



Management's Discussion and Analysis

DECEMBER 31, 2009 AND 2008

Management's Discussion and Analysis

FOR THE YEARS ENDED DECEMBER 31, 2009 AND 2008

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, 2009 and 2008 and is based on information available as of March 19, 2010.

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

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

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

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, 2009, funds from operations were \$31.3 million (\$0.25 per share) down 61% from 2008 due to significant declines in commodity prices. The effect of lower revenues was partially offset by significant reductions in royalties and operating expenses. Sales volumes averaged 7,603 BOED, 2% lower than the previous year due to the cuts in capital spending made in response to lower prices.

Capital expenditures were \$33.6 million, net of drilling incentive credits of \$6.0 million, and included the drilling of 118 gross (89.5 net) wells with a success rate of 92%. In May 2009, the Company completed a bought deal equity financing for net proceeds after commission and expenses of \$56.5 million. Net proceeds were used to pay down bank indebtedness and finance a significant farm-in drilling program in its core Edmonton Sands shallow gas play. The Company drilled 106 wells under the farm-in in the fourth quarter of 2009 and achieved a finding, development and acquisition cost, net of the change in future development capital and net of revisions and drilling incentive credits of \$7.97 per BOE on a proved plus probable basis for the year.

Debt, net of working capital deficiency was \$72.5 million at December 31, 2009. Total bank lines are currently \$100 million. In February 2010, the Company completed a bought deal share financing for net proceeds after commission and expenses of \$29.8 million. Proceeds were initially used to pay down bank debt. The availability created in the credit facilities was

used to increase the Company's 2010 capital budget from \$75 million to \$87 million in order to expand its Cardium horizontal light oil drilling program.

Revenue and Production. Gas sales comprised 84% of Anderson Energy's total oil and gas sales volumes for the year ended December 31, 2009, consistent with the prior year.

Gas sales volumes for the year ended December 31, 2009 decreased marginally to an average of 38.5 MMcfd from 39.0 MMcfd last 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 36.7 MMcfd (33.9 MMcfd during 2008). Due to low commodity prices and the need to conserve funds for the farm-in drilling program in the fourth quarter, new wells were not drilled and brought on production during the year to offset natural production decline. The Company also chose to shut-in higher cost wells for a significant portion of the year due to the low prices. Property dispositions in the fourth quarter of 2008 also affected volumes compared to the prior year.

Gas sales volumes averaged 34.9 MMcfd in the fourth quarter of 2009. This compares to 36.3 MMcfd in the third quarter of 2009 and 38.1 MMcfd in the fourth quarter of 2008. Production from the wells drilled in the fourth quarter of 2009 will not have a significant impact on sales volumes until the second quarter of 2010.

Oil sales for the year ended December 31, 2009 averaged 395 bpd compared to 487 bpd for the year ended December 31, 2008. Oil production averaged 351 bpd in the fourth quarter of 2009 compared to 376 bpd in the third quarter of 2009 and 491 bpd in the fourth quarter of 2008. The majority of the Company's current oil production is from Central and Eastern Alberta. The decrease in 2009 is due to natural production decline, property sales in 2008 and workovers being deferred due to the low price environment. New capital initiatives for oil did not commence until the first quarter of 2010.

Natural gas liquids sales for the year ended December 31, 2009 averaged 794 bpd compared to 806 bpd for the year ended December 31, 2008. Natural gas liquids sales averaged 906 bpd in the fourth quarter of 2009 compared to 637 bpd in the third quarter of 2009 and 850 bpd in the fourth quarter of 2008. Natural gas liquids volumes were affected by reductions in ethane sales due to the deep cut facility not operating at Bigoray for approximately half of the year. This facility resumed operations in the fourth quarter of 2009.

The following tables outline production revenue, volumes and average sales prices for the years and for the fourth quarters ended December 31, 2009 and 2008.

OIL AND NATURAL GAS REVENUE

<i>(thousands of dollars)</i>	<i>Three months ended Dec. 31</i>		<i>Year ended Dec. 31</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Natural gas	\$ 13,754	\$ 23,706	\$ 55,426	\$ 117,237
Loss on fixed price natural gas contracts	-	-	-	(1,341)
Oil	2,247	2,511	8,540	16,441
NGL	3,973	3,469	12,375	21,170
Royalty and other	465	416	652	2,738
Total	\$ 20,439	\$ 30,102	\$ 76,993	\$ 156,245

PRODUCTION

	Three months ended Dec. 31		Year ended Dec. 31	
	2009	2008	2009	2008
Natural gas (Mcf)	34,938	38,090	38,489	38,968
Oil (bpd)	351	491	395	487
NGL (bpd)	906	850	794	806
Total (BOED)	7,080	7,689	7,603	7,787

PRICES

	Three months ended Dec. 31		Year ended Dec. 31	
	2009	2008	2009	2008
Natural gas (\$/Mcf)	\$ 4.28	\$ 6.76	\$ 3.95	\$ 8.13
Oil (\$/bbl)	69.60	55.63	59.26	92.27
NGL (\$/bbl)	47.67	44.37	42.73	71.78
Total (\$/BOE)*	\$ 31.38	\$ 42.55	\$ 27.74	\$ 54.82

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

Anderson Energy's average gas sales price was \$3.95 per Mcf for the year ended December 31, 2009 compared to \$8.13 per Mcf for the year ended December 31, 2008. For the three months ended December 31, 2009, the gas sales price was \$4.28 per Mcf. This compares to \$2.81 per Mcf realized in the third quarter of 2009 and \$6.76 per Mcf realized in the fourth quarter of 2008. Gas prices were significantly affected by increased supply and lower industrial consumption of natural gas in the United States. Prices improved in the last quarter of 2009, but volatility in the marketplace continues. 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.

Historically, Anderson Energy has sold most of its gas at Alberta spot market prices. From November 2008 to October 2009, the Company was selling approximately 30% of its production at the average monthly index price, and the balance at the average daily index price. The Company is currently selling all of its unhedged 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 25 MMcfd of natural gas sales for various terms ranging from one to ten years.

Fixed Price Contracts. In December 2009, as part of its risk management program, the Company entered into fixed price natural gas contracts to manage commodity price risk. The Company entered into physical contracts to sell 20,000 GJ per day of natural gas for each of January, February and March 2010 at an average AECO price of \$5.41 per GJ. As of December 31, 2009, there were no gains or losses recognized in association with these physical contracts.

In January 2008, 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 risk management contract.

Royalties. Royalties were 11% of revenue for the year ended December 31, 2009 compared to 22% of revenue for the year ended December 31, 2008. Royalties were 9% of revenue in the fourth quarter of 2009 compared to 6% of revenue in the third quarter of 2009 and 22% of revenue in the fourth quarter of 2008. During the year, the Company received \$2.8 million more in gas cost allowance adjustments than had previously been accrued relating to 2008 and

prior periods as a result of changes to the corporate average effective royalty rate and net additions to eligible costs. Royalty rates would have been 14% for the year and 10% for the fourth quarter without these adjustments. On January 1, 2009, the Alberta government's New Royalty Framework came into effect. While royalties increased in some areas, overall, the changes reduced royalties due to the Company's focus on shallow gas, lower productivity wells and due to lower natural gas prices. In addition, when prices and corresponding revenues are lower, gas cost allowance becomes more significant to the overall royalty rate.

On March 3, 2009, new royalty initiatives were announced by the Alberta government that focused on future drilling activity. Two measures were announced. The first was a \$200 per meter drilling credit based on drilling activity from April 1, 2009 to March 31, 2011. The credit is capped at 50% of Crown royalties payable from April 1, 2009 to March 31, 2011. These drilling credits are accounted for as reductions in the associated drilling costs. The second measure announced was that new wells tied in for production on Crown lands from the period April 1, 2009 to March 31, 2011 would 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. All of these changes have benefited the Company. On March 11, 2010, the Alberta government announced that the 5% Crown royalty rate for new wells tied in for production on Crown lands would become a permanent measure. The Alberta government also announced reducing the maximum royalty paid on oil from 50% to 40% and on natural gas from 50% to 36%. The new royalty curves are to be made available on May 31, 2010. At this time, the Company anticipates that the royalty curve changes will benefit production from its new Cardium oil drilling program.

	Three months ended Dec. 31		Year ended Dec. 31	
	2009	2008	2009	2008
Royalties (%)	9%	22%	11%	22%
Royalties (\$/BOE)	\$ 2.66	\$ 9.46	\$ 2.97	\$ 11.94

Operating Expenses. Operating expenses were \$9.70 per BOE for the year ended December 31, 2009 compared to \$11.27 per BOE for the year ended December 31, 2008. The Company completed three large plant construction projects in mid 2008 at Willesden Green, Wilson Creek and Buck Lake that helped to reduce reliance on third party processing and lower operating costs per BOE. Approximately 200 BOED of production was shut-in on marginal properties during 2009 due to lower prices which also contributed to the reduction in operating expenses per BOE. The Company has also been negotiating with service providers to reduce costs. Operating expenses were \$10.49 per BOE in the fourth quarter of 2009 compared to \$7.72 per BOE in the third quarter of 2009 and \$11.51 per BOE in the fourth quarter of 2008. The \$7.72 per BOE reported in the third quarter of 2009 reflects the reversal of some prior quarter accruals where the effect of cost reductions had previously been underestimated. Operating expenses in the third quarter would have been \$9.68 per BOE without these adjustments, closer to the average for the year. The Company also incurred additional costs in the fourth quarter of 2009 for workovers and compressor maintenance as well as the costs associated with the resumption of previously shut-in higher operating cost production.

OPERATING NETBACK

(thousands of dollars)	Three months ended Dec. 31		Year ended Dec. 31	
	2009	2008	2009	2008
Revenue	\$ 20,439	\$ 30,102	\$ 76,993	\$ 156,245
Royalties	(1,731)	(6,694)	(8,253)	(34,038)
Operating expenses	(6,831)	(8,140)	(26,906)	(32,110)
	\$ 11,877	\$ 15,268	\$ 41,834	\$ 90,097
Sales (MBOE)	651.4	707.4	2,775.2	2,850.1
Per BOE				
Revenue	\$ 31.38	\$ 42.55	\$ 27.74	\$ 54.82
Royalties	(2.66)	(9.46)	(2.97)	(11.94)
Operating expenses	(10.49)	(11.51)	(9.70)	(11.27)
	\$ 18.23	\$ 21.58	\$ 15.07	\$ 31.61

General and Administrative Expenses. General and administrative expenses were \$7.0 million or \$2.52 per BOE for the year ended December 31, 2009 compared to \$6.4 million or \$2.24 per BOE for the year ended December 31, 2008. General and administrative expenses were \$2.94 per BOE in the fourth quarter of 2009 compared to \$2.18 per BOE in the third quarter of 2009 and \$1.40 per BOE in the fourth quarter of 2008. General and administrative costs increased in 2009 as a result of lower overhead recoveries due to lower capital spending in 2009. A bonus accrual was also included in the fourth quarter of 2009 in recognition of the success of the winter drilling program. In 2009, fourth quarter costs were higher than the previous quarter and the fourth quarter of last year due to unusual adjustments in those comparative quarters. Prior period overhead adjustments were recorded in the third quarter of 2009 and a bonus accrual was reversed in the fourth quarter of 2008 due to market conditions. On a BOE basis, G&A costs were also affected by lower production volumes.

(thousands of dollars)	Three months ended Dec. 31		Year ended Dec. 31	
	2009	2008	2009	2008
General and administrative (gross)	\$ 3,276	\$ 2,324	\$ 12,284	\$ 11,986
Overhead recoveries	(437)	(720)	(1,721)	(2,114)
Capitalized	(924)	(612)	(3,565)	(3,495)
General and administrative (net)	\$ 1,915	\$ 992	\$ 6,998	\$ 6,377
General and administrative (\$/BOE)	\$ 2.94	\$ 1.40	\$ 2.52	\$ 2.24
% Capitalized	28%	26%	29%	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 2009 (\$1.1 million net of amounts capitalized) versus \$2.0 million (\$1.1 million net of amounts capitalized) in 2008. The minimal increase is a result of additional stock options being granted to new and existing staff members, offset partially by options reaching their full vesting terms.

Interest Expense. Interest expense was \$3.7 million for the year ended December 31, 2009 compared to \$4.5 million in 2008. In the fourth quarter of 2009, interest expense was \$0.8 million compared to \$0.8 million in the third quarter of 2009 and \$1.1 million in the fourth quarter of 2008. The decrease in interest expense is due to the lower debt levels and lower interest rates. Bank loans were \$62 million at December 31, 2009 as compared to \$85 million at

December 31, 2008. The average effective interest rate on outstanding bank loans was 4.2% in 2009 compared to 5.0% in 2008. Lower prime and bankers acceptance interest rates on borrowings have been offset in part by higher margins applied to the banking facilities.

Depletion and Depreciation. Depletion and depreciation was \$28.33 per BOE for the year ended December 31, 2009 compared to \$22.26 per BOE in 2008. Depletion and depreciation was \$26.39 per BOE in the fourth quarter of 2009 compared to \$29.09 per BOE in the third quarter of 2009 and \$28.46 per BOE in the fourth quarter of 2008. 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 an increase in total proved reserves. In addition, future development costs decreased in the new reserve report, reflecting measures taken in the 2009/2010 winter drilling program to reduce drilling and completion costs.

Asset Retirement Obligation. As a result of new drilling, the Company recorded \$1.3 million in additional asset retirement obligations in the fourth quarter of 2009 and \$1.5 million for the year ended December 31, 2009. Revisions to estimated reclamation costs and timelines added \$0.7 million to the obligation in the year. Accretion expense was \$2.3 million for 2009 compared with \$1.9 million for 2008. 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 2010. The estimated tax pool balances at December 31, 2009 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 2009 that will not be taxed until 2010.

Canadian Exploration Expenses (CEE)	\$ 62 million
Canadian Development Expenses (CDE)	95 million
Undepreciated Capital Cost (UCC)	95 million
Canadian Oil and Gas Property Expenses (COGPE)	16 million
Non-Capital Losses and Other	<u>41 million</u>
Total	\$ 309 million

Funds from Operations. Funds from operations decreased by 61% to \$31.3 million in 2009 compared to \$79.3 million in 2008. On a per share basis, funds from operations were \$0.25 per share in 2009 compared to \$0.91 per share in 2008. For the three months ended December 31, 2009, funds from operations were \$9.2 million or \$0.06 per share, an increase of 38% over the previous quarter of \$6.6 million or \$0.04 per share, and a decrease of 31% from the fourth quarter of 2008 of \$13.2 million or \$0.15 per share. The decrease in funds from operations in 2009 is a result of lower commodity prices in 2009, with the low for natural gas prices coming in the third quarter of the year. This was partially offset by lower royalties and lower operating expenses. Cash from operating activities decreased year over year for similar reasons. Commodity prices, particularly for natural gas, remain volatile in 2010.

(thousands of dollars)	Three months ended Dec. 31		Year ended Dec. 31	
	2009	2008	2009	2008
Cash from operating activities	\$ 5,361	\$ 11,261	\$ 23,820	\$ 82,688
Changes in non-cash working capital	3,246	1,464	5,956	(4,492)
Asset retirement obligations	544	479	1,482	1,132
Funds from operations	\$ 9,151	\$ 13,204	\$ 31,258	\$ 79,328

Earnings. The Company reported a \$6.5 million loss in the fourth quarter of 2009 and a \$36.5 million loss for the year ended December 31, 2009. 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 charge were \$8.5 million in 2008. The loss in 2009 resulted from low commodity prices and higher depletion and depreciation charges partially offset by a reduction in royalties and operating expenses and a future income tax recovery.

The Company's funds from operations and earnings are highly sensitive to changes in factors that are beyond its control. An estimate of the Company's sensitivities to changes in commodity prices, exchange rates and interest rates is summarized below:

SENSITIVITIES

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

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

CAPITAL EXPENDITURES

The Company spent \$11.3 million in capital expenditures, net of dispositions and anticipated drilling incentive credits, in the fourth quarter and \$33.6 million for the year ended December 31, 2009. 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>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Land, geological and geophysical costs	\$ (15)	167	\$ 173	\$ 1,211
Acquisitions, net of dispositions	-	(17,186)	(54)	(18,043)
Drilling, completion and recompletion	15,492	25,713	23,952	68,075
Drilling incentive credits	(6,000)	-	(6,000)	-
Facilities and well equipment	3,642	17,958	11,349	51,174
Capitalized G&A	924	611	3,565	3,494
Total finding, development & acquisition expenditures	14,043	27,263	32,985	105,911
Change in compressor and other equipment inventory	(2,736)	(101)	542	295
Office equipment and furniture	5	308	31	463
Total capital expenditures	11,312	27,470	33,558	106,669
Non-cash asset retirement obligations and capitalized stock-based compensation	2,003	2,800	3,220	6,421
Total cash and non-cash capital additions	\$ 13,315	30,270	\$ 36,778	\$ 113,090

Drilling statistics are shown below:

	<i>Three months ended Dec. 31</i>				<i>Year ended Dec. 31</i>			
	<i>2009</i>		<i>2008</i>		<i>2009</i>		<i>2008</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	98	73.6	86	59.5	109	81.9	196	134.7
Oil	-	-	-	-	-	-	6	2.9
Dry	9	7.6	5	2.5	9	7.6	15	10.6
Total	107	81.2	91	62.0	118	89.5	217	148.2
Success rate (%)	92%	91%	95%	96%	92%	92%	93%	93%

Capital expenditures included \$16.5 million spent on wells drilled under the farm-in agreement and \$2.8 on pre-expenditures for equipping and tie-in related to this program. An additional \$2.4 million was spent on fit-for purpose processing facilities expected to be commissioned in 2010. Other significant expenditures in the year relate to completion of the prior winter's Edmonton Sands drilling program in the first quarter of 2009 and the tie-in of several standing gas wells in the third and fourth quarters of 2009.

The Company drilled 118 gross (89.5 net) Edmonton Sands wells in 2009 of which 107 gross (81.2 net) wells were drilled in the fourth quarter. Well tie-ins are proceeding in the field with most of the new production coming on-stream in late March or April 2010. Some well tie-ins have been deferred until after spring breakup as the flush production from new wells tied-in in the first quarter will initially be enough to fill available plant capacity.

The Company accrued \$6.0 million for drilling incentive credits in 2009. 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 were earned through drilling in the fourth quarter of 2009 but are expected to be paid out between 2009 and 2011 as crown royalties are paid. The estimate is highly dependent on commodity prices, production levels, crown royalty rates and gas cost allowance earned over this period. To the extent that crown royalties paid are lower or higher, drilling credits will be lower or higher as well. In March 2010, the Company received \$2.6 million in proceeds on the sale of some of its surplus credits.

CEILING TEST/GOODWILL IMPAIRMENT

At December 31, 2009, 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 2009 ceiling test.

At December 31, 2008, the Company wrote off \$35.4 million of goodwill recorded as a result of acquisitions made in 2005 and 2008 due to a decline in the Company's fair value as represented by its market capitalization at that time. There was 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 GLJ Petroleum Consultants ("GLJ") in accordance with National Instrument 51-101 ("NI 51-101") as of December 31, 2009. 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, 2009 ("AIF") as the Company's NI 51-101 annual required filings.

SUMMARY OF GROSS OIL AND GAS RESERVES

As at December 31, 2009

	Natural Gas (Bcf)	Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Total BOE (MBOE)
Proved developed producing	45,562	542	1,087	9,223
Proved developed non-producing	15,466	52	82	2,712
Proved undeveloped	66,937	219	305	11,680
Total proved	127,965	813	1,474	23,615
Probable	59,030	647	796	11,281
Total proved plus probable	186,995	1,460	2,270	34,896

Notes: (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, 2009

(GLJ December 31, 2009 Price Forecast, Escalated Prices)

(thousands of dollars)	0%	5%	10%	15%	20%
Proved developed producing	218,089	181,508	156,423	138,174	124,293
Proved developed non-producing	50,755	43,065	37,265	32,764	29,183
Proved undeveloped	110,307	73,429	48,827	32,002	20,266
Total proved	379,151	298,002	242,515	202,940	173,742
Probable	255,607	170,723	121,575	90,761	70,270
Total proved plus probable	634,758	468,725	364,090	293,701	244,012

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, 2009

GLJ Forecast Prices and Costs

Year	Oil		Natural Gas		Edmonton Liquids Prices		Inflation Rate % (US\$/Cdn)	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)		
2010	80.00	83.26	5.96	52.46	64.11	84.93	2.0	0.95
2011	83.00	86.42	6.79	54.45	66.54	88.15	2.0	0.95
2012	86.00	89.58	6.89	56.43	68.98	91.37	2.0	0.95
2013	89.00	92.74	6.95	58.42	71.41	94.59	2.0	0.95
2014	92.00	95.90	7.05	60.42	73.84	97.82	2.0	0.95
2015	93.84	97.84	7.16	61.64	75.33	99.79	2.0	0.95
2016	95.72	99.81	7.42	62.88	76.85	101.81	2.0	0.95
2017	97.64	101.83	7.95	64.15	78.41	103.86	2.0	0.95
2018	99.59	103.88	8.52	65.45	79.99	105.96	2.0	0.95
2019	101.58	105.98	8.69	66.77	81.60	108.10	2.0	0.95

Thereafter 2%

Total future development costs included in the reserves evaluation were \$197.6 million for total proved reserves and \$260.1 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 2009 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) ⁽¹⁾			Oil & Natural Gas Liquids (Mbbbls)		
	Proved	Probable	Total	Proved	Probable	Total
Opening balance						
December 31, 2008	125.4	47.5	172.9	2,498	980	3,478
Extensions and						
improved recovery	17.9	8.1	26.0	288	369	657
Net acquisitions ⁽²⁾	16.6	5.7	22.3	47	15	62
Revisions	(17.9)	(2.3)	(20.2)	(112)	79	(33)
Dispositions	-	-	-	-	-	-
Production	(14.0)	-	(14.0)	(434)	-	(434)
Closing balance						
December 31, 2009	128.0	59.0	187.0	2,287	1,443	3,730

Note: ⁽¹⁾ Closing balance for natural gas includes 5.5 Bcf of proved and 3.0 Bcf of probable Coal Bed Methane reserves.

⁽²⁾ There were no property acquisitions during the year. The acquisition additions in this continuity table relate to the reserve additions associated with the Edmonton Sands farm-in.

The Company's reserves life indices are 9.1 years total proved and 13.5 years total proved plus probable, based on 2009 fourth quarter production. Reserves additions, net of revisions, were 3.0 MMBOE total proved and 5.4 MMBOE total proved plus probable. The Company replaced 194% of its production with new proved plus probable reserves additions, net of revisions, in 2009. A large portion of the negative revisions were due to a significant reduction in GLJ's price deck for natural gas.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Year Ended December 31, 2009

(in thousands of dollars)	Proved	Proved plus Probable
Finding, development & acquisition expenditures	\$ 32,985	\$ 32,985
Change in future development costs	(7,131)	12,467
Sale of surplus drilling incentive credits	(2,613)	(2,613)
Total costs	\$ 23,241	\$ 42,839
Reserve additions, net of revisions (MBOE)	2,996	5,378
2009 finding, development & acquisition costs (\$/BOE)	\$ 7.76	\$ 7.97

The Company's FD&A costs in 2009 were \$7.76 per BOE on a proved basis and \$7.97 per BOE on a proved plus probable basis. Reserve additions related to the Edmonton Sands farm-in have been classified as acquisitions by GLJ in the reserve report. There were no property acquisitions in the year and dispositions were negligible, so a separate calculation of finding and development costs excluding acquisitions and dispositions has not been presented. FD&A costs in 2008 were negative due to downward revisions to reserves. The three year average FD&A costs were \$29.53 total proved and \$25.37 proved plus probable, including the effects of these revisions as well as large central facility expenditures incurred in 2008. 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 December 31, 2009, there were 150.5 million common shares outstanding and 10.3 million stock options outstanding. During 2009, no shares were

issued under the employee stock option plan.

SHARE PRICE ON TSX

		<i>2009</i>		<i>2008</i>
High	\$	1.48	\$	5.45
Low	\$	0.65	\$	0.87
Close	\$	1.16	\$	1.15
Volume		125,408,442		76,653,637
Shares outstanding at December 31		150,500,401		87,300,401
Market capitalization at December 31	\$	174,580,465	\$	100,395,461

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 21.4 million common shares traded on these alternative exchanges in the year. Including these exchanges, an average of 584,790 common shares traded per day in 2009, representing a turnover ratio of 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 TRANSACTION

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, 2009, the Company had outstanding bank loans of \$62.4 million and a working capital deficiency of \$10.1 million. 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 2010 is \$87 million with \$47 million budgeted for the first quarter of 2010, in order to fulfill its farm-in commitments and commence its horizontal multistage frac drilling. In February 2010, the Company completed a common share equity issue for net proceeds of \$29.8 million after commission and expenses. The financing allowed the Company to expand its Cardium horizontal light oil drilling program in 2010.

The Company's need for capital will be both short-term and long-term in nature. Short-term capital is required to finance accounts receivable and other similar short-term assets while the acquisition and development of oil and natural gas properties requires larger amounts of long-term capital. At December 31, 2009, the Company has a \$90 million extendible revolving term credit facility and a \$10 million working capital credit facility with a syndicate of Canadian banks. Anderson Energy will prudently use its bank loan facilities to finance its operations as required. The available lending limits under the bank facilities are reviewed twice a year and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The last review was conducted in November 2009. 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 13, 2010. As a result of the current economic climate and changes to global credit markets, the Company has incurred 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.

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 \$100 million have a revolving period ending July 13, 2010 extendible at the option of the lenders, followed by a term period with three equal quarterly principal repayments commencing 180 days from the term date.
- *Lease for office space* – This lease expires on November 30, 2012. Future minimum lease payments are expected to be \$1.8 million per year in 2010 and 2011, and \$1.6 million in 2012.
- *Firm service transportation commitments* – The Company has entered into firm service transportation agreements for approximately 25 million cubic feet per day of gas sales for various terms expiring between 2010 and 2020. Based on rate schedules announced to date, the payments in each of the next five years and thereafter are estimated to be \$1.6 million in 2010, \$1.5 million in 2011, \$1.1 million in 2012, \$0.8 million in 2013, \$0.6 million in 2014 and \$1.2 million thereafter.
- *Farm-in* – On January 30, 2009, the Company announced a farm-in agreement with a large international oil and gas company on lands near its existing core operations. Under the farm-in agreement, the Company has access to 388 gross (205 net) sections of land. During the commitment phase of the transaction, the Company is committed to drill, complete and equip 200 wells to earn an interest in up to 120 sections. The Company drilled 106 wells under the commitment to December 31, 2009 and a further 20 wells in the first quarter of 2010. The Company is obligated to complete the drilling of the wells on or before December 31, 2010. The commitment is subject to various guarantees. The Company estimates that it will spend approximately \$50 million in 2010 on the farm-in to drill, complete and equip farm-in wells, which has been included in the \$87 million capital budget for 2010.

These obligations are described further in other parts of this discussion and analysis and in notes 6 and 14 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. 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.

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

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. The Company adopted the new standard for the year ended December 31, 2009. Adoption of the standard did not have any impact on the Company's results of operations or financial position.

In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862, Financial Instruments – Disclosures, to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These disclosures are included in note 12 of the consolidated financial statements.

FUTURE ACCOUNTING POLICIES

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 International Financial Reporting Standards ("IFRS").

In 2009, the CICA issued Section 1601, Consolidated Financial Statements and Section 1602, Non-controlling Interests which replace the existing guidance under Section 1600, Consolidated Financial Statements. These standards provide guidance for preparing consolidated financial statements and for accounting for a non-controlling interest in a subsidiary. These standards are effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011, with early adoption permitted.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

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

In response, the Company has completed its high-level IFRS changeover plan and established a preliminary timeline for the execution and completion of the conversion project. The

changeover plan was determined following a preliminary assessment of the differences between Canadian GAAP and IFRS and the potential effects of IFRS to accounting and reporting processes, information systems, business processes and external disclosures. This assessment has provided insight into what are anticipated to be the most significant areas of difference applicable to the Company.

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

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

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

IFRS 1 "First-Time Adoption of International Financial Reporting Standards" provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions, in certain areas, to the general requirement for full retrospective application of IFRS. The Company is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate in the Company's circumstances.

Property, Plant and Equipment. International Accounting Standard (IAS) 16 "Property, Plant & Equipment" and Canadian GAAP contain the same basic principles, however there are some differences. IFRS requires that significant parts of an asset be depreciated separately and depreciation commences when the asset is available for use. There will be more depreciable components than the current single full cost pool. IFRS also permits property, plant equipment to be measured using the fair value model or the historical cost model. The Company is not planning on adopting the fair value measurement model for property, plant and equipment.

IFRS 1 contains an exemption 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 is currently evaluating the impact of allocating the net book values based on reserve volumes or values.

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

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

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

Impairment of Assets. IAS 36 "Impairment of Assets" requires that impairments be determined based on 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. There are more cash generating units than the current single full cost pool.

Income taxes. Under IAS 12 "Income Taxes", current and deferred tax are normally recognized in the income statement, except to the extent that tax arises from (1) an item that has been recognized directly in equity, whether in the same or a different period, (2) a business combination or (3) a share based payment transaction. If a deferred tax asset or liability is re-measured subsequent to initial recognition, the impact of re-measurement is recorded in earnings, unless it relates to an item originally recognized in equity, in which case the change would also be recorded in equity. The practice of tracking the re-measurement of taxes back to the item which originally triggered the recognition is commonly referred to as "backwards tracing." Canadian GAAP prohibits backwards tracing except on business combinations and financial reorganizations.

Share based payments. Under IFRS 2 "Share-Based Payments", graded vested options are required to be separated into their vesting tranches and valued and accounted for separately. This differs from Canadian GAAP, where graded vested options 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 is currently evaluating the transitional impact.

Throughout 2010, the Company will continue to document and define its IFRS accounting policies and the Company will start to evaluate the financial impact of IFRS on its financial statements. Staff training programs have continued in 2009 and will be ongoing as the project unfolds.

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

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, 2009 and have concluded that such disclosure controls and procedures were effective.

The Chief Executive Officer and the Chief Financial Officer have evaluated and tested the design and operating effectiveness of Anderson Energy's internal controls over financial reporting as of December 31, 2009 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. Natural gas prices in particular have weakened on fears of reduced industrial use due to the continued U.S. recession and increased supply from U.S. natural gas shale plays. The industry is subject to extensive governmental regulation with respect to the environment. Operational risks include well performance, uncertainties inherent in estimating reserves, timing of/ability to obtain drilling licences and other regulatory approvals, ability to obtain equipment, expiration of licences and leases, competition from other producers, sufficiency of insurance, ability to manage growth, reliance on key personnel, third party credit risk and appropriateness of accounting estimates. These risks are described in more detail in the Company's Annual Information Form for the year ended December 31, 2009 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 U.S. policy. 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 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.

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

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

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

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

Further refinements to the amendments are anticipated to be announced by the Government of Alberta within 60 days of March 11, 2010 including, without limitation, the royalty curves that are to be utilized to determine the applicable royalty rates.

The changes to the royalty regime in the Province of Alberta are subject to certain risks and uncertainties. There may be modifications introduced to the royalty structure and such changes

may be adverse to the business of the Company. There can be no assurance that the Government of Alberta or the Government of Canada will not adopt new royalty regimes which may render the Company's projects uneconomic or otherwise adversely affect the business of the Company.

BUSINESS PROSPECTS

The Company believes it has an excellent future drilling inventory, including several years of vertical development drilling locations, particularly in the Edmonton Sands and West Pembina Rock Creek plays. The Company has also identified high impact multistage frac horizontal drilling opportunities targeting Cardium light oil and Whitemud Sands gas in Central Alberta.

During periods of price weakness, the Company's business strategy is to grow its assets and reduce its costs. The Company previously 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. The Company drilled 118 gross Edmonton Sands wells in 2009, 106 of which were part of the farm-in. In the first quarter of 2010, the Company drilled an additional 20 gross wells, resulting in 126 wells drilled to date under the farm-in agreement.

The equity financings completed during the second quarter of 2009 and the first quarter of 2010, along with the Company's available bank lines, provide the Company with the financial flexibility to take advantage of the opportunities provided by the farm-in and expand its drilling program on its Cardium lands.

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

QUARTERLY INFORMATION

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

SELECTED QUARTERLY INFORMATION

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

	Q4 2009	Q3 2009	Q2 2009	Q1 2009
Oil and gas revenue before royalties	\$ 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
Loss	\$ (6,457)	\$ (9,432)	\$ (10,410)	\$ (10,159)
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)	\$ 31.38	\$ 22.50	\$ 24.70	\$ 31.91
	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 (BOED)	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

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

SELECTED ANNUAL INFORMATION

YEARS ENDED DECEMBER 31

(in thousands, except per share amounts)

	2009	2008	2007
Total oil and gas revenues	\$ 76,993	\$ 156,245	\$ 83,585
Total oil and gas revenues, net of royalties	\$ 68,740	\$ 122,207	\$ 67,827
Earnings (loss) before goodwill impairment	\$ (36,458)	\$ 8,500	\$ 2,184
Earnings (loss) before goodwill impairment per share			
Basic	\$ (0.29)	\$ 0.10	\$ 0.03
Diluted	\$ (0.29)	\$ 0.10	\$ 0.03
Earnings (loss)	\$ (36,458)	\$ (26,864)	\$ 2,184
Earnings (loss) per share			
Basic	\$ (0.29)	\$ (0.31)	\$ 0.03
Diluted	\$ (0.29)	\$ (0.31)	\$ 0.03
Total assets	\$ 497,169	\$ 543,533	\$ 531,324
Total long-term debt	\$ 62,404	\$ 85,314	\$ 67,981

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 to the royalty regime applicable to the Company, including payment of drilling incentive credits, commodity price outlook and general economic outlook may constitute forward-looking statements under applicable securities laws and necessarily involve risks and assumptions made by management of the Company including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserves estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, wells not performing as expected, incorrect assessment of the value of acquisitions and farm-ins, failure to realize the anticipated benefits of acquisitions and farm-ins, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Anderson Energy's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at Anderson Energy's website (www.andersonenergy.ca).

Furthermore, the forward-looking statements contained in this 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

Mcfd – thousand cubic feet per day

MMcf – million cubic feet

MMcfd – million cubic feet per day

Bcf – billion cubic feet