



Management's Discussion and Analysis

DECEMBER 31, 2010 AND 2009

The following discussion and analysis of financial results should be read in conjunction with the audited consolidated financial statements of Anderson Energy Ltd. ("Anderson Energy" or the "Company") for the years ended December 31, 2010 and 2009 and is based on information available as of March 25, 2011.

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

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

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

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, 2010, funds from operations were \$37.2 million (\$0.22 per share), up 19% from 2009 as a result of the Company's refocus on Cardium light oil drilling. Sales volumes averaged 7,566 BOED, similar to the previous year.

Capital additions, net of dispositions were \$112.2 million for the year ended December 31, 2010. During the year, the Company drilled 22 gross (16.3 net capital) Cardium horizontal light oil wells, four gross (4.0 net) Rock Creek deep gas wells, two gross (1.1 net) Ellerslie deep gas wells and two gross (2.0 net) Whitemud horizontal wells with a 100% success rate. In the first quarter of 2010, the Company drilled 19 gross (14.7 net) Edmonton Sands wells with a 79% success rate. The Company tied in 13 gross (10.0 net) Cardium horizontal light oil wells and seven gross (4.5 net) Edmonton Sands shallow gas wells in the fourth quarter of 2010. The Company has deferred the drilling of the remaining 74 Edmonton Sands gas wells under its farm-in agreement until the first quarter of 2012. The Company's finding, development and acquisition costs, net of the change in future development capital and before economic factors was \$22.35 per BOE on a proved plus probable basis for 2010.

Bank loans plus the working capital deficiency before the unrealized loss on derivative contracts and future income tax asset was \$71.5 million at December 31, 2010. Total bank facilities are currently \$125 million. On December 31, 2010, the Company completed a convertible subordinated debenture financing for proceeds, net of commission and expenses, of \$47.7 million. Proceeds were initially used to pay down bank debt. The availability created in the credit facilities, along with cash flows, will be used to help finance the Company's 2011 capital program.

**Revenue and Production.** In 2010, the Company changed its focus to oil prospects in light of the depressed natural gas market. Oil and natural gas liquids revenue went from 27% of total revenue in the first quarter of 2010 to 48% of total revenue in the fourth quarter of 2010.

Gas sales volumes for the year ended December 31, 2010 decreased to an average of 37.1 MMcfd from 38.5 MMcfd last year due to the suspension of shallow gas drilling after the first quarter. 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 35.6 MMcfd (36.7 MMcfd during 2009).

Gas sales volumes averaged 38.5 MMcfd in the fourth quarter of 2010 compared to 35.8 MMcfd in the third quarter of 2010 and 34.9 MMcfd in the fourth quarter of 2009. The increase in the gas volumes from the third quarter of 2010 resulted from the tie-in of natural gas wells drilled earlier in the year, as well as the shallow gas fit for purpose processing facilities in the Medicine River area being fully operational throughout the fourth quarter of 2010.

Oil sales for the year ended December 31, 2010 averaged 601 bpd compared to 395 bpd for the year ended December 31, 2009. Oil production averaged 992 bpd in the fourth quarter of 2010 compared to 568 bpd in the third quarter of 2010 and 351 bpd in the fourth quarter of 2009. The increase in volumes is due to new oil production from 17 gross (11.0 net) Cardium horizontal light oil wells which were brought on production during the fourth quarter of 2010. There were no oil wells drilled in 2009.

Natural gas liquids sales for the year ended December 31, 2010 averaged 778 bpd compared to 794 bpd for the year ended December 31, 2009. Natural gas liquids sales averaged 823 bpd in the fourth quarter of 2010 compared to 761 bpd in the third quarter of 2010 and 906 bpd in the fourth quarter of 2009. The increase in sales volumes in the fourth quarter of 2010 is due to well tie-ins occurring late in the third quarter of 2010 at Westpem.

The following tables outline production revenue, volumes and average sales prices for the three and twelve months ended December 31, 2010 and 2009.

#### OIL AND NATURAL GAS REVENUE

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2010	2009	2010	2009
Natural gas	\$ 12,320	\$ 13,754	\$ 52,304	\$ 55,426
Gain on fixed price natural gas contracts	-	-	1,302	-
Total natural gas	12,320	13,754	53,606	55,426
Oil <sup>(1)</sup>	7,081	2,247	16,142	8,540
NGL	4,459	3,973	15,672	12,375
Royalty and other	86	465	1,037	652
Total revenue <sup>(1)</sup>	\$ 23,946	\$ 20,439	\$ 86,457	\$ 76,993

<sup>(1)</sup> Excludes realized loss on derivative contracts of \$0.1 million and unrealized loss on derivative contracts of \$1.9 million pertaining to fixed price crude oil swaps recorded in the fourth quarter of 2010.

## PRODUCTION

	Three months ended December 31		Year ended December 31	
	2010	2009	2010	2009
Natural gas (Mcf)	38,479	34,938	37,124	38,489
Oil (bpd)	992	351	601	395
NGL (bpd)	823	906	778	794
<b>Total (BOED)</b>	<b>8,228</b>	<b>7,080</b>	<b>7,566</b>	<b>7,603</b>

## PRICES

	Three months ended December 31		Year ended December 31	
	2010	2009	2010	2009
Natural gas (\$/Mcf) <sup>(1)</sup>	\$ 3.48	\$ 4.28	\$ 3.96	\$ 3.95
Oil (\$/bbl) <sup>(2)</sup>	77.62	69.60	73.62	59.26
NGL (\$/bbl)	58.87	47.67	55.22	42.73
<b>Total (\$/BOE)<sup>(2)(3)</sup></b>	<b>\$ 31.63</b>	<b>\$ 31.38</b>	<b>\$ 31.31</b>	<b>\$ 27.74</b>

(1) Includes gain on fixed price natural gas contracts of \$1.3 million from the first quarter of 2010.

(2) Excludes realized loss on derivative contracts of \$0.1 million and unrealized loss on derivative contracts of \$1.9 million pertaining to fixed price crude oil swaps recorded in the fourth quarter of 2010.

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

Anderson Energy's average gas sales price was \$3.96 per Mcf for the year ended December 31, 2010 compared to \$3.95 per Mcf for the year ended December 31, 2009. For the three months ended December 31, 2010, the gas sales price was \$3.48 per Mcf compared to \$3.43 per Mcf realized in the third quarter of 2010 and \$4.28 per Mcf in the fourth quarter of 2009. Gas prices were significantly affected by increased supply and lower industrial consumption of natural gas in the United States. Prices were higher in the last quarter of 2009 and first quarter of 2010, but remained low for the remainder of 2010. The natural gas price in 2010 includes a gain on fixed price natural gas contracts of \$1.3 million. The 2010 natural gas price before the gain was \$3.86 per Mcf. The oil price in 2010 does not include a realized loss on derivative contracts of \$0.1 million. The realized oil price including this loss was \$76.18 per barrel for the fourth quarter of 2010 and \$73.02 per barrel for the year ended December 31, 2010.

The Company is currently selling all of its gas production 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 29 MMcfd of natural gas sales for various terms ranging from one to ten years.

**Commodity Contracts.** In October 2010, as part of its risk management program, the Company entered into fixed price swap contracts for 1,000 barrels per day of crude oil for December 2010 at a NYMEX crude oil price of Canadian \$85.70 per barrel and for calendar 2011 at a NYMEX crude oil price of Canadian \$88.45 per barrel. In 2010, these contracts had the following impact on the consolidated statements of operations:

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2010	2009	2010	2009
Realized loss on derivative contracts	\$ (131)	\$ -	\$ (131)	\$ -
Unrealized loss on derivative contracts	(1,918)	-	(1,918)	-
	<b>\$ (2,049)</b>	<b>\$ -</b>	<b>\$ (2,049)</b>	<b>\$ -</b>

In March 2011, the Company entered into a fixed price swap contract for 250 barrels per day of crude oil for calendar 2012 at a NYMEX crude oil price of Canadian \$103.20 per barrel.

The Company had no fixed price natural gas contracts in place at December 31, 2010.

**Royalties.** Royalties were 10.4% of revenue for the year ended December 31, 2010 compared to 10.7% of revenue for the year ended December 31, 2009. Royalties were 9.4% of revenue in the fourth quarter of 2010 compared to 8.8% of revenue in the third quarter of 2010 and 8.5% of revenue in the fourth quarter of 2009. The increase in the royalty rate in the fourth quarter of 2010 is due to an estimated reduction in gas cost allowance for 2010 as a result of lower crown royalties and lower facility effective royalty rates expected to be used in the annual assessment. This increase was partially offset by the decline in the gross crown royalty rate due to a larger percentage of royalties calculated at the 5% royalty rate for new production.

Royalties as a percentage of revenue are highly sensitive to prices and adjustments to gas cost allowance and so royalty rates can fluctuate from quarter to quarter. In addition, when prices and corresponding revenues are lower, fixed monthly gas cost allowance becomes more significant to the overall royalty rate. On January 1, 2009, the Alberta government's New Royalty Framework came into effect. The Alberta government revised the royalty regime in March 2009, and again in March 2010, for new wells tied in on Crown lands. Producers will pay a reduced Crown royalty rate of 5% for the first year on up to 500 MMcf of gas production or up to 50 Mstb of oil production. In addition, the Alberta government changed the maximum royalty payable on oil from 50% to 40% and on natural gas from 50% to 36%. Other important changes positively impact the Company's refocused horizontal oil program, where based on the measured depth of the well, the Company will pay the Crown a 5% royalty for 24 to 30 months for up to 60 to 70 Mstb of oil production. The majority of the Company's horizontal program on Crown lands would qualify for the 30 months of 5% royalty for up to 70 Mstb of oil production.

	Three months ended December 31		Year ended December 31	
	2010	2009	2010	2009
Gross crown royalties	10.9%	15.3%	12.5%	15.4%
Gas cost allowance	(3.7%)	(10.8%)	(7.2%)	(11.1%)
Other royalties	2.2%	4.0%	5.1%	6.4%
Total royalties	9.4%	8.5%	10.4%	10.7%
Total royalties (\$/BOE)	\$ 2.98	\$ 2.66	\$ 3.26	\$ 2.97

**Operating Expenses.** Operating expenses were \$10.56 per BOE for the year ended December 31, 2010 compared to \$9.70 per BOE for the year ended December 31, 2009. Operating expenses were \$11.62 per BOE in the fourth quarter of 2010 compared to \$9.71 per BOE in the third quarter of 2010 and \$10.49 per BOE in the fourth quarter of 2009. Start up costs associated with new Cardium production, various production optimization initiatives, reclassification of co-gen power credits and a large one time compressor repair cost at Buck Lake offset some of the cost savings associated with the Edmonton Sands lower operating cost gas production during 2010.

## OPERATING NETBACK

(thousands of dollars) ( <sup>(1)</sup> )	Three months ended December 31		Year ended December 31	
	2010	2009	2010	2009
Revenue	\$ 23,946	\$ 20,439	\$ 86,457	\$ 76,993
Realized loss on derivative contracts	(131)	-	(131)	-
Royalties	(2,256)	(1,731)	(9,011)	(8,253)
Operating expenses	(8,799)	(6,831)	(29,148)	(26,906)
	<u>\$ 12,760</u>	<u>\$ 11,877</u>	<u>\$ 48,167</u>	<u>\$ 41,834</u>
Sales (MBOE)	757.0	651.4	2,761.5	2,775.2
Per BOE				
Revenue ( <sup>(1)</sup> )	\$ 31.63	\$ 31.38	\$ 31.31	\$ 27.74
Realized loss on derivative contracts	(0.17)	-	(0.05)	-
Royalties	(2.98)	(2.66)	(3.26)	(2.97)
Operating expenses	(11.62)	(10.49)	(10.56)	(9.70)
	<u>\$ 16.86</u>	<u>\$ 18.23</u>	<u>\$ 17.44</u>	<u>\$ 15.07</u>

(1) Includes royalty and other income classified with oil and gas sales. Excludes unrealized loss on derivative contracts of \$1.9 million pertaining to fixed price crude oil swaps recorded in the fourth quarter of 2010.

**General and Administrative Expenses.** General and administrative expenses were \$7.7 million or \$2.80 per BOE for the year ended December 31, 2010 compared to \$7.0 million or \$2.52 per BOE for the year ended December 31, 2009. General and administrative expenses were \$2.87 per BOE in the fourth quarter of 2010 compared to \$2.82 per BOE in the third quarter of 2010 and \$2.94 per BOE in the fourth quarter of 2009. In light of a more competitive labour market in 2010, the Company reversed the salary cutbacks taken in 2009 and reinstated its employee stock savings plan effective April 1, 2010. The Company also accrued additional bonuses for employees in the fourth quarter of 2010 in acknowledgement of employee efforts in refocusing the Company in 2010.

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2010	2009	2010	2009
General and administrative (gross)	\$ 4,082	\$ 3,276	\$ 13,742	\$ 12,284
Overhead recoveries	(570)	(437)	(1,751)	(1,721)
Capitalized	(1,339)	(924)	(4,258)	(3,565)
General and administrative (net)	<u>\$ 2,173</u>	<u>\$ 1,915</u>	<u>\$ 7,733</u>	<u>\$ 6,998</u>
General and administrative (\$/BOE)	\$ 2.87	\$ 2.94	\$ 2.80	\$ 2.52
% Capitalized	33%	28%	31%	29%

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 \$2.1 million in 2010 (\$1.2 million net of amounts capitalized) versus \$2.1 million (\$1.1 million net of amounts capitalized) in 2009. Stock-based compensation costs were \$0.4 million for the fourth quarter of 2010 (\$0.3 million net of amounts capitalized) versus \$0.4 million (\$0.2 million net of amounts capitalized) in the fourth quarter of 2009.

**Interest Expense.** In the fourth quarter of 2010, interest expense was \$1.1 million compared to \$0.8 million in the third quarter of 2010 and \$0.8 million in the fourth quarter of 2009. The increase in interest expense from the third quarter of 2010 is due to the higher average debt levels. Interest expense was \$3.4 million for the year ended December 31, 2010 compared to \$3.7 million in 2009. The decrease in interest expense from the comparable 2009 period is due to lower average debt levels in 2010 partially offset by increases in interest rates. The average effective interest rate on outstanding bank loans was 4.9% in 2010 compared to 4.2% in 2009.

**Depletion and Depreciation.** Depletion and depreciation was \$78.7 million (\$28.51 per BOE) for the year ended December 31, 2010 compared to \$78.6 million (\$28.33 per BOE) in 2009. Depletion and depreciation was \$22.2 million (\$29.38 per BOE) in the fourth quarter of 2010 compared to \$18.9 million (\$28.23 per BOE) in the third quarter of 2010 and \$17.2 million (\$26.39 per BOE) in the fourth quarter of 2009. Depletion and depreciation expense is calculated based on proved reserves only. Fourth quarter depletion and depreciation is calculated using the new reserves evaluation and incorporates a decrease in total proved natural gas reserves.

**Asset Retirement Obligation.** The Company recorded a \$1.4 million increase in asset retirement obligations in 2010 (\$0.3 million the fourth quarter of 2010) related to current activity and changes in estimates. Accretion expense was \$2.5 million for 2010 compared with \$2.3 million for 2009. 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 2011. The estimated tax pool balances at December 31, 2010 are summarized below. Non-capital losses are estimated assuming full claims for CDE, COGPE and UCC are made in the current year. 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 2010 that will not be taxed until 2011.

Canadian Exploration Expenses (CEE)	\$	66 million
Canadian Development Expenses (CDE)		126 million
Undepreciated Capital Cost (UCC)		108 million
Canadian Oil and Gas Property Expenses (COGPE)		12 million
Non-Capital Losses and Other		<u>78 million</u>
Total	\$	<u>390 million</u>

**Funds from Operations.** Funds from operations increased by 19% to \$37.2 million in 2010 compared to \$31.3 million in 2009. On a per share basis, funds from operations were \$0.22 per share in 2010 compared to \$0.25 per share in 2009. For the three months ended December 31, 2010, funds from operations were \$9.5 million or \$0.06 per share, an increase of 19% over the previous quarter of \$8.0 million or \$0.05 per share, and an increase of 4% from the fourth quarter of 2009 of \$9.2 million or \$0.06 per share. Funds from operations increased as the Company refocused its capital initiatives on oil prospects, which are brought on production at significantly higher expected operating margins. In the fourth quarter of 2010, oil and NGLs accounted for \$11.5 million or 48% of revenue compared to \$7.2 million or 38% in the third quarter of 2010 and \$6.2 million or 30% in the fourth quarter of 2009.

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2010	2009	2010	2009
Cash from operating activities	\$ 10,721	\$ 5,361	\$ 40,996	\$ 23,820
Changes in non-cash working capital	(1,324)	3,246	(5,365)	5,956
Asset retirement expenditures	<u>118</u>	<u>544</u>	<u>1,549</u>	<u>1,482</u>
Funds from operations	<u>\$ 9,515</u>	<u>\$ 9,151</u>	<u>\$ 37,180</u>	<u>\$ 31,258</u>

**Earnings.** The Company reported an \$11.7 million net loss in the fourth quarter of 2010 compared to a net loss \$9.0 million in the third quarter of 2010 and \$6.5 million in the fourth quarter of 2009. Earnings were lower in the fourth quarter of 2010 compared to the previous

quarter as a result of higher depletion due to a reduction in proved natural gas reserves. The Company reported a net loss of \$35.6 million in 2010 compared to a net loss of \$36.5 million in 2009. As with funds from operations, earnings continue to be impacted by low natural gas prices. The change in the Company's focus to crude oil, with its currently higher operating margins, is expected to improve future earnings.

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>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	\$ 6.4	\$ 0.04	\$ 4.8	\$ 0.03
US \$5.00/bbl in the WTI crude price	\$ 1.8	\$ 0.01	\$ 1.4	\$ 0.01
US \$0.01 in the US/Cdn exchange rate	\$ 0.8	\$ 0.00	\$ 0.6	\$ 0.00
1% in short-term interest rate	\$ 0.4	\$ 0.00	\$ 0.3	\$ 0.00

This sensitivity analysis was calculated by applying different pricing, interest rate and exchange rate assumptions to the 2010 actual results related to production, prices, royalty rates, operating costs and capital spending. As the Company changes its focus to crude oil development, the impact of oil prices is expected to become more significant and the impact of natural gas prices is expected to become less significant to funds from operations and earnings than is shown in the table above.

### CAPITAL EXPENDITURES

The Company spent \$26.5 million in capital expenditures, net of dispositions and drilling incentive credits, in the fourth quarter of 2010 and \$112.2 million for the year ended December 31, 2010. The breakdown of expenditures is shown below:

<i>(thousands of dollars)</i>	<i>Three months ended December 31</i>		<i>Year ended December 31</i>	
	<i>2010</i>	<i>2009</i>	<i>2010</i>	<i>2009</i>
Land, geological and geophysical costs	\$ (11)	\$ (15)	\$ 416	\$ 173
Acquisitions, net of dispositions	299	-	(464)	(54)
Drilling, completion and recompletion	19,336	15,492	72,873	23,952
Drilling incentive credits	162	(6,000)	(3,455)	(6,000)
Facilities and well equipment	6,297	3,642	40,079	11,349
Capitalized G&A	1,339	924	4,258	3,565
Total finding, development & acquisition expenditures	27,422	14,043	113,707	32,985
Change in compressor and other equipment inventory	(957)	(2,736)	(1,601)	542
Office equipment and furniture	8	5	67	31
Total capital expenditures	26,473	11,312	112,173	33,558
Non-cash asset retirement obligations and capitalized stock-based compensation	504	2,003	2,369	3,220
Total cash and non-cash capital additions	\$ 26,977	\$ 13,315	\$ 114,542	\$ 36,778

Drilling statistics are shown below:

	Three months ended December 31				Year ended December 31			
	2010		2009		2010		2009	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gas	-	-	98	73.6	23	19.0	109	81.9
Oil	6	5.1	-	-	22	16.3	-	-
Dry	-	-	9	7.6	4	2.8	9	7.6
<b>Total</b>	<b>6</b>	<b>5.1</b>	<b>107</b>	<b>81.2</b>	<b>49</b>	<b>38.1</b>	<b>118</b>	<b>89.5</b>
Success rate (%)	100%	100%	92%	91%	92%	93%	92%	92%

For the year ended December 31, 2010, the Company drilled 22 gross (16.3 net capital) Cardium horizontal light oil wells. Of the 22 gross well drilled, the Company drilled six gross (5.1 net capital) Cardium horizontal light oil wells in the fourth quarter of 2010. The Company has not drilled any vertical Edmonton Sands shallow gas wells since the first quarter of 2010. In 2010, the Company tied in 97 gross (65.7 net) Edmonton Sands shallow gas wells, of which seven gross (4.5 net) were tied-in in the fourth quarter of 2010. The Company also brought 20 gross (14.3 net capital) Cardium horizontal light oil wells on-stream during 2010, of which 13 gross (10.0 net) well were brought on-stream in the fourth quarter. In addition, the Company tied in four gross (4.0 net) Rock Creek wells during 2010. In 2009, the Company drilled 118 gross (89.5 net) Edmonton Sands wells of which 107 gross (81.2 net) wells were drilled in the fourth quarter under a large scale farm-in.

In the fourth quarter of 2009, the Company accrued \$6.0 million for drilling incentive credits. Drilling credits earned are capped at 50% of crown royalties paid between April 1, 2009 and March 31, 2011 and the Company estimates that it will earn more drilling credits than it will be able to claim. These credits are expected to be paid out between 2009 and 2011 as crown royalties are paid. The estimate is highly dependent on commodity prices, production levels, crown royalty rates and gas cost allowance earned over this period. To the extent that crown royalties paid are lower or higher, drilling credits will be lower or higher as well. As a result of the cap, the Company reduced its accrual by \$1.0 million in the fourth quarter of 2010 and did not accrue any additional drilling credits related to drilling in 2010. The Company received \$4.5 million in proceeds on the sale of some of these surplus credits in 2010.

#### CEILING TEST

At December 31, 2010, the ceiling test resulted in the discounted cash flows from proved plus probable 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. See "Reserves – Summary of Pricing and Inflation Rate Assumptions" for the prices used in the 2010 ceiling test.

#### RESERVES

The Company's reserves were evaluated by GLJ Petroleum Consultants ("GLJ") in accordance with National Instrument 51-101 ("NI 51-101") as of December 31, 2010. 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, 2010 ("AIF") as the Company's NI 51-101 annual required filings.

## SUMMARY OF GROSS OIL AND GAS RESERVES

As at December 31, 2010

	Natural Gas <sup>(1)</sup> (MMcf)	Oil <sup>(1)</sup> (Mbbbls)	Natural Gas Liquids (Mbbbls)	Total BOE (MBOE)
Proved developed producing	52,498	1,303	1,376	11,428
Proved developed non-producing	7,457	168	50	1,461
Proved undeveloped	37,358	755	247	7,228
Total proved	97,313	2,226	1,673	20,117
Probable	53,308	1,682	1,003	11,570
Total proved plus probable	150,621	3,908	2,676	31,687

(1) Coal Bed Methane is not material to report separately and is included in the Natural Gas category. Heavy Oil is not material to report separately and is included in the Oil category.

## NET PRESENT VALUE BEFORE INCOME TAXES

As at December 31, 2010

GLJ December 31, 2010 Price Forecast, Escalated Prices

(thousands of dollars)	0%	5%	10%	15%	20%
Proved developed producing	252,854	196,268	166,058	145,193	129,562
Proved developed non-producing	19,167	13,331	9,561	6,988	5,154
Proved undeveloped	52,833	24,954	8,629	(1,310)	(7,520)
Total proved	324,854	234,553	184,248	150,870	127,197
Probable	231,850	136,742	87,221	58,520	40,543
Total proved plus probable	556,704	371,295	271,469	209,391	167,739

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, 2010

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)		
2011	88.00	86.22	4.16	54.32	67.26	90.54	2.0	0.98
2012	89.00	89.29	4.74	56.25	68.75	91.96	2.0	0.98
2013	90.00	90.92	5.31	57.28	70.01	92.74	2.0	0.98
2014	92.00	92.96	5.77	58.56	71.58	94.82	2.0	0.98
2015	95.17	96.19	6.22	60.60	74.07	98.12	2.0	0.98
2016	97.55	98.62	6.53	62.13	75.94	100.59	2.0	0.98
2017	100.26	101.39	6.76	63.87	78.07	103.42	2.0	0.98
2018	102.74	103.92	6.90	65.47	80.02	106.00	2.0	0.98
2019	105.45	106.68	7.06	67.21	82.15	108.82	2.0	0.98
2020	107.56	108.84	7.21	68.57	83.80	111.01	2.0	0.98

Thereafter 2%

Total future development costs included in the reserves evaluation were \$137.0 million for total proved reserves and \$239.9 million for 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 2010 fiscal year. Future development costs are associated with the reserves as disclosed in the GLJ report and do not necessarily represent the Company's current exploration and development budget.

## CONTINUITY OF GROSS RESERVES

	Natural Gas (Bcf) <sup>(1)</sup>			Oil & Natural Gas Liquids (Mbbbls)		
	Proved	Probable	Total	Proved	Probable	Total
Opening balance						
December 31, 2009	128.0	59.0	187.0	2,287	1,443	3,730
Extensions and improved recovery	7.6	9.0	16.6	1,766	1,432	3,198
Technical revisions	17.1	(17.6)	(0.5)	472	(114)	358
Economic factors	(41.8)	2.9	(38.9)	(120)	(30)	(150)
Dispositions	-	-	-	(3)	(46)	(49)
Production	(13.6)	-	(13.6)	(503)	-	(503)
Closing balance						
December 31, 2010 <sup>(1)</sup>	97.3	53.3	150.6	3,899	2,685	6,584

(1) The closing balance for natural gas includes 4.4 Bcf of proved and 3.9 Bcf of probable Coal Bed Methane reserves. The closing balance for oil and natural gas liquids includes 251 Mbbbls of proved and 140 Mbbbls of probable Heavy Oil reserves.

The Company's reserves life indices are 7.3 years total proved and 11.5 years proved plus probable, based on 2010 annual production. With the 25% reduction in GLJ's natural gas price outlook in the years 2011 to 2015, and 16% thereafter, the Company experienced a negative revision for economic factors of 7.1 MMBOE for total proved and 6.6 MMBOE for proved plus probable reserves. The economic factors negative revision was almost entirely related to the Company's undeveloped gas reserves in the Edmonton Sands. Offsetting the economic factors were positive technical revisions of 3.3 MMBOE total proved and 0.3 MMBOE proved plus probable reserves. In addition, the Company experienced positive proved developed producing additions and revisions of 2.2 MMBOE in the Edmonton Sands, indicative of improved performance. Reserves additions before revisions were 3.0 MMBOE total proved and 5.9 MMBOE proved plus probable, predominantly from Cardium oil horizontal drilling. The Company replaced 224% of its production with new proved plus probable reserves additions and technical revisions in 2010. The Company replaced 697% of its 2010 oil and NGL production with new P&P oil and NGL reserves.

## FINDING, DEVELOPMENT AND ACQUISITION COSTS

Year Ended December 31, 2010

	(in thousands of dollars)	
	Proved	Proved plus Probable
Finding, development & acquisition expenditures	\$ 113,707	\$ 113,707
Change in future development costs	(60,613)	(20,200)
	\$ 53,094	\$ 93,507
Adjustment to change in future development costs for natural gas economic factors	88,290	44,642
	\$ 141,384	\$ 138,149
Reserve additions (MBOE)	3,023	5,913
Technical revisions (MBOE)	3,318	269
	6,341	6,182
Economic factors (MBOE)	(7,078)	(6,630)
	(737)	(448)
2010 finding, development & acquisition costs – additions only, including change in future development costs (\$/BOE)	\$ 17.56	\$ 15.81
2010 finding, development & acquisition costs – additions and technical revisions, including change in future development costs, excluding economic factors and the change in future development costs related to economic factors (\$/BOE)	\$ 22.30	\$ 22.35

The Company's FD&A costs in 2010 were \$17.56 per BOE on a proved basis and \$15.81 per BOE on a proved plus probable basis for additions only, including changes in future development costs. The Company experienced a significant revision for economic factors in 2010 which not only reduced reserves but also reduced future development capital. To measure FD&A costs excluding the impact of economic factors, the future development capital was also adjusted upwards to exclude the effect of removing these reserves. FD&A costs including future development costs for additions and technical revisions, but excluding economic factors were \$22.30 per BOE total proved and \$22.35 per BOE for proved plus probable. FD&A costs are presented before economic factors as the amount would be negative or indeterminate after consideration of those revisions. Economic factors are influenced by consultant price forecasts and an uplift in natural gas price forecasts may cause economic factors to be positive in future years. Calculated on a similar basis, the Company's FD&A costs in 2009 were \$8.64 per BOE on a proved basis and \$8.46 per BOE on a proved plus probable basis and FD&A costs in 2008 were indeterminate. The three year average FD&A costs was also indeterminate as a result of the negative revisions in 2010 and 2008. There were no property acquisitions in the year and dispositions were negligible, so a separate calculation of finding and development costs excluding acquisitions has not been presented. The aggregate of the exploration, development and acquisition 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, development and acquisition costs related to reserves additions for that year.

#### SHARE INFORMATION

The Company's shares have been listed on the Toronto Stock Exchange since September 7, 2005 under the symbol "AXL". As of March 25, 2011, there were 172.5 million common shares outstanding, 11.4 million stock options outstanding and \$50.0 million principal amount of convertible debentures which are convertible into common shares at a conversion price of \$1.55 per common share. During 2010, 84,900 common shares (2009 – Nil) were issued under the employee stock option plan.

#### SHARE PRICE ON TSX

	2010		2009	
High	\$	1.57	\$	1.48
Low	\$	0.95	\$	0.65
Close	\$	1.05	\$	1.16
Volume		120,489,236		125,408,442
Shares outstanding at December 31		172,485,301		150,500,401
Market capitalization at December 31	\$	181,109,566	\$	174,580,465

The statistics above include trading on the Toronto Stock Exchange only. Shares also trade on alternative platforms like Alpha, Chi-X, Pure and Omega. Approximately 65.0 million common shares traded on these alternative exchanges in 2010. Including these exchanges, an average of 736,212 common shares traded per day in 2010 (2009 – 584,790), representing a turnover ratio of 109% (2009 – 117%).

In February 2010, the Company issued 21.9 million common shares at a price of \$1.45 per share pursuant to a short form prospectus.

#### RELATED PARTY TRANSACTIONS

On December 31, 2010, the Company issued 1,000 convertible debentures to directors at a price of \$1,000 per convertible debenture for total gross proceeds of \$1.0 million as part of a \$50.0 million bought share offering of convertible debentures.

In February 2010, the Company issued 352,466 common shares to directors at a price of \$1.45 per share for total gross proceeds of \$0.5 million as part of a \$31.8 million bought deal offering of common shares.

On May 28 2009, the Company issued 4,992,034 common shares to management and directors and 3,377,966 common shares to family of management and directors of the Company at a price of \$0.95 per share for total gross proceeds of \$8.0 million as part of a \$60.0 million bought deal offering of common shares.

#### LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2010, the Company had outstanding bank loans of \$52.7 million, convertible debentures of \$50.0 million (principal) and a working capital deficiency of \$18.8 million, excluding the unrealized loss on derivative contracts and future income tax assets. The working capital deficiency is due to accruals associated with the capital program in the last quarter of the year.

The Company's current capital budget for 2011 is \$75 million, which is almost entirely directed at oil horizontal drilling, primarily in the Cardium. The Company is committed to drill 74 gross Edmonton Sands gas wells under its farm-in agreement by March 31, 2012. The Company does not plan to drill any additional Edmonton Sands gas wells until the first quarter of 2012. The Company plans to drill 15 gross (11.3 net revenue) Cardium oil wells in the first quarter of 2011.

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, 2010, the Company had total credit facilities of \$125 million, consisting of an \$80 million extendible revolving term credit facility, a \$10 million working capital credit facility and a \$35 million supplemental credit facility with a syndicate of Canadian banks. The Company had \$72.2 million of credit available at December 31, 2010. Draws over \$30 million under the supplemental facility will be subject to the consent of the syndicate at the time of the drawdown. On December 31, 2010, the Company completed a convertible subordinated debenture financing for proceeds, net of commission and expenses, of \$47.7 million. The net proceeds were initially used to pay down bank debt. Anderson Energy will prudently use its bank loan facilities to finance its operations as required. The available lending limits under the bank facilities are reviewed twice a year and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The last review was conducted in November 2010. 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 12, 2011. The Company will continue to fund its ongoing operations from a combination of cash flow, debt, asset dispositions and equity financing as needed.

#### CONTRACTUAL OBLIGATIONS

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

- *Loan agreements* – The reserves-based extendible, revolving term credit facility and working capital credit facility have a revolving period ending on July 12, 2011, extendible at the option of the lenders. If not extended, the facilities cease to revolve and all outstanding advances thereunder become repayable one year from the term date of July 12, 2011. The supplemental facility is available on a revolving basis and expires on July 1, 2011 with any amounts outstanding due in full at that time. No amounts were drawn under the supplemental facility at December 31, 2010.
- *Convertible debentures* – The Company issued \$50.0 million in convertible debentures on December 31, 2010. The convertible debentures have a face value of \$1,000, bear

interest at the rate of 7.5% per annum payable semi-annually in arrears on the last day of January and July of each year, commencing on July 31, 2011 and mature on January 31, 2016. The convertible debentures are convertible at the holder's option at a conversion price of \$1.55 per common share, subject to adjustment in certain events. The Debentures are not redeemable by the Corporation before January 31, 2014.

- *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 2011, and \$1.6 million in 2012.
- *Firm service transportation commitments* – The Company has entered into firm service transportation agreements for approximately 29 million cubic feet per day of gas sales for various terms expiring between 2011 and 2020. Based on rate schedules announced to date, the payments in each of the next five years and thereafter are estimated to be \$1.6 million in 2011, \$1.3 million in 2012, \$0.8 million in 2013, \$0.7 million in 2014, \$0.6 million in 2015 and \$0.4 million thereafter.
- *Oil transportation contract* – In 2010, the Company entered into a facilities construction and operation agreement pursuant to which it is committed to ship a minimum volume of gross crude oil through new facilities and pipelines being constructed in Garrington. The total financial commitment is \$2.6 million to be incurred over a minimum of five years. The contract contains a minimum volume requirement per year for the first five years following completion of construction which is expected to be in the second quarter of 2011. In the event that the volume shipped is less than the minimum volume, the Company will be subject to a fee per cubic metre of oil on the difference between actual volumes shipped and the minimum volume required. Conversely, if the Company exceeds the minimum volume requirement in a single year, the excess is carried forward as a credit to the minimum volume requirement in the subsequent year. If no volumes were shipped, a minimum of \$0.26 million would be payable each year. After the total contracted volumes have been shipped, the contract will automatically renew for one year periods unless terminated.
- *Farm-in* – On January 30, 2009, the Company announced a farm-in agreement with a large international oil and gas company on lands near its existing core operations. Under the farm-in agreement, the Company has access to 388 gross (205 net) sections of land. During the commitment phase of the transaction, the Company is committed to drill, complete and equip 200 wells to earn an interest in up to 120 sections. The Company has drilled 126 wells under the commitment to December 31, 2010. The Company is obligated to complete the drilling of the remaining wells on or before March 31, 2012. The commitment is subject to certain guarantees. The Company estimates that its minimum commitment to drill the remaining 74 wells is \$10 million. The Company currently plans to defer its spending on the farm-in project until the first quarter of 2012.

### 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.* In order to recognize stock-based compensation costs, 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.

#### INTERNATIONAL FINANCIAL REPORTING STANDARDS (“IFRS”)

In October 2009, the Accounting Standards Board issued a third and final IFRS Omnibus Exposure Draft confirming that publicly accountable enterprises will be required to apply IFRS, in full and without modification, for all financial periods beginning January 1, 2011. The adoption date of January 1, 2011 requires the restatement, for comparative purposes, of amounts reported by the Company for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

In response, the Company has completed its high-level IFRS changeover plan and established a 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.

The Company has performed 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 were also 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 to assist management with the project on an as needed basis to ensure IFRS readiness for the filing of the Company's first quarterly IFRS financial statements of 2011.

The Audit Committee has approved the IFRS accounting policy selections presented by management to date and disclosed herein. Below is a summary of the Company's accounting policies that are expected to have a significant impact on the Company's consolidated financial statements. The list and comments below should not be regarded as a complete list of changes that will result from the transition to IFRS. The amounts quantified are based on the Company's internal calculations and have not been audited by the Company's external auditors.

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

IFRS 1 “First-Time Adoption of International Financial Reporting Standards” provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions, in certain areas, to the general requirement for full retrospective application of IFRS. The Company has finalized the various accounting policy choices available with the significant IFRS 1 exemptions taken described below.

*Property, Plant and Equipment.* International Accounting Standard (IAS) 16 “Property, Plant & Equipment” and Canadian GAAP contain the same basic principles, however there are some differences. IFRS requires that significant parts of an asset be depreciated separately and depreciation commences when the asset is available for use. There will be more depreciable components than the current single full cost pool as depletion and depreciation cannot be calculated at a level more aggregated than a cash generating unit. At transition, the Company did not identify any significant components that needed to be depreciated on a basis other than unit-of-production.

IFRS also permits property, plant equipment to be measured using the fair value model or the historical cost model. The Company is not planning on adopting the fair value measurement model for property, plant and equipment.

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

The Company has the option to calculate depletion using a reserve base of proved reserves or both proved plus probable reserves, as compared to the Canadian GAAP method of calculating depletion using proved reserves only. The Company plans to deplete its property, plant and equipment using proved plus probable reserves. As a result of this policy choice, the Company expects that its quarterly depletion under IFRS will be lower than it was under Canadian GAAP.

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

The Company intends to apply the IFRS 1 exemption whereby the decommissioning liability provision is recalculated at January 1, 2010 using the IFRS methodology and any adjustments would be offset against opening retained earnings. As a result of applying this IFRS 1 exemption, at transition, the Company expects to increase its provision by \$12 to \$15 million. The increase in the provision is a result of the Company applying a risk free rate to the future cash flows. The use of a risk free rate will result in lower accretion expense, which is included in finance expenses, and higher depletion expense subsequent to transition.

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

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

Another difference arises in the level at which an impairment test is performed. Under IFRS, impairment testing will be performed on cash generating units. The Company has identified its cash generating units based on the reserve characteristics. At transition, the Company has four cash generating units: Horizontal Oil, Deep Gas, Shallow Gas and Non-Core.

As a result of applying the IFRS 1 exemption for deemed cost, the Company tested for impairment at transition. Based on preliminary calculations, the Company expects an impairment at transition on January 1, 2010 of between \$50 and \$70 million with the offset going to opening retained earnings. Throughout 2010, the estimates of forward natural gas prices declined significantly (GLJ price forecasts declined 25% on average for 2011 to 2015, and 16% thereafter) and year end reserves were subject to a 6.6 MMBOE reduction for economic factors. As a result, the Company expects to record additional significant impairments in the natural gas weighted cash generating units for 2010.

*Income taxes.* Under IAS 12 "Income Taxes", current and deferred tax are normally recognized in the income statement, except to the extent that tax arises from (1) an item that has been recognized directly in equity, whether in the same or a different period, (2) a business combination or (3) a share based payment transaction. If a deferred tax asset or liability is re-measured subsequent to initial recognition, the impact of re-measurement is recorded in earnings, unless it relates to an item originally recognized in equity, in which case the change would also be recorded in equity. The practice of tracking the re-measurement of taxes back to the item which originally triggered the recognition is commonly referred to as "backwards tracing." Canadian GAAP prohibits backwards tracing except on business combinations and financial reorganizations. As a result of the changes to the Company's transition balance sheet described herein, the Company estimates that its deferred tax liability will be reduced by \$18 to \$22 million with the offset going to opening retained earnings.

*Share based payments.* Under IFRS 2 "Share-Based Payments", graded vested options are required to be separated into their vesting tranches and valued and accounted for separately. This differs from Canadian GAAP, where graded vested options are valued at grant date and expensed using the straight line method. IFRS 1 provides an exemption on IFRS 2 for equity instruments which vested before the transition date and does not require them to be retroactively restated. All unvested options at transition date will be required to be retroactively restated with the adjustment going through opening retained earnings on transition. The Company intends to use this exemption and expects the transition impact to be less than \$0.5 million.

In addition to accounting policy differences discussed above, the Company's transition to IFRS is expected to impact its internal controls over financial reporting, disclosure controls and procedures, certain business activities and IT systems.

*Internal controls over financial reporting ("ICFR").* The Company is currently in the process of reviewing its ICFR documentation and is identifying instances where controls must be amended or added in order to address the accounting policy changes required under IFRS. No material changes in control procedures are expected as a result of transition to IFRS.

*Disclosure controls and procedures.* The Company is currently assessing the impact of transition to IFRS on its disclosure controls and procedures and does not expect any material changes required in its control environment. It is expected that there will be increased note disclosure around certain financial statement items than what is currently required under Canadian GAAP. Management is currently drafting its IFRS note disclosure in accordance with current IFRS standards and continues to monitor requirements put forth by the International Accounting Standards Board ("IASB") in discussion papers and exposure drafts for future disclosure requirements. Throughout the transition process, the Company has carefully considered its stakeholders' information requirements and will continue to ensure that adequate and timely information is provided to meet these needs.

*Business activities.* Management has been cognizant of the upcoming transition to IFRS, and as such, has worked with its counterparties and lenders to ensure that any agreements that contain references to Canadian GAAP financial statements are modified to allow for IFRS statements. Based on the changes to the Company's accounting policies, no issues are expected to arise with the existing wording of credit facilities and related agreements as a result of the conversion to IFRS.

*IT systems.* The Company has recently completed the accounting system upgrades required in order to prepare for IFRS reporting. The modifications were not significant, however, they were deemed critical in order to allow for reporting of both Canadian GAAP and IFRS statements in 2010 as well as the modifications required to track property, plant and equipment at a more granular level of detail for IFRS reporting.

Throughout the first half of 2011, the Company will continue calculating the quarterly impact of its policy choices under IFRS. The Company's external auditors have been engaged to review the 2010 adjustments in early April 2011 in order to have sufficient time to review the Company's information for its first IFRS financial statements.

The Company continues to monitor standards development as issued by the IASB and the AcSB as well as regulatory developments as issued by the Canadian Securities Administrators, which may affect the timing, nature or disclosure of its adoption of IFRS.

#### CONTROLS AND PROCEDURES

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

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

Oil and gas exploration and production is capital intensive and involves a number of business risks including, without limitation, the uncertainty of finding new reserves, the instability of commodity prices, weather and various operational risks. Commodity prices are influenced by local and worldwide supply and demand, OPEC actions, ongoing global economic concerns, the U.S. dollar exchange rate, transportation costs, political stability and seasonal and weather related changes to demand. The price of natural gas has weakened due to increasing U.S. gas production driven primarily by the U.S. shale gas plays. The large amount of gas in storage combined with strong U.S. gas production and financial market fears has continued to suppress the price of natural gas. Oil prices have increased recently as crude oil is a geopolitical commodity, and is responding to instability in the Middle East. The industry is subject to extensive governmental regulation with respect to the environment. Operational risks include well performance, uncertainties inherent in estimating reserves, timing of/ability to obtain drilling licences and other regulatory approvals, ability to obtain equipment, expiration of licences and leases, competition from other producers, sufficiency of insurance, ability to manage growth,

reliance on key personnel, third party credit risk and appropriateness of accounting estimates. These risks are described in more detail in the Company's Annual Information Form for the year ended December 31, 2010 to be filed with Canadian securities regulatory authorities on SEDAR.

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

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

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

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

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

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. Such legislation may also impose restrictions and prohibitions on water use or processing in connection with certain oil and gas operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant

expenditures and a breach of such requirements may result, amongst other things in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Canada is a signatory to the United Nations Framework Convention on Climate Change. The Canadian federal government previously released the Regulatory Framework for Air Emissions, updated March 10, 2008 by Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions (collectively, the "Regulatory Framework"), for regulating greenhouse gas ("GHG") emissions by proposing mandatory emissions intensity reduction obligations on a sector by sector basis. Legislation to implement the Regulatory Framework had been expected to be put in place this year, but the federal government has delayed the release of any such legislation and potential federal requirements in respect of GHG emissions are unclear. On January 30, 2010, the Canadian federal government announced its new target to reduce overall Canadian GHG emissions by 17% below 2005 levels by 2020, from the previous target of 20% from 2006 levels by 2020, to align itself with the GHG emission reduction goals of the United States. In 2009, the Canadian federal government announced its commitment to work with the provincial governments to implement a North American-wide cap and trade system for GHG emissions, in cooperation with the United States. Canada would have its own cap-and-trade market for Canadian-specific industrial sectors that could be integrated into a North American market for carbon permits. 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 and establishes a target of reducing specified 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. The accompanying regulations, the Specified Gas Emitters Regulation and the Specified Gas Emitters Reporting Regulation require mandatory emissions reductions through the use of emissions intensity targets and impose duties to report. 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.

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

In November 2008, the Government of Alberta announced that companies drilling new natural gas and conventional oil wells at depths between 1,000 and 3,500 metres, which are spudded between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new transitional royalty rates or the new royalty framework rates. The transition option provides lower royalties in the initial years of a well's life. For example, under the transition option, royalty rates for natural gas wells will range from 5% to 30%. The option for producers to elect transitional royalties in respect of qualifying deep wells ended on December 31, 2010 and any wells spudded on or after January 1, 2011 are subject to the royalty rates discussed below. Wells that are subject to transitional royalty rates will automatically revert to the new royalty framework rates on January 1, 2014.

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

On March 11, 2010, the Alberta government announced its intention to adjust royalty rates effective January 1, 2011. This adjustment includes making the incentive program royalty rate of 5% on new natural gas and conventional oil wells a permanent feature of the royalty system with the time and volume limits discussed above. The maximum royalty rate was reduced from the current level of 50% to 40% for conventional oil and to 36% for natural gas. The transitional royalty framework for oil and gas will continue until December 31, 2013 as announced but no new wells will be allowed to select transitional royalty rates effective January 1, 2011; wells that have selected the transitional royalty rates will be allowed to switch to the new rates effective January 1, 2011. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010.

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

### BUSINESS PROSPECTS

The Company believes it has an excellent future drilling inventory in the Cardium light oil horizontal oil play and is focused on growing its production and reserves with Cardium horizontal drilling. The Company has 112.5 gross (65.8 net) sections in the fairway. At a drilling density of three wells per section, the potential drilling inventory is 338 gross (197.4 net) Cardium horizontal locations. The Company continues to add to its land position and drilling inventory through a combination of acquisitions, property swaps and farm-ins, and continues to implement new technologies to control and reduce its costs in this project.

The Company's annual production guidance for 2011 is 7,500 BOED. Risks associated with this guidance include continued low commodity prices which may restrict capital spending, new well performance, gas plant capacity, gas plant turnaround duration, regulatory issues, weather problems and access to industry services.

### QUARTERLY INFORMATION

The following table provides financial and operating results for the last eight quarters. Commodity prices have declined from the first quarter of 2009 and remain volatile, affecting funds from operations and earnings throughout 2009 and 2010.

## SELECTED QUARTERLY INFORMATION

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

	<u>Q4 2010</u>	<u>Q3 2010</u>	<u>Q2 2010</u>	<u>Q1 2010</u>
Oil and gas revenue before royalties <sup>(1)</sup>	\$ 23,946	\$ 18,928	\$ 20,318	\$ 23,265
Funds from operations	\$ 9,515	\$ 8,026	\$ 9,004	\$ 10,635
Funds from operations per share				
Basic	\$ 0.06	\$ 0.05	\$ 0.05	\$ 0.06
Diluted	\$ 0.06	\$ 0.05	\$ 0.05	\$ 0.06
Net loss	\$ (11,741)	\$ (9,046)	\$ (8,891)	\$ (5,953)
Net loss per share				
Basic	\$ (0.07)	\$ (0.05)	\$ (0.05)	\$ (0.04)
Diluted	\$ (0.07)	\$ (0.05)	\$ (0.05)	\$ (0.04)
Capital expenditures, including acquisitions, net of dispositions	\$ 26,473	\$ 39,528	\$ 12,745	\$ 33,427
Cash from operating activities	\$ 10,721	\$ 8,437	\$ 8,892	\$ 12,946
Daily sales				
Natural gas (Mcf)	38,479	35,778	38,998	35,221
Liquids (bpd)	1,815	1,329	1,232	1,130
BOE (BOED)	8,228	7,292	7,732	7,000
Average prices				
Natural gas (\$/Mcf)	\$ 3.48	\$ 3.43	\$ 3.78	\$ 5.22
Liquids (\$/bbl)	\$ 69.11	\$ 58.61	\$ 60.28	\$ 62.43
BOE (\$/BOE) <sup>(1)</sup>	\$ 31.63	\$ 28.21	\$ 28.88	\$ 36.93

	<u>Q4 2009</u>	<u>Q3 2009</u>	<u>Q2 2009</u>	<u>Q1 2009</u>
Oil and gas revenue before royalties <sup>(1)</sup>	\$ 20,439	\$ 14,617	\$ 17,508	\$ 24,429
Funds from operations	\$ 9,151	\$ 6,623	\$ 6,692	\$ 8,792
Funds from operations per share				
Basic	\$ 0.06	\$ 0.04	\$ 0.06	\$ 0.10
Diluted	\$ 0.06	\$ 0.04	\$ 0.06	\$ 0.10
Net loss	\$ (6,457)	\$ (9,432)	\$ (10,410)	\$ (10,159)
Net loss per share				
Basic	\$ (0.04)	\$ (0.06)	\$ (0.09)	\$ (0.12)
Diluted	\$ (0.04)	\$ (0.06)	\$ (0.09)	\$ (0.12)
Capital expenditures, including acquisitions net of dispositions	\$ 11,312	\$ 6,571	\$ 2,130	\$ 13,545
Cash from operating activities	\$ 5,361	\$ 6,689	\$ 2,472	\$ 9,298
Daily sales				
Natural gas (Mcf)	34,938	36,282	40,495	42,344
Liquids (bpd)	1,257	1,013	1,040	1,448
BOE (BOED)	7,080	7,060	7,789	8,505
Average prices				
Natural gas (\$/Mcf)	\$ 4.28	\$ 2.81	\$ 3.43	\$ 5.15
Liquids (\$/bbl)	\$ 53.79	\$ 53.84	\$ 49.00	\$ 38.69
BOE (\$/BOE) <sup>(1)</sup>	\$ 31.38	\$ 22.50	\$ 24.70	\$ 31.91

(1) Includes royalty and other income classified with oil and gas sales and excludes the realized and unrealized losses on derivative contracts in the fourth quarter of 2010 of \$0.1 million and \$1.9 million respectively.

## SELECTED ANNUAL INFORMATION

### YEARS ENDED DECEMBER 31

(in thousands, except per share amounts)

	2010	2009	2008
Total oil and gas revenues <sup>(1)</sup>	\$ 86,457	\$ 76,993	\$ 156,245
Total oil and gas revenues, net of royalties <sup>(1)</sup>	\$ 77,446	\$ 68,740	\$ 122,207
Earnings (loss) before goodwill impairment	\$ (35,631)	\$ (36,458)	\$ 8,500
Earnings (loss) before goodwill impairment per share			
Basic	\$ (0.21)	\$ (0.29)	\$ 0.10
Diluted	\$ (0.21)	\$ (0.29)	\$ 0.10
Net loss	\$ (35,631)	\$ (36,458)	\$ (26,864)
Net loss per share			
Basic	\$ (0.21)	\$ (0.29)	\$ (0.31)
Diluted	\$ (0.21)	\$ (0.29)	\$ (0.31)
Total assets	\$ 535,115	\$ 497,169	\$ 543,533
Total bank loans	\$ 52,719	\$ 62,404	\$ 85,314
Total convertible debentures, liability component	\$ 43,460	\$ -	\$ -

(1) Includes royalty and other income classified with oil and gas sales. Excludes the realized and unrealized losses on derivative contracts in 2010 of \$0.1 million and \$1.9 million respectively.

## ADVISORY

Certain information regarding Anderson Energy Ltd. in this management's discussion and analysis including, without limitation, management's assessment of future plans and operations, benefits and valuation of the development prospects described herein, number of locations in drilling inventory and wells to be drilled, timing and location of drilling and tie-in of wells and the costs thereof, productive capacity of the wells, timing of and construction of facilities, expected production rates, dates of commencement of production, amount of capital expenditures and timing thereof, value of undeveloped land, extent of reserves additions, ability to attain cost savings, drilling program success, impact of changes in commodity prices on operating results, impact of changes to the royalty regime applicable to the Company, including payment of drilling incentive credits, commodity price outlook and general economic outlook may constitute forward-looking statements under applicable securities laws and necessarily involve risks and assumptions made by management of the Company including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserves estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, wells not performing as expected, incorrect assessment of the value of acquisitions and farm-ins, failure to realize the anticipated benefits of acquisitions and farm-ins, delays resulting from or inability to obtain required regulatory approvals, changes to government regulation 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](http://www.sedar.com)) and at Anderson Energy's website ([www.andersonenergy.ca](http://www.andersonenergy.ca)).

Furthermore, the forward-looking statements contained in this management's discussion and analysis are made as at the date of this management's discussion and analysis 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.

**Abbreviations used**

AECO – intra-Alberta Nova inventory transfer price  
bbl – barrel  
bpd – barrels per day  
Mbbls – thousand barrels  
Mstb – thousand stock tank barrels  
BOE – barrels of oil equivalent  
BOED – barrels of oil equivalent per day  
MBOE – thousand barrels of oil equivalent  
MMBOE – million barrels of oil equivalent  
GJ – gigajoule  
Mcf – thousand cubic feet  
Mcf/d – thousand cubic feet per day  
MMcf – million cubic feet  
MMcf/d – million cubic feet per day  
Bcf – billion cubic feet  
NGL – natural gas liquids