

ANDERSON ENERGY ANNOUNCES 2009 FIRST QUARTER RESULTS

Calgary, Alberta, May 14, 2009 - Anderson Energy Ltd. ("Anderson Energy" or the "Company") (TSX:AXL) is pleased to announce its operating and financial results for the first quarter ended March 31, 2009.

HIGHLIGHTS:

- The Company achieved record average quarterly production of 8,505 BOED in the first quarter of 2009, an increase of 8% over the first quarter of 2008.
- Funds from operations were \$8.8 million (\$0.10 per share) in the first quarter of 2009, down 50% from the first quarter of 2008 due to lower commodity prices.
- On January 30, 2009, the Company announced a significant farm-in transaction in its Edmonton Sands project area. This farm-in more than doubles the Company's existing land base with the addition of 388 gross (205 net) sections of land.
- The Company drilled 11 gross (8.3 net) Edmonton Sands gas wells with a success rate of 100% in the first quarter of 2009.
- The Company's current drilling inventory, including the recent farm-in lands, is 1,805 gross (994 net) locations with the Edmonton Sands representing 96% of the net locations.
- The average royalty rate as a percentage of revenue was 18% in the first quarter of 2009 compared to 23% in the comparable quarter of 2008. The reduction in royalties is primarily due to the effect of lower natural gas prices on royalties paid under the Alberta New Royalty Framework. Operating expenses in the first quarter of 2009 were \$10.81 per BOE, which were 11% lower than the comparable quarter of 2008.
- The Alberta government recently announced new royalty incentives which will benefit Anderson Energy. They include a royalty credit of \$200 per drilling meter, as well as a 5% royalty on any new production tied in between April 1, 2009 and April 1, 2010. With respect to the Company's Edmonton Sands drilling program, the \$200 per drilling meter royalty credit is approximately the same as the Company's drilling cost. The net impact of the reduction in Crown royalties is that the drilling portion of the Edmonton Sands wells drilled as part of the farm-in transaction on Crown lands prior to April 1, 2010 will be at no net cost to the Company.
- On May 7, 2009, the Company entered into an agreement with a syndicate of underwriters to purchase on a bought deal basis pursuant to a short form prospectus, 63,200,000 common shares at a price of \$0.95 per common share for gross proceeds to Anderson Energy of approximately \$60 million.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended March 31		% Change
<i>(thousands of dollars, unless otherwise stated)</i>	2009	2008	
Oil and gas revenue before royalties	\$ 24,429	\$ 37,695	(35%)
Funds from operations	\$ 8,792	\$ 17,591	(50%)
Funds from operations per share			
Basic	\$ 0.10	\$ 0.20	(50%)
Diluted	\$ 0.10	\$ 0.20	(50%)
Earnings (loss)	\$ (10,159)	\$ 1,696	(699%)
Earnings (loss) per share			
Basic	\$ (0.12)	\$ 0.02	(700%)
Diluted	\$ (0.12)	\$ 0.02	(700%)
Capital expenditures, including acquisitions net of dispositions	\$ 13,545	\$ 35,359	(62%)
Debt, net of working capital	\$ 130,971	\$ 114,770	14%
Shareholders' equity	\$ 299,949	\$ 336,553	(11%)
Average shares outstanding <i>(thousands)</i>			
Basic	87,300	87,294	0%
Diluted	87,300	87,294	0%
Ending shares outstanding <i>(thousands)</i>	87,300	87,294	0%
Average daily sales			
Natural gas <i>(Mcf)</i>	42,344	39,210	8%
Liquids <i>(bpd)</i>	1,448	1,345	8%
Barrels of oil equivalent <i>(bpd)</i>	8,505	7,879	8%
Average prices			
Natural gas <i>(\$/Mcf)</i>	\$ 5.15	\$ 7.55	(32%)
Liquids <i>(\$/bbl)</i>	\$ 38.69	\$ 83.91	(54%)
Barrels of oil equivalent <i>(\$/BOE) *</i>	\$ 31.91	\$ 52.57	(39%)
Royalties <i>(\$/BOE)</i>	\$ 5.79	\$ 12.12	(52%)
Operating costs <i>(\$/BOE)</i>	\$ 10.81	\$ 12.13	(11%)
Operating netback <i>(\$/BOE)</i>	\$ 15.31	\$ 28.32	(46%)
General and administrative <i>(\$/BOE)</i>	\$ 2.62	\$ 2.16	21%
Wells drilled <i>(gross)</i>	11	86	(87%)

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

2009 FIRST QUARTER IN REVIEW

In the first quarter, the Company drilled 11 gross (8.3 net) Edmonton Sands wells at a 100% success rate. In addition, the Company tied in 32 gross (24.5 net) Edmonton Sands wells. The highlight of the quarter was the Wilson Creek discovery where 5 Edmonton Sands wells were drilled and tied in for production late in the quarter. The Company's Wilson Creek gas plant is currently running at full capacity with approximately 6.5 MMcfd gross (4.6 MMcfd net) raw gas being compressed at the facility. One of the Wilson Creek Edmonton Sands wells represents 42% of the throughput in the facility. This is the best producing Edmonton Sands well in the Company.

For the quarter ended March 31, 2009, the Company averaged 8,505 BOED, with peak production occurring in the middle of March at 8,700 BOED. The Company originally planned to drill 200 Edmonton Sands wells in the winter of 2008/2009 and to complete and equip essentially all of the wells for production prior to spring breakup. However, with the deterioration of commodity prices in the fourth quarter of 2008 and the first quarter of 2009, the Company reduced the size of the winter drilling program to 95 gross (67.8 net) wells and elected not to tie-in 1,000 BOED of behind pipe production from the newly drilled wells. The behind pipe production will be tied in when natural gas prices are stronger. The Company's strategy is to preserve its balance sheet and allow for future financial flexibility for the significant farm-in project that is expected to commence drilling in the fourth quarter of this year.

The Company expects average production in the second quarter of 2009 to be 7,600 to 8,000 BOED. Current behind pipe production capability is approximately 1,000 BOED. In addition, the Company has shut-in 200 BOED of production due to poor natural gas prices. Production is also being negatively impacted by approximately 100 BOED due to re-injection of ethane into the gas stream due to poor ethane pricing. Historically, the Company experiences significant plant turnaround activity in the second quarter which will negatively impact production.

Capital expenditures, net of dispositions, were \$13.5 million in the first quarter of 2009, and were comprised almost entirely of expenditures on Edmonton Sands drilling and well tie-ins.

The Company's funds from operations were \$8.8 million in the first quarter of 2009 as compared to \$17.6 million in the first quarter of 2008. The Company's average natural gas sales price was \$5.15 per Mcf in the first quarter of 2009 as compared to \$7.55 per Mcf in the first quarter of 2008. The Company's average crude oil and natural gas liquids sales price in the first quarter of 2009 was \$38.69 per bbl as compared to \$83.91 per bbl in the first quarter of 2008. The Company's operating netback was \$15.31 per BOE in the first quarter of 2009 as compared to \$28.32 per BOE in the first quarter of 2008. The change in the operating netback was primarily due to lower commodity prices partially offset by lower operating expenses and lower royalties. The average royalty rate as a percentage of revenue in the first quarter of 2009 was 18% as compared to 23% in the comparable quarter of 2008. The reduction is primarily due to the effect of lower natural gas prices on royalties paid under the Alberta New Royalty Framework. Operating expenses in the first quarter of 2009 were \$10.81 per BOE, which were 11% lower than the comparable quarter of 2008. The Company has recently implemented various operating expense reduction initiatives on its asset base, including negotiations with service providers and the shut-in of higher cost production. In addition, the Wilson Creek discovery is flowing into the Wilson Creek gas plant, which was constructed in 2008 and is the first gas plant constructed to

specifications designed specifically for operation in the Edmonton Sands. With the plant now operating at full capacity, the current operating expenses of the facility are less than \$1.50 per BOE. The Company is reviewing the potential to construct similar facilities to compress gas produced from wells to be drilled on lands under its recently announced Edmonton Sands farm-in agreement.

FARM-IN TRANSACTION

On January 30, 2009, the Company announced a significant farm-in transaction (the "Farm-In") with an international oil company in its Edmonton Sands project area.

Anderson Energy believes that the transaction will deliver significant benefits to the Company and will define it as the major Edmonton Sands resource player in Central Alberta. Through the Farm-In, the Company more than doubles its land and prospect inventory in its primary core area. The Company will preserve its financial position through 2010 by focusing the 2009/2010 winter drilling program primarily on earning new lands under the Farm-In and deferring drilling on equal opportunities on existing lands.

Under the Farm-In, the Company has access to 388 gross (205 net) sections of land in the middle of the Edmonton Sands fairway. Anderson Energy has identified 293 sections with Edmonton Sands drilling potential on the lands.

During the commitment phase of the Farm-In, 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 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.

Under the terms of the Farm-In agreement, the Company also has access to drilling opportunities on lands with existing production and access to suspended wellbores with Edmonton Sands potential.

The Company estimates the average working interest of the 200 well commitment is approximately 65% and expects to commence drilling in a meaningful way in the fourth quarter of 2009. The first 200 wells will be concentrated on the Farmor's contiguous land blocks.

The Company believes that this transaction has several key benefits:

- The Company more than doubles its total land position in the Edmonton Sands play.
- Lands earned create a more contiguous land base in the heart of the Edmonton Sands fairway.
- The Farm-In offers the ability to high grade the Company's drilling program to the most prospective lands with the highest production and reserve potential. Only 16% of the Farm-In lands have had an Edmonton Sands well drilled on them.

- The contiguous nature of the lands is well suited to constructing customized gas processing facilities which will lower overall corporate operating costs.
- The Farm-In will be relatively low risk development drilling in an area where the Company has extensive experience with repeatable results.
- At current prices, the Alberta New Royalty Framework results in lower royalties in this shallow gas drilling area than under the previous royalty regime.
- Economics of the Edmonton Sands play are still attractive in the current low gas price environment when combined with the royalty incentives announced on March 3, 2009.
- The Company is positioned to expand future drilling programs if commodity and financial markets improve.

The Company has grown its Edmonton Sands land position from 303 gross (179 net) sections in 2007 to 716 gross (403 net) sections currently, including lands acquired through the Farm-In.

As of March 31, 2009 the Company's drilling inventory is as follows:

	<i>Gross</i>	<i>Net</i>
Edmonton Sands (as booked in the GLJ reserves report)	658	357
Edmonton Sands Farm-In lands	1,000	595
Horseshoe Canyon CBM (as booked in the AJM reserves report)	120	23
Other	27	19
Total	1,805	994

ROYALTY INCENTIVES

On March 3, 2009, the Alberta government announced new royalty initiatives which reduce royalties based on future drilling activity. There are two measures being implemented. The first is a \$200 per drilling meter royalty credit based on drilling activity on Crown lands from April 1, 2009 to April 1, 2010. The Company is committed to drill 125 wells on the Farm-In lands during that period and could potentially generate a royalty credit of \$12 million through that activity as approximately 75% of the Farm-In lands are Crown lands. This credit can be used to offset 50% of Crown royalties payable after the wells have been drilled, until March 31, 2011. With the Edmonton Sands drilling costs similar to the \$200 per drilling meter royalty credit, the impact of the reduction in Crown royalties is that the drilling portion of the Edmonton Sands wells will be at no net cost to the Company. The second measure announced was that new wells tied in for production on Crown lands from April 1, 2009 to April 1, 2010 would pay a reduced Crown royalty rate of 5% for the first 500 MMcf of gas production. All of these measures have the potential to significantly reduce future Crown royalties payable by the Company.

SHARE OFFERING

On May 7, 2009, the Company entered into an agreement with a syndicate of underwriters to purchase on a bought deal basis pursuant to a short form prospectus, 63,200,000 common shares at a price of \$0.95 per common share for gross proceeds to Anderson Energy of approximately \$60 million (the "Offering"). Anderson Energy has also granted the underwriters

an option to buy up to an additional 9,480,000 common shares for additional gross proceeds of approximately \$9 million, to cover over-allotments.

J.C. Anderson, Chairman of the Board, certain members of the Anderson family and Brian Dau, President and Chief Executive Officer, are expected to acquire over 12% of the Offering (11% if the overallotment option is exercised).

Proceeds of the Offering will be used to pay down the Company's bank debt and fund its capital program including commitments under the Farm-In. On May 13, 2009, the Company agreed with its lenders to renew its credit facilities to July 13, 2010 at a combined amount of \$100 million, subject to customary loan and security documentation, completion of the Offering and normal course closing conditions. Pro forma debt, net of working capital deficiency, after giving effect to the Offering would be \$74 million at March 31, 2009.

Closing of the Offering is expected to occur on or about May 28, 2009 and is subject to certain conditions including, but not limited to, the receipt of all necessary approvals, including the approval of the Toronto Stock Exchange.

OUTLOOK

The Company has seen significant unprecedented changes in capital, equity, commodity and currency markets in the later part of 2008 and the first half of 2009. The price of natural gas has weakened considerably, as fears of an extended U.S. recession have led to concerns of reduced U.S. industrial use of natural gas. Although there has been normal winter weather in North America, Canadian dollar natural gas prices are less than half of last year's average price. Another factor dampening the expectations on natural gas prices is the increased U.S. supply of natural gas in 2008, primarily from shale gas plays. United States dry gas supply has grown from an average of 52.3 Bcfd in 2007 to an average of 56.4 Bcfd in 2008 based on information from the Energy Information Administration. According to Baker Hughes Inc. rig data, in August 2008, the U.S. natural gas rig count peaked at 1,606 rigs, and in October 2008, the U.S. oil and gas horizontal rig count peaked at 650 rigs. Since then, the U.S. natural gas rig count has dropped to 730 rigs, which is the lowest it has been since July 2000. The U.S. oil and gas horizontal rig count has declined to 380 rigs. Shale gas wells typically have first year declines of 70 to 80 per cent and second year declines of 30 to 40 per cent. With the collapse in U.S. natural gas rig counts, the reduction in the horizontal rig count and the inherent high first year shale gas declines, the Company expects the U.S. natural gas supply to decline in the second half of 2009. Although natural gas prices are weaker today than last year, the Company expects U.S. natural gas prices to climb later in the year as a consequence of reduced supply. Historically in the natural gas business, the level of supply of natural gas is corrected, upward or downward, by strong or weak natural gas prices. The strength of price response later in the year will likely be impacted by the duration and impact of the U.S. recession.

The first half of 2009 is presenting challenging conditions in the natural gas business and the Company will be managing its business carefully during these times. However, the weak natural gas and crude oil prices also present an opportunity to reduce the cost of doing business and the Company plans to take advantage of that opportunity. The Offering will provide the Company with more financial flexibility to pursue its objectives. The Company is very enthused about its recent Farm-In and drilling is expected to commence in the fourth quarter of 2009 on these lands.

Vincent Chahley will be stepping down from the Board at the May 14, 2009 annual shareholders' meeting to return to his career in investment banking. On behalf of the Board and Management team, I would like to thank Vincent for his wise counsel and direction over the last 3 ½ years and wish him well in his future endeavours.

The Company invites its shareholders to attend the Company's annual general and special meeting of shareholders on May 14, 2009 at the Metropolitan Centre in Calgary, Alberta at 2:00 pm MDT and encourages anyone interested in further details on our Company to visit the Company's website at www.andersonenergy.ca.

Brian H. Dau
President & Chief Executive Officer
May 14, 2009

Management's Discussion and Analysis

FOR THE THREE MONTHS ENDED MARCH 31, 2009 AND 2008

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, 2009 and the audited consolidated financial statements and Management's Discussion and Analysis of Anderson Energy for the years ended December 31, 2008 and 2007 and is based on information available as of May 13, 2009.

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 and development ("F&D") 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. F&D 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 news release.

REVIEW OF FINANCIAL RESULTS

Overview. Sales volumes for the three months ended March 31, 2009 averaged 8,505 BOED, a new record for the Company and 11% higher than the fourth quarter of 2008. Significantly lower natural gas and crude oil prices decreased funds from operations for the three months ended March 31, 2009 to \$8.8 million, 33% lower than the fourth quarter of 2008. Product prices on a combined BOE basis have decreased 25% from the fourth quarter of 2008.

The Alberta New Royalty Framework came into effect on January 1, 2009 and, when combined with lower commodity prices, resulted in a reduction in royalties payable on the Company's Edmonton Sands gas wells.

Capital expenditures were \$13.5 million for the three months ended March 31, 2009. During the first quarter of 2009, the Company drilled 11 gross (8.3 net) wells with a 100% success rate. The Company tied in 32 gross (24.5 net) wells for production during the first quarter of 2009.

Debt, net of working capital, was \$131 million at March 31, 2009, \$6 million higher than at December 31, 2008 as a result of capital expenditures during the quarter being in excess of funds from operations. On May 7, 2009, the Company announced a bought deal share financing for gross proceeds of approximately \$60 million. Net proceeds after commission and expenses are estimated to be \$56.5 million and will be used to pay down bank debt and fund the Company's capital program, including the previously announced Edmonton Sands farm-in.

Revenue and Production. Gas sales comprised 83% of Anderson Energy's total oil and gas sales volumes for the three months ended March 31, 2009, consistent with the fourth quarter of 2008.

Gas sales volumes for the three months ended March 31, 2009 increased 11% to 42.3 MMcfd from 38.1 MMcfd in the fourth quarter of 2008. The increase is a result of realizing a full quarter of production from the 55 wells that were tied in during the last quarter of 2008 as well as new production from wells tied in during the first quarter of 2009. Gas sales volumes increased 8% from the first quarter of 2008 as a result of drilling success partially offset by property dispositions in the fourth quarter of 2008.

Oil sales for the three months ended March 31, 2009 averaged 443 bpd compared to 491 bpd in the fourth quarter of 2008 and 588 bpd for the first quarter of 2008. The majority of the Company's oil production is from central and eastern Alberta. Oil sales have declined since the first quarter of 2008 due to properties sales in 2008 and repairs required on oil wells in the first quarter of 2009.

Natural gas liquids sales for the three months ended March 31, 2009 averaged 1,005 bpd compared to 850 bpd in the fourth quarter of 2008 and 757 bpd for the first quarter of 2008.

Royalty and other revenue include adjustments to revenue related to periods prior to the acquisition date of properties acquired in 2005.

The following tables outline production revenue, volumes and average sales prices for the period ended March 31, 2009 and 2008.

OIL AND NATURAL GAS REVENUE

	<i>Three months ended March 31</i>	
<i>(thousands of dollars)</i>	<i>2009</i>	<i>2008</i>
Natural gas	\$ 19,638	\$ 28,278
Natural gas hedging loss	-	(1,341)
Oil	1,714	4,872
NGL	3,328	5,393
Royalty and other	(251)	493
Total	\$ 24,429	\$ 37,695

PRODUCTION

	<i>Three months ended March 31</i>	
	<i>2009</i>	<i>2008</i>
Natural gas (Mcf)	42,344	39,210
Oil (bpd)	443	588
NGL (bpd)	1,005	757
Total (BOED)	8,505	7,879

PRICES

	<i>Three months ended March 31</i>	
	<i>2009</i>	<i>2008</i>
Natural gas (\$/Mcf)	\$ 5.15	\$ 7.55
Oil (\$/bbl)	42.97	91.13
NGL (\$/bbl)	36.80	78.30
Total (\$/BOE)*	\$ 31.91	\$ 52.57

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

Anderson Energy's average gas sales price was \$5.15 per Mcf for the three months ended March 31, 2009, 24% lower than the fourth quarter 2008 price of \$6.76 per Mcf and 32% lower than the first quarter of 2008 price of \$7.55 per Mcf. In February and March of 2008, the Company had a fixed price natural gas sales contract for 25,000 GJ per day at \$6.89 per GJ. This contract resulted in a \$1.3 million loss in sales dollars. The average gas price for the three months ended March 31, 2008 was \$7.93 per Mcf before this loss.

Historically, Anderson Energy has sold most of its gas at Alberta spot market prices. In November 2008, the Company began selling approximately 30% of its production at the average monthly index price, and the balance 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 25 MMcfd of natural gas sales for various terms ranging from one to seven years.

Hedging Contracts. There were no physical or financial hedging contracts outstanding as at March 31, 2009.

Royalties. Royalties were 18% of revenue for the three months ended March 31, 2009 compared to 22% for the fourth quarter of 2008 and 23% for the three months ended March 31, 2008. The \$1.3 million hedging loss in the first quarter of 2008 also impacted the effective royalty rate in 2008. 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 at current production levels and prices due to the Company's focus on shallow gas, lower productivity wells. Increases in estimates of gas cost allowance related to 2008 capital additions also reduced royalties in the period. On March 3, 2009, new royalty initiatives were announced by the Alberta government to reduce royalties based on future drilling activity. Two measures were announced. The first is a \$200 per meter royalty credit based on drilling activity from April 1, 2009 to April 1, 2010. The credit can be used to offset up to 50% of Crown royalties payable after the wells have been drilled until March 2011. The second measure announced was that new wells tied in for production on Crown lands from the period April 1, 2009 to April 1, 2010 would pay a reduced Crown royalty rate of 5% for the first 500 MMcf of gas production. Both of these measures have the potential to significantly reduce future Crown royalties payable by the Company.

	<i>Three months ended March 31</i>	
	<i>2009</i>	<i>2008</i>
Royalties (%)	18%	23%
Royalties (\$/BOE)	\$ 5.79	\$ 12.12

Operating Expenses. Operating expenses were \$10.81 per BOE for the three months ended March 31, 2009 compared to and \$11.51 per BOE in the last quarter of 2008 and \$12.13 per BOE in the first quarter of 2008. The Company completed three large plant construction projects in mid 2008 at Willesden Green, Wilson Creek and Buck Lake that helped to reduce reliance on third party processing and lower operating cost per BOE.

OPERATING NETBACK

	<i>Three months ended March 31</i>	
	<i>2009</i>	<i>2008</i>
<i>(thousands of dollars)</i>		
Revenue	\$ 24,429	\$ 37,695
Royalties	(4,434)	(8,688)
Operating expenses	(8,272)	(8,694)
	\$ 11,723	\$ 20,313
Sales (MBOE)	765.5	717.0
Per BOE		
Revenue	\$ 31.91	\$ 52.57
Royalties	(5.79)	(12.12)
Operating expenses	(10.81)	(12.13)
	\$ 15.31	\$ 28.32

General and Administrative Expenses. General and administrative expenses were \$2.0 million or \$2.62 per BOE for the three months ended March 31, 2009 compared to \$1.0 million or \$1.40 per BOE in the fourth quarter of 2008 and \$1.6 million or \$2.16 per BOE for the three months ended March 31, 2008. General and administrative costs on a per BOE basis increased from the same period in the prior year as a result of decreased capital recoveries due to lower capital spending and higher salaries costs. In the first quarter of 2009, the Company took steps to reduce its administration costs including a 5% salary reduction for all staff and the termination of the Employee Stock Savings Plan effective April 1, 2009. Employee lay offs and the termination of certain consultants' contracts resulted in approximately a 15% reduction in head office personnel.

<i>(thousands of dollars)</i>	<i>Three months ended March 31,</i>	
	<i>2009</i>	<i>2008</i>
General and administrative (gross)	\$ 3,503	\$ 2,920
Overhead recoveries	(392)	(536)
Capitalized	(1,104)	(832)
General and administrative (net)	\$ 2,007	\$ 1,552
General and administrative (\$/BOE)	\$ 2.62	\$ 2.16
% Capitalized	32%	28%

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 \$0.5 million for the first quarter of 2009 (\$0.3 million net of amounts capitalized) versus \$0.4 million (\$0.2 million net of amounts capitalized) in the first quarter of 2008. The increase is a result of additional stock options being granted to new and existing staff members.

Interest Expense. Interest expense was \$1.0 million for the first quarter of 2009, compared to \$1.1 million in the fourth quarter of 2008 and \$1.2 million in the first quarter of the prior year. The decrease in interest expense is due to lower overall interest rates, partially offset by higher debt levels. Decreasing funds from operations since the second quarter of 2008 has resulted in higher amounts funded through debt financing. Bank loans were \$111 million at March 31, 2009 compared to \$85 million at December 31, 2008 and \$88 million at March 31, 2008. The average effective interest rate on outstanding bank loans was 4.4% for the three months ended March 31, 2009 compared to 5.7% for the three months ended March 31, 2008.

Depletion and Depreciation. Depletion and depreciation was \$28.85 per BOE or \$22 million for the first quarter of 2009 compared to \$28.46 per BOE, or \$20 million in the fourth quarter of 2008 and \$20.20 per BOE, or \$14 million in the first quarter of 2008. Depletion and depreciation expense is calculated based on proved reserves only. A decrease in proved reserves in 2008 resulted in an increase in depletion rates per BOE and total dollars in the fourth quarter of 2008 and first quarter of 2009.

Asset Retirement Obligation. As a result of new drilling, the Company recorded \$0.2 million in asset retirement obligations in the first quarter of 2009. Other changes in estimates were \$0.2 million. Accretion expense was \$0.6 million for the first quarter of 2009 compared to \$0.4 million in the first quarter of 2008 and was included in depletion and depreciation expense. Accretion expense increased due to new wells drilled and acquisitions.

Income Taxes. Anderson Energy is not currently taxable. The Company does not anticipate paying current income tax in 2009. Future income tax expense (reduction) has decreased as a percentage of pre-tax earnings (loss) due to reductions in corporate tax rates. The Company has approximately \$308 million in tax pools at March 31, 2009, including approximately \$61 million of Canadian Exploration Expense (CEE) and \$31 million of non-capital losses that expire between 2011 and 2029. The Company expects to be able to fully utilize the losses.

Funds from Operations. Funds from operations for the first quarter of 2009 were \$8.8 million (\$0.10 per share), a 33% decrease over the \$13.2 million (\$0.15 per share) recorded in the fourth quarter of 2008 and 50% lower than the \$17.6 million (\$0.20 per share) recorded in the same period of the prior year. The decrease in funds from operations in 2009 is a result of lower commodity prices, partially offset by higher production. Cash from operating activities also decreased year over year for similar reasons.

	<i>Three months ended March 31</i>	
<i>(thousands of dollars)</i>	<i>2009</i>	<i>2008</i>
Cash from operating activities	\$ 9,298	\$ 17,416
Changes in non-cash working capital	(1,444)	75
Asset retirement expenditures	938	100
Funds from operations	\$ 8,792	\$ 17,591

The Company reported a loss of \$10.2 million in the first quarter of 2009 compared to a loss of \$41.2 million for the three months ended December 31, 2008 and earnings of \$1.7 million for the first quarter of 2008. Earnings in the first quarter of 2009 were negatively impacted by lower commodity prices and higher depletion and depreciation expense. In 2008, the Company determined that the carrying amount of goodwill exceeded its fair value and a non-cash impairment loss of \$35.4 million was recognized in the fourth quarter. The 2008 fourth quarter loss was \$5.9 million before the write-down. 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	\$ 5.7	\$ 0.06	\$ 4.0	\$ 0.05
US \$5.00/bbl in the WTI crude price	\$ 1.5	\$ 0.02	\$ 1.1	\$ 0.01
US \$0.01 in the US/Cdn exchange rate	\$ 1.2	\$ 0.01	\$ 0.8	\$ 0.01
1% in short-term interest rate	\$ 0.7	\$ 0.01	\$ 0.5	\$ 0.01

This sensitivity analysis was calculated using the corporate budget model and applying different pricing, interest rate and exchange rate assumptions. The key assumptions were based on 2008 actual results related to production, prices, royalty rates, operating costs and capital spending.

CAPITAL EXPENDITURES

The Company spent \$13.5 million on capital expenditures in the first quarter of 2009. The breakdown of expenditures is shown below:

<i>(thousands of dollars)</i>	<i>Three months ended March 31</i>	
	<i>2009</i>	<i>2008</i>
Land, geological and geophysical costs	\$ 89	\$ 476
Acquisitions, net of dispositions	(27)	-
Drilling, completion and recompletion	6,119	22,383
Facilities and well equipment	6,240	11,643
Capitalized G&A	1,104	832
Total finding, development & acquisition expenditures	13,525	35,334
Office equipment and furniture	20	25
Total capital expenditures	13,545	35,359
Non-cash asset retirement obligations and capitalized stock-based compensation	657	1,530
Total cash and non-cash capital additions	\$ 14,202	\$ 36,889

Drilling statistics are shown below:

	<i>Three months ended March 31</i>			
	<i>2009</i>		<i>2008</i>	
	<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>
Gas	11	8.3	75	53.8
Oil	-	-	4	0.9
Dry	-	-	7	6.1
Total	11	8.3	86	60.8
Success rate (%)	100%	100%	92%	90%

During the first quarter of 2009, the Company drilled 11 gross (8.3 net) Edmonton Sands wells with a 100% success rate. The Company also completed 34 gross (27 net) wells and tied in 32 gross (24.5 net) wells. Approximately \$1.0 million was spent on inventory that was not deployed due to the cutback in the 2008/2009 capital program and which will be available for use in the 2009/2010 capital program.

CEILING TEST

No impairment was recognized under the ceiling test at March 31, 2009. 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:

	<i>AECO Gas Price (\$Cdn/Mcf)</i>	<i>WTI Cushing (\$US/bbl)</i>	<i>Exchange rate (US\$/Cdn)</i>
2009 Q2-Q4	4.94	55.00	0.810
2010	6.93	62.00	0.830
2011	7.71	70.00	0.850
2012	7.97	77.00	0.885
2013	8.16	85.00	0.925
2014	8.47	93.85	0.950
2015	8.75	95.73	0.950
Thereafter 2%			

After 2015, 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 2015 forward.

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 13, 2009, there were 87.3 million common shares outstanding and 7.4 million stock options outstanding.

	<i>Three months ended March 31,</i>	
	<i>2009</i>	<i>2008</i>
High	\$ 1.48	\$ 3.95
Low	\$ 0.75	\$ 2.44
Close	\$ 0.84	\$ 3.65
Volume	6,131,128	23,958,323
Shares outstanding at March 31	87,300,401	87,294,401
Market capitalization at March 31	\$ 73,332,337	\$ 318,624,564

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2009, the Company had outstanding long term bank loans of \$100 million and a working capital deficiency of \$31 million.

The Company expects capital expenditures to be minimal in the second quarter of 2009. With the significant volatility in commodity prices, the signing of the farm-in agreement in its core Edmonton Sands project area, the recent announcement of a \$60 million equity financing and the renegotiation of its banking facilities, the Company believes it will be in a better position to announce a full year 2009 capital budget and associated guidance this summer.

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, 2009, the Company has a \$110 million extendible revolving term credit facility, a \$10 million working capital credit facility and a \$10 million supplemental credit facility with a syndicate of Canadian banks. The supplemental facility was scheduled to expire on June 30, 2009. 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. On May 13, 2009, the Company agreed with its lenders to renew the credit facilities to July 13, 2010 at a total combined amount of \$100 million, subject to execution of customary documentation to confirm renewal terms, completion of the equity financing discussed below and normal course closing conditions. The \$10 million supplemental facility will be cancelled. As a result of the current economic climate and credit market, the Company will incur increased margins and fees.

On May 7, 2009, the Company entered into an agreement with a syndicate of underwriters pursuant to which the underwriters have agreed to purchase on a bought deal basis pursuant to a short form prospectus, 63,200,000 common shares at a price of \$0.95 per common share for gross proceeds to Anderson Energy of approximately \$60 million (the "Offering"). Anderson Energy has also granted the underwriters an option to buy up to an additional 9,480,000 common shares for additional gross proceeds of approximately \$9 million, to cover over-allotments. Net proceeds of the Offering will be used to pay down the Company's bank debt and fund its capital program including its commitments under the previously announced Edmonton Sands farm-in. Closing is expected to occur on or about May 28, 2009 and is subject to certain conditions including, but not limited to, the receipt of all necessary approvals, including the approval of the Toronto Stock Exchange.

The Company will continue to fund its ongoing operations from a combination of cash flow, debt, asset dispositions and equity financing as needed. While management is confident that it will be able to continue to fund its ongoing operations, due to the current global economic uncertainties, absolute assurance cannot be given that the funds considered necessary to operate will be available as required.

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 in July each year 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. As previously discussed, the reserves based credit facilities were reduced to \$100 million as part of the 2009 renewal.
- *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 2009 through 2011, and \$1.7 million in 2012.
- *Firm service transportation commitments* – The Company has entered into firm service transportation agreements for approximately 25 million cubic feet per day of gas sales for various terms expiring between 2009 and 2015. Based on rate schedules announced to date, the payments in each of the next five years and thereafter are estimated to be \$0.9 million in the remainder of 2009, \$1.1 million in 2010, \$0.9 million in 2011, \$0.6 million in 2012, \$0.3 million in 2013 and \$0.6 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 is obligated to complete the drilling of the wells on or before December 31, 2010. The commitment is subject to various guarantees and to complete the commitment, the Company estimates that it could spend between \$10 and \$14 million in 2009 and between \$39 and \$45 million in 2010 on the farm-in. See note 8 to the consolidated financial statements for the three months ended March 31, 2009 for more details.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (“IFRS”)

In February 2008, the CICA Accounting Standards Board (“AcSB”) confirmed the changeover to International Financial Reporting Standards (“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.

The International Accounting Standards Board (“IASB”) has also issued an exposure draft relating to certain amendments and exemptions to IFRS 1. It is anticipated that this exposure draft will not result in an amended IFRS 1 standard until late 2009. The amendment, if implemented, will permit the Company to apply IFRS prospectively by utilizing its current reserves at the transition date to allocate the Company’s full cost pool, with the provision that a ceiling test, under IFRS standards, be conducted at the transition date.

Although the amended IFRS 1 standard would provide relief, the changeover to IFRS represents a significant change in accounting standards and the transition from current Canadian GAAP to IFRS will be a significant undertaking that may materially affect the Company’s reported financial position and reported results of operations.

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, scheduled to take place during 2009, the Company will perform 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. Staff training programs will continue in 2009 and be ongoing as the project unfolds.

The Company will also continue to monitor standards development as issued by the 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.

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, 2009 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 months ended March 31, 2009 and have concluded that, these internal controls are designed properly 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 in the first quarter of the Company's fiscal year.

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

Market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility in commodity prices. These conditions are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial

instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Commodity prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of world economies, OPEC actions and the ongoing global credit and liquidity concerns.

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 credit crisis 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.

Oil and gas exploration and production is capital intensive and involves a number of business risks including 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, the U.S. dollar exchange rate, transportation costs, political stability and seasonal and weather related changes to demand. 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 AIF for the year ended December 31, 2008 filed with Canadian securities regulatory authorities on SEDAR.

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 and have a material adverse impact on Anderson.

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%.

In November 2008, the Government of Alberta announced that companies drilling new natural gas and conventional oil wells at depths between 1,000 and 3,500 meters, which are spudded between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new transitional royalty rates or the new royalty framework rates. The transition option provides lower royalties in the initial years of a well's life. For example, under the transition option, royalty rates for natural gas wells will range from 5% to 30%. The election must be made prior to the end of the first calendar month in which the leased substance is produced. All wells using the transitional royalty rates must shift to the new royalty framework rates on January 1, 2014.

On March 3, 2009, the Government of Alberta announced a three-point incentive program. This incentive program includes a drilling royalty credit for new oil and natural gas wells drilled between April 1, 2009 and April 1, 2010, providing a \$200-per-metre-drilled royalty credit to companies. The credit can be used to offset up to 50% of Crown royalties payable after the wells have been drilled and up until March 31, 2011. 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 April 1, 2010 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 inactive wells.

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 nor 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.

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

Canada is a signatory to the United Nations Framework Convention on Climate Change and has adopted the Kyoto Protocol established thereunder requiring binding targets to reduce national emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases. Details regarding Canada's implementation of the Kyoto Protocol remain unclear. The Government of Canada has indicated an intention to regulate emissions of industrial greenhouse gas ("GHG") emissions from a broad range of industrial sectors in the *Regulatory Framework for Air Emissions* released April 26, 2007 and updated in a March 10, 2008 document entitled *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions* (collectively, the "Federal Plan"). The Federal Plan states the Government of Canada's national GHG emissions reduction target is an absolute 20 percent reduction from 2006 levels by 2020, and a 60 to 70 percent reduction by 2050. The Federal Plan provides some, but not full, detail on planned new GHG and industrial air pollutant limits and compliance mechanisms that the Government of Canada intends to apply to various sectors, including oil and natural gas producers. Details on potential legislation to enact the proposed Federal Plan remain unclear. Since November 2008, the Government of Canada has expressed an interest in pursuing a potential harmonization of future Canadian GHG regulation with future regulation in the United States of America, pursuant to a treaty, raising uncertain implications for GHG emission requirements to be applied to Canadian industry, including the oil and gas sector.

In 2007, the Government of Alberta enacted the *Specified Gas Emitters Regulation*, under the *Climate Change and Emissions Management Act (Alberta)*, imposing certain greenhouse gas emissions reduction requirements on large industrial emitters. In January 2008, the Government of Alberta announced a new Climate Change Strategy stating a provincial target of an absolute reduction in greenhouse gas emissions of 14 percent below 2005 levels by 2050. Details on potential legislation to achieve the proposed provincial target remain unclear.

Future federal legislation, including potential international requirements enacted under Canadian law, as well as provincial emissions reduction requirements, may require the reduction of GHG or

other industrial air emissions, or emissions intensity, from the Company's operations and facilities. Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and natural gas producers. The Company is unable to predict the impact of emissions reduction legislation on the Company and it is possible that such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows.

Anderson believes that it is in material compliance with applicable environmental legislation and is committed to continued compliance. The Company believes that it is reasonably likely that a trend towards stricter standards in environmental legislation will continue and the Company anticipates making increased expenditures of both a capital and an expense nature as a result of increasingly stringent environmental laws.

BUSINESS PROSPECTS

The Company believes it has an excellent future drilling inventory with several years of development drilling locations in the Sylvan Lake Edmonton Sands and Horseshoe Canyon Coal Bed Methane resource plays and the West Pembina Rock Creek play.

During periods of price weakness, the Company's business strategy is to grow its assets and reduce its costs. The Company recently announced a significant farm-in transaction in the Edmonton Sands Project Area. Anderson Energy believes the transaction will deliver significant benefits to the Company and will define it as the major Edmonton Sands resource player in Central Alberta. Anderson Energy drilled 11 Edmonton Sands wells in the first quarter of 2009 and tied in 32 Edmonton Sands wells. This is less than originally planned in order to maintain the Company's financial flexibility and to accommodate the drilling program on the farm-in lands later in the year. A minimum of 75 Edmonton Sands locations are committed to be drilled in the second half of 2009 on the farm-in lands. The recently announced Offering and the renewal of the Company's credit facilities provide the Company with the financial flexibility to take advantage of the opportunities provided by the farm-in.

The Company expects average production in the second quarter of 2009 to be 7,600 to 8,000 BOED. Risks associated with this guidance include 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. The \$117.6 million acquisition completed in September 2007 had a significant impact on operating results in 2008. Product prices improved significantly between the third quarter of 2007 and the second quarter of 2008, which had a significant impact on funds from operations and earnings in the second quarter of 2008. Prices have been declining since the second quarter of 2008 which decreased funds from operations and earnings in the most recent two quarters. Earnings were negatively impacted in the fourth quarter of 2008 by a \$35.4 million charge for impairment of goodwill.

SELECTED QUARTERLY INFORMATION

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

	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 (bpd)	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

	Q1 2008	Q4 2007	Q3 2007	Q2 2007
Oil and gas revenue before royalties	\$ 37,695	\$ 27,775	\$ 17,261	\$ 18,440
Funds from operations	\$ 17,591	\$ 12,564	\$ 6,255	\$ 8,972
Funds from operations per share				
Basic	\$ 0.20	\$ 0.14	\$ 0.09	\$ 0.15
Diluted	\$ 0.20	\$ 0.14	\$ 0.09	\$ 0.15
Earnings (loss)	\$ 1,696	\$ 4,867	\$ (3,018)	\$ 368
Earnings (loss) per share				
Basic	\$ 0.02	\$ 0.06	\$ (0.04)	\$ 0.01
Diluted	\$ 0.02	\$ 0.06	\$ (0.04)	\$ 0.01
Capital expenditures, including acquisition net of dispositions	\$ 35,359	\$ 30,300	\$ 135,966	\$ 17,586
Cash from operating activities	\$ 17,416	\$ 11,110	\$ 5,801	\$ 8,943
Daily sales				
Natural gas (Mcf)	39,210	35,672	26,860	22,928
Liquids (bpd)	1,345	1,150	843	602
BOE (bpd)	7,879	7,095	5,320	4,423
Average prices				
Natural gas (\$/Mcf)	\$ 7.55	\$ 6.09	\$ 5.00	\$ 7.25
Liquids (\$/bbl)	\$ 83.91	\$ 72.28	\$ 63.31	\$ 58.18
BOE (\$/BOE)*	\$ 52.57	\$ 42.55	\$ 35.27	\$ 45.81

* 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 Farm-In 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, commodity price outlook, general economic outlook, closing date and use of proceeds from the Offering and insider participation therein and future share performance 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, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash	\$ -	\$ 1
Accounts receivable and accruals (note 7)	24,014	28,960
Prepaid expenses and deposits	<u>2,735</u>	<u>2,692</u>
	26,749	31,653
Property, plant and equipment (note 1)	<u>504,075</u>	<u>511,880</u>
	<u>\$ 530,824</u>	<u>\$ 543,533</u>
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accruals	\$ 46,900	\$ 71,619
Current portion of bank loans (note 2)	<u>10,820</u>	<u>-</u>
	57,720	71,619
Bank loans (note 2)	100,000	85,314
Asset retirement obligations (note 3)	30,942	30,820
Future income taxes	<u>42,213</u>	<u>46,168</u>
	230,875	233,921
Shareholders' equity:		
Share capital (note 4)	334,176	334,176
Contributed surplus (note 4)	4,496	4,000
Deficit	<u>(38,723)</u>	<u>(28,564)</u>
	299,949	309,612
Commitments (note 8)		
Subsequent event (note 9)	<u> </u>	<u> </u>
	<u>\$ 530,824</u>	<u>\$ 543,533</u>

See accompanying notes to the consolidated financial statements.

ANDERSON ENERGY LTD.

Consolidated Statements of Operations, Comprehensive Income (Loss) and Deficit

THREE MONTHS ENDED MARCH 31, 2009 AND 2008

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

	2009	2008
REVENUES		
Oil and gas sales	\$ 24,429	\$ 37,695
Royalties	(4,434)	(8,688)
Interest income	116	32
	<u>20,111</u>	<u>29,039</u>
EXPENSES		
Operating	8,272	8,694
General and administrative	2,007	1,552
Stock-based compensation	265	233
Interest and other financing charges	1,040	1,202
Depletion, depreciation and accretion	22,721	14,927
	<u>34,305</u>	<u>26,608</u>
Earnings (loss) before taxes	(14,194)	2,431
Future income tax expense (reduction)	(4,035)	735
Earnings (loss) and comprehensive income (loss) for the period	(10,159)	\$ 1,696
Deficit, beginning of period	(28,564)	\$ (1,700)
Deficit, end of period	<u>\$ (38,723)</u>	<u>\$ (4)</u>
Earnings (loss) per share <i>(note 4)</i>		
Basic	\$ (0.12)	\$ 0.02
Diluted	\$ (0.12)	\$ 0.02

See accompanying notes to the consolidated financial statements.

ANDERSON ENERGY LTD.

Consolidated Statements of Cash Flows

THREE MONTHS ENDED MARCH 31, 2009 AND 2008

(Stated in thousands of dollars)
(Unaudited)

	2009	2008
CASH PROVIDED BY (USED IN)		
OPERATIONS		
Earnings (loss) for the period	\$ (10,159)	\$ 1,696
Items not involving cash:		
Depletion, depreciation and accretion	22,721	14,927
Future income tax expense (reduction)	(4,035)	735
Stock-based compensation	265	233
Asset retirement expenditures	(938)	(100)
Changes in non-cash working capital:		
Accounts receivable and accruals	1,215	(4,825)
Prepaid expenses and deposits	23	(148)
Accounts payable and accruals	206	4,898
	<u>9,298</u>	<u>17,416</u>
FINANCING		
Increase in bank loans	25,506	19,923
INVESTMENTS		
Additions to property, plant and equipment	(13,572)	(35,359)
Proceeds on disposition of properties	27	-
Changes in non-cash working capital:		
Accounts receivable and accruals	3,731	3,530
Prepaid expenses and deposits	(66)	(343)
Accounts payable and accruals	(24,925)	(5,166)
	<u>(34,805)</u>	<u>(37,338)</u>
Increase (decrease) in cash	(1)	1
Cash, beginning of period	<u>1</u>	<u>2</u>
Cash, end of period	\$ -	\$ 3

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, 2009 AND 2008

(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, 2008. 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, 2008.

Future operations. These consolidated financial statements have been prepared by management on a going concern basis in accordance with Canadian generally accepted accounting principles. The going concern basis of presentation assumes that the Company will continue in operation for the foreseeable future and be able to realize its assets and discharge its obligations in the normal course of business. Recent market events, including disruptions in credit markets and other financial systems and the deterioration of global economic conditions have resulted in significant declines in commodity prices. At March 31, 2009, the Company has a working capital deficiency of \$31 million and long term bank loans outstanding of \$100 million for total net debt of \$131 million in relation to available bank facilities of \$130 million.

On May 7, 2009, the Company entered into an agreement with a syndicate of underwriters who have agreed to purchase on a bought deal basis, 63.2 million common shares for gross proceeds to the Company of approximately \$60 million. Closing is expected to occur on May 28, 2009. Net proceeds will be used to pay down bank debt and fund capital programs, including commitments under a farm-in agreement (see note 8). On May 13, 2009, the Company agreed with its lenders to renew the extendible, revolving term and working capital credit facilities to July 13, 2010 at a total combined borrowing base of \$100 million, subject to execution of customary documentation to confirm the renewal terms, completion of the equity financing and normal course closing conditions. The \$10 million supplemental credit facility will be cancelled. Management has restricted capital and administrative spending and believes that proceeds from the equity financing and available bank lines will be sufficient to fund its future prospects and commitments. If the going concern assumption were not appropriate for these consolidated financial statements, adjustments might be necessary to the carrying values of assets and liabilities, the reported revenues and expenses and the balance sheet classifications used.

1. PROPERTY, PLANT AND EQUIPMENT

	<i>March 31, 2009</i>	<i>December 31, 2008</i>
Cost	\$ 700,702	\$ 686,420
Less accumulated depletion and depreciation	<u>(196,627)</u>	<u>(174,540)</u>
Net book value	\$ 504,075	\$ 511,880

At March 31, 2009, unproved property costs of \$8.4 million (December 31, 2008 - \$8.5 million) have been excluded from the full cost pool for depletion and depreciation calculations. Future development costs of proved, undeveloped reserves of \$200.3 million (December 31, 2008 - \$204.7 million) have been included in the depletion and depreciation calculation.

For the three months ended March 31, 2009, \$1.3 million (March 31, 2008 - \$1.0 million) of general and administrative costs including \$0.2 million (March 31, 2008 - \$0.2 million) of stock-based compensation costs were capitalized. The future tax liability of \$80,000 (March 31, 2008 - \$60,000) 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, 2009. 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:

	<i>AECO Gas Price (\$Cdn/Mcf)</i>	<i>WTI Cushing (\$US/bbl)</i>	<i>Exchange rate (US\$/Cdn)</i>
2009 Q2-Q4	4.94	55.00	0.810
2010	6.93	62.00	0.830
2011	7.71	70.00	0.850
2012	7.97	77.00	0.885
2013	8.16	85.00	0.925
2014	8.47	93.85	0.950
2015	8.75	95.73	0.950
<u>Thereafter 2%</u>			

After 2015, 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 2015 forward.

2. BANK LOANS

At March 31, 2009, the Company has a \$110 million extendible, revolving term credit facility and a \$10 million working capital credit facility (the "Facilities") with a syndicate of Canadian banks. The reserves-based Facilities have a revolving period ending on July 14, 2009, 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 average effective interest rate on advances in 2009 was 4.4% (March 31, 2008 – 5.7%).

At March 31, 2009, the Company has a \$10 million supplemental credit facility (the "Supplemental Facility") with the existing syndicate of Canadian banks. The Supplemental Facility is in addition to the Facilities noted above and is available on a revolving basis. The Supplemental Facility was scheduled to expire on June 30, 2009.

Advances under the Facilities and the Supplemental Facility 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, 2009 there were no advances in U.S. funds or under the Supplemental Facility.

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. On May 13, 2009, the Company agreed with its lenders to renew the Facilities to July 13, 2010 at a total combined amount of \$100 million, subject to execution of customary documentation to confirm the renewal terms, completion of the equity financing discussed in note 9 and normal course closing conditions. As the amount drawn on March 31, 2009 exceeds the \$100 million available line, \$10.8 million of the outstanding bank loans have been classified as a current liability. The \$10 million Supplemental Facility will be cancelled.

3. ASSET RETIREMENT OBLIGATIONS

The Company estimates the total undiscounted cash flows required to settle its asset retirement obligations is approximately \$68.5 million (December 31, 2008 - \$63.4 million), including expected inflation of 2% (December 31, 2008 – 2%) per annum. The majority of the costs will be incurred between 2009 and 2020. A credit adjusted risk-free rate of 8% to 10% (December 31, 2008 – 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:

3. ASSET RETIREMENT OBLIGATIONS *(Continued)*

	<i>March 31, 2009</i>	<i>December 31, 2008</i>
Balance, beginning of period	\$ 30,820	\$ 24,526
Liabilities incurred during period	240	3,951
Liabilities settled in period	(938)	(1,132)
Liabilities settled on disposition	-	(1,234)
Change in estimate	186	2,770
Accretion expense	634	1,939
Balance, end of period	<u>\$ 30,942</u>	<u>\$ 30,820</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 (thousands)</i>
Balance at December 31, 2007	87,294,401	\$ 334,147
Stock options exercised	6,000	25
Transferred from contributed surplus on stock option exercise	-	4
Balance at December 31, 2008 and March 31, 2009	<u>87,300,401</u>	<u>\$ 334,176</u>

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 number of options outstanding during the three months ended March 31, 2009 and year ended December 31, 2008 are as follows:

	<i>Number of options</i>	<i>Weighted average exercise price</i>
Balance at December 31, 2007	6,297,306	\$ 4.65
Granted	1,468,300	3.21
Exercised	(6,000)	4.13
Forfeitures	(164,750)	4.44
Balance at December 31, 2008	<u>7,594,856</u>	<u>\$ 4.37</u>
Granted	45,000	1.00
Expirations and forfeitures	(235,000)	4.47
Balance at March 31, 2009	<u>7,404,856</u>	<u>\$ 4.35</u>
Exercisable at March 31, 2009	<u>4,812,956</u>	<u>\$ 4.79</u>

4. SHARE CAPITAL AND CONTRIBUTED SURPLUS (Continued)

Range of exercise prices	Options outstanding			Options exercisable	
	Number of options	Weighted average exercise price	Weighted average remaining life (years)	Number of options	Weighted average exercise price
\$1.00 to \$3.75	1,022,400	\$ 2.62	4.5	-	\$ -
\$3.76 to \$5.00	5,145,056	4.01	3.3	3,671,056	4.00
\$5.01 to \$7.50	543,000	6.15	2.2	447,500	6.27
\$7.51 to \$9.01	694,400	8.00	1.6	694,400	8.00
Total at March 31, 2009	7,404,856	\$ 4.35	3.2	4,812,956	\$ 4.79

The fair value of the options issued during the three months ended March 31, 2009 was \$0.66 per option. The weighted average assumptions used in arriving at the values were: a risk-free interest rate of 1.70%, expected option life of five years, expected volatility of 83% and a dividend yield of 0%. There were no options granted during the three months ended March 31, 2008.

Per share amounts. During the three months ended March 31, 2009 there were 87,300,401 weighted average shares outstanding (March 31, 2008 – 87,294,401). On a diluted basis, there were 87,300,401 weighted average shares outstanding (March 31, 2008 – 87,294,401) after giving effect to dilutive stock options. At March 31, 2009, there were 7,404,856 options that were anti-dilutive (March 31, 2008 – 6,282,406).

Contributed surplus

	Amount
Balance at December 31, 2007	\$ 2,005
Stock-based compensation	1,999
Transferred from contributed surplus on stock option exercise	(4)
Balance at December 31, 2008	\$ 4,000
Stock-based compensation	496
Balance at March 31, 2009	\$ 4,496

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 \$300 million, long term bank loans of \$100 million and the working capital deficiency of \$31 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

5. MANAGEMENT OF CAPITAL STRUCTURE *(Continued)*

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 (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.

	<i>March 31, 2009</i>	<i>December 31, 2008</i>
Bank loans - long term	\$ 100,000	\$ 85,314
Current liabilities (including current portion of bank loans)	57,720	71,619
Current assets	(26,749)	(31,653)
Total debt	\$ 130,971	\$ 125,280
Cash from operating activities in quarter	\$ 9,298	\$ 11,261
Changes in non-cash working capital	(1,444)	1,464
Asset retirement expenditures	938	479
Funds from operations in quarter	\$ 8,792	\$ 13,204
Annualized current quarter funds from operations	\$ 35,168	\$ 52,816
Total debt to funds from operations	3.7	2.4

At March 31, 2009, the Company's total debt to annualized funds from operations was 3.7. At December 31, 2008, the Company's total debt to annualized funds from operations was 2.4 times. During the fourth quarter of 2008 and the first quarter of 2009, the market price of oil and natural gas decreased significantly, adversely affecting the Company's cash flow. The Company's capital program is also heavily weighted to the winter months and this ratio will tend to be higher during that time of the year. Net proceeds from the equity financing discussed in note 9 will be used to pay down bank debt and so will help to reduce this ratio.

Commodity prices at the end of the first quarter of 2009 were lower than the average prices received in the quarter and used in this calculation. The Company plans to adjust its capital expenditures program to remain within funds from operations until commodity prices recover. In addition, on May 7, 2009, the Company entered into an agreement with a syndicate of underwriters who have agreed to purchase on a bought deal basis, 63.2 million common shares for gross proceeds to the Company of approximately \$60 million.

The Company's share capital is not subject to external restrictions, however, the Facilities and Supplemental Facility 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, 2009</i>	<i>March 31, 2008</i>
Interest paid	\$ 1,177	\$ 943
Interest received	(4)	(35)

7. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

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

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, 2009, the maximum credit exposure is the carrying amount of the accounts receivable and accruals of \$24.0 million (December 31, 2008 - \$29.0 million). As at March 31, 2009, the Company's receivables consisted of \$14.8 million (December 31, 2008 - \$17.3 million) from joint venture partners and other trade receivables and \$9.2 million (December 31, 2008 - \$11.7 million) of revenue accruals and other receivables from petroleum and natural gas marketers. Of the \$9.2 million of revenue accruals and receivables from petroleum and natural gas marketers, \$7.3 million was received on or about April 25, 2009. 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, 2009 is \$1.4 million. The Company did not write-off any receivables during the three months ended March 31, 2009.

As at March 31, 2009 the Company considers its receivables to be aged as follows:

<i>Aging</i>	<i>March 31, 2009</i>
Not past due	\$ 21,129
Past due by less than 120 days	1,237
Past due by more than 120 days	<u>1,648</u>
Total	<u>\$ 24,014</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.

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

The following are the contractual maturities of financial liabilities and associated interest payments as at March 31, 2009:

<i>Financial Liabilities</i>		<i>< 1 Year</i>		<i>1 -2 Years</i>
Accounts payable and accruals	\$	46,900	\$	-
Bank loans – principal		10,820		100,000
Total	\$	57,720	\$	100,000

Please refer to note 8 for additional details on commitments.

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, 2009 or December 31, 2008.

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.

No commodity price contracts were entered into during the three months ended March 31, 2009 and there were no commodity price risk contracts outstanding at March 31, 2009 or December 31, 2008.

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, 2009, if interest rates had been 1% lower with all other variables held constant, earnings for the period would have been \$155,000 (March 31, 2008 - \$99,000) higher, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amounts.

The Company had no interest rate swap or financial contracts in place at March 31, 2009 or December 31, 2008.

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

8. COMMITMENTS *(Continued)*

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 estimates the average working interest of the 200 well commitment is approximately 65% and expects to commence drilling in the fourth quarter of 2009. The Company's initial commitment is 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. After December 31, 2009 and April 30, 2010 respectively, the Farmor has the ability to request a letter of credit from the Company in the amount of \$550,000 per well not drilled under the minimum commitment at that date, subject to certain reductions due to unavoidable events beyond the Company's control and rights of first refusal. To complete the commitment, the Company estimates that it could spend between \$10 and \$14 million in 2009 and between \$39 and \$45 million in 2010 on the farm-in.

The Company has entered into an agreement to lease office space until November 30, 2012. Future minimum lease payments are expected to be \$1.4 million for the remainder of 2009, \$1.8 million in 2010 through 2011 and \$1.7 million in 2012.

The Company entered into firm service transportation agreements for approximately 25 million cubic feet per day of gas sales in central Alberta for various terms expiring in one to seven 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 (Mmcf/d)</i>	<i>Committed amount</i>
2009 Q2-Q4	25	\$ 936
2010	20	\$ 1,068
2011	16	\$ 912
2012	9	\$ 579
2013	4	\$ 338
Thereafter	5	\$ 552

9. SUBSEQUENT EVENT

On May 7, 2009, the Company entered into an agreement with a syndicate of underwriters to purchase on a bought deal basis, 63,200,000 common shares at a price of \$0.95 per common share for gross proceeds of approximately \$60 million.

The Company has also granted the underwriters an option to buy up to an additional 9,480,000 common shares for additional gross proceeds of approximately \$9 million to cover over-allotments.

The equity financing is subject to certain conditions including, but not limited to, the receipt of all necessary approvals, including the approval of the Toronto Stock Exchange.

Closing is expected to occur on May 28, 2009.

Corporate Information

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Calgary, Alberta

Member of:

- (1) Audit Committee
- (2) Compensation & Corporate Governance Committee
- (3) Reserves Committee
- (4) Retiring from Board of Directors effective May 14, 2009

Auditors

KPMG LLP
Calgary, Alberta

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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President & Chief Executive Officer
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Officers

J.C. Anderson
Chairman of the Board

Brian H. Dau
President & Chief Executive 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

David M. Spyker
Vice President, Business Development

Abbreviations used

AECO – intra-Alberta Nova inventory transfer price
bbl – barrel
bpd – barrels per day
Mbbls – thousand barrels
BOE – barrels of oil equivalent
BOED – barrels of oil equivalent per day
MBOE – thousand barrels of oil equivalent
MMBOE – million barrels of oil equivalent
CBM – Coal Bed Methane
GJ – gigajoule
Mcf – thousand cubic feet
Mcf/d – thousand cubic feet per day
MMcf – million cubic feet
MMcf/d – million cubic feet per day
Bcf – billion cubic feet