to date in the Edmonton Sands shallow gas play. This project features high economic success rates, predictable well performance and a favorable fiscal regime. Input costs have progressively declined. The farm-in agreement entered into in 2009 has significantly increased the drilling inventory in the play. Anderson has access to 613 gross (344 net) sections of land and has an inventory of 1,182 gross (664 net) drilling locations. Economics are similar to U.S. shale gas plays. The Company is also evaluating horizontal multi-stage frac opportunities in the Whitemud Sands and has an inventory of drilling locations for liquids rich natural gas horizons deeper than the Edmonton Sands.

The equity financing completed during the first quarter of 2010, along with the Company's available bank lines, provide the Company with the financial flexibility to take advantage of the opportunities provided by the farm-in and expand its drilling program on its Cardium lands.

The Company's annual production guidance for 2010 is 8,000 to 8,500 BOED. Risks associated with this guidance include continued low prices which may restrict capital spending, gas plant capacity, gas plant turnaround duration, regulatory issues, weather problems and access to industry services.

QUARTERLY INFORMATION

The following table provides financial and operating results for the last eight quarters. Earnings were negatively impacted in the fourth quarter of 2008 by a \$35.4 million charge for impairment of goodwill. Prices declined from the second quarter of 2008 to the third quarter of 2009 and remain volatile, resulting in lower funds from operations and earnings throughout most of 2009 and into the first quarter of 2010.

SELECTED QUARTERLY INFORMATION

(\$ amounts in thousands, except per share amounts and prices)

	Q1 2010	Q4 2009	Q3 2009	Q2 2009
Oil and gas revenue before royalties	\$ 23,265	\$ 20,439	\$ 14,617	\$ 17,508
Funds from operations	\$ 10,635	\$ 9,151	\$ 6,623	\$ 6,692
Funds from operations per share				
Basic	\$ 0.06	\$ 0.06	\$ 0.04	\$ 0.06
Diluted	\$ 0.06	\$ 0.06	\$ 0.04	\$ 0.06
Loss	\$ (5,953)	\$ (6,457)	\$ (9,432)	\$ (10,410)
Loss per share				
Basic	\$ (0.04)	\$ (0.04)	\$ (0.06)	\$ (0.09)
Diluted	\$ (0.04)	\$ (0.04)	\$ (0.06)	\$ (0.09)
Capital expenditures, including acquisitions net of dispositions	\$ 33,427	\$ 11,312	\$ 6,571	\$ 2,130
Cash from operating activities	\$ 12,946	\$ 5,361	\$ 6,689	\$ 2,472
Daily sales				
Natural gas (Mcf)	35,221	34,938	36,282	40,495
Liquids (bpd)	1,130	1,257	1,013	1,040
BOE (BOED)	7,000	7,080	7,060	7,789
Average prices				
Natural gas (\$/Mcf)	\$ 5.22	\$ 4.28	\$ 2.81	\$ 3.43
Liquids (\$/bbl)	\$ 62.43	\$ 53.79	\$ 53.84	\$ 49.00
BOE (\$/BOE)*	\$ 36.93	\$ 31.38	\$ 22.50	\$ 24.70

	Q1 2009	Q4 2008	Q3 2008	Q2 2008
Oil and gas revenue before royalties	\$ 24,429	\$ 30,102	\$ 39,427	\$ 49,021
Funds from operations	\$ 8,792	\$ 13,204	\$ 21,212	\$ 27,321
Funds from operations per share				
Basic	\$ 0.10	\$ 0.15	\$ 0.24	\$ 0.31
Diluted	\$ 0.10	\$ 0.15	\$ 0.24	\$ 0.31
Earnings (loss) before goodwill impairment	\$ (10,159)	\$ (5,865)	\$ 4,160	\$ 8,509
Earnings (loss) before goodwill impairment per share				
Basic	\$ (0.12)	\$ (0.07)	\$ 0.05	\$ 0.10
Diluted	\$ (0.12)	\$ (0.07)	\$ 0.05	\$ 0.10
Earnings (loss)	\$ (10,159)	\$ (41,229)	\$ 4,160	\$ 8,509
Earnings (loss) per share				
Basic	\$ (0.12)	\$ (0.47)	\$ 0.05	\$ 0.10
Diluted	\$ (0.12)	\$ (0.47)	\$ 0.05	\$ 0.10
Capital expenditures, including acquisitions net of dispositions	\$ 13,545	\$ 27,470	\$ 27,068	\$ 16,772
Cash from operating activities	\$ 9,298	\$ 11,261	\$ 26,351	\$ 27,660
Daily sales				
Natural gas (Mcf)	42,344	38,090	38,703	39,881
Liquids (bpd)	1,448	1,341	1,221	1,265
BOE (BOED)	8,505	7,689	7,671	7,912
Average prices				
Natural gas (\$/Mcf)	\$ 5.15	\$ 6.76	\$ 7.86	\$ 10.26
Liquids (\$/bbl)	\$ 38.69	\$ 48.49	\$ 90.19	\$ 97.61
BOE (\$/BOE)*	\$ 31.91	\$ 42.55	\$ 55.87	\$ 68.08

* Includes royalty and other income classified with oil and gas sales.

ADVISORY

Certain information regarding Anderson Energy Ltd. in this news release including, without limitation, management's assessment of future plans and operations, benefits and valuation of the development prospects described herein, number of locations in drilling inventory and wells to be drilled, timing and location of drilling and tie-in of wells and the costs thereof, productive capacity of the wells, timing of and construction of facilities, expected production rates, dates of commencement of production, amount of capital expenditures and timing thereof, value of undeveloped land, extent of reserves additions, ability to attain cost savings, drilling program success, impact of changes to the royalty regime applicable to the Company, including payment of drilling incentive credits, commodity price outlook and general economic outlook may constitute forward-looking statements under applicable securities laws and necessarily involve risks and assumptions made by management of the Company including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserves estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, wells not performing as expected, incorrect assessment of the value of acquisitions and farm-ins, failure to realize the anticipated benefits of acquisitions and farm-ins, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Anderson Energy's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at Anderson Energy's website (www.andersonenergy.ca).

Furthermore, the forward-looking statements contained in this news release are made as at the date of this news release and Anderson Energy does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Disclosure provided herein in respect of barrels of oil equivalent (BOE) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

ANDERSON ENERGY LTD.

Consolidated Balance Sheets

(Stated in thousands of dollars)
(Unaudited)

	March 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash	\$ 1	\$ 1
Accounts receivable and accruals (note 7)	20,838	22,990
Prepaid expenses and deposits	<u>3,939</u>	<u>3,778</u>
	24,778	26,769
Property, plant and equipment (note 1)	<u>487,118</u>	<u>470,400</u>
	<u>\$ 511,896</u>	<u>\$ 497,169</u>
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accruals	\$ 51,706	\$ 36,889
Current portion of bank loans (note 2)	<u>10,000</u>	<u>-</u>
	61,706	36,889
Bank loans (note 2)	28,825	62,404
Asset retirement obligations (note 3)	34,994	33,879
Future income taxes	<u>28,896</u>	<u>31,278</u>
	154,421	164,450
Shareholders' equity:		
Share capital (note 4)	421,936	391,637
Contributed surplus (note 4)	6,514	6,104
Deficit	<u>(70,975)</u>	<u>(65,022)</u>
	357,475	332,719
Commitments (note 8)		
	<u>\$ 511,896</u>	<u>\$ 497,169</u>

See accompanying notes to the consolidated financial statements.

ANDERSON ENERGY LTD.

Consolidated Statements of Operations, Comprehensive Loss and Deficit

THREE MONTHS ENDED MARCH 31, 2010 AND 2009

(Stated in thousands of dollars, except per share amounts)
(Unaudited)

	2010	2009
REVENUES		
Oil and gas sales	\$ 23,265	\$ 24,429
Royalties	(3,394)	(4,434)
Interest income	<u>58</u>	<u>116</u>
	19,929	20,111
EXPENSES		
Operating	6,876	8,272
General and administrative	1,719	2,007
Stock-based compensation	224	265
Interest and other financing charges	699	1,040
Depletion, depreciation and accretion	<u>18,303</u>	<u>22,721</u>
	<u>27,821</u>	<u>34,305</u>
Loss before taxes	(7,892)	(14,194)
Future income tax reduction	<u>(1,939)</u>	<u>(4,035)</u>
Loss and comprehensive loss for the period	(5,953)	(10,159)
Deficit, beginning of period	<u>(65,022)</u>	<u>(28,564)</u>
Deficit, end of period	\$ (70,975)	\$ (38,723)
Loss per share (note 4)		
Basic	\$ (0.04)	\$ (0.12)
Diluted	<u>\$ (0.04)</u>	<u>\$ (0.12)</u>

See accompanying notes to the consolidated financial statements.

ANDERSON ENERGY LTD.

Consolidated Statements of Cash Flows

THREE MONTHS ENDED MARCH 31, 2010 AND 2009

(Stated in thousands of dollars)
(Unaudited)

	2010	2009
CASH PROVIDED BY (USED IN) OPERATIONS		
Loss for the period	\$ (5,953)	\$ (10,159)
Items not involving cash:		
Depletion, depreciation and accretion	18,303	22,721
Future income tax reduction	(1,939)	(4,035)
Stock-based compensation	224	265
Asset retirement expenditures	(229)	(938)
Changes in non-cash working capital:		
Accounts receivable and accruals	185	1,215
Prepaid expenses and deposits	147	23
Accounts payable and accruals	2,208	206
	<u>12,946</u>	<u>9,298</u>
FINANCING		
Increase (decrease) in bank loans	(23,579)	25,506
Issue of common shares, net of issue costs	29,792	-
Changes in non-cash working capital:		
Accounts payable and accruals	260	-
	<u>6,473</u>	<u>25,506</u>
INVESTMENTS		
Additions to property, plant and equipment	(35,398)	(13,572)
Proceeds on disposition of properties	1,971	27
Changes in non-cash working capital:		
Accounts receivable and accruals	1,967	3,731
Prepaid expenses and deposits	(308)	(66)
Accounts payable and accruals	12,349	(24,925)
	<u>(19,419)</u>	<u>(34,805)</u>
Decrease in cash	-	(1)
Cash, beginning of period	<u>1</u>	<u>1</u>
Cash, end of period	<u>\$ 1</u>	<u>\$ -</u>

See note 6 for additional cash information.

See accompanying notes to the consolidated financial statements.

ANDERSON ENERGY LTD.

Notes to the Consolidated Financial Statements

THREE MONTHS ENDED MARCH 31, 2010 AND 2009

(Tabular amounts in thousands of dollars, unless otherwise stated)
(Unaudited)

Anderson Energy Ltd. (“Anderson Energy” or the “Company”) was incorporated under the laws of the province of Alberta on January 30, 2002. Anderson Energy is engaged in the acquisition, exploration and development of oil and gas properties in western Canada. These interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2009. The disclosures included below are incremental to those included with the annual consolidated financial statements. These interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto for the year ended December 31, 2009.

1. PROPERTY, PLANT AND EQUIPMENT

	<i>March 31, 2010</i>	<i>December 31, 2009</i>
Cost	\$ 757,956	\$ 723,549
Less accumulated depletion and depreciation	<u>(270,838)</u>	<u>(253,149)</u>
Net book value	<u>\$ 487,118</u>	<u>\$ 470,400</u>

At March 31, 2010, unproved property costs of \$5.2 million (December 31, 2009 – \$6.2 million) have been excluded from the full cost pool for depletion and depreciation calculations. Future development costs of proved, undeveloped reserves of \$149.4 million (December 31, 2009 – \$197.6 million) have been included in the depletion and depreciation calculation.

For the three months ended March 31, 2010, \$1.0 million (March 31, 2009 – \$1.3 million) of general and administrative costs including \$0.2 million (March 31, 2009 – \$0.2 million) of stock-based compensation costs were capitalized. The future tax liability of \$64,000 (March 31, 2009 – \$80,000) associated with the capitalized stock-based compensation has also been capitalized. Capitalized general and administrative costs consist of salaries and associated office rent of staff involved in capital activities.

No impairment was recognized under the ceiling test at March 31, 2010. The future commodity prices used in the ceiling test were based on commodity price forecasts of the Company’s independent reserve engineers adjusted for differentials specific to the Company’s reserves. Factors used in the ceiling test calculation are as follows:

1. PROPERTY, PLANT AND EQUIPMENT *(Continued)*

	<i>AECO Gas Price (\$Cdn/Mcf)</i>	<i>WTI Cushing (\$US/bbl)</i>	<i>Exchange rate (US\$/Cdn)</i>
2010 Q2-Q4	4.30	80.00	0.95
2011	5.26	83.00	0.95
2012	5.95	86.00	0.95
2013	6.42	89.00	0.95
2014	6.79	92.00	0.95
2015	7.05	93.84	0.95
2016	7.40	95.72	0.95
2017	7.72	97.64	0.95
2018	7.89	99.59	0.95
2019	8.06	101.58	0.95
Thereafter 2%			

After 2019, only inflationary growth of 2% was considered. Natural gas liquids prices were tied to crude oil prices based on historical trends and analysis. Exchange rates were expected to remain consistent from 2019 forward.

2. BANK LOANS

At March 31, 2010, the Company has a \$90 million extendible, revolving term credit facility and a \$10 million working capital credit facility (the "Facilities") with a syndicate of Canadian banks. At March 31, 2010, the Company has \$0.4 million of letters of credit outstanding, which reduces the amount of credit available to the Company.

The reserves-based Facilities have a revolving period ending on July 13, 2010, extendible at the option of the lenders, followed by a term period with three equal quarterly principal repayments commencing 180 days from the term date. At March 31, 2010, the Company classified \$10 million of the outstanding bank loan as a current liability as the normal annual review by lenders had not yet been completed. The review is currently underway and is expected to be completed by the end of May 2010. The Company has no reason to believe that the revolving period of the facility will not be extended for another year or, therefore, that any portion of the bank loan will ultimately become payable in the next year. The average effective interest rate on advances in 2010 was 4.5% (March 31, 2009 – 4.4%).

Advances under the Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR loan rates plus applicable margins. The margins vary depending on the borrowing option used and the Company's financial ratios. At March 31, 2010, there were no advances in U.S. funds.

Loans are secured by a floating charge debenture over all assets and guarantees by material subsidiaries. The available lending limits of the Facilities are reviewed semi-annually and are based on the bank syndicate's interpretations of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facilities or the applicable margins will not be adjusted during the lender's review.

3. ASSET RETIREMENT OBLIGATIONS

The Company estimates the total undiscounted cash flows required to settle its asset retirement obligations is approximately \$71.7 million (December 31, 2009 – \$70.1 million), including expected inflation of 2% (December 31, 2009 – 2%) per annum. The majority of the costs will be incurred between 2010 and 2020. A credit adjusted risk-free rate of 8% to 10% (December 31, 2009 – 8% to 10%) was used to calculate the fair value of the asset retirement obligations. A reconciliation of the asset retirement obligations is provided below:

	<i>March 31, 2010</i>	<i>December 31, 2009</i>
Balance, beginning of period	\$ 33,879	\$ 30,820
Liabilities incurred	348	1,544
Liabilities settled	(229)	(1,482)
Change in estimate	382	666
Accretion expense	614	2,331
Balance, end of period	<u>\$ 34,994</u>	<u>\$ 33,879</u>

4. SHARE CAPITAL AND CONTRIBUTED SURPLUS

Authorized share capital. The Company is authorized to issue an unlimited number of common and preferred shares. The preferred shares may be issued in one or more series.

Issued share capital.

	<i>Number of Common Shares</i>	<i>Amount</i>
Balance at December 31, 2008	87,300,401	\$ 334,176
Issued pursuant to prospectus ⁽¹⁾	63,200,000	60,040
Share issue costs	-	(3,502)
Tax effect of share issue costs	-	923
Balance at December 31, 2009	150,500,401	\$ 391,637
Issued pursuant to prospectus ⁽²⁾	21,900,000	31,755
Share issue costs	-	(1,963)
Tax effect of share issue costs	-	507
Balance at March 31, 2010	<u>172,400,401</u>	<u>\$ 421,936</u>

(1) Includes 4,992,034 common shares issued to management and directors and 3,377,966 common shares issued to family of management and directors for total gross proceeds of \$8.0 million.

(2) Includes 352,466 common shares issued to directors for total gross proceeds of \$0.5 million.

Stock options. The Company has an employee stock option plan under which employees, directors and consultants are eligible to receive grants. The exercise price of stock options equals the weighted average trading price of the Company's shares for the five trading days prior to the date of the grant. Options have terms of either five or ten years and vest equally over a three year period starting on the first anniversary date of the grant. Changes in the

4. SHARE CAPITAL AND CONTRIBUTED SURPLUS (Continued)

number of options outstanding during the three months ended March 31, 2010 and year ended December 31, 2009 are as follows:

	<i>Number of options</i>	<i>Weighted average exercise price</i>
Balance at December 31, 2008	7,594,856	\$ 4.37
Granted	3,316,200	0.80
Expirations	(252,300)	6.47
Forfeitures	(400,00)	3.01
Balance at December 31, 2009	10,258,756	\$ 3.22
Granted	74,100	1.28
Expirations	(17,500)	4.87
Forfeitures	(12,500)	1.67
Balance at March 31, 2010	10,302,856	\$ 3.20
Exercisable at March 31, 2010	5,812,039	\$ 4.51

<i>Range of exercise prices</i>	<i>Options outstanding</i>			<i>Options exercisable</i>	
	<i>Number of options</i>	<i>Weighted average exercise price</i>	<i>Weighted average remaining life (years)</i>	<i>Number of options</i>	<i>Weighted average exercise price</i>
\$0.79 to \$0.99	3,136,200	\$ 0.79	4.4	-	-
\$1.00 to \$1.50	163,200	1.17	4.5	17,700	1.05
\$2.26 to \$3.35	842,700	2.68	3.5	280,900	2.68
\$3.36 to \$5.00	5,090,156	4.01	2.3	4,448,839	4.00
\$5.01 to \$7.50	429,600	6.03	1.3	423,600	6.05
\$7.51 to \$9.01	641,000	7.93	0.6	641,000	7.93
Total at March 31, 2010	10,302,856	\$ 3.20	2.9	5,812,039	\$ 4.51

The fair value of the options issued during the three months ended March 31, 2010 was \$0.68 (March 31, 2009 – \$0.66) per option. The weighted average assumptions used in arriving at the values were: a risk-free interest rate of 2.34% (March 31, 2009 – 1.70%), expected option life of five years (March 31, 2009 – five years), expected volatility of 60% (March 31, 2009 – 83%) and a dividend yield of 0% (March 31, 2009 – 0%).

4. SHARE CAPITAL AND CONTRIBUTED SURPLUS (Continued)

Per share amounts. During the three months ended March 31, 2010 there were 163,810,957 weighted average shares outstanding (March 31, 2009 – 87,300,401). On a diluted basis, there were 163,810,957 weighted average shares outstanding (March 31, 2009 – 87,300,401) after giving effect to dilutive stock options. At March 31, 2010, there were 10,302,856 options that were anti-dilutive (March 31, 2009 – 7,404,856).

Contributed surplus

	<i>Amount</i>
Balance at December 31, 2008	\$ 4,000
Stock-based compensation	<u>2,104</u>
Balance at December 31, 2009	\$ 6,104
Stock-based compensation	<u>410</u>
Balance at March 31, 2010	<u>\$ 6,514</u>

Employee stock savings plan. Effective July 1, 2008, the Company initiated an Employee Stock Savings Plan (“ESSP”). Employees could contribute up to 5% of their base salaries towards the purchase of Company shares and the Company matched these contributions. The ESSP was suspended between April 1, 2009 and March 31, 2010 due to market conditions. The Company’s matching contribution, prior to the suspension of the plan, for the three months ended March 31, 2009 was \$77,000 and is included in general and administrative expenses. The Company reinstated the plan effective April 1, 2010.

5. MANAGEMENT OF CAPITAL STRUCTURE

The Company manages its capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Company’s capital structure includes shareholders’ equity of \$357.5 million, long-term bank loans of \$28.8 million and the working capital deficiency of \$36.9 million. In order to maintain or adjust the capital structure, the Company may from time to time issue shares, seek additional debt financing and adjust its capital spending to manage current and projected debt levels.

Consistent with other companies in the oil and gas sector, Anderson Energy monitors capital based on the ratio of total debt to funds from operations. This ratio is calculated by dividing total debt at the end of the period (comprised of the working capital deficiency and outstanding long term bank loans) by the annualized current quarter funds from operations (cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures). This ratio may increase at certain times as a result of acquisitions, the timing of capital expenditures and market conditions. In order to facilitate the management of this ratio, the Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast crude oil and natural gas prices, capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

5. MANAGEMENT OF CAPITAL STRUCTURE *(Continued)*

	<i>March 31, 2010</i>	<i>December 31, 2009</i>
Bank loans - long-term	\$ 28,825	\$ 62,404
Current liabilities (including current portion of bank loans)	61,706	36,889
Current assets	(24,778)	(26,769)
Total debt	\$ 65,753	\$ 72,524
Cash from operating activities in quarter	\$ 12,946	\$ 5,361
Changes in non-cash working capital	(2,540)	3,246
Asset retirement expenditures	229	544
Funds from operations in quarter	\$ 10,635	\$ 9,151
Annualized current quarter funds from operations	\$ 42,540	\$ 36,604
Total debt to funds from operations	1.5	2.0

At March 31, 2010, the Company's total debt to annualized funds from operations was 1.5. At December 31, 2009, the Company's total debt to annualized funds from operations was 2.0. In February 2010, the Company closed a common share equity issue for net proceeds of \$29.8 million which was initially used to pay down bank debt.

Commodity prices at the end of the first quarter of 2010 were lower than the average prices received in the quarter and used in this calculation. The Company's share capital is not subject to external restrictions, however, the Facilities are petroleum and natural gas reserves based (see note 2). Anderson Energy has not paid or declared any dividends since the date of incorporation and does not contemplate doing so in the foreseeable future.

6. CASH PAYMENTS

The following cash payments were made (received):

	<i>March 31, 2010</i>	<i>March 31, 2009</i>
Interest paid	\$ 262	\$ 1,177
Interest received	(56)	(4)

7. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Company's financial instruments include cash, accounts receivable and accruals, accounts payable and accruals and bank loans. The fair value of cash approximates its carrying value due to its short-term nature. The fair value of accounts receivable and accruals and accounts payable and accruals approximate their carrying value due to their demand nature or relatively short periods to maturity. The fair value of bank loans approximates their carrying value as they bear interest at a floating rate.

7. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT *(Continued)*

The Company has exposure to credit risk, liquidity risk and market risk as a result of its use of financial instruments.

Credit risk. Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. As at March 31, 2010, the maximum credit exposure is the carrying amount of the accounts receivable and accruals of \$20.8 million (December 31, 2009 – \$23.0 million). As at March 31, 2010, the Company's receivables consisted of \$12.2 million (December 31, 2009 – \$14.4 million) from joint venture partners and other trade receivables and \$8.6 million (December 31, 2009 – \$8.6 million) of revenue accruals and other receivables from petroleum and natural gas marketers. Of the \$8.6 million of revenue accruals and receivables from petroleum and natural gas marketers, \$8.0 million was received on or about April 26, 2010. The balance is expected to be received in subsequent months through joint venture billings from partners.

The Company's allowance for doubtful accounts as at March 31, 2010 is \$1.6 million (December 31, 2009 - \$1.6 million). The Company did not write-off any receivables during the three months ended March 31, 2010.

As at March 31, 2010 the Company considers its receivables net of allowance for doubtful accounts, to be aged as follows:

<i>Aging</i>	<i>March 31, 2010</i>	
Not past due	\$	20,331
Past due by less than 120 days		134
Past due by more than 120 days		<u>373</u>
Total	\$	<u>20,838</u>

These amounts are before offsetting amounts owing to joint venture partners that are included in accounts payable and accrued liabilities.

Liquidity risk. Liquidity risk is the risk that the Company will incur difficulties meeting its financial obligations as they are due.

The following are the contractual maturities of financial liabilities and associated interest payments as at March 31, 2010:

<i>Financial Liabilities</i>	<i>< 1 Year</i>		<i>1-2 Years</i>	
Accounts payable and accruals	\$	51,706	\$	-
Bank loans – principal		<u>10,000</u>		<u>28,825</u>
Total	\$	<u>61,706</u>	\$	<u>28,825</u>

Please refer to note 2 for additional details on bank loans and to note 8 for additional details on commitments.

7. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT *(Continued)*

Market risk. Market risk consists of currency risk, commodity price risk and interest rate risk.

Currency risk. Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. The Company had no outstanding forward exchange rate contracts in place at March 31, 2010 or December 31, 2009.

Commodity price risk. Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. In December 2009, the Company entered into physical sales contracts to sell 20,000 GJ per day of natural gas for each of January, February and March 2010 at an average AECO price of \$5.41 per GJ. The gains realized to March 31, 2010 were \$1.3 million and have been included in oil and gas sales. There were no commodity price risk contracts outstanding at March 31, 2010.

Interest rate risk. Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank debt which bears interest at a floating rate. For the three months ended March 31, 2010, if interest rates had been 1% lower with all other variables held constant, earnings for the period would have been \$81,800 (March 31, 2009 – \$155,000) higher, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amounts. The decrease period over period is due to lower average debt levels outstanding. The Company had no interest rate swap or financial contracts in place at March 31, 2010 or December 31, 2009.

8. COMMITMENTS

On January 29, 2009, the Company executed a farm-in agreement with a large international oil and gas company (the “Farmor”) on lands near its existing core operations. Under the farm-in agreement, the Company has access to 388 gross (205 net) sections of land. During the commitment phase of the transaction, the Company is committed to drill, complete and equip 200 wells to earn an interest in up to 120 sections. The Company is obligated to complete the drilling of the wells on or before December 31, 2010. The Company’s equipping obligation is up to, but does not include, multi-well gathering systems downstream of field compression and/or gas plants. The Company has an option to continue the farm-in transaction until April 30, 2012 by committing to drill a minimum of 100 additional wells under similar terms as in the commitment phase to earn a minimum of 50 sections of land. Following the commitment and/or option phases, the parties to the agreement can then jointly develop the lands on denser drilling spacing under terms of an operating agreement.

The Company commenced drilling in the fourth quarter of 2009 and currently estimates that the average working interest of the 200 well capital commitment will be approximately 80% to 85%, based on partner participation identified to date. The Company’s commitment was to drill 75 wells by December 31, 2009, a further 50 wells by April 30, 2010 and a further 75 wells by December 31, 2010. The Company earns its interest in each well as the well is put on production. A \$550,000 penalty is payable for each well not drilled under the commitment as of December 31, 2010, subject to certain reductions due to unavoidable events beyond

8. COMMITMENTS *(Continued)*

the Company's control and rights of first refusal. As of March 31, 2010, the Company has drilled 126 wells under the farm-in agreement and plans to drill the remaining 74 wells in the fourth quarter of 2010. The Company estimates that its minimum commitment to drill the remaining 74 wells is \$10 million to the end of 2010. The Company currently plans to spend a total of \$23 million in the remainder of 2010 on the farm-in project to drill and complete the remaining farm-in wells, tie-in wells drilled in the first quarter of 2010 and complete the construction of facilities..

The Company has entered into an agreement to lease office space until November 30, 2012. Future minimum lease payments are expected to be \$1.3 million for the remainder of 2010, \$1.8 million in 2011 and \$1.6 million in 2012.

The Company entered into firm service transportation agreements for approximately 27 million cubic feet per day of gas sales in central Alberta for various terms expiring in one to ten years. Based on rate schedules announced to date, the payments in each of the next five years and thereafter are estimated as follows:

	<i>Committed volume (MMcfd)</i>	<i>Committed amount</i>
2010 Q2-Q4	27	\$ 1,902
2011	26	\$ 1,809
2012	17	\$ 1,312
2013	7	\$ 810
2014	4	\$ 689
Thereafter	12	\$ 1,013

Corporate Information

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Glenn D. Hockley ⁽¹⁾⁽³⁾
Calgary, Alberta

David G. Scobie ⁽¹⁾⁽²⁾
Calgary, Alberta

David J. Sandmeyer has been nominated for election to the Board of Directors at the Annual General Meeting on May 13, 2010

Member of:

- (1) Audit Committee
- (2) Compensation & Corporate Governance Committee
- (3) Reserves Committee

Auditors

KPMG LLP

Independent Engineers

GLJ Petroleum Consultants

Legal Counsel

Bennett Jones LLP

Registrar & Transfer Agent

Valiant Trust Company

Stock Exchange

The Toronto Stock Exchange
Symbol AXL

Contact Information

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Brian H. Dau
President & Chief Executive Officer
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Officers

J.C. Anderson
Chairman of the Board

Brian H. Dau
President & Chief Executive Officer

David M. Spyker
Chief Operating Officer

M. Darlene Wong
Vice President Finance, Chief Financial Officer & Secretary

Blaine M. Chicoine
Vice President, Operations

Philip A. Harvey
Vice President, Exploitation

Daniel F. Kell
Vice President, Land

Jamie A. Marshall
Vice President, Exploration

Abbreviations used

AECO – intra-Alberta Nova inventory transfer price
bbl – barrel
bpd – barrels per day
Mbbls – thousand barrels
Mstb – thousand stock tank barrels
BOE – barrels of oil equivalent
BOED – barrels of oil equivalent per day
BOPD – barrels of oil per day
MBOE – thousand barrels of oil equivalent
GJ – gigajoule
Mcf – thousand cubic feet
Mcfcd – thousand cubic feet per day
MMcf – million cubic feet
MMcfcd – million cubic feet per day
Bcf – billion cubic feet