

ANDERSON ENERGY ANNOUNCES 2008 FOURTH QUARTER AND YEAR END RESULTS

Calgary, Alberta, March 23, 2009 - Anderson Energy Ltd. ("Anderson Energy" or the "Company") (TSX:AXL) is pleased to announce its operating and financial results for the fourth quarter and year ended December 31, 2008.

HIGHLIGHTS:

- For the year ended December 31, 2008, funds from operations achieved record levels of \$79.3 million (\$0.91 per share), up 118% over 2007 funds from operations. Funds from operations in the fourth quarter of 2008 were \$13.2 million (\$0.15 per share) up 5% over the fourth quarter of 2007.
- For the year ended December 2008, production averaged 7,787 BOED, a 46% increase over 2007 levels. Production averaged 7,689 BOED for the fourth quarter of 2008, 8% higher than the same period in 2007. Production in the quarter was negatively impacted by the extremely cold weather in December. The Company estimates its first quarter 2009 production to be approximately 8,300 to 8,400 BOED. Behind pipe production capability is approximately 1,100 BOED.
- Year end reserves were 23.4 MMBOE on a total proved basis and 32.3 MMBOE on a total proved plus probable basis. Reserve life indices are 8.2 years total proved and 11.3 years total proved plus probable based on 2008 annual production.
- 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 estimates a net asset value per share range to be approximately \$4.26 to \$4.91 per share. The basis of the calculation is shown on page 6 and includes a value assigned to the farm-in agreement entered into subsequent to year end.
- In the fourth quarter of 2008, the Company drilled 91 gross (62.0 net) wells with a success rate of 95%. In 2008, the Company drilled 217 gross (148.2 net) wells with a success rate of 93%.
- The Company's current drilling inventory, including the recent farm-in lands, is 1,816 gross (1,002 net) locations with the Edmonton Sands representing 96% of the net locations.
- Based on additions only, the Company's finding and development ("F&D") costs net of major facility expenditures and project cancellations were \$25.57 per BOE total proved and \$18.83 per BOE total proved plus probable.
- The Alberta government recently announced new royalty incentives which will benefit Anderson Energy. They include a royalty credit of \$200 per meter, which is approximately the Company's drilling costs per meter in the Edmonton Sands play, as well as a 5% royalty on any new production tied in between April 1, 2009 and April 1, 2010.

FINANCIAL AND OPERATING HIGHLIGHTS

| <i>(thousands of dollars)</i> | <i>Three months ended December 31,</i> | | <i>% Change</i> | <i>Year ended December 31,</i> | | <i>% Change</i> |
|--|--|-------------|---------------------|------------------------------------|-------------|---------------------|
| | <i>2008</i> | <i>2007</i> | | <i>2008</i> | <i>2007</i> | |
| Oil and gas revenue before royalties | \$ 30,102 | \$ 27,775 | 8% | \$ 156,245 | \$ 83,585 | 87% |
| Funds from operations | \$ 13,204 | \$ 12,564 | 5% | \$ 79,328 | \$ 36,414 | 118% |
| Funds from operations per share | | | | | | |
| Basic | \$ 0.15 | \$ 0.14 | 7% | \$ 0.91 | \$ 0.54 | 69% |
| Diluted | \$ 0.15 | \$ 0.14 | 7% | \$ 0.91 | \$ 0.54 | 69% |
| Earnings (loss) before impairment of goodwill | \$ (5,865) | \$ 4,867 | (221%) | \$ 8,500 | \$ 2,184 | 289% |
| Earnings (loss) before impairment of goodwill per share | | | | | | |
| Basic | \$ (0.07) | \$ 0.06 | (217%) | \$ 0.10 | \$ 0.03 | 233% |
| Diluted | \$ (0.07) | \$ 0.06 | (217%) | \$ 0.10 | \$ 0.03 | 233% |
| Earnings (loss) | \$ (41,229) | \$ 4,867 | (947%) | \$ (26,864) | \$ 2,184 | (1330%) |
| Earnings (loss) per share | | | | | | |
| Basic | \$ (0.47) | \$ 0.06 | (883%) | \$ (0.31) | \$ 0.03 | (1133%) |
| Diluted | \$ (0.47) | \$ 0.06 | (883%) | \$ (0.31) | \$ 0.03 | (1133%) |
| Capital expenditures, including acquisitions net of dispositions | \$ 27,470 | \$ 30,300 | (9%) | \$ 106,669 | \$ 211,133 | (49%) |
| Debt, net of working capital | | | | \$ 125,280 | \$ 96,832 | 29% |
| Shareholders' equity | | | | \$ 309,612 | \$ 334,452 | (7%) |
| Average shares outstanding <i>(thousands)</i> | | | | | | |
| Basic | 87,300 | 87,294 | 0% | 87,298 | 67,794 | 29% |
| Diluted | 87,300 | 87,294 | 0% | 87,298 | 67,847 | 29% |
| Ending shares outstanding <i>(thousands)</i> | | | | 87,300 | 87,294 | 0% |
| Average daily sales | | | | | | |
| Natural gas <i>(Mcf)</i> | 38,090 | 35,672 | 7% | 38,968 | 26,942 | 45% |
| Liquids <i>(bpd)</i> | 1,341 | 1,150 | 17% | 1,293 | 837 | 54% |
| Barrels of oil equivalent <i>(bpd)</i> | 7,689 | 7,095 | 8% | 7,787 | 5,328 | 46% |
| Average prices | | | | | | |
| Natural gas <i>(\$/Mcf)</i> | \$ 6.76 | \$ 6.09 | 11% | \$ 8.13 | \$ 6.48 | 25% |
| Liquids <i>(\$/bbl)</i> | \$ 48.49 | \$ 72.28 | (33%) | \$ 79.50 | \$ 63.12 | 26% |
| Barrels of oil equivalent <i>(\$/BOE)</i> | \$ 42.55 | \$ 42.55 | 0% | \$ 54.82 | \$ 42.98 | 28% |
| Royalties <i>(\$/BOE)</i> | \$ 9.46 | \$ 7.89 | 20% | \$ 11.94 | \$ 8.10 | 47% |
| Operating costs <i>(\$/BOE)</i> | \$ 11.51 | \$ 11.71 | (2%) | \$ 11.27 | \$ 11.70 | (4%) |
| Operating netback <i>(\$/BOE)</i> | \$ 21.58 | \$ 22.95 | (6%) | \$ 31.61 | \$ 23.18 | 36% |
| Reserves (MBOE) | | | | | | |
| Proved developed producing & non-producing | | | | 13,035 | 12,769 | 2% |
| Total proved | | | | 23,396 | 28,893 | (19%) |
| Total proved plus probable | | | | 32,297 | 39,888 | (19%) |
| Wells drilled <i>(gross)</i> | 91 | 40 | 128% | 217 | 122 | 78% |
| Undeveloped land <i>(thousands of acres)</i> | | | | | | |
| Gross | | | | 153 | 316 | (50%) |
| Net | | | | 77 | 138 | (44%) |

ABOUT THE COMPANY

Anderson Energy is a resource based “gas manufacturing company”, with a focus on the Edmonton Sands play in Central Alberta. The Edmonton Sands are high quality under pressured reservoir sands in Central Alberta ranging from a depth of 350 to 1,100 metres with up to 18 sands present in a single wellbore. The natural gas in the Edmonton Sands play is almost exclusively methane with no hydrogen sulphide or moveable water present. Anderson Energy has developed a proprietary technical expertise which has made the Company the leading driller in this play. As of December 31, 2008, the Company has drilled 459 operated wells and has over 1,650 locations to drill in the Edmonton Sands. The Company has been developing its lands on 160 acre (4 wells per section) spacing and recently has commenced downspacing its lands to 107 acre (6 wells per section) spacing.

2008 IN REVIEW

In 2008, the Company completed the construction of four major natural gas facilities at Willesden Green, Wilson Creek, Westpem and Buck Lake, which provided additional processing capacity and flexibility to lower per unit operating costs for the Company’s Edmonton Sands and Rock Creek operations. The Company drilled 217 gross (148.2 net) wells, with the Edmonton Sands representing 175 gross (130.7 net) of the wells drilled. The Company operated the drilling of 14 gross (12.5 net) deeper than Edmonton targets in Central Alberta with an overall net success rate of 88% in the deeper formations. All of the successful deeper wells are now on production. Near the end of 2008, the Company completed the tie-in of three newly drilled Rock Creek wells and the previously curtailed production at Westpem. In 2008, the Company participated in the drilling of 18 gross (2.9 net) outside operated Horseshoe Canyon Coal Bed Methane (“CBM”) wells.

For the year ended December 31, 2008, the Company averaged 7,787 BOED with fourth quarter production averaging 7,689 BOED. The fourth quarter production was negatively impacted by severe cold weather in December. 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 drilling program to 95 gross (67.8 net) wells and elected not to tie-in 1,100 BOED of behind pipe production from the newly drilled wells. Most of the behind pipe production could be tied in later in the year when the Company expects natural gas prices to be stronger. The Company wants 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 first quarter of 2009 to be 8,300 to 8,400 BOED. Production in the first quarter of 2009 peaked late in the quarter at 8,700 BOED with the tie-in of the recent Wilson Creek discovery. Production guidance estimated for the first six months of 2009 is 8,000 to 8,300 BOED. Current behind pipe production capability is 1,100 BOED.

Capital expenditures, net of dispositions were \$106.7 million in 2008. The Company spent \$22.7 million on major facility project installations, modifications and the Chedderville production test in 2008. This compares to capital expenditures of \$211.1 million in 2007, of which \$84.6 million were field capital expenditures. During 2008, the Company sold various properties for total net proceeds (after adjustments) of \$18.0 million.

During the fourth quarter of 2008, the Company drilled 91 gross (62.0 net) wells with a success rate of 95%, of which 84 gross (60.1 net) wells were Edmonton Sand wells and the balance were primarily outside operated Horseshoe Canyon CBM wells.

The Company's funds from operations achieved record results of \$79.3 million in 2008 as compared to \$36.4 million in 2007. Earnings before the goodwill write down were \$8.5 million as compared to \$2.2 million in 2007. The Company's average natural gas sales price was \$8.13 per Mcf in 2008 as compared to \$6.48 per Mcf in 2007. Natural gas sales prices on a quarterly basis were volatile with \$7.55 per Mcf in the first quarter, \$10.26 per Mcf in the second quarter, \$7.86 per Mcf in the third quarter and \$6.76 per Mcf in the fourth quarter. The Company's average natural gas sales price in the first quarter of 2009 is estimated to be approximately \$5.00 per Mcf. The Company's average crude oil and natural gas liquids sales price in 2008 was \$79.50 per bbl as compared to \$63.12 per bbl in 2007. In 2008, WTI oil prices in U.S. dollars averaged \$99.65 per bbl and in the first two months of 2009 have averaged \$40.59 per bbl. The Company's operating netback was \$31.61 per BOE in 2008 as compared to \$23.18 per BOE in 2007. The change in the operating netback was primarily due to commodity prices.

FARM-IN TRANSACTION

On January 30, 2009, the Company announced a significant farm-in transaction (the "Farm-In") with ConocoPhillips Canada 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. The Company believes that it will be able to satisfy all of its farm-in commitments with a budget that is based on cash flow throughout the period. If commodity and financial markets strengthen, Anderson Energy would be positioned to significantly expand its capital program as a result of the increased prospect inventory.

Under the Farm-In, the Company has access to 388 gross (205 net) sections of land in the middle of the Edmonton Sands fairway. This Farm-In more than doubles the Company's existing Edmonton Sands land base of 328 gross (198 net) sections of land. 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.

RESERVES

GLJ Petroleum Consultants ("GLJ") and AJM Petroleum Consultants ("AJM") were engaged to prepare a National Instrument NI 51-101 ("NI 51-101") compliant evaluation of the Company's reserves as of December 31, 2008. Previously, AJM had completed all of the Company's prior years' reserves evaluations. This year, the Reserves Committee elected to contract GLJ to evaluate all of the Company's Edmonton Sands properties and AJM to evaluate all of the Company's non Edmonton Sands properties. Next year, the Reserves Committee has elected to have GLJ evaluate all of the Company's reserves.

A summary of the Company's reserves evaluation is shown below as of December 31, 2008.

| <i>Reserves Category</i> | <i>Natural Gas (Bcf)</i> | <i>Oil (Mbbbls)</i> | <i>Natural Gas Liquids (Mbbbls)</i> | <i>Barrels of Oil equivalent (MBOE)</i> | <i>Percentage of reserves that are Edmonton Sands on a BOE basis</i> |
|--|--------------------------|---------------------|-------------------------------------|---|--|
| <i>Proved Developed Producing & Proved Developed Non Producing</i> | 67.0 | 513 | 1,339 | 13.0 | 42% |
| <i>Total Proved</i> | 125.4 | 656 | 1,842 | 23.4 | 57% |
| <i>Total Proved plus Probable</i> | 172.9 | 1,002 | 2,476 | 32.3 | 56% |

The Company's reserves life indices are 8.2 years total proved and 11.3 years total proved plus probable, based on 2008 annual production. Reserves additions (prior to dispositions) were 3.8 MMBOE total proved and 5.2 MMBOE total proved plus probable. The Company replaced more than 182% of its production with new proved plus probable reserves additions in 2008. Negative reserves revisions in the year were 5.6 MMBOE total proved and 8.0 MMBOE total proved plus probable. The majority of the negative revisions were undeveloped reserves where GLJ in their first year evaluating the properties has assigned lower new well average reserves in certain areas than in the previous evaluation. Dispositions in the year were 0.8 MMBOE total proved and 2 MMBOE total proved plus probable. Properties were sold for total proceeds of \$18 million and released future development costs of \$15 million. The impact of the negative revisions and the dispositions resulted in negative finding, development and acquisition costs. To estimate the normal course drilling, completion and tie-in capital efficiency, the Company determined that, net of major facility expenditures of \$22.7 million and 2009 project cancellation costs of \$3.4 million, the Company's F&D costs for additions only and excluding changes in future development costs were \$25.57 per BOE total proved and \$18.83 per BOE total proved plus probable. See the MD&A for more details on these calculations. The Company has a substantive drilling inventory, an 11.3 year reserve life index and an estimated net asset value per share range of \$4.26 to \$4.91 per share including a value assigned to the Farm-In. The new engineering evaluation

appraisal on the Company's Edmonton Sands was conducted by Canada's largest engineering evaluator of Canadian oil and gas properties, GLJ Petroleum Consultants. This was the first year that GLJ evaluated the Company's Edmonton Sands reserves. No reserves have been assigned to the Edmonton Sands Farm-In lands as of December 31, 2008. The Company expects to add significant reserves by December 31, 2009 with its first phase of drilling on the Farm-In lands. The GLJ price forecast as of December 31, 2008 is shown in the Company's MD&A for the year ended December 31, 2008. The complete reserves disclosure as required under NI 51-101, will be contained in the Company's 2008 Annual Information Form, to be filed on SEDAR on or before March 31, 2009.

The Company has 153,253 gross (76,828 net) undeveloped acres of land as of December 31, 2008 and has assigned a value of \$8.5 million to this acreage position. These undeveloped lands are primarily non Edmonton Sands lands.

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 December 31, 2008 the Company's drilling inventory is as follows:

| | <i>Gross</i> | <i>Net</i> |
|---|--------------|--------------|
| Edmonton Sands (as booked in GLJ reserves report) | 669 | 365 |
| Edmonton Sands Farm-In lands | 1,000 | 595 |
| Horseshoe Canyon CBM (as booked in AJM reserves report) | 120 | 23 |
| Other | 27 | 19 |
| Total | 1,816 | 1,002 |

NET ASSET VALUATION

The Company prepared net asset value per share estimates using the independent engineers' evaluation of the Company's reserves as of December 31, 2008, GLJ's December 31, 2008 price forecast, net debt at December 31, 2008, an internal evaluation of undeveloped land (\$110 per net acre) and an estimate for the Edmonton Sands Farm-In as if it had been effective December 31, 2008. Net asset value estimates are outlined below and are based on total issued and outstanding shares of 87,300,401 as of December 31, 2008.

| <i>(in millions except per share amounts)</i> | <i>Farm-In low end of management estimate</i> | <i>Farm-In high end of management estimate</i> |
|---|---|--|
| December 31, 2008 P&P Reserves Pretax 10% | 417 | 417 |
| Edmonton Sands Farm-In | 72 | 129 |
| Undeveloped Land | 8 | 8 |
| Net Debt (December 31, 2008) | (125) | (125) |
| Net Asset Value | 372 | 429 |
| Net Asset Value per Share (\$ per Share) | \$4.26 | \$4.91 |

The Company assigned a valuation range of \$72 million to \$129 million for the Edmonton Sands Farm-In. The impact of the Farm-In is estimated to be \$0.83 to \$1.48 per share. In accordance

with NI 51-101, the Company derived this valuation using the cost to drill, complete, equip and tie-in 200 wells during the commitment phase and 162 wells in the option phase with an average working interest of 65% and \$550,000 per well. The Company believes this methodology to be a conservative means of valuing the Farm-In. Using this method, the range of valuation would be \$72 million for the commitment alone to \$129 million for the commitment plus option. Based on available information today, the Company believes that it is likely it will exercise the option in the Farm-In.

CEILING TEST AND GOODWILL IMPAIRMENT

The Company is required to test the goodwill on its balance sheet on an annual basis or as events occur that could result in impairment. The goodwill was added to the balance sheet in 2005 and 2007 through corporate acquisitions. Due to a decline in the Company's fair value as represented by its market capitalization at December 31, 2008, the Company's carrying amount exceeded its fair value and it was determined that a non-cash impairment loss of \$35.4 million should be recognized. There has been no impairment to the carrying amount of the Company's petroleum and natural gas assets and no write down of petroleum and natural gas assets has been recorded in any period.

OUTLOOK

The Company has seen significant unprecedented changes in capital, equity, commodity and currency markets in the later part of 2008 and the first quarter 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 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 out at 1,606 rigs, and in October 2008, the U.S. oil and gas horizontal rig count peaked out a 650 rigs. Since then, the U.S. natural gas rig count has dropped to 857 rigs, which is the lowest it has been since May 2003. The U.S. oil and gas horizontal rig count has declined to 436 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 with reduced supply. Historically in the natural gas business, supply of natural gas gets corrected in both directions 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 Company felt it was prudent to slow down its capital spending program in the first half of the year and limit spending to less than \$14 million, with only 11 Edmonton Sands wells drilled and 29 Edmonton Sands wells tied in. Three significant wells at Wilson Creek were tied in for production late in the quarter and two additional wells will come on-stream after April 1, 2009. The Company is planning on spending approximately \$14 million on the Farm-In lands in the

second half of the year. Spending additional capital on the Farm-In lands in 2009 or on its existing lands will be dependent on higher commodity prices in the second half of the year.

Most of the Company's drilling inventory is low cost, lower productivity natural gas which at current prices attracts similar royalties under both the old and new Alberta government royalty regimes. The introduction of the new Alberta royalty framework in 2009 is not expected to have a significant impact on either the pace of the Company's activity or the intrinsic value of the drilling inventory.

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 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 and up until March 2011. 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 potentially have a significant impact on reducing future Crown royalties payable. As the initiatives were announced subsequent to year end, the value of the initiatives has not yet been incorporated into the reserves report or the net asset value calculations presented here.

The first quarter of 2009 presents 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 presents an opportunity to reduce the cost of doing business and the Company plans to take advantage of that opportunity. 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.

The Company invites its shareholders to attend the Company's annual and special meeting on May 14, 2009 at the Metropolitan Centre in Calgary 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
March 20, 2009

Management's Discussion and Analysis

FOR THE YEARS ENDED DECEMBER 31, 2008 AND 2007

The following discussion and analysis of financial results should be read in conjunction with the consolidated financial statements of Anderson Energy Ltd. ("Anderson Energy" or the "Company") for the years ended December 31, 2008 and 2007 and is based on information available as of March 20, 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.

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

REVIEW OF FINANCIAL RESULTS

Overview. For the year ended December 31, 2008, funds from operations achieved record levels of \$79.3 million (\$0.91 per share) up 118% over 2007. Sales volumes averaged 7,787 BOED, which were 46% higher than the previous year. Capital expenditures were \$106.7 million, net of dispositions of \$18.0 million, and included construction of four major facility projects as well as the drilling of 217 gross (148.2 net) wells with a success rate of 93%.

Debt, net of working capital deficiency was \$125 million at December 31, 2008. Subsequent to year end, the Company announced a significant farm-in transaction in its Edmonton Sands project area. The farm-in more than doubles the Company's existing land base with the addition of 388 gross (205 net) sections of land.

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. Management has restricted capital and administrative spending, including a significant reduction in the 2009 first quarter drilling program, in order to preserve financial flexibility for the farm-in project. Management continues to monitor financing opportunities to fund its future prospects and commitments. Bank lines are currently at \$130 million including a supplemental credit facility of \$10 million put in place for the winter drilling program which expires on June 30, 2009.

Revenue and Production. Gas sales comprised 83% of Anderson Energy's total oil and gas sales volumes for the year ended December 31, 2008, consistent with the prior year.

Gas sales volumes for the year ended December 31, 2008 increased 45% to an average of 39.0 MMcfd from 26.9 MMcfd last year. The increase reflects the acquisition of oil and gas assets in September 2007 and new wells on production as a result of drilling during the year. The Central Alberta area, centered around the Sylvan Lake area and northwest to Pembina, remains the Company's largest area of production, with gas sales averaging 33.9 MMcfd (20.1 MMcfd during 2007). Gas sales volumes were negatively impacted by delays in well tie-ins and plant outages at various facilities in the month of September. Extremely cold weather also impacted production in the month of December. The Company disposed of 420 BOED of production late in the fourth quarter of 2008.

The Company achieved average gas sales of 38.1 MMcfd in the fourth quarter of 2008. This compares to 38.7 MMcfd in the third quarter of 2008 and 35.7 MMcfd in the fourth quarter of 2007.

Oil sales for the year ended December 31, 2008 averaged 487 bpd compared to 540 bpd for the year ended December 31, 2007. Oil production averaged 491 bpd in the fourth quarter of 2008 compared to 434 bpd in the third quarter of 2008 and 602 bpd in the fourth quarter of 2007. The decrease in 2008 production is due largely to the sale of minor oil properties earlier in the year. The majority of the Company's oil production is from Central and Eastern Alberta.

Natural gas liquids sales for the year ended December 31, 2008 averaged 806 bpd compared to 297 bpd for the year ended December 31, 2007. Natural gas liquids sales averaged 850 bpd in the fourth quarter of 2008 compared to 787 bpd in the third quarter of 2008 and 548 bpd in the fourth quarter of 2007. Drilling activity on deeper projects contributed to the volume increase in 2008.

The following tables outline production revenue, volumes and average sales prices for the year and for the fourth quarter.

OIL AND NATURAL GAS REVENUE

| <i>(thousands of dollars)</i> | <i>Three months ended Dec. 31</i> | | <i>Year ended Dec. 31</i> | |
|---------------------------------|-----------------------------------|------------------|---------------------------|------------------|
| | <i>2008</i> | <i>2007</i> | <i>2008</i> | <i>2007</i> |
| Natural gas | \$ 23,706 | \$ 20,001 | \$ 117,237 | \$ 62,558 |
| Natural gas hedging gain (loss) | - | - | (1,341) | 1,157 |
| Oil | 2,511 | 3,993 | 16,441 | 12,369 |
| NGL | 3,469 | 3,653 | 21,170 | 6,927 |
| Royalty and other | 416 | 128 | 2,738 | 574 |
| Total | \$ 30,102 | \$ 27,775 | \$ 156,245 | \$ 83,585 |

PRODUCTION

| | <i>Three months ended Dec. 31</i> | | <i>Year ended Dec. 31</i> | |
|----------------------------|-----------------------------------|--------------|---------------------------|--------------|
| | <i>2008</i> | <i>2007</i> | <i>2008</i> | <i>2007</i> |
| Natural gas (<i>Mcf</i>) | 38,090 | 35,672 | 38,968 | 26,942 |
| Oil (<i>bpd</i>) | 491 | 602 | 487 | 540 |
| NGL (<i>bpd</i>) | 850 | 548 | 806 | 297 |
| Total (BOED) | 7,689 | 7,095 | 7,787 | 5,328 |

PRICES

| | <i>Three months ended Dec. 31</i> | | <i>Year ended Dec. 31</i> | |
|-------------------------------|-----------------------------------|-----------------|---------------------------|-----------------|
| | <i>2008</i> | <i>2007</i> | <i>2008</i> | <i>2007</i> |
| Natural gas (<i>\$/Mcf</i>) | \$ 6.76 | \$ 6.09 | \$ 8.13 | \$ 6.48 |
| Oil (<i>\$/bbl</i>) | 55.63 | 72.12 | 92.27 | 62.71 |
| NGL (<i>\$/bbl</i>) | 44.37 | 72.45 | 71.78 | 63.88 |
| Total (<i>\$/BOE</i>)* | \$ 42.55 | \$ 42.55 | \$ 54.82 | \$ 42.98 |

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

Anderson Energy's average gas sales price was \$8.13 per Mcf for the year ended December 31, 2008 compared to \$6.48 per Mcf for the year ended December 31, 2007. For the three months ended December 31, 2008, the gas sales price was \$6.76 per Mcf. This compares to \$7.86 per Mcf realized in the third quarter of 2008 and \$6.09 per Mcf realized in the fourth quarter of 2007. Gas prices decreased significantly over the course of the year and into the first quarter of 2009 and are being significantly impacted by the global economic recession. The natural gas price in 2008 includes a hedging loss of \$1.3 million. The 2008 gas price before the hedging loss was \$8.22 per Mcf. The natural gas price in 2007 includes hedging gains of \$1.2 million. The 2007 gas price before hedging gains was \$6.36 per Mcf.

Historically, Anderson Energy has sold most of its gas at Alberta spot market prices. Beginning in November 2008, the Company is selling approximately 30% of its production at the average monthly index price, and the balance is being sold 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 26 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 December 31, 2008. In January 2008, as part of its risk management program, the Company entered into fixed price natural gas contracts to manage commodity price risk. The Company had physical contracts to sell 25,000 GJ per day of natural gas for February and March 2008 at an average AECO price of \$6.89 per GJ. The Company realized a \$1.3 million loss on this hedging contract.

Royalties. Royalties were 22% of revenue for the year ended December 31, 2008 compared to 19% of revenue for the year ended December 31, 2007. Royalties were 22% of revenue in the fourth quarter of 2008 compared to 20% of revenue in the third quarter of 2008 and 19% of revenue in the fourth quarter of 2007. Royalties in 2007 were reduced by large credits related to prior period gas cost allowance assessments. In addition, royalty rates increased in the current year as a result of the higher rate gas wells and higher natural gas liquids yields from new drilling on deeper projects. 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 the changes are expected to have a negative impact on the oil and gas business as a whole, the impact on shallow gas programs is expected to be less than on other areas of the business. Anderson Energy believes that the proposed changes will have a positive impact on royalties at current production levels and prices and do not negatively impact the Company's long-term Edmonton Sands business strategy, as the focus is predominantly on shallow gas lower productivity wells. 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 and up 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.

| | <i>Three months ended Dec. 31</i> | | <i>Year ended Dec. 31</i> | |
|---------------------------|-----------------------------------|-------------|---------------------------|-------------|
| | <i>2008</i> | <i>2007</i> | <i>2008</i> | <i>2007</i> |
| <i>Royalties (%)</i> | 22% | 19% | 22% | 19% |
| <i>Royalties (\$/BOE)</i> | \$ 9.46 | \$ 7.89 | \$ 11.94 | \$ 8.10 |

Operating Expenses. Operating expenses were \$11.27 per BOE for the year ended December 31, 2008 compared to \$11.70 per BOE for the year ended December 31, 2007. Operating expenses were \$11.51 in the fourth quarter of 2008 compared to \$10.10 in the third quarter of 2008 and \$11.71 in the fourth quarter of 2007. The reduction in operating expenses in the third quarter of 2008 was due to the new gas plant projects that came onstream early in the quarter, and the sale of a high operating expense property in the second quarter. Operating expenses in the fourth quarter of 2008 were impacted by some larger than normal overhaul and repair costs. Fourth quarter operating costs were also higher than the third quarter due to additional downhole work, maintenance of rotating equipment, additional water hauling and water disposal related to

the Chedderville production test. The Chedderville test project was suspended late in the quarter due to low product prices.

OPERATING NETBACK

| <i>(thousands of dollars)</i> | <i>Three months ended Dec. 31</i> | | <i>Year ended Dec. 31</i> | |
|-------------------------------|-----------------------------------|------------------|---------------------------|------------------|
| | <i>2008</i> | <i>2007</i> | <i>2008</i> | <i>2007</i> |
| Revenue | \$ 30,102 | \$ 27,775 | \$ 156,245 | \$ 83,585 |
| Royalties | (6,694) | (5,152) | (34,038) | (15,758) |
| Operating expenses | (8,140) | (7,645) | (32,110) | (22,743) |
| | <u>\$ 15,268</u> | <u>\$ 14,978</u> | <u>\$ 90,097</u> | <u>\$ 45,084</u> |
| Sales (MBOE) | 707.4 | 652.8 | 2,850.1 | 1,944.7 |
| Per BOE | | | | |
| Revenue | \$ 42.55 | \$ 42.55 | \$ 54.82 | \$ 42.98 |
| Royalties | (9.46) | (7.89) | (11.94) | (8.10) |
| Operating expenses | (11.51) | (11.71) | (11.27) | (11.70) |
| | <u>\$ 21.58</u> | <u>\$ 22.95</u> | <u>\$ 31.61</u> | <u>\$ 23.18</u> |

General and Administrative Expenses. General and administrative expenses were \$6.4 million or \$2.24 per BOE for the year ended December 31, 2008 compared to \$6.3 million or \$3.25 per BOE for the year ended December 31, 2007. General and administrative expenses were \$1.40 per BOE in the fourth quarter of 2008 compared to \$2.90 per BOE in the third quarter of 2008 and \$2.13 per BOE in the fourth quarter of 2007. Staffing levels were increased in the second and third quarters of 2008 in anticipation of higher expected activity levels this winter. However, general and administrative costs on a per BOE basis decreased in the year as a result of increased production and the elimination of the 2008 bonus accrual for employees as a result of the rapidly changing economic climate. While staffing levels are expected to decline somewhat from 2008 to 2009, overall, general and administrative expenses are expected to increase in 2009 largely due to decreased overhead recoveries from reduced capital spending.

| <i>(thousands of dollars)</i> | <i>Three months ended Dec. 31</i> | | <i>Year ended Dec. 31</i> | |
|-------------------------------------|-----------------------------------|-----------------|---------------------------|-----------------|
| | <i>2008</i> | <i>2007</i> | <i>2008</i> | <i>2007</i> |
| General and administrative (gross) | \$ 2,324 | \$ 2,784 | \$ 11,986 | \$ 10,799 |
| Overhead recoveries | (720) | (614) | (2,114) | (1,669) |
| Capitalized | (612) | (780) | (3,495) | (2,809) |
| General and administrative (net) | <u>\$ 992</u> | <u>\$ 1,390</u> | <u>\$ 6,377</u> | <u>\$ 6,321</u> |
| General and administrative (\$/BOE) | \$ 1.40 | \$ 2.13 | \$ 2.24 | \$ 3.25 |
| % Capitalized | 26% | 28% | 29% | 26% |

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 expense was \$2.0 million in 2008 (\$1.1 million net of amounts capitalized) versus \$1.2 million (\$0.6 million net of amounts

capitalized) in 2007. The increase is a result of additional stock options being granted to new and existing staff members.

Interest Expense. Interest expense was \$4.5 million for the year ended December 31, 2008 compared to \$2.6 million in 2007. In the fourth quarter of 2008, interest expense was \$1.1 million compared to \$1.0 million in the third quarter of 2008 and \$1.0 million in the fourth quarter of 2007. The increase in interest expense is due to the higher debt levels resulting from the Company's capital program. Assets acquired in the second half of 2007 were also partially financed with debt. The average effective interest rate on outstanding bank loans was 5.0% in 2008 compared to 5.9% in 2007. Lower prime and bankers acceptance interest rates on borrowings have been offset in part by higher margins applied to the banking facilities. Interest expense is expected to increase in 2009 due to the higher debt levels expected to be carried in the first half of 2009 as a result of winter drilling and lower commodity prices.

Depletion and Depreciation. Depletion and depreciation was \$22.26 per BOE for the year ended December 31, 2008 compared to \$20.96 per BOE in 2007. Depletion and depreciation was \$28.46 per BOE in the fourth quarter of 2008 compared to \$20.28 per BOE in the third quarter of 2008 and \$20.76 per BOE in the fourth quarter of 2007. Depletion and depreciation expense is calculated based on proved reserves only. The recent reserves evaluations completed by GLJ Petroleum Consultants ("GLJ") and AJM Petroleum Consultants ("AJM") maintained the ratio of proved to proved plus probable reserves at 72% consistent with 2007. However, revisions to reserves and asset sales resulted in an overall decline in proved reserves after production and drilling. In addition, future development costs increased 15% to \$204.7 million.

Asset Retirement Obligation. As a result of new drilling and facility construction, the Company recorded \$2.4 million in asset retirement obligations in the fourth quarter of 2008 and \$5.5 million for the year ended December 31, 2008. Revisions in estimated reclamation costs and timelines made up \$2.8 million of the annual additions and disposals of assets late in the year reduced obligations by \$1.2 million. Accretion expense was \$1.9 million for 2008 compared with \$1.4 million for 2007. Accretion expense was included in depletion and depreciation expense and increased due to the higher obligations.

Income Taxes. Anderson Energy is not currently taxable. The Company does not anticipate paying current income tax in 2009. The estimated tax pool balances at December 31, 2008 are summarized below. Tax pool classifications are estimates as some new wells have not yet had their status as exploratory or development confirmed. The balances below have been reduced for the effect of income recorded in 2008 that will not be taxed until 2009.

| | |
|--|----------------|
| Canadian Exploration Expenses (CEE) | \$ 60 million |
| Canadian Development Expenses (CDE) | 59 million |
| Undepreciated Capital Cost (UCC) | 114 million |
| Canadian Oil and Gas Property Expenses (COGPE) | 16 million |
| Non-Capital Losses and Other | 53 million |
| Total | \$ 302 million |

Funds from Operations. Funds from operations increased by 118% to \$79.3 million in 2008 compared to \$36.4 million in 2007. On a per share basis, funds from operations were \$0.91 per share in 2008 compared to \$0.54 per share in 2007. For the three months ended December 31, 2008, funds from operations were \$13.2 million or \$0.15 per share, a decrease of 38% over the previous quarter of \$21.2 million or \$0.24 per share, and an increase of 5% over the fourth quarter of 2007 of \$12.6 million or \$0.14 per share. The increase in funds from operations in 2008 is a result of higher production and higher commodity prices on average in 2008, partially offset by higher royalty expenses. Cash from operating activities also increased year over year for similar reasons. The decline in commodity prices during the last half of 2008, particularly in the fourth quarter, negatively impacted the Company's funds from operations. During the first quarter of 2009, prices continued to decline with gas prices in the first quarter of 2009 expected to average approximately \$5.00 per Mcf.

| <i>(thousands of dollars)</i> | <i>Three months ended Dec. 31</i> | | <i>Year ended Dec. 31</i> | |
|-------------------------------------|-----------------------------------|------------------|---------------------------|------------------|
| | <i>2008</i> | <i>2007</i> | <i>2008</i> | <i>2007</i> |
| Cash from operating activities | \$ 11,261 | \$ 11,110 | \$ 82,688 | \$ 34,259 |
| Changes in non-cash working capital | 1,464 | 1,404 | (4,492) | 1,413 |
| Asset retirement obligations | 479 | 50 | 1,132 | 742 |
| Funds from operations | \$ 13,204 | \$ 12,564 | \$ 79,328 | \$ 36,414 |

Earnings. The Company reported a \$41.2 million loss in the fourth quarter of 2008 and a \$26.9 million loss for the year ended December 31, 2008. 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. Earnings before this write-down were \$8.5 million in 2008 compared to \$2.2 million in 2007, an increase of 289%, and reflect higher production volumes and operating netbacks on average for the year. The fourth quarter loss was \$5.9 million before the write-down and was due to the negative impacts of weather on production volumes and higher depletion and depreciation expense. Earnings in 2007 were positively impacted by the federal income tax rate reductions enacted in the fourth quarter.

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 \$27.5 million in capital expenditures net of dispositions in the fourth quarter and \$106.7 million for the year ended December 31, 2008. The breakdown of expenditures is shown below:

| <i>(thousands of dollars)</i> | <i>Three months ended Dec. 31</i> | | <i>Year ended Dec. 31</i> | | |
|--|-----------------------------------|----------|---------------------------|----------|-------------|
| | <i>2008</i> | | <i>2008</i> | | <i>2007</i> |
| Land, geological and geophysical costs | \$ | 167 | \$ | 1,211 | \$ 2,081 |
| Acquisitions, net of dispositions | | (17,186) | | (18,043) | 126,564 |
| Drilling, completion and recompletion | | 25,713 | | 68,075 | 42,128 |
| Facilities and well equipment | | 17,958 | | 51,174 | 35,485 |
| Capitalized G&A | | 611 | | 3,494 | 2,809 |
| Total finding, development & acquisition expenditures | | 27,263 | | 105,911 | 209,067 |
| Compressor and other equipment inventory | | (101) | | 295 | 1,879 |
| Office equipment and furniture | | 308 | | 463 | 187 |
| Total capital expenditures | | 27,470 | | 106,669 | 211,133 |
| Non-cash asset retirement obligations and capitalized stock-based compensation | | 2,800 | | 6,421 | 3,632 |
| Total cash and non-cash capital additions | \$ | 30,270 | \$ | 113,090 | \$ 214,765 |

Capital expenditures included \$22.7 million for major facilities projects at Willisden Green, Buck Lake, Westpem and Wilson Creek, as well as other major project installations and modifications. The Company also spent approximately \$3.4 million of capital on initial engineering, surveying equipment and surface land acquisition costs related to wells that were ultimately not drilled when the planned winter Edmonton Sands drilling program was reduced from 200 wells to 95 wells late in the year due to the rapidly changing economic climate. The tie-in of standing Edmonton Sands wells from the winter drilling program was also halted early in 2009 resulting in approximately 6 MMcf of gas remaining behind pipe. The Company expects to spend less than \$14 million for the first six months of 2009. The Company continues to monitor economic conditions and at the first quarter press release scheduled for May 14, 2009, the Company believes it will be in a better position to announce a full year 2009 capital budget and associated guidance.

Drilling statistics are shown below:

| | <i>Three months ended Dec. 31</i> | | | | <i>Year ended Dec. 31</i> | | | |
|------------------|-----------------------------------|------------|--------------|------------|---------------------------|------------|--------------|------------|
| | <i>2008</i> | | <i>2007</i> | | <i>2008</i> | | <i>2007</i> | |
| | <i>Gross</i> | <i>Net</i> | <i>Gross</i> | <i>Net</i> | <i>Gross</i> | <i>Net</i> | <i>Gross</i> | <i>Net</i> |
| Gas | 86 | 59.5 | 37 | 29.8 | 196 | 134.7 | 106 | 75.6 |
| Oil | - | - | - | - | 6 | 2.9 | 5 | 2.2 |
| Dry | 5 | 2.5 | 3 | 2.2 | 15 | 10.6 | 11 | 6.9 |
| Total | 91 | 62.0 | 40 | 32.0 | 217 | 148.2 | 122 | 84.7 |
| Success rate (%) | 95% | 96% | 93% | 93% | 93% | 93% | 91% | 92% |

The Company drilled 175 gross (130.7 net) Edmonton Sands wells in 2008 of which 84 gross (60.1 net) wells were drilled in the fourth quarter.

CEILING TEST/GOODWILL IMPAIRMENT

At December 31, 2008, the ceiling test resulted in the undiscounted cash flows from proved reserves being in excess of the carrying value of the underlying petroleum and natural gas assets and as such no ceiling test write-down was required. Prices used for the 2008 ceiling test are presented in note 4 of the consolidated financial statements.

Anderson Energy recorded goodwill as a result of acquisitions made in 2005 and 2007. Goodwill represents the excess of the purchase price of the acquired businesses over the fair value of net assets acquired and is assessed at least annually in the fourth quarter for impairment. Due to a decline in the Company's fair value as represented by its market capitalization at December 31, 2008, the Company's carrying amount exceeded its fair value and it was determined a non-cash impairment loss of \$35.4 million should be recognized. It should be noted that there has been no impairment to the carrying amount of the Company's petroleum and natural gas assets and no write down of petroleum and natural gas assets has been recorded in any period.

RESERVES

The Company's reserves were evaluated by AJM and GLJ with the consolidation being performed by GLJ in accordance with National Instrument 51-101 ("NI 51-101") as of December 31, 2008. Previously, AJM completed all of the Company's prior year's reserves evaluations. This year, the Reserves Committee elected to contract GLJ to evaluate all of the Company's Edmonton Sands properties and AJM to evaluate all of the Company's non Edmonton Sands properties. Next year, the Reserves Committee has elected to have GLJ evaluate all of the Company's reserves. AJM used GLJ pricing in preparing their evaluation of the non Edmonton Sands properties. The tables in this section are an excerpt from what will be contained in the Company's Annual Information Form for the year ended December 31, 2008 ("AIF") as the Company's NI 51-101 annual required filings.

SUMMARY OF GROSS OIL AND GAS RESERVES

*As at December 31, 2008
(Combined AJM and GLJ)*

| | <i>Natural Gas (Bcf)</i> | <i>Oil (Mbbbls)</i> | <i>Natural Gas Liquids (Mbbbls)</i> | <i>Total BOE (MBOE)</i> |
|--------------------------------|------------------------------|-------------------------|---|-----------------------------|
| Proved developed producing | 51.9 | 499 | 1,185 | 10,342 |
| Proved developed non-producing | 15.1 | 14 | 154 | 2,693 |
| Proved undeveloped | 58.3 | 142 | 503 | 10,362 |
| Total proved | 125.4 | 656 | 1,842 | 23,396 |
| Probable | 47.5 | 346 | 634 | 8,900 |
| Total proved plus probable | 172.9 | 1,002 | 2,476 | 32,297 |

*Notes: (1) Coal Bed Methane is not material to report separately and is included in the Natural Gas category.
(2) Columns may not add due to rounding in the reserves report.*

NET PRESENT VALUE BEFORE INCOME TAXES

As at December 31, 2008

(Combined AJM and GLJ)

(GLJ December 31, 2008 Price Forecast, Escalated Prices)

| (thousands of dollars) | 0% | 5% | 10% | 15% | 20% |
|--------------------------------|---------|---------|---------|---------|---------|
| Proved developed producing | 329,643 | 250,810 | 214,049 | 190,039 | 172,239 |
| Proved developed non-producing | 56,794 | 45,369 | 37,603 | 31,917 | 27,572 |
| Proved undeveloped | 100,814 | 70,004 | 45,435 | 28,044 | 15,745 |
| Total proved | 487,252 | 366,184 | 297,087 | 250,000 | 215,555 |
| Probable | 238,153 | 164,297 | 120,337 | 92,422 | 73,575 |
| Total proved plus probable | 725,405 | 530,481 | 417,425 | 342,422 | 289,130 |

Note: Columns may not add due to rounding in the reserves report.

The estimated net present value of future net revenues presented in the table above does not necessarily represent the fair market value of the Company's reserves.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

As at December 31, 2008

GLJ Forecast Prices and Costs

| Year | Oil | | Natural Gas | Edmonton Liquids Prices | | | Inflation Rate % | Exchange rate (US\$/Cdn) |
|------------|------------------------|---|----------------------------|-------------------------|--------------------|---------------------------|------------------|--------------------------|
| | WTI Cushing (\$US/bbl) | Light, Sweet Crude Edmonton (\$Cdn/bbl) | AECO Gas Price (\$Cdn/Mcf) | Propane (\$Cdn/bbl) | Butane (\$Cdn/bbl) | Pentanes Plus (\$Cdn/bbl) | | |
| 2009 | 57.50 | 68.61 | 7.58 | 43.22 | 52.14 | 69.98 | 2.0 | 0.825 |
| 2010 | 68.00 | 78.94 | 7.94 | 49.73 | 61.57 | 80.52 | 2.0 | 0.850 |
| 2011 | 74.00 | 83.54 | 8.34 | 52.63 | 65.16 | 85.21 | 2.0 | 0.875 |
| 2012 | 85.00 | 90.92 | 8.70 | 57.28 | 70.92 | 92.74 | 2.0 | 0.925 |
| 2013 | 92.01 | 95.91 | 8.95 | 60.42 | 74.81 | 97.82 | 2.0 | 0.950 |
| 2014 | 93.85 | 97.84 | 9.14 | 61.64 | 76.32 | 99.80 | 2.0 | 0.950 |
| thereafter | 2% | | | | | | | |

Total future development costs included in the reserves evaluation were \$204.7 million for total proved reserves and \$247.6 million for total proved plus probable reserves. Further details related to future development costs, including assumptions regarding the timing of the expenditures, will be included in the Company's AIF for the 2008 fiscal year. Future development costs are associated with the reserves as disclosed in the AJM and GLJ reports and do not necessarily represent the Company's current exploration and development budget.

CONTINUITY OF GROSS RESERVES

| | Natural Gas (Bcf) | | | Oil & Natural Gas Liquids (Mbbbls) | | |
|-------------------|-------------------|----------|--------|------------------------------------|----------|-------|
| | Proved | Probable | Total | Proved | Probable | Total |
| Opening balance | | | | | | |
| December 31, 2007 | 159.3 | 59.8 | 219.1 | 2,350 | 1,022 | 3,372 |
| Extensions | 20.0 | 7.2 | 27.2 | 448 | 102 | 550 |
| Net acquisitions | 0.2 | 0.3 | 0.5 | 7 | 10 | 17 |
| Revisions | (35.3) | (13.5) | (48.8) | 250 | (69) | 181 |
| Dispositions | (4.5) | (6.3) | (10.8) | (84) | (85) | (169) |
| Production | (14.3) | - | (14.3) | (473) | - | (473) |
| Closing balance | | | | | | |
| December 31, 2008 | 125.4 | 47.5 | 172.9 | 2,498 | 980 | 3,478 |

Note: Closing balance for natural gas includes 6.3 Bcf of proved and 2.3 Bcf of probable Coal Bed Methane reserves.

The Company's reserves life indices are 8.2 years total proved and 11.3 years total proved plus probable, based on 2008 annual production. Reserves additions (prior to dispositions) were 3.8 MMBOE total proved and 5.2 MMBOE total proved plus probable. The Company replaced more than 182% of its production with new proved plus probable reserves additions in 2008. Negative reserves revisions in the year were 5.6 MMBOE total proved and 8.0 MMBOE total proved plus probable. The majority of the negative revisions were undeveloped reserves where GLJ in their first year evaluating the properties has assigned lower new well average reserves in certain areas than in the previous evaluation. Dispositions in the year were 0.8 MMBOE total proved and 2 MMBOE total proved plus probable. Properties were sold for total proceeds of \$18 million and released future development costs of \$15 million.

The negative revisions and the dispositions resulted in negative finding, development and acquisition costs in 2008. This compares to \$19.55 per BOE proved and \$16.71 per BOE proved plus probable in 2007 and \$13.30 per BOE proved and \$13.36 per BOE proved plus probable in 2006. The three year average finding, development and acquisition costs were \$26.19 total proved and \$25.08 total proved plus probable. To estimate the normal course drilling, completion and tie-in capital efficiency, the Company determined that, net of major facility expenditures of \$22.7 million and 2009 project cancellation costs of \$3.4 million, the Company's F&D costs for additions only and before changes in future development costs were \$25.57 per BOE total proved and \$18.83 per BOE total proved plus probable. Comparable numbers for 2007 were \$11.45 per BOE proved and \$11.66 per BOE proved plus probable and for 2006 were \$29.07 per BOE proved and \$18.07 per BOE proved plus probable, resulting in a three year average of \$18.97 per BOE total proved and \$15.62 per BOE total proved plus probable. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. BOEs 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.

SHARE INFORMATION

The Company's shares have been listed on the Toronto Stock Exchange since September 7, 2005 under the symbol "AXL". As of December 31, 2008, there were 87.3 million common shares outstanding and 7.6 million stock options outstanding. During 2008, 6,000 shares were issued under the employee stock option plan. The annualized trading turnover ratio was 88%.

SHARE PRICE ON TSX

| | <i>2008</i> | <i>2007</i> |
|---|-----------------------|-----------------------|
| High | \$ 5.45 | \$ 5.40 |
| Low | \$ 0.87 | \$ 2.53 |
| Close | \$ 1.15 | \$ 2.88 |
| Volume | 76,653,637 | 43,601,931 |
| Shares outstanding at December 31 | 87,300,401 | 87,294,401 |
| <u>Market capitalization at December 31</u> | <u>\$ 100,395,461</u> | <u>\$ 251,407,875</u> |

RELATED PARTY TRANSACTION

In August 2007, the Company issued 344,494 common shares to directors and officers of the Company at a price of \$3.90 per share for total proceeds of \$1.3 million as part of a \$100.2 million public offering of common shares.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2008, the Company had outstanding bank loans of \$85 million and a working capital deficiency of \$40 million. The large working capital deficiency is due to accruals associated with the large capital program in the last quarter of the year.

The Company expects to spend less than \$14 million in capital in the first half of 2009 which is essentially a "cash flow" budget. With the significant volatility in commodity prices and the recent signing of the farm-in agreement in its core Edmonton Sands project area, the Company believes it will be in a better position to announce a full year 2009 capital budget and associated guidance with the first quarter press release scheduled to be released on May 14, 2009.

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 December 31, 2008, 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 will expire on June 30, 2009. Anderson Energy will prudently use its bank loan facilities to finance its operations as required. The available lending limits under the bank facilities are reviewed twice a year and are based on the bank syndicate's interpretation of the Company's reserves and future commodity

prices. There can be no assurance that the amount of the available bank lines will not be adjusted at the next scheduled review to be completed prior to July 14, 2009. As a result of the current economic climate and weak global credit market, it is expected the Company will incur increased margins and fees. 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 in the amount of \$120 million have a revolving period ending 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 \$10 million supplemental facility expires on June 30, 2009.
- *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 26 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 \$1.3 million in 2009, \$1.1 million in 2010, \$0.9 million in 2011, \$0.5 million in 2012, \$0.3 million in 2013 and \$0.6 million thereafter.
- *Farm-in* – On January 29, 2009, the Company executed 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.

These obligations are described further in other parts of this discussion and analysis and in notes 7, 15 and 16 to the consolidated financial statements.

CRITICAL ACCOUNTING ESTIMATES

The Company's significant accounting policies are disclosed in note 1 to the consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These accounting policies are discussed below and are included to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results than reported. The Company's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results that differ materially from current estimates.

Proved Oil and Gas Reserves. Proved oil and gas reserves, as defined by the Canadian Securities Administrators in NI 51-101 with reference to the Canadian Oil and Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. Determination of reserves is a complex process involving judgments, estimates and decisions based on available geological, engineering, production and any other relevant data. These estimates are subject to material change as economic conditions change and ongoing production and development activities provide new information.

Independent reserves evaluators have prepared the Company's oil and gas reserves estimate. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance, methodology of booking undeveloped reserves, or a change in the Company's development plans. The effect of changes in proved oil and gas reserves on the financial results and financial position of the Company is described below under the heading "Full Cost Accounting" and "Full Cost Accounting Ceiling Test".

Full Cost Accounting. The Company follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of exploring for and developing petroleum and natural gas properties and related reserves are capitalized. The capitalized costs are depleted and depreciated using the unit-of-production method based on estimated proved reserves. Reserves estimates can have a significant impact on earnings, as they are a key component in the calculation of depletion and depreciation. Downward revisions in reserves estimates or upward revisions in future development cost estimates could result in a higher depletion and depreciation charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserves estimates (see "Full Cost Accounting Ceiling Test"), the excess must be written off as an expense charged against earnings. In the event of property dispositions, proceeds are normally deducted from the full cost pool without recognition of gain or loss unless there is a change in the depletion rate of 20% or greater.

Unproved Properties. Certain costs related to unproved properties are excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted. The costs relating to unproved properties are also excluded from the book value subject to the ceiling test measurement.

Full Cost Accounting Ceiling Test. Petroleum and natural gas assets are evaluated in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

Impairment is indicated if the carrying value of the oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the oil and gas assets is charged to earnings. The ceiling test is based on estimates of reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Asset Retirement Obligations. The Company is required to provide for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to property, plant & equipment and the appropriate liability account over the expected service life of the asset. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of the economic life of the asset, costs associated with abandonment and site restoration, review of potential abandonment methods and salvage/usage of tangible equipment.

Income Taxes. The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ from that estimated and recorded by management. The Company estimates its future income tax rate in calculating its future income tax liability. Various assumptions are made in assessing when temporary differences will reverse and this will impact the rate used.

Stock-Based Compensation Expense. In order to recognize stock-based compensation expense, the Company estimates the fair value of stock options granted using assumptions related to interest rates, expected life of the option, forfeitures, volatility of the underlying security and expected dividend yields. These assumptions may vary over time.

Goodwill. The process of accounting for the purchase of a company results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise, the determination of goodwill is also imprecise. Goodwill is assessed periodically for impairment. Impairment is indicated if the fair value of the Company falls below the book value of its equity.

CHANGES IN ACCOUNTING POLICIES

On January 1, 2008, the Company adopted Section 1535 "Capital Disclosures". This section requires a discussion of the Company's objectives, policies and processes for managing capital including: quantitative data about what is considered capital, whether the entity has complied with any capital requirements and the consequences of non-compliance if the entity has not complied.

These disclosures are included in note 11 of the accompanying consolidated financial statements.

On January 1, 2008, the Company also adopted the new Canadian standards for financial instruments: Section 3862 “Financial Instruments – Disclosures” and Section 3863 “Financial Instruments – Presentation”, which apply to both recognized and unrecognized financial instruments. These disclosures include a discussion of the nature and extent of risks arising from financial instruments and are included in note 13 of the accompanying consolidated financial statements.

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.

GOODWILL AND INTANGIBLE ASSETS

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets. Effective for fiscal years beginning on or after October 1, 2008, this section provides guidance on the recognition, measurement, presentation and disclosure for goodwill and intangible assets, other than the initial recognition of goodwill or intangible assets acquired in a business combination. Retroactive application to prior-period financial statements will be required.

BUSINESS COMBINATIONS

In January 2009, the CICA issued Section 1582, Business Combinations. This section is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company. Early adoption is permitted. This section replaces Section 1581, Business Combination and harmonizes the Canadian standards with 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 December 31, 2008 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 and operating effectiveness of Anderson Energy's internal controls over financial reporting as of December 31, 2008 and have concluded that, these internal controls are designed properly and operating effectively 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 last 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

Recent 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 worsened in 2008 and 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 the 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 to be 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.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other "greenhouse gases". In response to the Kyoto Protocol, the Canadian federal government introduced the *Regulatory Framework for Air Emissions* (the "Regulatory Framework") for regulating air pollution and industrial greenhouse gas ("GHG") emissions by establishing mandatory emissions reduction requirements on a sector basis. Sector-specific regulations are expected to come into force in 2010 and targets would be based on percentages rather than absolute reductions. The Regulatory Framework also proposes a credit emissions trading system. Additionally, regulation can take place at the provincial and municipal level. For example, Alberta introduced the *Climate Change and Emissions Management Act*, which provides a framework for managing GHG emissions by reducing specific gas emissions relative to gross domestic product to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020 and which imposes duties to report. The accompanying regulation, the *Specified Gas Emitters Regulation*, effective July 1, 2007, requires mandatory emissions reductions through the use of emissions intensity targets. The Canadian federal government proposes to enter into equivalency agreements with provinces that establish a regulatory regime to ensure consistency with the federal plan, but the success of any such plan is doubtful in the current political climate, leaving multiple overlapping levels of regulation.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of the requirements on Anderson Energy and its operations and financial condition.

On October 25, 2007, the Alberta government announced changes to the Alberta Crown royalty system that came into effect on January 1, 2009. On March 3, 2009, the Alberta government announced new royalty initiatives which reduce royalties based on future drilling activity. Two measures were announced. The first is a \$200 per meter royalty credit based on drilling activity on Crown lands from April 1, 2009 to April 1, 2010. The credit can be used to offset 50% of Crown royalties payable after the wells have been drilled and up until March 2011. The second measure announced was that new wells tied in for production on Crown lands for 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. These measures will potentially have a significant impact on reducing future Crown royalties payable.

BUSINESS PROSPECTS

The Company 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 29 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 Company's first half 2009 average production guidance is 8,000 to 8,300 BOED. Risks associated with this guidance include gas plant capacity, 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. 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)

| | Q4 2008 | Q3 2008 | Q2 2008 | Q1 2008 |
|--|-------------|------------|-----------|-----------|
| Oil and gas revenue before royalties | \$ 30,102 | \$ 39,427 | \$ 49,021 | \$ 37,695 |
| Funds from operations | \$ 13,204 | \$ 21,212 | \$ 27,321 | \$ 17,591 |
| Funds from operations per share | | | | |
| Basic | \$ 0.15 | \$ 0.24 | \$ 0.31 | \$ 0.20 |
| Diluted | \$ 0.15 | \$ 0.24 | \$ 0.31 | \$ 0.20 |
| Earnings (loss) before goodwill impairment | \$ (5,865) | \$ 4,160 | \$ 8,509 | \$ 1,696 |
| Earnings (loss) before goodwill impairment per share | | | | |
| Basic | (0.07) | \$ 0.05 | \$ 0.10 | \$ 0.02 |
| Diluted | (0.07) | \$ 0.05 | \$ 0.10 | \$ 0.02 |
| Earnings (loss) | \$ (41,229) | \$ 4,160 | \$ 8,509 | \$ 1,696 |
| Earnings (loss) per share | | | | |
| Basic | \$ (0.47) | \$ 0.05 | \$ 0.10 | \$ 0.02 |
| Diluted | \$ (0.47) | \$ 0.05 | \$ 0.10 | \$ 0.02 |
| Capital expenditures, including acquisitions net of dispositions | \$ 27,470 | \$ 27,068 | \$ 16,772 | \$ 35,359 |
| Cash from operating activities | \$ 11,261 | \$ 26,351 | \$ 27,660 | \$ 17,416 |
| Daily sales | | | | |
| Natural gas (Mcf) | 38,090 | 38,703 | 39,881 | 39,210 |
| Liquids (bpd) | 1,341 | 1,221 | 1,265 | 1,345 |
| BOE (bpd) | 7,689 | 7,671 | 7,912 | 7,879 |
| Average prices | | | | |
| Natural gas (\$/Mcf) | \$ 6.76 | \$ 7.86 | \$ 10.26 | \$ 7.55 |
| Liquids (\$/bbl) | \$ 48.49 | \$ 90.19 | \$ 97.61 | \$ 83.91 |
| BOE (\$/BOE) | \$ 42.55 | \$ 55.87 | \$ 68.08 | \$ 52.57 |
| | Q4 2007 | Q3 2007 | Q2 2007 | Q1 2007 |
| Oil and gas revenue before royalties | \$ 27,775 | \$ 17,261 | \$ 18,440 | \$ 20,109 |
| Funds from operations | \$ 12,564 | \$ 6,255 | \$ 8,972 | \$ 8,623 |
| Funds from operations per share | | | | |
| Basic | \$ 0.14 | \$ 0.09 | \$ 0.15 | \$ 0.16 |
| Diluted | \$ 0.14 | \$ 0.09 | \$ 0.15 | \$ 0.16 |
| Earnings (loss) | \$ 4,867 | \$ (3,018) | \$ 368 | \$ (33) |
| Earnings (loss) per share | | | | |
| Basic | \$ 0.06 | \$ (0.04) | \$ 0.01 | \$ - |
| Diluted | \$ 0.06 | \$ (0.04) | \$ 0.01 | \$ - |
| Capital expenditures, including acquisition net of dispositions | \$ 30,300 | \$ 135,966 | \$ 17,586 | \$ 27,281 |
| Cash from operating activities | \$ 11,110 | \$ 5,801 | \$ 8,943 | \$ 8,405 |
| Daily sales | | | | |
| Natural gas (Mcf) | 35,672 | 26,860 | 22,928 | 22,162 |
| Liquids (bpd) | 1,150 | 843 | 602 | 750 |
| BOE (bpd) | 7,095 | 5,320 | 4,423 | 4,444 |
| Average prices | | | | |
| Natural gas (\$/Mcf) | \$ 6.09 | \$ 5.00 | \$ 7.25 | \$ 8.14 |
| Liquids (\$/bbl) | \$ 72.28 | \$ 63.31 | \$ 58.18 | \$ 52.59 |
| BOE (\$/BOE) | \$ 42.55 | \$ 35.27 | \$ 45.81 | \$ 50.28 |

SELECTED ANNUAL INFORMATION

YEARS ENDED DECEMBER 31

(in thousands, except per share amounts)

| | 2008 | 2007 | 2006 |
|--|-------------|------------|------------|
| Total oil and gas revenues | \$ 156,245 | \$ 83,585 | \$ 63,812 |
| Total oil and gas revenues, net of royalties | \$ 122,207 | \$ 67,827 | \$ 50,507 |
| Earnings (loss) before goodwill impairment | \$ 8,500 | \$ 2,184 | \$ (3,534) |
| Earnings (loss) before goodwill impairment per share | | | |
| Basic | \$ 0.10 | \$ 0.03 | \$ (0.07) |
| Diluted | \$ 0.10 | \$ 0.03 | \$ (0.07) |
| Earnings (loss) | \$ (26,864) | \$ 2,184 | \$ (3,534) |
| Earnings (loss) per share | | | |
| Basic | \$ (0.31) | \$ 0.03 | \$ (0.07) |
| Diluted | \$ (0.31) | \$ 0.03 | \$ (0.07) |
| Total assets | \$ 543,533 | \$ 531,324 | \$ 317,364 |
| Total long-term debt | \$ 85,314 | \$ 67,981 | \$ 27,627 |

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 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), 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.

Consolidated Balance Sheets

DECEMBER 31, 2008 AND 2007

(Stated in thousands of dollars)
(Unaudited)

2008

2007

ASSETS

Current assets:

| | | | | |
|--|----|----------------|----|----------------|
| Cash | \$ | 1 | \$ | 2 |
| Accounts receivable and accruals (note 13) | | 28,960 | | 31,540 |
| Prepaid expenses and deposits | | 2,692 | | 2,522 |
| | | <u>31,653</u> | | <u>34,064</u> |
| Property, plant and equipment (note 4) | | 511,880 | | 461,896 |
| Goodwill (notes 5 and 6) | | - | | 35,364 |
| | \$ | <u>543,533</u> | \$ | <u>531,324</u> |

LIABILITIES AND SHAREHOLDERS' EQUITY

Current liabilities:

| | | | | |
|---------------------------------------|----|----------------|----|----------------|
| Accounts payable and accruals | \$ | 71,619 | \$ | 62,915 |
| Bank loans (note 7) | | 85,314 | | 67,981 |
| Asset retirement obligations (note 8) | | 30,820 | | 24,526 |
| Future income taxes (note 9) | | 46,168 | | 41,450 |
| | | <u>233,921</u> | | <u>196,872</u> |

Shareholders' equity:

| | | | | |
|-------------------------------|--|-----------------|--|----------------|
| Share capital (note 10) | | 334,176 | | 334,147 |
| Contributed surplus (note 10) | | 4,000 | | 2,005 |
| Deficit | | <u>(28,564)</u> | | <u>(1,700)</u> |
| | | 309,612 | | 334,452 |

Commitments (note 15)

Subsequent event (note 16)

| | | | | |
|--|----|----------------|----|----------------|
| | \$ | <u>543,533</u> | \$ | <u>531,324</u> |
|--|----|----------------|----|----------------|

See accompanying notes to the consolidated financial statements.

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

YEARS ENDED DECEMBER 31, 2008 AND 2007

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

| | Three months ended, Dec. 31, | | Year ended, Dec. 31, | |
|--|------------------------------|-------------------|----------------------|-------------------|
| | 2008 | 2007 | 2008 | 2007 |
| REVENUES | | | | |
| Oil and gas sales | \$ 30,102 | \$ 27,775 | \$ 156,245 | \$ 83,585 |
| Royalties | (6,694) | (5,152) | (34,038) | (15,758) |
| Interest income | 14 | 12 | 67 | 297 |
| | <u>23,422</u> | <u>22,365</u> | <u>122,274</u> | <u>68,124</u> |
| EXPENSES | | | | |
| Operating | 8,140 | 7,645 | 32,110 | 22,743 |
| General and administrative | 992 | 1,390 | 6,377 | 6,321 |
| Stock-based compensation | 373 | 197 | 1,065 | 613 |
| Interest and other financing charges | 1,086 | 1,036 | 4,459 | 2,646 |
| Depletion, depreciation and accretion | 20,621 | 14,000 | 65,373 | 42,137 |
| Impairment of goodwill (note 6) | 35,364 | - | 35,364 | - |
| | <u>66,576</u> | <u>24,268</u> | <u>144,748</u> | <u>74,460</u> |
| Loss before taxes | (43,154) | (1,633) | (22,474) | (6,336) |
| Future income tax (reduction) expense (note 9) | (1,925) | (6,500) | 4,390 | (8,520) |
| Earnings (loss) for the period | (41,229) | 4,867 | (26,864) | 2,184 |
| Reclassification of accumulated other comprehensive income to earnings (note 10) | - | - | - | (1,465) |
| Comprehensive income (loss) | \$ (41,229) | \$ 4,867 | \$ (26,864) | \$ 719 |
| Retained earnings (deficit), beginning of period | \$ 12,665 | \$ (6,567) | \$ (1,700) | \$ (3,884) |
| Earnings (loss) for the period | (41,229) | 4,867 | (26,864) | 2,184 |
| Deficit, end of period | \$ (28,564) | \$ (1,700) | \$ (28,564) | \$ (1,700) |
| Earnings (loss) per share (note 10) | | | | |
| Basic | \$ (0.47) | \$ 0.06 | \$ (0.31) | \$ 0.03 |
| Diluted | \$ (0.47) | \$ 0.06 | \$ (0.31) | \$ 0.03 |

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

YEARS ENDED DECEMBER 31, 2008 AND 2007

(Stated in thousands of dollars)
(Unaudited)

| | Three months ended, Dec. 31, | | Year ended, Dec. 31 | |
|---|------------------------------|-----------------|---------------------|------------------|
| | 2008 | 2007 | 2008 | 2007 |
| CASH PROVIDED BY (USED IN) | | | | |
| OPERATIONS | | | | |
| Earnings (loss) for the period | \$ (41,229) | \$ 4,867 | \$ (26,864) | \$ 2,184 |
| Items not involving cash | | | | |
| Depletion, depreciation and accretion | 20,621 | 14,000 | 65,373 | 42,137 |
| Future income tax (reduction) expense | (1,925) | (6,500) | 4,390 | (8,520) |
| Impairment of goodwill | 35,364 | - | 35,364 | - |
| Stock-based compensation | 373 | 197 | 1,065 | 613 |
| Asset retirement expenditures | (479) | (50) | (1,132) | (742) |
| Changes in non-cash working capital | | | | |
| Accounts receivable and accruals | 1,600 | (4,923) | 1,553 | (5,894) |
| Prepaid expenses and deposits | 24 | 584 | (591) | (371) |
| Accounts payable and accruals | <u>(3,088)</u> | <u>2,935</u> | <u>3,530</u> | <u>4,852</u> |
| | 11,261 | 11,110 | 82,688 | 34,259 |
| FINANCING | | | | |
| Increase in bank loans | 3,124 | 11,891 | 17,333 | 40,354 |
| Issue of common shares, net of issue costs | <u>-</u> | <u>-</u> | <u>25</u> | <u>127,282</u> |
| | 3,124 | 11,891 | 17,358 | 167,636 |
| INVESTMENTS | | | | |
| Additions to property, plant and equipment | (44,656) | (30,343) | (124,712) | (93,979) |
| Acquisition of 3210700 Nova Scotia Company (note 5) | - | - | - | (117,634) |
| Payment of liabilities assumed on acquisition (note 5) | - | - | - | (324) |
| Proceeds on disposition of properties | 17,186 | 43 | 18,043 | 804 |
| Changes in non-cash working capital | | | | |
| Accounts receivable and accruals | (2,273) | 1,337 | 1,027 | 3,239 |
| Prepaid expenses and deposits | 274 | (64) | 421 | (183) |
| Accounts payable and accruals | <u>15,084</u> | <u>6,027</u> | <u>5,174</u> | <u>6,173</u> |
| | <u>(14,385)</u> | <u>(23,000)</u> | <u>(100,047)</u> | <u>(201,904)</u> |
| Increase (decrease) in cash | - | 1 | (1) | (9) |
| Cash, beginning of period | <u>1</u> | <u>1</u> | <u>2</u> | <u>11</u> |
| Cash, end of period | \$ 1 | \$ 2 | \$ 1 | \$ 2 |

See note 12 for additional cash information.

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

YEARS ENDED DECEMBER 31, 2008 AND 2007
(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.

1. SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of presentation. These consolidated financial statements include the accounts of Anderson Energy Ltd. and its wholly owned subsidiaries and a partnership and have been prepared by management in accordance with accounting principles generally accepted in Canada. All inter-entity transactions and balances have been eliminated. Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenue and expenses during the reported period. Actual results could differ from these estimates. Specifically, the amounts recorded for depletion and depreciation of oil and gas properties and the accretion of asset retirement obligations are based on estimates. The ceiling test is based on estimates of reserves, production rates, oil and gas prices, future costs and other relevant assumptions. The amounts for stock-based compensation are based on estimates of risk-free rates, expected lives, forfeitures and volatility. Future income taxes are based on estimates as to the timing of the reversal of temporary differences and tax rates currently substantively enacted. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(b) 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 December 31, 2008, the Company has a working capital deficiency of \$40 million and bank loans outstanding of \$85 million for total net debt of \$125 million in relation to currently available bank facilities of \$130 million. The available lending limits of the \$120 million extendible, revolving term and working capital credit facilities are based on the syndicate’s interpretation of the Company’s reserves and future commodity prices of which there can be no assurance that the amount of the available bank facility will not decrease at the next scheduled review to be completed on or before July 14, 2009. The \$10 million supplemental credit facility expires on June 30, 2009. The Company has outlined its operating commitments in notes 15 and 16. Management has restricted capital and administrative spending and continues to monitor

financing opportunities to fund its future prospects and commitments. No financing agreements have been signed nor can it be assured that such agreements will be reached, however, management believes the courses of action being taken will mitigate the conditions and events which could raise doubt about the validity of the going concern assumption used in preparing these consolidated financial statements. 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.

(c) Cash. Cash is defined as cash in the bank, less outstanding cheques.

(d) Property, plant and equipment. The Company follows the full cost method of accounting for oil and gas properties. Under this method, all costs relative to the exploration for and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, geological and geophysical costs, lease rentals on non-producing properties, costs of drilling productive and non-productive wells, plant and production equipment costs, asset retirement costs and that portion of general and administrative expenses directly attributable to exploration and development activities. Proceeds received from disposals of oil and gas properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20%, in which case a gain or loss on disposal is recorded.

Oil and gas capitalized costs are depleted and depreciated using the unit of production method based on total proved reserves before royalties. Natural gas sales and reserves are converted to equivalent units of crude oil using their relative energy content. The costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations until it is determined whether or not proved reserves are attributable to the property or impairment occurs. Office equipment and furniture are being depreciated over their useful lives using the declining balance method at rates between 20% and 30% per annum.

A detailed impairment calculation is performed when events or circumstances indicate a potential impairment of the carrying amount of oil and gas properties may have occurred, and at least annually in the fourth quarter. An impairment loss is recognized when the carrying amount of a cost centre is not recoverable and exceeds its fair value. The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from proved reserves plus the cost of unproved properties, net of impairments, exceeds the carrying amount of the cost centre. When the carrying amount is assessed not to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows from proved and probable reserves plus the cost of unproved properties, net of impairments, of the cost centre. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

1. SIGNIFICANT ACCOUNTING POLICIES (Continued)

(e) Asset retirement obligations. The Company records the fair value of asset retirement obligations as a liability in the period in which it incurs a legal obligation to restore an oil and gas property, typically when a well is drilled, equipment is put in place or in the event of an acquisition. The fair value is discounted using the Company's credit adjusted, risk-free rate with the associated asset retirement costs capitalized as part of the carrying amount of property, plant and equipment and depleted and depreciated using the unit of production method based on total proved reserves before royalties. Subsequent to the initial measurement of the obligations, the obligations are increased at the end of each period to reflect the passage of time resulting in an accretion charge to earnings. The obligations are also adjusted for changes in the estimated future cash flows underlying the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

(f) Goodwill. Goodwill is the excess purchase price over the fair value of identifiable assets and liabilities acquired in a business combination. Goodwill is not amortized and is tested for impairment annually in the fourth quarter or more frequently if events or changes in circumstances indicate that the asset might be impaired. To assess impairment, the fair value of the Company, deemed to be the reporting unit, is determined and compared to the book value of the Company. If the fair value of the Company is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the individual assets and liabilities from the fair value of the Company to determine the implied fair value of goodwill. An impairment loss is recognized for the excess of the carrying value of goodwill over the implied fair value.

(g) Income taxes. The Company follows the asset and liability method of accounting for income taxes. Under this method, income tax assets and liabilities are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using income tax rates that are substantively enacted and expected to apply in the periods when the temporary differences are expected to reverse. The effect of a change in rates on future income tax assets and liabilities is recognized in the period that the change occurs.

(h) Flow-through shares. The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. An estimate of the additional tax liability to be incurred and included in the future tax provision is recognized and charged to share capital at the time the resource expenditure deductions for income tax purposes are renounced to investors.

1. SIGNIFICANT ACCOUNTING POLICIES (Continued)

(i) Stock-based compensation plans. The Company accounts for stock options granted to employees and directors using the fair value method of accounting for stock-based compensation plans. Under this method, the Company recognizes compensation expense, with a corresponding increase to contributed surplus, based on the fair value of the options over the vesting period of the grant. The Company uses a Black-Scholes option pricing model to determine the fair value of options at the date of grant. When exercised, the consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

(j) Revenue recognition. Revenue from the sale of oil and gas is recognized when title passes from the Company to the purchaser.

(k) Financial instruments. A financial instrument is any contract that gives rise to a financial asset to one entity and a financial liability or equity instrument to another entity. Upon initial recognition, all financial instruments, including all derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then based on the financial instruments being classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale and other liabilities. The Company has designated its cash as held for trading which is measured at fair value. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Accounts payable and accrued liabilities and bank loans are classified as other liabilities which are measured at amortized cost determined using the effective interest rate.

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by the Company to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. The Company does not use these derivative instruments for trading or speculative purposes. The Company considers all of these transactions to be economic hedges, however, the Company's contracts do not qualify or have not been designated as hedges for accounting purposes. As a result, derivative contracts are classified as held for trading and are recorded on the balance sheet at fair value, with changes in the fair value recognized in earnings, unless specific hedge criteria are met. If specific hedge criteria are met, changes in the fair value are initially recognized in other comprehensive income, and are subsequently reclassified to earnings in the same period in which the revenues associated with the hedged transactions are recognized. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity given future market prices and other relevant factors.

The Company has elected to account for its physical delivery sales contracts for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts on an accrual basis rather than as non-financial derivatives.

1. SIGNIFICANT ACCOUNTING POLICIES (Continued)

The Company measures and recognizes embedded derivatives separately from the host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative and when the entire contract is not measured at fair value. Embedded derivatives are recorded at fair value.

The Company nets all transaction costs incurred, in relation to the acquisition of a financial asset or liability, against the related financial asset or liability. Bank loans are presented net of deferred interest payments, with interest recognized in earnings on an effective interest basis.

The Company applies trade-date accounting for the recognition of a purchase or sale of cash equivalents and derivative contracts.

(l) Interests in joint operations. A substantial portion of the Company's oil and gas exploration and development activities are conducted jointly with others, and accordingly, the consolidated financial statements reflect only the Company's proportionate interest in such activities.

(m) Per share amounts. Basic per share amounts are calculated using the weighted average number of common shares outstanding during the period. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only options for which the exercise price is less than the market value impact the dilution calculations.

(n) Comparative figures. Certain comparative figures have been reclassified to conform to the current year's presentation.

2. CHANGES IN ACCOUNTING POLICIES

On January 1, 2008, the Company adopted Section 1535 "Capital Disclosures". This section requires a discussion of the Company's objectives, policies and processes for managing capital including: quantitative data about what is considered capital, whether the entity has complied with all capital requirements and the consequences of non-compliance if the entity has not complied. These disclosures are included in note 11.

On January 1, 2008, the Company also adopted the new Canadian accounting standards for financial instruments: Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation", which apply to both recognized and unrecognized financial instruments. These disclosures include a discussion of the nature and extent of risks arising from financial instruments and are included in note 13.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

International financial reporting standards. 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.

3. FUTURE ACCOUNTING PRONOUCEMENTS (Continued)

Goodwill and intangible assets. In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets. Effective for fiscal years beginning on or after October 1, 2008, this section provides guidance on the recognition, measurement, presentation and disclosure for goodwill and intangible assets, other than the initial recognition of goodwill or intangible assets acquired in a business combination. Retroactive application to prior-period financial statements will be required.

Business combinations. In January 2009, the CICA issued Section 1582, Business Combinations. This section is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company. Early adoption is permitted. This section replaces Section 1581, Business Combinations and harmonizes the Canadian standards with IFRS.

4. PROPERTY, PLANT AND EQUIPMENT

| | <i>2008</i> | <i>2007</i> |
|---|-------------------|-------------------|
| Cost | \$ 686,420 | \$ 573,002 |
| Less accumulated depletion and depreciation | <u>(174,540)</u> | <u>(111,106)</u> |
| Net book value | <u>\$ 511,880</u> | <u>\$ 461,896</u> |

At December 31, 2008, unproved property costs of \$8.5 million (December 31, 2007 - \$16.1 million) have been excluded from the full cost pool for depletion and depreciation calculations. Future development costs of proved, undeveloped reserves of \$204.7 million (December 31, 2007 - \$177.8 million) have been included in the depletion and depreciation calculation.

For the year ended December 31, 2008, \$4.4 million (December 31, 2007 - \$3.4 million) of general and administrative costs including \$0.9 million (December 31, 2007 - \$0.6 million) of stock-based compensation costs were capitalized. The future tax liability of \$0.3 million (December 31, 2007 - \$0.2 million) 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.

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

No impairment was recognized under the ceiling test at December 31, 2008. The future commodity prices used in the ceiling test were based on commodity price forecasts of the Company's independent reserves 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 | 7.58 | 57.50 | 0.825 |
| 2010 | 7.94 | 68.00 | 0.850 |
| 2011 | 8.34 | 74.00 | 0.875 |
| 2012 | 8.70 | 85.00 | 0.925 |
| 2013 | 8.95 | 92.01 | 0.950 |
| 2014 | 9.14 | 93.85 | 0.950 |
| <u>Thereafter 2%</u> | | | |

After 2014, 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 2013 forward.

5. ACQUISITION OF 3210700 NOVA SCOTIA COMPANY

On September 1, 2007, the Company completed the acquisition of certain oil and natural gas assets indirectly through the purchase of all of the issued and outstanding shares of a newly formed company, 3210700 Nova Scotia Company, for aggregate cash consideration of \$117.1 million (\$117.6 million after adjustments and acquisition costs). The acquisition has been accounted for using the purchase method of accounting. The net revenues from the assets have been included with the results of the Company commencing September 1, 2007. The purchase price has been allocated as follows:

| | |
|--|-------------------|
| Net assets at assigned values | |
| Property, plant and equipment | \$ 133,441 |
| Deposits | 241 |
| Goodwill | 21,044 |
| Future income taxes | (30,604) |
| Provision for loss on transportation contracts | (565) |
| Asset retirement obligations | <u>(5,923)</u> |
| | <u>\$ 117,634</u> |
| <hr/> | |
| Consideration | |
| Cash | \$ 117,234 |
| Acquisition costs | <u>400</u> |
| Total purchase price | <u>\$ 117,634</u> |

6. GOODWILL

The Company reviewed the valuation of goodwill as of December 31, 2008 and determined that the fair value of the reporting entity had declined. Based upon this review, an impairment of goodwill of \$35.4 million (December 31, 2007 – \$nil) has been recorded as a non-cash charge to earnings as of December 31, 2008. There has been no impairment to the carrying amount of the Company's petroleum and natural gas assets as at December 31, 2008.

7. BANK LOANS

At December 31, 2008, total bank facilities were \$130 million.

On August 27, 2008 the Company entered into 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 2008 was 5.0% (December 31, 2007 – 5.9%).

On August 27, 2008, the Company entered into 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 expires 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 December 31, 2008 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 renewed semi-annually and are based on the bank syndicate's interpretations of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facilities or the applicable margins will not be adjusted at the next scheduled review on or before July 14, 2009.

8. ASSET RETIREMENT OBLIGATIONS

The Company estimates the total undiscounted cash flows required to settle its asset retirement obligations is approximately \$63.4 million (December 31, 2007 - \$52.2 million), including expected inflation of 2% (December 31, 2007 – 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, 2007 – 8%) was used to calculate the fair value of the asset retirement obligations. A reconciliation of the asset retirement obligations is provided below:

| | <i>2008</i> | <i>2007</i> |
|--|------------------|------------------|
| Balance, beginning of year | \$ 24,526 | \$ 14,905 |
| Liabilities incurred during year | 3,951 | 3,132 |
| Liabilities assumed on corporate acquisition <i>(note 5)</i> | - | 5,923 |
| Liabilities settled in year | (1,132) | (742) |
| Liabilities settled on disposition | (1,234) | (72) |
| Change in estimate | 2,770 | - |
| Accretion expense | 1,939 | 1,380 |
| Balance, end of year | <u>\$ 30,820</u> | <u>\$ 24,526</u> |

9. TAXES

The temporary differences that gave rise to the Company's future income tax liabilities (assets) at December 31, 2008 and 2007 were as follows:

| | <i>2008</i> | <i>2007</i> |
|--|------------------|------------------|
| Future income tax liabilities (assets): | | |
| Property, plant and equipment in excess of tax basis | \$ 39,869 | \$ 45,012 |
| Asset retirement obligations | (7,705) | (6,156) |
| Share issue costs | (1,841) | (2,578) |
| Current income deferred | 15,845 | 5,172 |
| Balance, end of year | <u>\$ 46,168</u> | <u>\$ 41,450</u> |

The provision for income taxes differs from the result that would have been obtained by applying the combined federal and provincial tax rates to the loss before income taxes. The difference results from the following items:

| | <i>2008</i> | <i>2007</i> |
|---|-----------------|-------------------|
| Loss before taxes | \$ (22,474) | \$ (6,336) |
| Combined federal and provincial tax rates | <u>29.6%</u> | <u>32.24%</u> |
| Expected future income tax reduction | (6,652) | (2,043) |
| Increase (decrease) in income taxes resulting from: | | |
| Non-deductible impairment of goodwill | 10,468 | - |
| Changes in expected future tax rates | - | (6,684) |
| Non-deductible stock-based compensation and other | 574 | 207 |
| Future income tax expense (reduction) | <u>\$ 4,390</u> | <u>\$ (8,520)</u> |

9. TAXES (Continued)

At December 31, 2008, the Company has loss carryforwards of \$48.8 million that will expire between 2011 and 2029. The Company expects to be able to fully utilize these losses.

10. 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, 2006 | 53,641,401 | \$ 208,994 |
| Issued pursuant to prospectuses ⁽¹⁾ | 33,635,000 | 134,747 |
| Share issue costs | - | (7,537) |
| Tax effect of share issue costs | - | 2,329 |
| Stock options exercised | 18,000 | 72 |
| Tax effect of flow-through shares issued in 2006 | - | (4,458) |
| 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 | 87,300,401 | \$ 334,176 |

(1) Includes 344,494 common shares issued to management and directors.

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 years ended December 31, 2008 and December 31, 2007 are as follows:

| | <i>Number of options</i> | <i>Weighted average exercise price</i> |
|----------------------------------|------------------------------|--|
| Balance at December 31, 2006 | 4,830,406 | \$ 4.89 |
| Granted | 1,531,500 | 3.94 |
| Exercised | (18,000) | 4.00 |
| Forfeitures | (46,600) | 7.28 |
| 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 | 7,594,856 | \$ 4.37 |
| Exercisable at December 31, 2008 | 4,750,356 | \$ 4.77 |

10. SHARE CAPITAL AND CONTRIBUTED SURPLUS (Continued)

| <i>Range of exercise prices</i> | <i>Options outstanding</i> | | | <i>Options exercisable</i> | |
|-----------------------------------|----------------------------|--|--|----------------------------|--|
| | <i>Number of options</i> | <i>Weighted average exercise price</i> | <i>Weighted average remaining life (years)</i> | <i>Number of options</i> | <i>Weighted average exercise price</i> |
| \$1.35 to \$3.75 | 1,046,400 | \$ 2.74 | 4.7 | - | \$ - |
| \$3.76 to \$5.00 | 5,280,056 | 4.02 | 3.5 | 3,666,056 | 4.00 |
| \$5.01 to \$7.50 | 543,000 | 6.15 | 2.5 | 400,500 | 6.24 |
| \$7.51 to \$9.01 | 725,400 | 8.01 | 1.8 | 683,800 | 8.03 |
| Total at December 31, 2008 | 7,594,856 | \$ 4.37 | 3.5 | 4,750,356 | \$ 4.77 |

The fair value of the options issued during the year ended December 31, 2008 ranged from \$0.85 to \$2.75 per option (December 31, 2007 - \$1.55 to \$1.99 per option). The weighted average assumptions used in arriving at the values were: a risk-free interest rate of 3.13% (December 31, 2007 – 4.3%), expected option life of five years, expected volatility of 57% (December 31, 2007 – 40%) and a dividend yield of 0%.

Per share amounts. During the year ended December 31, 2008 there were 87,298,057 weighted average shares outstanding (December 31, 2007 – 67,793,774). On a diluted basis, there were 87,298,057 weighted average shares outstanding (December 31, 2007 – 67,846,897) after giving effect to dilutive stock options. At December 31, 2008, there were 7,594,856 options that were anti-dilutive (December 31, 2007 – 2,249,100).

Contributed surplus

| | <i>Amount</i> |
|---|-----------------|
| Balance at December 31, 2006 | \$ 820 |
| Stock-based compensation | 1,185 |
| 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 |

10. SHARE CAPITAL AND CONTRIBUTED SURPLUS (Continued)

Accumulated other comprehensive income. The adoption of the new Canadian accounting standards for financial instruments resulted in an amount being recognized in accumulated other comprehensive income for the fair value at January 1, 2007 of the Company's financial derivatives to manage the price risk attributable to the anticipated sale of natural gas production. The amount recognized in accumulated other comprehensive income was \$1.5 million, representing the value of the asset of \$2.2 million net of future income taxes of \$0.7 million. The amount was reclassified resulting in an increase in earnings over the term of the contracts with a corresponding decrease to other comprehensive income.

| | 2008 | 2007 |
|---|------|---------|
| Accumulated other comprehensive income, beginning of year | \$ - | \$ - |
| Fair value of financial derivatives on transition to new accounting standards (net of tax of \$695) | - | 1,465 |
| Reclassification to earnings (net of tax of \$695) | - | (1,465) |
| Accumulated other comprehensive income, end of year | \$ - | \$ - |

Employee stock savings plan. Effective July 1, 2008, the Company initiated an Employee Stock Savings Plan ("ESSP"). Employees may contribute up to 5% of their base salaries towards the purchase of Company shares and the Company matches these contributions. The Company's matching contribution for the year ended December 31, 2008 was \$149,000 and is included in general and administrative expenses.

11. MANAGEMENT OF CAPITAL STRUCTURE

Anderson Energy's capital management policy is to maintain a strong, but flexible capital structure that optimizes the cost of capital and maintains investor, creditor and market confidence while sustaining the future development of the business.

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 \$310 million, bank loans of \$85 million and the working capital deficiency of \$40 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.

11. MANAGEMENT OF CAPITAL STRUCTURE (Continued)

As a result of the global economic downturn, there is uncertainty in capital markets and, as such, the Company anticipates that it and others in the oil and gas sector will have limited access to capital and an increased cost of capital. Although the business and assets of the Company have not changed, financial institutions and investors have increased their risk premiums and their overall lending capacity and equity investment has diminished. The Company continually monitors its financing alternatives, including the level of bank credit that may be attainable from its lenders based on oil and gas reserves, the availability of other sources of debt with different characteristics than the existing back debt, partnership with others on the development of assets, the sale of assets, limiting the size of the capital expenditure program and new equity if available on favourable terms.

Consistent with other companies in the oil and gas sector, Anderson Energy monitors capital based on the ratio of total debt to funds from operations. This ratio is calculated by dividing total debt at the end of the year (comprised of the working capital deficiency and outstanding bank loans) by the annualized current quarter funds from operations (before changes in non-cash working capital and asset retirement expenditures). The Company's strategy is to maintain a ratio of total debt to annualized funds from operations under 2 times. This ratio may increase above this 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>2008</i> | | <i>2007</i> |
|--|----|-------------|----|-------------|
| Bank loans | \$ | 85,314 | \$ | 67,981 |
| Current liabilities | | 71,619 | | 62,915 |
| Current assets | | (31,653) | | (34,064) |
| Total debt | \$ | 125,280 | \$ | 96,832 |
| | | | | |
| Cash from operating activities in quarter | \$ | 11,261 | \$ | 11,110 |
| Changes in non-cash working capital | | 1,464 | | 1,404 |
| Asset retirement expenditures | | 479 | | 50 |
| Funds from operations in quarter | \$ | 13,204 | \$ | 12,564 |
| Annualized current quarter funds from operations | \$ | 52,816 | \$ | 50,256 |
| | | | | |
| Total debt to funds from operations | | 2.4 | | 1.9 |

11. MANAGEMENT OF CAPITAL STRUCTURE (Continued)

At December 31, 2008, the Company's total debt to annualized funds from operations was 2.4 times, which is outside the established range. During the fourth quarter of 2008, 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. In addition, commodity prices at the end of 2008 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 or an alternative form of financing is available. At December 31, 2007, the Company's total debt to annualized funds from operations was 1.9 times, within the established range. In the third quarter of 2007, Anderson Energy completed a significant oil and gas asset acquisition which was partially financed with debt.

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 7). Anderson Energy has not paid or declared any dividends since the date of incorporation and does not contemplate doing so in the foreseeable future.

12. CASH PAYMENTS

The following cash payments were made (received):

| | | | | |
|-------------------|----|-------------|----|-------------|
| | | <i>2008</i> | | <i>2007</i> |
| Interest paid | \$ | 3,765 | \$ | 3,071 |
| Interest received | | (69) | | (299) |

13. 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's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

The Company has exposure to credit risk, liquidity risk and market risk as a result of its use of financial instruments. This note presents information about the Company's exposure to each of the above risks and the Company's objectives, policies and processes for measuring and managing these risks. Further quantitative disclosures are included throughout these financial statements.

13. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT (Continued)

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has implemented and monitors compliance with risk management policies.

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. A substantial portion of the Company's accounts receivable are with natural gas and liquids marketers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's natural gas and liquids are subject to credit review to minimize the risk of non-payment. As at December 31, 2008, the maximum credit exposure is the carrying amount of the accounts receivable and accruals of \$29.0 million (December 31, 2007 - \$31.5 million). As at December 31, 2008, the Company's receivables consisted of \$17.3 million (December 31, 2007 - \$22.4 million) from joint venture partners and other trade receivables and \$11.7 million (December 31, 2007 - \$9.1 million) of revenue accruals and other receivables from petroleum and natural gas marketers.

Receivables from petroleum and natural gas marketers are typically collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any significant collection issues with its petroleum and natural gas marketers. Of the \$11.7 million of revenue accruals and receivables from petroleum and natural gas marketers, \$9.2 million was received on or about January 25, 2009. The balance is expected to be received in subsequent months through joint venture billings from partners.

Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company mitigates the risk from joint venture receivables by obtaining partner approval of capital expenditures prior to starting a project. However, the receivables are from participants in the petroleum and natural gas sector, and collection is dependent on typical industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. Further risks exist with joint venture partners, as disagreements occasionally arise that increase the potential for non-collection. For properties that are operated by Anderson Energy, production can be withheld from joint venture partners who are in default of amounts owing. In addition, the Company often has offsetting amounts payable to joint venture partners from which it can net receivable balances. As at December 31, 2008, the largest amount owing from one partner is \$3.7 million.

The Company is from time to time exposed to credit risk associated with possible non-performance by counterparties to derivative financial instrument contracts. The Company believes these risks to be minimal as the counterparties are major financial institutions.

13. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT (Continued)

The Company's allowance for doubtful accounts as at December 31, 2008 is \$1.4 million. This allowance was mostly created in prior years and is associated with prior corporate acquisitions and potential joint venture billing disputes. The Company provided for an additional \$0.1 million in allowance and did not write-off any receivables during the year ended December 31, 2008. The Company would only choose to write-off a receivable balance (as opposed to providing an allowance) after all reasonable avenues of collection had been exhausted.

As at December 31, 2008 the Company considers its receivables to be aged as follows:

| | | |
|--------------------------------|----|--------|
| Aging | | 2008 |
| Not past due | \$ | 24,036 |
| Past due by less than 120 days | | 2,197 |
| Past due by more than 120 days | | 2,727 |
| Total | \$ | 28,960 |

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

Liquidity risk. Liquidity risk is the risk that the Company will incur difficulties meeting its financial obligations as they are due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Company's reputation.

The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. The Company uses authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. To facilitate the capital expenditure program, the Company has revolving reserves based credit facilities, as outlined in note 7, which are reviewed at least annually by the lenders. The Company monitors its total debt position monthly. The Company also attempts to match its payment cycle with collection of petroleum and natural gas revenues on the 25th of each month. The Company anticipates it will have adequate liquidity to fund its financial liabilities through its future cash flows.

The following are the contractual maturities of financial liabilities and associated interest payments as at December 31, 2008:

| | | | | |
|-------------------------------|----|----------|----|------------|
| Financial Liabilities | | < 1 Year | | 1 -2 Years |
| Accounts payable and accruals | \$ | 71,619 | \$ | - |
| Bank loans – principal | | - | | 85,314 |
| Total | \$ | 71,619 | \$ | 85,314 |

Please refer to notes 15 and 16 for additional details on commitments.

13. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT (Continued)

Market risk. Market risk consists of currency risk, commodity price risk and interest rate risk. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with a risk management policy that has been approved by the Board of Directors.

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. Substantially all of the Company's petroleum and natural gas sales are denominated in Canadian dollars, however, the underlying market prices in Canada for petroleum and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollar. From time to time in 2007 and 2008, the Company chose to sell a portion of its oil in United States dollars.

The Company had no outstanding forward exchange rate contracts in place at 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. Commodity prices for petroleum and natural gas are impacted by world economic events that dictate the levels of supply and demand as well as the relationship between the Canadian and United States dollar, as outlined above. The Company may mitigate commodity price risk through the use of financial derivatives and physical delivery fixed price sales contracts. All such contracts require approval of the Board of Directors.

On January 10, 2008, the Company entered into physical sales contracts to sell 25,000 GJ per day for February and March 2008 at an average AECO price of \$6.89 per GJ. The losses realized to December 31, 2008 were \$1.3 million and have been included in oil and gas sales.

In 2007, the Company also entered into certain fixed price natural gas financial swap contracts. The gains realized for the year ended December 31, 2007 were \$1.2 million and were included in oil and gas sales.

There were no commodity price risk contracts outstanding at December 31, 2008.

13. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT (Continued)

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 year ended December 31, 2008, if interest rates had been 1% lower with all other variables held constant, earnings for the year would have been \$0.5 million (December 31, 2007 - \$0.3 million) 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 December 31, 2008.

14. RELATED PARTY TRANSACTION

In August 2007, the Company issued 344,494 common shares to directors and officers of the Company at a price of \$3.90 per share for total proceeds of \$1.3 million as part of a \$100.2 million public offering of common shares.

15. COMMITMENTS

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

The Company entered into firm service transportation agreements for approximately 26 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 | 26 | \$ 1,344 |
| 2010 | 20 | \$ 1,068 |
| 2011 | 15 | \$ 858 |
| 2012 | 8 | \$ 526 |
| 2013 | 4 | \$ 338 |
| Thereafter | 5 | \$ 552 |

Please refer to note 16 for additional commitments.

16. SUBSEQUENT EVENT

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

The Company estimates the average working interest of the 200 well commitment is approximately 65% and expects to commence drilling in the third 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.

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

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Calgary, Alberta

Independent Engineers

GLJ Petroleum Consultants
AJM Petroleum Consultants

Legal Counsel

Bennett Jones LLP

Registrar & Transfer Agent

Valiant Trust Company

Stock Exchange

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Symbol AXL

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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
Mbbbls – 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
Mcfcd – thousand cubic feet per day
MMcf – million cubic feet
MMcfcd – million cubic feet per day
Bcf – billion cubic feet