ANDERSON ENERGY LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2009

March 31, 2010

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ABBREVIATIONS AND CONVERSION FACTORS

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
BOED	barrels of oil equivalent per day
bpd	barrels per day
Mstb	thousand stock tank barrels
NGL	natural gas liquids

Natural Gas

Bcf	billion cubic feet
CBM	coal bed methane
GJ	gigajoule
Mcf	thousand cubic feet
Mcfd	thousand cubic feet per day
Mcfe	thousand cubic feet equivalent
MMcf	million cubic feet
MMcfd	million cubic feet per day

OTHER

AECO	Intra-Alberta Nova Inventory Transfer Price (NIT net price of natural gas)
API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
BOE	barrel of oil equivalent of natural gas on the basis of 1 BOE for 6 Mcf of natural gas (unless otherwise stated)
BOED	barrel of oil equivalent per day
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to one BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CONVERSION FACTORS

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	*To*	*Multiply By*
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

GLOSSARY OF TERMS

"ABCA" means the *Business Corporations Act* (Alberta) and the regulations promulgated thereunder, all as amended from time to time.

"Anderson" or the *"Company"* means Anderson Energy Ltd., a corporation amalgamated under the laws of the Province of Alberta.

"Aquest" means Aquest Energy Ltd., a corporation amalgamated pursuant to the laws of the Province of Alberta. Aquest amalgamated with Anderson effective January 1, 2006.

"Developed Producing Reserves" are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"GLJ" means GLJ Petroleum Consultants, independent petroleum consultants of Calgary, Alberta.

"GLJ Report" means the independent engineering evaluation of Anderson's oil and gas interests prepared by GLJ Petroleum Consultants, dated March 18, 2010 and effective December 31, 2009.

"Gross" or *"gross"* means:

(a) in relation to the Company's interest in reserves, Anderson's working interest (operated and non-operated) share before deduction of royalties and without including any royalty interest owned by Anderson;
(b) in relation to wells, the total number of wells in which Anderson has an interest; and
(c) in relation to land, the total area in which Anderson has an interest.

"Net" or *"net"* means

(a) in relation to the Company's interest in reserves, Anderson's working interest (operated and non-operated) share after deduction of royalty obligations, plus Anderson's royalty interests in reserves;
(b) in relation to wells, the total number of wells obtained by aggregating Anderson's working interest in each of its gross wells; and
(c) in relation to land, the total area in which Anderson has an interest multiplied by Anderson's working interest.

"Probable Reserves" are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved Plus Probable Reserves. At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved Plus Probable Reserves is the targeted level of certainty.

"Proved Plus Probable Reserves" means the aggregate of Proved Reserves and Probable Reserves, before deduction of royalties.

"Proved Reserves" are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the targeted level of certainty.

"Reserves" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

"Royalties" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling prices, the price forecasts for the individual properties in question have been employed.

"Undeveloped Reserves" are those Reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the Reserves classification (proved, probable, possible) to which they are assigned.

FORWARD LOOKING STATEMENTS

Certain information regarding Anderson in this Annual Information Form including, without limitation, management's growth strategy and management's assessment of future plans and operations, capital expenditures including source, timing thereof and areas where such capital expenditures are expected to be made, reserves, net present values of future net revenue from reserves, commodity prices, development plans and programs, tax horizon, abandonment and reclamation costs, government royalty rates and expiring acreage 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 reserve 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's operations and financial results are included under the heading "Risk Factors" in this Annual Information Form. Furthermore, the forward-looking statements contained in this Annual Information Form are made as at the date hereof and Anderson 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.

CORPORATE STRUCTURE

Anderson Energy Ltd. was incorporated under the ABCA on January 30, 2002. On April 4, 2002, Anderson amended its articles to amend the rights, privileges, restrictions and conditions of the Class A common shares, Class B common shares and preferred shares of Anderson and remove the private company restrictions. Anderson has conducted oil and gas exploration, development and acquisition activities in western Canada since completing its initial private placement in April 2002.

On June 27, 2005 the Company entered into an agreement with Aquest, a publicly traded oil and gas company, whereby they agreed to complete a plan of arrangement (the "Arrangement") pursuant to which Anderson acquired all of the outstanding shares of Aquest. The Arrangement was approved by the shareholders of Anderson and Aquest and received regulatory approval on August 31, 2005 and the transaction closed on September 1, 2005. As a result of the Arrangement, Anderson became a public company effective September 7, 2005.

Effective January 1, 2006, Anderson, Aquest, Eravista Explorations Ltd. (a subsidiary of Aquest) and 1022864 Alberta Ltd. (a subsidiary of Anderson) amalgamated under a short form vertical amalgamation to form Anderson Energy Ltd.

Effective January 1, 2009, Anderson and 1347662 Alberta Ltd. (a subsidiary of Anderson) amalgamated under a short form vertical amalgamation. 1347662 Alberta Ltd. was incorporated on March 1, 2007 as 3210700 Nova Scotia Company, was acquired by Anderson in a transaction completed on September 1, 2007 and was continued into Alberta as 1347662 Alberta Ltd. on September 12, 2007.

Anderson has one wholly-owned subsidiary, 1023095 Alberta Ltd. 1023095 Alberta Ltd. was incorporated under the ABCA on December 20, 2002. Anderson and 1023095 Alberta Ltd. are partners of Anderson Energy Partnership, a general partnership under the laws of Alberta.

The registered office and head office of Anderson is located at 700 Selkirk House, 555 4th Avenue S.W. Calgary, Alberta, Canada T2P 3E7.

BUSINESS AND STRATEGY

Development of the Business. Anderson was formed as a private company in 2002. On April 29, 2002, Anderson completed its initial private placement, issuing 0.9 million Class A common shares and 28.5 million Class B common shares for gross proceeds of $80.0 million and began to establish an exploration land base. Anderson conducted its first drilling operations in late 2002.

On April 24, 2007, Anderson issued 7.9 million common shares at a price of $4.35 per share for gross proceeds of $34.5 million ($32.5 million after commission and expenses).

In 2007, Anderson completed two significant acquisitions in the Central Alberta area. The first was a property acquisition for $9.2 million which closed on June 29, 2007. The second was the acquisition of 3210700 Nova Scotia Company which was completed on September 1, 2007 for $117.6 million. 3210700 Nova Scotia Company was subsequently continued into Alberta and its name was changed to 1347662 Alberta Ltd.

On August 31, 2007, Anderson issued 25.7 million common shares at a price of $3.90 per share for gross proceeds of $100.2 million ($94.7 million after commission and expenses) in conjunction with the acquisition completed on September 1, 2007.

On January 29, 2009, the Company executed a farm-in agreement with a large international oil and gas company (the "Farmor") on lands near its existing core operations. Under the farm-in agreement, the Company has access to 388 gross (205 net) sections of land. During the commitment phase of the transaction, the Company is committed to drill, complete and equip 200 wells to earn an interest in up to 120 sections. The Company is obligated to complete the drilling of the wells on or before December 31, 2010. As of March 30, 2010, the Company has drilled 126 wells in connection with the farm-in. The Company has an option to continue the farm-in transaction until April 30, 2012 by committing to drill a minimum of 100 additional wells under similar terms as in the commitment phase to earn a minimum of 50 sections of land. Following the commitment and/or option phases, the parties to the agreement can then jointly elect to develop the lands on denser drilling spacing under terms of an operating agreement.

On May 28, 2009, the Company issued 63.2 million common shares at a price of $0.95 per common share for gross proceeds to the Company of $60.0 million ($56.5 million after commission and expenses).

In February 2010, the Company issued 21.9 million common shares at a price of $1.45 per common share for gross proceeds to the Company of $31.8 million ($29.8 million after commission and expenses).

Stated Business Objectives. The business plan of Anderson is to focus on sustainable and profitable per share growth in both net asset value and cash flow from operations. To accomplish this, Anderson focuses on enhancing its asset base through land acquisitions and farm-ins, seismic interpretation, exploratory and development drilling and strategic acquisitions within its core project areas in western Canada.

Anderson expects to continue to focus on development of prospects in the Central Alberta area, centered around the Sylvan Lake area and northwest to Pembina. Anderson also intends to pursue strategic acquisitions of corporations and/or oil and natural gas properties where it believes further exploration, exploitation and development opportunities exist.

Anderson intends to generate exploration and development opportunities possessing low to medium risk and multi-zone potential. Anderson intends to pursue exploration, development and exploitation drilling, combined with acquisition opportunities that meet Anderson's business parameters. To achieve sustainable and profitable growth, management of Anderson believes in controlling the timing and costs of its projects wherever possible. Anderson will seek to become the operator of its properties to the greatest extent possible. Further, to minimize competition within its geographic areas of interest, Anderson will strive to maximize its working interest ownership in its properties where reasonably possible. While Anderson believes it will have the skills and resources necessary to achieve its objectives, participation in exploration and development in the oil and natural gas industry has a number of inherent risks beyond the direct control of company personnel. Among these risks are those associated with exploration, development and production, economic conditions, commodity prices, capital requirements, financing requirements, industry competition, ability to attract key personnel, government regulation and royalties, the environment, foreign exchange rates and interest rates. See “Risk Factors”.

In reviewing potential drilling or acquisition opportunities, Anderson generally considers the following:

- risk capital required to secure or evaluate the investment opportunity;
- the potential return on the project, if successful;
- the likelihood of success; and
- the risked return versus cost of capital.

In general, Anderson intends to use a portfolio approach in developing opportunities with a balance of risk profiles and commodity exposure, in an attempt to generate sustainable levels of profitable production and financial growth.

The board of directors of Anderson may, in its discretion, approve acquisitions that do not conform to these guidelines based upon its consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserves life and asset quality.

Business Cycle and Seasonality. Anderson's business is generally cyclical. Light oil prices fluctuate with the balance between world supply and demand, levels of inventory and OPEC policy, while natural gas prices are influenced by levels of inventory and storage, estimates of current and forecast supply and weather expectations.

The exploration for and development of oil and natural gas reserves is dependent on access to areas where exploration and exploitation is to be conducted. Seasonal weather variations, including freeze-up and break-up affect access to various properties in certain circumstances.

Trends. A global economic crisis led to unprecedented changes in capital, equity, commodity and currency markets during 2008 and 2009. These changes negatively impacted company valuations, access to credit and commodity prices, and resulted in a significant slow down in activity levels in the industry.

Crude oil and natural gas prices are volatile and subject to a number of external factors, as noted above. Natural gas prices are greatly influenced by the weather and economy in North America. The Canadian/U.S. currency exchange rate also influences commodity prices received by Canadian producers as oil and natural gas production is ultimately priced in U.S. dollars.

Access to qualified people and equipment is affected by the level of industry activity. In recent years, high levels of activity had tightened the markets for both staff and rigs. However, by the beginning of 2009, activity levels had declined significantly due to changing economic conditions and falling commodity prices.

Employees. As at December 31, 2009, Anderson had 56 full time and 9 part time employees.

PRINCIPAL PROPERTIES

Oil and Gas Properties. The following is a description of Anderson's principal oil and natural gas properties on production or under development as at December 31, 2009. Anderson has a highly centralized land base so only one principal property is described. Unless otherwise noted, references to Anderson's production means Anderson's working interest in production (operated and non-operated) before deduction of royalties and without including any royalty interests of Anderson. Current production means average production for February 2010. Reserves are stated, before deduction of royalties, at December 31, 2009, based on forecast price and cost assumptions as evaluated in the GLJ Report. The term "net", when used to describe Anderson's working interest in land, means the total area in which Anderson has an interest multiplied by Anderson's working interest. The term "net", when used to describe Anderson's working interest in wells, means the number of wells determined by aggregating Anderson's working interest in each of its gross wells. Unless otherwise specified, gross and net acres and well count information are stated as at December 31, 2009.

Central Alberta. The focus of Anderson's current Central Alberta operations runs from the Sylvan Lake area centered approximately 110 kilometres north of Calgary, Alberta to the Pembina area less than 100 kilometres southwest of Edmonton, Alberta. This area is a combination of several subsidiary operated fields including West Pembina, Bigoray, Buck Lake, Sylvan Lake, Prevo, Gilby, Willesden Green, Strachan, and Wilson Creek. A non operated field in the Ghost Pine area is located approximately 100 kilometres northeast of Calgary. The Central Alberta area consists of 65,573 gross (32,919 net) acres of undeveloped land.

The majority of Anderson's production in the Central Alberta area is natural gas that originates from multiple Edmonton Sands pools at depths of less than 1,000 metres. Other hydrocarbon producing zones include Horseshoe Canyon Coal, Belly River, Cardium, Viking, Mannville, Pekisko and Leduc. Anderson has an interest in 929 gross (541 net) natural gas wells and 130 gross (49.2 net) oil wells in the Central Alberta area.

Anderson has ownership in gas plants at 04-18-032-22 W4, 05-10-033-26 W4, 14-32-037-03 W5, 11-35-037-09 W5, 01-21-038-02 W5, 05-14-039-05 W5 and 10-05-046-06 W5. Natural gas produced in the Central Alberta area is also processed in third party facilities and the most significant ones are located at 10-07-051-09 W5 and 11-22-049-12 W5. Anderson has working interests up to 100% in numerous well site and intermediate field booster compression facilities in Central Alberta from 60 to 1,000 horsepower. This includes a 75% working interest in a fit for purpose shallow gas battery at 05-26-043-05 W5. A working interest position of 100% is held in an oil battery at 08-10-039-02 W5 as well as a 44% interest is in an oil battery at 15-16-039-28W4 and a 20.9% working interest in the 16-14-039-01W5 oil battery.

As at December 31, 2009 in the Central Alberta area, Anderson's total proved reserves were 125 Bcf of natural gas, 1,479 Mstb of NGL and 512 Mstb of oil. Total proved plus probable reserves were 182 Bcf of natural gas, 2,265 Mstb of NGL and 958 Mstb of oil. In 2009, Anderson drilled 118 gross (90 net) natural gas wells and no oil wells in the area.

Anderson's production in 2009 from the Central Alberta area was 7,121 BOED or 94% of total production. Central Alberta is the Company's primary production growth area. Anderson has an active infill and step out operated drilling program in Central Alberta targeting the Edmonton Sands and Whitemud Sands for 2010 through to 2014. The Edmonton Sands 200 well farm-in commitment will be complete in 2010. Also in 2010, Anderson will participate in an estimated seven Cardium horizontal multistage frac wells targeting light sweet crude oil. Finally, various deep drilling projects such as Rock Creek rich gas development drilling in the West Pembina field and Mannville rich gas development in Willesden Green will resume in 2010.

STATEMENT OF RESERVES DATA AND OTHER INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement of Reserves") has an effective date of December 31, 2009 and was prepared as of March 18, 2010.

Disclosure of Reserves Data

The reserves data in the Statement of Reserves summarizes the estimated oil, NGL and natural gas reserves of Anderson and the net present values of future net revenue for these reserves using forecast prices and costs. The evaluations were prepared in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation ("COGE") handbook. The reserves definitions used in preparing the GLJ Report are those contained in the COGE handbook and the Canadian Securities Administrators National Instrument 51-101 ("NI 51-101"). Anderson engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The results of the evaluations of GLJ, contained in the GLJ Report based on forecast price and cost assumptions are summarized in the tables below. All evaluations of future revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs, but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of Anderson's reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to the following tables. The recovery and reserves estimates on Anderson's properties described herein are estimates only. The actual reserves on Anderson's properties may be greater or less than those calculated.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to effects of aggregation.

The Report on Reserves Data by GLJ in Form 51-101F2 and the Report of Management and Directors on Reserves Data and Other Information in Form 51-101F3 are included in Schedules 1 and 2 to this Annual Information Form.

All of Anderson's reserves are in Canada, in the province of Alberta. As of December 31, 2009, Anderson has both heavy oil reserves and quantities of CBM reserves which have been segregated in the accompanying tables.

SUMMARY OF OIL AND GAS RESERVES

As of December 31, 2009
GLJ Forecast Prices and Costs(1)(2)(3)(5)(6)

	Light and Medium Oil		Heavy Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids	
	Gross (Mstb)	Net (Mstb)	Gross (Mstb)	Net (Mstb)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mstb)	Net (Mstb)
Proved Developed Producing	382	343	160	138	43,684	37,155	1,878	1,597	1,087	736
Proved Developed Non-Producing	12	11	40	37	14,964	13,313	502	453	82	64
Proved Undeveloped	161	138	58	57	63,838	57,192	3,099	2,634	305	206
Total Proved	555	492	258	232	122,486	107,660	5,479	4,684	1,474	1,006
Probable	494	393	153	140	55,975	47,891	3,055	2,606	796	539
Total Proved Plus Probable	1,049	885	411	372	178,461	155,551	8,534	7,290	2,270	1,545

NET PRESENT VALUES OF FUTURE NET REVENUE

As of December 31, 2009
GLJ Forecast Prices and Costs (1)(2)(3)(7)

	Before Income Taxes Discounted at (%/year)					Unit Value Before Income Taxes (discounted at 10%/year)(8)
(thousands of dollars)	*0%*	*5%*	*10%*	*15%*	*20%*	*$/BOE*
Proved Developed Producing	218,089	181,508	156,423	138,174	124,293	20.38
Proved Developed Non-Producing	50,755	43,065	37,265	32,764	29,183	15.49
Proved Undeveloped	110,307	73,429	48,827	32,002	20,266	4.71
Total Proved	379,151	298,002	242,515	202,940	173,742	11.86
Probable	255,607	170,723	121,575	90,761	70,270	12.81
Total Proved Plus Probable	634,758	468,725	364,090	293,701	244,012	12.16

	After Income Taxes Discounted at (%/year)				
(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	90,687	59,525	38,715	24,481	14,559
Total Proved	359,531	284,098	232,403	195,419	168,035
Probable	193,637	128,095	90,479	67,102	51,693
Total Proved Plus Probable	553,168	412,193	322,882	262,521	219,728

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

As of December 31, 2009

GLJ Forecast Prices and Costs (1)(2)(3)(7)

(in thousands of dollars)	*Revenue*	*Royalties*	*Operating Costs*	*Development Costs*	*Abandonment Costs*	*Future Net Revenue Before Income Taxes*	*Future Income Taxes*	*Future Net Revenue After Future Income Taxes*
Proved	1,101,020	130,257	370,679	197,583	23,350	379,151	19,620	359,531
Proved Plus Probable	1,711,754	217,542	570,792	260,076	28,586	634,758	81,590	553,168

FUTURE NET REVENUE BY PRODUCTION GROUP

As of December 31, 2009

GLJ Forecast Prices and Costs (2)(3)(4)

	Production Group	*Future net Revenue Before Income Taxes (discounted at 10%/year) (in thousands of dollars)*	*Unit Value Before Income Taxes Discounted at (10%/year)*[8] ($/unit)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	18,389	29.57/bbl
	Heavy Oil (including by-products, but excluding solution gas)	7,108	22.92/bbl
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)	209,117	1.86/Mcfe
	Coal Bed Methane Gas	7,902	1.68/Mcfe
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	22,442	27.06/bbl
	Heavy Oil (including by-products, but excluding solution gas)	10,867	21.58/bbl
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)	317,532	1.93/Mcfe
	Coal Bed Methane Gas	13,249	1.82/Mcfe

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

As of December 31, 2009

GLJ Forecast Prices and Costs

	Oil				Natural Gas	Edmonton Liquids Prices			Inflation Rates(3a)	Exchange Rates(3b)
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Cromer Medium 29° API ($Cdn/bbl)	AECO Gas Price ($Cdn/Mcf)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	%/Year	(US$/Cdn)
2010	80.00	83.26	64.99	76.60	5.96	52.46	64.11	84.93	2.0	0.95
2011	83.00	86.42	65.24	78.64	6.79	54.45	66.54	88.15	2.0	0.95
2012	86.00	89.58	65.33	80.62	6.89	56.43	68.98	91.37	2.0	0.95
2013	89.00	92.74	65.26	82.54	6.95	58.42	71.41	94.59	2.0	0.95
2014	92.00	95.90	67.52	85.35	7.05	60.42	73.84	97.82	2.0	0.95
2015	93.84	97.84	68.90	87.07	7.16	61.64	75.33	99.79	2.0	0.95
2016	95.72	99.81	70.32	88.83	7.42	62.88	76.85	101.81	2.0	0.95
2017	97.64	101.83	71.76	90.63	7.95	64.15	78.41	103.86	2.0	0.95
2018	99.59	103.88	73.22	92.46	8.52	65.45	79.99	105.96	2.0	0.95
2019	101.58	105.98	74.72	94.32	8.69	66.77	81.60	108.10	2.0	0.95
Thereafter 2%										

Notes:

(1) Columns may not add due to rounding.

(2) *"Gross"* or *"gross"* means Anderson's working interest (operated and non-operated) share before deduction of royalties and without including any royalty interest owned by Anderson.

"Net" or *"net"* means Anderson's working interest (operated and non-operated) share after deduction of royalty obligations, plus Anderson's royalty interests in reserves.

"Royalties" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling prices, the price forecasts for the individual properties in question have been employed.

"Reserves" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

"Proved Plus Probable Reserves" means the aggregate of Proved Reserves and Probable Reserves.

"Proved Reserves" are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the targeted level of certainty.

"Probable Reserves" are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved Plus Probable Reserves. At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved Plus Probable Reserves is the targeted level of certainty.

"Proved Developed Reserves" are those Reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the Reserves on production. The developed category may be subdivided into producing and non-producing.

"Developed Producing Reserves" are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"Developed Non-Producing Reserves" are those Reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"Undeveloped Reserves" are those Reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of

production. They must fully meet the requirements of the Reserves classification (proved, probable, possible) to which they are assigned.

(3) The forecast cost and price assumptions assume the continuance of current laws and regulations and increases in wellhead selling prices, and take into account inflation with respect to future operating and capital costs. In the GLJ Report, operating costs are assumed to escalate at 2% per annum. Crude oil and natural gas base case prices as forecast by GLJ effective December 31, 2009 consider the following:

(a) Inflation rates for forecasting prices and costs; and

(b) Exchange rates used to generate the benchmark reference prices in this table.

(4) Future net revenue is attributed to a product group based on each field's primary producing product. Anderson's properties produce primarily gas.

(5) Substantially all of the proved producing reserves evaluated in the GLJ Report were on production at December 31, 2009.

(6) The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. The crude oil and natural gas reserves calculations and any projections upon which the GLJ Report is based were determined in accordance with generally accepted evaluation practices. No field inspections were conducted.

(7) GLJ includes well abandonment costs for all wells with reserves at the property level. Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment costs have not been included in the analysis.

(8) Unit values for future net revenue are calculated using net reserves.

Reconciliation of Reserves. The following table provides a summary of the changes in the Company's reserves which occurred in the most recent fiscal year, based upon escalated price and cost assumptions, net of applicable royalties.

RESERVES RECONCILIATION SUMMARY BY PRINCIPAL PRODUCT TYPE

GLJ Forecast Prices and Costs

Gross Reserves

	Proved					*Probable*					*Total Proved Plus Probable*				
	Light & Medium Oil (Mstb)	*Heavy Oil (Mstb)*	*Conventional Natural Gas (MMcf)*	*CBM Gas (MMcf)*	*NGL (Mstb)*	*Light & Medium Oil (Mstb)*	*Heavy Oil (Mstb)*	*Conventional Natural Gas (MMcf)*	*CBM Gas (MMcf)*	*NGL (Mstb)*	*Light & Medium Oil (Mstb)*	*Heavy Oil (Mstb)*	*Conventional Natural Gas (MMcf)*	*CBM Gas (MMcf)*	*NGL (Mstb)*
Opening, December 31, 2008	656	-	119,083	6,306	1,842	346	-	45,228	2,294	634	1,002	-	164,311	8,600	2,476
Drilling activity:															
Extensions and Improved Recovery	150	40	17,847	30	98	312	14	7,982	108	44	462	54	25,829	138	141
A&D:															
Acquisition[2]	-	-	16,660	-	47	-	-	5,750	-	14	-	-	22,410	-	62
Divestiture	-	-	-	(15)	-	-	-	-	(4)	-	-	-	-	(19)	-
Revisions	(161)	272	(17,324)	(574)	(223)	(164)	139	(2,985)	657	104	(325)	411	(20,309)	83	(119)
Production	(90)	(54)	(13,780)	(268)	(290)	-	-	-	-	-	(90)	(54)	(13,780)	(268)	(290)
Closing, December 31, 2009	555	258	122,486	5,479	1,474	494	153	55,975	3,055	796	1,049	411	178,461	8,534	2,270

Notes:

(1) Table prepared by management. Refer to prior table entitled "Summary of Pricing and Inflation Rate Assumptions as of December 31, 2009" for detailed pricing assumptions.

(2) Reserve additions related to farm-ins are classified as acquisitions by GLJ. There were no property acquisitions in 2009.

(3) Columns may not add due to rounding.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves.

ATTRIBUTION HISTORY

	Natural gas				Oil				NGL			
	Proved Undeveloped		Probable Undeveloped		Proved Undeveloped		Probable Undeveloped		Proved Undeveloped		Probable Undeveloped	
	First attributed (Bcf)	Booked (Bcf)	First attributed (Bcf)	Booked (Bcf)	First attributed (Mstb)	Booked (Mstb)	First attributed (Mstb)	Booked (Mstb)	First attributed (Mstb)	Booked (Mstb)	First attributed (Mstb)	Booked (Mstb)
Prior to 2007	56.7	56.7	32.5	32.5	125	125	66	66	131	131	123	123
2007	50.9	93.2	12.7	41.6	57	175	48	108	447	414	87	178
2008	8.2	58.3	4.0	28.1	-	142	-	89	286	503	40	157
2009	24.4	66.9	13.6	40.3	122	219	289	454	93	305	135	343

The increase in both proved and probable undeveloped reserves from 2008 to 2009 relates primarily to the farm-in with an international oil and gas company in the shallow Edmonton Sands gas play.

In the greater Sylvan Lake area of Central Alberta there are a large number of Edmonton Sands natural gas infill locations that have been attributed proved undeveloped reserves by GLJ if there is high confidence net pay at that location and if there is offsetting Edmonton Sands production in an immediately adjacent spacing unit. Recovery factor on the section is used as a final test of reserves assignment quality. Per location undeveloped reserves values are assigned based on average analog decline analysis. Drilling of these undeveloped tracts is ongoing at a financially and operationally sustainable drilling pace of approximately 200 wells per year. This will allow for existing proved undeveloped reserves to be converted into proved developed producing reserves by 2014.

The methodology for assigning Edmonton Sands probable undeveloped reserves to infill locations in the greater Sylvan Lake area is similar to that for proved undeveloped reserves only the net pay assignment may be of median confidence and the productive analog can be up to two drilling spacing units away. Conversion of probable reserves into proved developed producing reserves is also expected to take place up to 2014.

Minor amounts of both proved undeveloped and probable undeveloped reserves are also found in the West Pembina Rock Creek formation and in Coal Bed Methane in the Ghost Pine and Wimborne fields. In the West Pembina Rock Creek formation, natural gas and NGL proved and probable undeveloped reserves are assigned based on the net pay mapping confidence. These locations are scheduled to be drilled in 2010 and 2011. For Coal Bed Methane, the reserves are assigned using a similar methodology to the Edmonton Sands. This development is largely expected to be completed by the end of 2012.

Significant Factors or Uncertainties. The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, geological evaluation, engineering data, prices and economic conditions and were evaluated by GLJ, an independent engineering firm. These factors and assumptions include among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserves estimates can arise from changes in year end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

For additional details of significant economic factors and uncertainties affecting the reserves of Anderson, see “Risk Factors” in this Annual Information Form.

Future Development Costs. The following table sets forth future development costs deducted in the estimation of Anderson's future net revenue attributable to the reserves categories noted below.

	Forecast Prices and Costs	
(in thousands of dollars)	*Proved Reserves*	*Proved Plus Probable Reserves*
2010	24,988	36,041
2011	59,962	75,487
2012	41,076	52,223
2013	42,561	48,095
2014	28,125	45,428
Thereafter	871	2,802
Total (undiscounted)	197,583	260,076
Total (discounted at 10%)	157,164	205,649

Future development costs are associated with reserves as disclosed in the GLJ Report and do not necessarily represent Anderson's exploration and development budget. Anderson expects to fund its future development capital with a combination of internally generated cash flow, periodic issuance of equity and bank debt. Corporate cost of capital has been affected by the recent turbulence in capital markets, but future net revenue discount factors used herein are still considered appropriate.

Planned total capital expenditures for 2010 are $87 million, of which $20 million is directed at horizontal multistage hydraulic fractured wells with no reserves booking to date so it is not incorporated in the GLJ Report.

Oil and Gas Properties and Wells. The following table summarizes the location of the Company's interests in crude oil and natural gas wells which are producing or which the Company considers to be capable of production as at December 31, 2009:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]
Alberta	115	49.6	1	0.1	639	336.8	182	110.1
British Columbia	-	-	-	-	-	-	1	0.7
Total	115	49.6	1	0.1	639	336.8	183	110.8

Notes:

(1) *"Gross"* wells are defined as the total number of wells in which Anderson has an interest.

(2) *"Net"* wells are defined as the aggregate of the numbers obtained by multiplying each gross well by Anderson's working interest therein.

Properties with No Attributed Reserves.

UNDEVELOPED LAND

	Gross Acres	Net Acres
Alberta	121,113	61,168
British Columbia	1,992	822
Total	123,105	61,990

The December 31, 2009 undeveloped land position of Anderson, was estimated at $6.2 million and was valued internally.

Rights to explore, develop and exploit up to 19,839 net acres of undeveloped land holdings with respect to the Company's oil and gas assets could expire by December 31, 2010. The Company may be able to continue these lands by drilling and applying for continuation applications with regulatory agencies.

Forward Contracts. As at December 31, 2009, Anderson was not bound by any agreement (including transportation agreements), directly or indirectly through an aggregator, under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas except for certain gas supply pool agreements with aggregators for approximately 1 MMcfd which will attract a pool price and the following physical fixed price natural gas contracts.

In December 2009, the Company entered into fixed price natural gas contracts to manage commodity price risk. The Company had physical contracts to sell 20,000 GJ per day of natural gas for January, February and March 2010 at an average price of $5.41 per GJ at AECO. This represents approximately 19 MMcfd of natural gas sales for the first quarter of 2010.

Abandonment Costs. The following table sets out Anderson's abandonment costs deducted in the estimation of Anderson's future net revenue attributable to the reserve categories noted below based on forecast prices and costs at December 31, 2009:

	Total Abandonment Costs	
(in thousands of dollars)	*Proved*	*Proved Plus Probable*
2010	800	718
2011	463	370
2012	784	679
2013	1,082	581
2014	1,007	882
Remainder	19,214	25,356
Total	23,350	28,586
Total (discounted at 10% per year)	9,287	8,991

Well abandonment costs are included in the reserves data and were either provided by management of Anderson (and reviewed by GLJ for reasonableness) or estimated by GLJ. Anderson will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of funds from operations of Anderson. The total liability in respect of Anderson's total proved reserves, as at December 31, 2009, represents cost estimates in respect of 718 net wells and associated facilities. The total liability in respect of Anderson's total proved plus probable reserves, as at December 31, 2009, represents cost estimates in respect of 860 net wells and associated facilities.

Tax Horizon. Anderson was not required to pay any cash income taxes for the year ended December 31, 2009. Based on current production, price assumptions in the GLJ Report and budgeted capital spending, interest and general and administrative cost levels, Anderson does not expect to be taxable until 2013 or later.

Costs Incurred. The following table summarizes the costs incurred (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to Anderson's activities for the years ended December 31, 2009 and December 31, 2008:

(in thousands of dollars)	*Year Ended December 31, 2009*	*Year Ended December 31, 2008*
Property acquisition costs		
Unproved properties(1)	173	1,211
Proved properties	(54)	(18,043)
Exploration costs(2)	817	6,194
Development costs(3)	32,049	116,549
Total	32,985	105,911

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(3) Drilling costs for development wells and costs for equipping, tie-in and facilities for all wells.

Exploration and Development Activities. The following table sets forth the gross and net exploratory and development wells in which Anderson participated during the financial years ended December 31, 2009 and December 31, 2008:

December 31, 2009

	Exploratory Wells		*Development Wells*	
	Gross(1)	*Net*(2)	*Gross*(1)	*Net*(2)
Light and Medium Oil	-	-	-	-
Natural Gas	5	4.8	104	77.1
Service	-	-	-	-
Dry	7	6.9	2	0.7
Total	12	11.7	106	77.8

Notes:

(1) *"Gross"* wells are defined as the total number of wells in which Anderson has an interest.

(2) *"Net"* wells are defined as the aggregate of the numbers obtained by multiplying each gross well by Anderson's working interest therein.

December 31, 2008

	Exploratory Wells		*Development Wells*	
	Gross(1)	*Net*(2)	*Gross*(1)	*Net*(2)
Light and Medium Oil	-	-	6	2.9
Natural Gas	9	5.7	187	129.0
Service	-	-	-	-
Dry	3	2.2	12	8.4
Total	12	7.9	205	140.3

Notes:

(1) *"Gross"* wells are defined as the total number of wells in which Anderson has an interest.

(2) *"Net"* wells are defined as the aggregate of the numbers obtained by multiplying each gross well by Anderson's working interest therein.

Production. In the GLJ Report, estimates of 2010 future net revenue in the total proved reserves forecast pricing case are based on 38.8 MMcfd of natural gas production, 417 bpd of oil production and 646 bpd of NGL production. The Central Alberta area represents 37.4 MMcfd of natural gas production, 265 bpd of oil production and 641 bpd of NGL production in the total proved case.

In the total proved plus probable reserves forecast pricing case, the future net revenue estimates are based on 42.3 MMcfd of natural gas production, 530 bpd oil production and 732 bpd of NGL production. The Central Alberta area represents 40.8 MMcfd of natural gas production, 372 bpd of oil production and 727 bpd of NGL production in the total proved plus probable case.

Production History. The following tables summarize certain information in respect of production, prices, royalties, production costs and netbacks, before deduction of royalties, for the periods indicated below:

	Fiscal 2009 Three Months Ended				
	March 31, 2009	*June 30, 2009*	*September 30, 2009*	*December 31, 2009*	*Total*
Average daily production:					
Natural gas (Mcfd)	42,344	40,495	36,282	34,938	38,489
NGL (bpd)	1,005	630	637	906	794
Oil (bpd)	443	410	376	351	395
Combined (BOED)	8,505	7,789	7,060	7,080	7,603
Average price received:					
Natural gas ($/Mcf)	5.15	3.43	2.81	4.28	3.95
NGL ($/bbl)	36.80	42.86	44.70	47.67	42.73
Oil ($/bbl)	42.97	58.42	69.30	69.60	59.26
Combined ($/BOE)*	31.91	24.70	22.50	31.38	27.74
Royalties paid:					
Natural gas and NGL ($/Mcfe)	0.96	0.25	0.13	0.36	0.45
Oil ($/bbl)	6.98	8.83	7.45	6.10	7.22
Combined ($/BOE)	5.79	1.81	1.24	2.66	2.97
Production costs:					
Natural gas and NGL ($/Mcfe)	1.71	1.58	1.22	1.72	1.57
Oil ($/bbl)	15.03	13.31	18.22	14.58	15.19
Combined ($/BOE)	10.81	9.58	7.72	10.49	9.70
Netback received:					
Natural gas and NGL ($/Mcfe)	2.61	1.92	1.91	2.69	2.27
Oil ($/bbl)	20.96	36.28	43.63	48.92	36.85
Combined ($/BOE)	15.31	13.31	13.54	18.23	15.07

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

	Fiscal 2008 Three Months Ended				
	March 31, 2008	*June 30, 2008*	*September 30, 2008*	*December 31, 2008*	*Total*
Average daily production:					
Natural gas (Mcfd)	39,210	39,881	38,703	38,090	38,968
NGL (bpd)	757	829	787	850	806
Oil (bpd)	588	436	434	491	487
Combined (BOED)	7,879	7,912	7,671	7,689	7,787
Average price received:					
Natural gas ($/Mcf)	7.55	10.26	7.86	6.76	8.13
NGL ($/bbl)	78.30	88.21	78.06	44.37	71.78
Oil ($/bbl)	91.13	115.48	112.18	55.63	92.27
Combined ($/BOE)*	52.57	68.08	55.87	42.55	54.82
Royalties paid:					
Natural gas and NGL ($/Mcfe)	1.98	2.43	1.84	1.60	1.96
Oil ($/bbl)	15.30	17.05	17.58	7.72	14.28
Combined ($/BOE)	12.12	14.70	11.43	9.46	11.94
Production costs:					
Natural gas and NGL ($/Mcfe)	1.94	1.91	1.59	1.78	1.82
Oil ($/bbl)	14.90	15.61	15.55	20.45	14.90
Combined ($/BOE)	12.13	11.32	10.10	11.51	11.27
Netback received:					
Natural gas and NGL ($/Mcfe)	4.20	6.42	4.99	3.46	4.85
Oil ($/bbl)	60.93	82.82	79.05	27.46	63.09
Combined ($/BOE)	28.32	42.06	34.34	21.58	31.61

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

The following tables summarize Anderson's average daily production from the material fields comprising Anderson's assets for the years ended December 31, 2009 and December 31, 2008:

December 31, 2009

	Light and Medium Crude Oil and NGL (bpd)	*Natural Gas (Mcfd)*	*Combined (BOED)*
Central Alberta	1,017	36,656	7,126
North Central Alberta	57	1,809	358
Northeast BC	-	-	-
Other	115	24	119
Total	1,189	38,489	7,603

December 31, 2008

	Light and Medium Crude Oil and NGL (bpd)	*Natural Gas (Mcfd)*	*Combined (BOED)*
Central Alberta	1,048	33,935	6,705
North Central Alberta	95	2,775	557
Northeast BC	9	2,110	360
Other	141	148	165
Total	1,293	38,968	7,787

The production from Anderson's oil and gas assets for the year ended December 31, 2009 was 5.2% light and medium quality crude oil, 84.4% natural gas and 10.4% NGL and for the year ended December 31, 2008 was 6.2% light and medium quality crude oil, 83.4% natural gas and 10.4% NGL.

DIVIDENDS

Since inception, the Company has neither declared nor paid any dividends on its common shares. The Company intends to retain its earnings to finance growth and expand its operations and does not anticipate paying any dividends on its common shares in the foreseeable future.

CAPITAL STRUCTURE

Anderson is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares, of which 172,400,401 common shares are issued and outstanding as fully paid and non-assessable shares as at March 30, 2010. The following is a description of the Company's common and preferred shares.

Common Shares. The holders of common shares are entitled to one vote at all meetings of shareholders of Anderson except at meetings of which only holders of a specified class of shares are entitled to vote. Common shareholders are entitled to receive, subject to the prior rights and privileges attaching to any other class of shares of Anderson, such dividends as may be declared by Anderson. Holders of common shares will be entitled upon liquidation, dissolution or winding-up of Anderson, subject to the prior rights and privileges attaching to any other class of shares of Anderson, to receive the remaining property and assets of Anderson.

Preferred Shares. Anderson is authorized to issue an unlimited number of preferred shares, issuable in series. Subject to the provisions of the ABCA, the Board of Directors of Anderson is authorized to fix, before the issue thereof, the designation, rights and privileges, restrictions and conditions attaching thereto. No preferred shares are currently outstanding.

Market for Securities. The outstanding common shares of the Company have been listed and posted for trading on the Toronto Stock Exchange under the symbol "AXL" since September 7, 2005. The following table sets out the high and low prices and average trading volume of common shares as reported by the Toronto Stock Exchange, as applicable, since January 1, 2009, for the periods indicated.

Period	*High*	*Low*	*Average Daily Trading Volume*
2009			
January	1.48	0.97	67,521
February	1.12	0.79	75,544
March	0.93	0.75	148,994
April	0.94	0.65	292,138
May	1.30	0.80	591,082
June	1.15	0.82	1,161,618
July	0.85	0.68	407,499
August	0.87	0.73	565,859
September	1.12	0.73	1,229,726
October	1.18	0.88	802,536
November	1.12	0.96	343,355
December	1.19	0.97	266,433
2010			
January	1.57	1.18	1,135,407
February	1.41	1.21	454,168
March 1 to 30	1.42	1.10	544,459

DIRECTORS AND OFFICERS

Name and Municipality of Residence	*Office Held*	*Principal Occupation for the Last Five Years*	*Director Since*	*Common Shares of Anderson Owned* [4]
J.C. Anderson[2] [3] Calgary, Alberta	Chairman of the Board	Chairman of the Board of Anderson since January 2002	2002	10,500,000
Brian H. Dau [3] Calgary, Alberta	President and Chief Executive Officer and Director	President and Chief Executive Officer of Anderson since February 2002	2002	2,170,038
Christopher L. Fong[1] [2] Calgary, Alberta	Director	Corporate Director since June 2009; Global Head, Corporate Banking, Energy, with RBC Capital Markets until May 2009	2009	-
Glenn D. Hockley[1] [3] Calgary, Alberta	Director	Independent Businessman since 2005; Chairman of the Aquest Board from January 2004 to September 2005	2005	1,603,539
David G. Scobie[1] [2] Calgary, Alberta	Director	Corporate Director since April 2002; Interim Senior Vice President and Chief Financial Officer of Hawker Resources Inc. from November 2004 to March 2005	2002	242,424
David M. Spyker Dewinton, Alberta	Chief Operating Officer	Chief Operating Officer since July 2009, prior thereto Vice President, Business Development of Anderson from February 2002 to July 2009	N/A	402,473
M. Darlene Wong Calgary, Alberta	Vice President, Finance, Chief Financial Officer and Secretary	Vice President, Finance, Chief Financial Officer and Secretary of Anderson since February 2002	N/A	492,054
Blaine M. Chicoine Calgary, Alberta	Vice President, Operations	Vice President, Operations of Anderson since June 2002	N/A	308,199
Philip A. Harvey Cochrane, Alberta	Vice President, Exploitation	Vice President, Exploitation of Anderson since February 2002	N/A	445,443
Daniel F. Kell Calgary, Alberta	Vice President, Land	Vice President, Land of Anderson since February 2002	N/A	431,715

Name and Municipality of Residence	Office Held	Principal Occupation for the Last Five Years	Director Since	Common Shares of Anderson Owned (4)
Jamie A. Marshall Calgary, Alberta	Vice President, Exploration	Vice President, Exploration of Anderson since July 2008, prior thereto Manager, Exploration of Anderson from March 2006 to June 2008, prior thereto Senior Geologist of Anderson from June 2004 to March 2006	N/A	12,744

Notes:

(1) Member of the Audit Committee.
(2) Member of the Compensation and Corporate Governance Committee.
(3) Member of the Reserves Committee.
(4) The term of office of all directors will expire on the date of the next annual meeting of shareholders.
(5) Common shares held as of March 30, 2010.

Corporate Cease Trade Orders or Bankruptcies. Other than as disclosed below, no director or executive officer of Anderson is, as at the date of this Annual Information Form, or has been, within the past 10 years before the date hereof, a director or executive officer of any other issuer that, while that person was acting in that capacity:

(i) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(ii) was subject to an event that resulted, after the person ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(iii) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

J.C. Anderson was a director of Venus Exploration Inc., which was involuntarily petitioned into bankruptcy by its creditors in the United States Bankruptcy Court for the Eastern District of Texas in 2004.

Penalties or Sanctions. None of the directors, officers or insiders of Anderson have been subject to any penalties or sanctions under securities legislation.

Personal Bankruptcies. None of the directors, officers or insiders of Anderson have in the ten years preceding the date of this Annual Information Form become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold their assets.

Conflicts of Interest. There are potential conflicts of interest to which the directors and officers of Anderson will be subject to in connection with the operations of Anderson. In particular, certain of the directors and officers of Anderson are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Anderson or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Anderson. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with Anderson are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of Anderson. Certain of the directors of Anderson have either other employment or other business or time restrictions placed on them and accordingly, these directors of Anderson will only be able to devote part of their time to the affairs of Anderson.

AUDIT COMMITTEE INFORMATION

The Audit Committee of the Board of Directors of Anderson consists of three independent members: David G. Scobie, Chris L. Fong and Glenn D. Hockley.

The responsibilities and duties of the Audit Committee are set out in the Audit Committee's terms of reference which are set forth in Schedule 3 to this Annual Information Form.

The Board of Directors believes that the composition of the Audit Committee reflects a high level of financial literacy and expertise. Each member of the Audit Committee has been determined by the Board to be "independent" and "financially literate" as such terms are defined under Canadian securities laws. The Board has made these determinations based on the education and breadth and depth of experience of each member of the Audit Committee. The following is a description of the education and experience of each member of the Audit Committee that is relevant to the performance of his or her responsibilities as a member of the Audit Committee:

David G. Scobie has a Bachelor of Commerce degree and Chartered Accountant designation and worked as Vice President, Finance or Chief Financial Officer for various public companies from 1980 to 2005.

Chris L. Fong has a degree in Chemical Engineering and is a Professional Engineer. Mr. Fong retired in 2009 from his position as Global Head, Corporate Banking, Energy, with RBC Capital Markets after 28 years of service with the bank.

Glenn D. Hockley has a Master of Science degree majoring in Geology and is a Professional Geologist. Mr. Hockley previously served as Chairman of the Board of Aquest and Chairman, President and Chief Executive Officer of Eravista Energy Corp (a predecessor of Aquest) and has over 36 years of experience in the oil and gas industry.

Through acting in the capacities described above, each of Messrs. Scobie, Fong and Hockley have extensive experience in either overseeing management responsible for preparing financial statements or evaluating and analyzing financial statements.

Auditor Fees. The following summarizes fees earned by the Company's independent auditors, KPMG LLP, for the years ended December 31, 2009 and 2008.

	December 31, 2009	December 31, 2008
Audit fees:		
Audit of the Company's annual consolidated financial statements and review of the Company's interim consolidated financial statements	$ 152,000	$ 162,000
Tax fees:		
Tax consultations	-	1,200
All other fees:		
Fee associated with the adoption of International Financial Reporting Standards	17,000	-
Fees associated with the issuance of shares and French translation services	55,000	-
Total	$ 224,000	$ 163,200

RISK FACTORS

Exploration, Development and Production Risks. Oil and natural gas exploration involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by the Company will result in new discoveries of oil and natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Company will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage, processing or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Need to Replace and Grow Reserves. The future oil and natural gas production of the Company, and therefore future cash flows, are highly dependent upon ongoing success in exploring on the Company's current and future undeveloped land base, exploiting the current producing properties and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted.

There can be no assurance that the Company will be able to find and develop or acquire additional reserves to replace and grow production at acceptable costs.

The business of discovering, developing, or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the ability of the Company to make the necessary capital investments to maintain and expand its oil and natural gas reserves may be impaired.

If Anderson's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to Anderson. Failure to obtain such financing on a timely basis could cause Anderson to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations.

Uncertainty of Reserve Estimates. The reserves and recovery information contained in the GLJ Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the independent estimates of GLJ.

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Company. The reserves and cash flow information set forth herein represent estimates only. The reserves and estimated future net cash flow from the Company's assets have been independently evaluated effective December 31, 2009 by GLJ. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Global Economic Conditions. Recent market events and conditions, including the deterioration of global economic conditions, have caused significant volatility in commodity prices. 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. These conditions impacted 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although conditions showed signs of improvement near the end of 2009, these factors have negatively impacted company valuations and may impact the performance of the global economy going forward.

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

Volatility of Oil and Natural Gas Prices. The operational results and financial condition of the Company will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on the operations, proved reserves and financial conditions of the Company and could result in a reduction of the net production revenue of the Company causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings which might be made available to the Company are typically determined in part by the borrowing base of the reserves of the Company. A sustained material decline in prices from historical average prices could reduce the borrowing base of the Company, therefore reducing the bank credit available to the Company and could require that a portion of such bank debt be repaid.

Substantial Capital Requirements. The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future, including those related to fulfilling its commitments under the farm-in in Central Alberta. 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.

Competition. There is strong competition relating to all aspects of the oil and natural gas industry. The Company will actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than the Company.

Availability of Drilling Equipment and Access. Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted by the Company. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent the Company is not the operator of its oil and gas properties, the Company will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Operational Hazards. Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although the Company will maintain liability insurance, where available, in an amount which it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs that could have a material adverse effect upon its financial condition. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Seasonality. The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather, freeze-up and break-up may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of Anderson.

Title to Assets. Although property title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim on the Company which could result in a reduction of the revenue received by the Company.

Anderson's properties are held in the form of licences and leases and working interests in licences and leases. If Anderson or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of Anderson's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on Anderson's results of operations and business.

Project Risks. The Company manages a variety of small and large projects in the conduct of its business including the drilling and completion of individual wells or groups of wells and construction of facilities required to produce these wells. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic.

The Company's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including without limitation:

- Timely access to surface locations;
- The availability of processing capacity;
- The availability and proximity of pipeline capacity;
- The supply and demand for oil and natural gas;
- The effects of inclement weather;
- The availability of drilling and related equipment;
- Unexpected cost increases;
- Accidental events; and
- The availability, cost and productivity of skilled labor.

Because of these factors, the Company could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Acquisition Risks. The Company intends to continue acquiring oil and natural gas properties. Although the Company performs a review of the acquired properties that the Company believes is consistent with industry practices, it generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, the Company will focus the review efforts on the higher-value properties and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal every existing or potential problem, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Company often assumes certain environmental and other risks and liabilities in connection with acquired properties. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and actual future production rates and associated costs with respect to acquired properties, and actual results may vary substantially from those assumed in the estimates.

Key Personnel. The success of the Company will depend in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on the Company. The Company does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry has historically been intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business.

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

The Government of Alberta implemented a new oil and gas royalty framework effective January 2009. The new framework establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the new framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, 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 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.

The Natural Gas Deep Drilling Program ("NGDDP") began January 1, 2009. This program provides upfront royalty adjustments to new wells. The NGDDP applies to wells producing at a true vertical depth greater than 2,500 metres. The NGDDP will have an escalating royalty credit in line with progressively deeper wells from $625 per metre to a maximum of $3,750 per metre. There are additional benefits for the deepest wells. The NGDDP is a five year program. Any wells spud after December 31, 2013, or any wells that choose the transition option, will not qualify under the program. No royalty adjustments will be granted under the NGDDP after December 31, 2018.

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 royalty 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 and up until March 31, 2011. There is also a new well incentive program that provides a maximum 5% royalty rate for the first 12 months of production from new wells that begin producing oil or natural gas between April 1, 2009 and 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 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 nor the Government of Canada will not adopt new royalty regimes which may render the Company's projects uneconomic or otherwise adversely affect the business of the Company.

Environmental Risks. 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 and which imposes duties to report. The accompanying regulation, the Specified Gas Emitters Regulation, requires mandatory emissions reductions through the use of emissions intensity targets.

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

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

Foreign Exchange Rates and Interest Rates. Substantially all of the Company's petroleum and natural gas sales are denominated in Canadian dollars, however the underlying market prices in Canada are impacted by changes in the exchange rate between the Canadian dollar and United States dollar. Material increases in the value of the Canadian dollar negatively impact the Company's oil and gas revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Company's reserves as determined by independent evaluators.

An increase in interest rates could result in an increase in the amount the Company pays to service debt.

Risk management. From time to time, Anderson may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Anderson will not benefit from such increases. Similarly, from time to time, Anderson may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, Anderson will not benefit from the fluctuating exchange rate. From time to time, the Company may enter into agreements to fix the interest rate charged on its outstanding debt, in order to offset the risk of higher interest expense if market interest rates increase. However, if market interest rates decrease below the level set in such agreements, Anderson will not benefit from such decreases.

To the extent that the Company engages in these risk management activities, there is a credit risk associated with counterparties with which the Company may contract.

Third Party Credit Risk. An additional risk is credit risk for failure of performance by counter-parties. This risk is controlled by an evaluation of the credit risk before contract initiation and ensuring product sales and delivery contracts are made with well-known and financially strong crude oil and natural gas marketers.

The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

Income Taxes. Anderson will file all required income tax returns and believes that it will be in full compliance with the provisions of the Income Tax Act (Canada) and all applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of Anderson, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Financing Requirements. From time to time, Anderson may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase Anderson's debt levels above industry standards. Depending on future exploration and development plans, Anderson may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither Anderson's articles nor its by-laws limit the amount of indebtedness that Anderson may incur. The level of Anderson's indebtedness from time to time, could impair Anderson's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Borrowing. Anderson's lenders will be provided with security over substantially all of the assets of Anderson. If Anderson becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell Anderson's properties. The proceeds of any such sale would be applied to satisfy amounts owed to Anderson's lenders and other creditors and only the remainder, if any, would be available to Anderson.

Recent market events have resulted in significant declines in commodity prices. The available lending limits of the current extendible, revolving term and working capital credit facilities are based on the syndicate's interpretation of the Company's reserves and future commodity prices of which there can be no assurance that the amount of the available bank facility will not decrease at the next scheduled review to be completed on or before July 13, 2010. Management continues to monitor capital and administrative spending and financing opportunities to fund its future prospects and commitments. No financing agreements have been signed nor can it be assured that such agreements will be reached.

Sale of Additional Securities. The Company may issue an unlimited number of additional common shares and other securities in the future to finance its' activities without the approval of shareholders. The Company's Board of Directors has the discretion to set the price and terms of the issuance of any such additional securities and any issuance of additional securities may have a dilutive effect on the holders of common shares.

Insurance. Anderson's involvement in the exploration for and development of oil and natural gas properties may result in Anderson becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although prior to drilling Anderson will obtain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, Anderson may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Anderson. The occurrence of a significant event that Anderson is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Anderson's financial position, results of operations or prospects.

Management of Growth. Anderson may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Anderson to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expend, train and manage its employee base. The inability of Anderson to deal with this growth could have a material adverse impact on its business, operations and prospects.

Accounting Write-Downs as a Result of GAAP. Canadian generally accepted accounting principles ("GAAP") require that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in the financial statements of Anderson. The accounting policies may result in non-cash charges to earnings and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trading price of the common shares of Anderson.

The net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a cost-recovery test which is based in part upon estimated future net cash flow from reserves. If net capitalized costs exceed the future discounted cash flows, Anderson will have to charge the amounts of the excess to earnings. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings.

Goodwill is assessed periodically for impairment and if the fair value of the Company falls below the book value of the equity, there could be a write down of goodwill resulting in a charge against earnings. A goodwill write down of $35.4 million was recorded in 2008.

There may be non-cash charges against earnings as a result of changes in the fair market value of financial instruments. A decrease in the fair market value of the financial instruments as a result of fluctuations in commodity prices and foreign exchange rates may result in a non-cash charge against earnings. Such non-cash charges may be temporary in nature if the fair market value subsequently increases.

REGISTRAR AND TRANSFER AGENT

The registrar and transfer agent for the common shares of Anderson is Valiant Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as discussed herein, there are no material interests, direct or indirect, of directors, executive officers, senior officers, any shareholder of Anderson who beneficially owns, directly or indirectly, more than 10% of the outstanding common shares of Anderson or any known associate or affiliate of such persons, in any transaction within the last three years or in any proposed transaction which has materially affected or would materially affect Anderson.

INTEREST OF EXPERTS

As at the date hereof, the principals of GLJ, the independent reserves evaluator of Anderson, each as a group, beneficially owned less than 1% of the outstanding common shares of Anderson.

The auditors of Anderson are KPMG LLP, Chartered Accountants, Calgary, Alberta. KPMG LLP is independent in accordance with the auditor's rule of professional conduct of the Institute of Chartered Accountants of Alberta.

MATERIAL CONTRACTS

Other than those contracts entered into in the ordinary course of business, Anderson did not enter into any material contracts in the most recently completed financial year and Anderson is not a party to any contracts which would be considered material to the Company that were entered into prior to the most recently completed financial year that are still in effect.

LEGAL PROCEEDINGS

Neither the Company nor any of its properties are subject, nor were subject during the financial year ended December 31, 2009, to any material legal proceeding nor are there any such proceedings known to be contemplated.

ADDITIONAL INFORMATION

Additional information including Directors' and Officers' remuneration and indebtedness, options to acquire common shares and interests of insiders in material transactions (if applicable) is contained in the Management Information Circular and Proxy Statement to be issued by Management relating to the Annual General Meeting of the Shareholders to be held May 13, 2010. Additional financial information is also provided in management's discussion and analysis and the consolidated financial statements of the Company for the year ended December 31, 2009 filed on the Company's website (www.andersonenergy.ca). Copies of these documents have been filed with the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval at www.sedar.com.

SCHEDULE 1

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

FORM 51-101F2

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

To the board of directors of Anderson Energy Ltd. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2009, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)			
			Audited	**Evaluated**	**Reviewed**	Total
GLJ Petroleum Consultants	March 8, 2010	CANADA	-	364,090	-	364,090

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 18, 2010

Original signed by "Neil I. Dell"

Neil I. Dell, P. Eng.
Vice-President

SCHEDULE 2

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

FORM 51-101F3

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

Management of Anderson Energy Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) “Brian H. Dau”

Brian H. Dau
President and Chief Executive Officer

(signed) “Philip A. Harvey”

Philip A. Harvey
Vice President, Exploitation

(signed) “J.C. Anderson”

J. C. Anderson
Director

(signed) “Glenn D. Hockley”

Glenn D. Hockley
Director

March 30, 2010

SCHEDULE 3

AUDIT COMMITTEE TERMS OF REFERENCE

Terms of Reference

1. Establishment of Audit Committee

The board of directors (the "Board") of Anderson Energy Ltd. ("Anderson") hereby establishes a committee to be called the Audit Committee.

2. Composition of Audit Committee

The membership of the Audit Committee shall be as follows:

(a) The Audit Committee shall be composed of not less than three members or such greater number as the Board may from time to time determine.

(b) All members of the Audit Committee shall be independent within the meaning set forth under Multilateral Instrument 52-110 *Audit Committees* as amended from time to time ("MI 52-110"). Currently, a member of the Audit Committee is independent if the member has no direct or indirect material relationship with Anderson. A "material relationship" means a relationship which could, in the view of the Board, reasonably interfere with the exercise of a member's independent judgment.

(c) Each member of the Audit Committee shall be financially literate within the meaning set forth under MI 52-110. Currently, "financially literate" means the ability to read and understand a set of financial statements that present the breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can be reasonably expected to be raised by Anderson's financial statements. An Audit Committee member who is not financially literate may be appointed to the Audit Committee provided that the member becomes financially literate within a reasonable period of time following his or her appointment.

(d) Members shall be appointed annually by the Board from among directors of Anderson. The Chair of the Audit Committee shall be appointed by the Board. A member of the Audit Committee shall *ipso facto* cease to be a member of the Audit Committee upon ceasing to be a director of Anderson.

3. Relationship with External Auditors

The Audit Committee shall advise the external auditors of their accountability to the Audit Committee and the Board as representatives of the shareholders of Anderson to whom the external auditors are ultimately accountable. The external auditors of Anderson shall report directly to the Audit Committee.

4. Duties and Responsibilities of Audit Committee

Subject to the powers and duties of the Board and in addition to any other duties and responsibilities assigned to the Audit Committee from time to time by the Board, the Audit Committee shall have the following duties and responsibilities:

Financial Statements and Other Financial Information

(a) The primary responsibility of the Audit Committee shall be to assist the Board in the proper discharge of its duties and responsibilities to Anderson relating to the review of:

(i) Anderson's financial statements;

(ii) any other financial information relating to Anderson to be provided to shareholders; and

(iii) all audit processes.

The Audit Committee shall also be responsible for ensuring its compliance with all of the applicable requirements of MI 52-110 and for reporting any non-compliance with such requirements to the Board, including the reasons for such non-compliance.

(b) The Audit Committee shall be responsible for reviewing Anderson's financial statements, management's discussion and analysis and annual and interim earnings press releases before Anderson publicly discloses this information. The Audit Committee shall recommend for approval to the Board Anderson's audited annual financial statements, related management's discussion and analysis and annual earnings press releases. The Audit Committee shall approve on behalf of the Board Anderson's interim financial statements and related management's discussion and analysis and interim earnings press releases.

(c) The Audit Committee shall be responsible for ensuring that adequate procedures are in place for the review of Anderson's public disclosure of financial information extracted or derived from Anderson's financial statements, other than the public disclosure referred to in paragraph (b) above and must periodically assess the adequacy of those procedures.

(d) The Audit Committee shall be responsible for establishing procedures for:

(i) the receipt, retention and treatment of complaints received by Anderson regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of Anderson of concerns regarding questionable accounting or auditing matters.

(e) The Audit Committee shall review with the external auditors of Anderson:

(i) the scope of the audit;

(ii) significant changes to Anderson's accounting principles, practices or policies;

(iii) new or pending developments in accounting principles, reporting matters or industry practices which may materially affect Anderson; and

(iv) the quality of Anderson's accounting principles, practices or policies as applied in Anderson's financial statements in terms of disclosure quality and evaluation methods, including the degree of conservatism or aggressiveness of such accounting principles, practices or policies and the underlying estimates and other significant decisions made by management of Anderson in preparing Anderson's financial statements.

(f) The Audit Committee shall review with the external auditors of Anderson and/or management of Anderson the results of the annual audit, and make appropriate recommendations to the Board having regard to, among other things:

  (i) the financial statements;

  (ii) management's discussion and analysis and related financial disclosure contained in continuous disclosure documents;

  (iii) significant changes, if any, to the initial audit plan;

  (iv) accounting and reporting decisions relating to significant current year events and transactions;

  (v) the management letter, if any, outlining the external auditors' findings and recommendations, together with management's response, with respect to internal controls and accounting procedures; and

  (vi) any other matters relating to the conduct of the audit, including such other matters which should be communicated to the Audit Committee under generally accepted auditing standards.

(g) The Audit Committee shall review with management of Anderson and, if requested by the Audit Committee, the external auditors of Anderson, the interim financial statements and any other matters relating thereto.

Adoption and Periodic Assessment of Formal Terms of Reference

(h) The Audit Committee shall be responsible for adopting formal written terms of reference which sets out its mandate and responsibilities. The terms of reference must be approved by the Board. The Audit Committee shall review and assess the adequacy of the terms of reference on an annual basis and recommend for approval to the Board any amendments thereto.

External Auditors

(i) The Audit Committee must recommend to the Board:

  (i) the external auditors to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for Anderson; and

  (ii) the compensation of the external auditors.

(j) The Audit Committee shall be directly responsible for overseeing the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for Anderson, including the resolution of disagreements between management of Anderson and the external auditors regarding financial reporting.

Pre-Approval of Non-Audit Services

(k) The Audit Committee shall be responsible for pre-approving all types of non-audit services to be provided to Anderson or its subsidiary entities by Anderson's external auditors. The Audit Committee shall adopt specific policies and procedures for the engagement of non-audit services and any pre-approval policies and procedures shall be detailed as to the particular service and require that the Audit Committee be informed of each type of non-audit service. Such policies and procedures shall not include delegation of the Audit Committee's responsibilities to management of Anderson. The Audit Committee may delegate to one or more independent members the authority to pre-approve non-audit services. The pre-approval of non-audit services by any member of the Audit Committee to whom authority has been delegated must be presented to the Audit Committee at its first scheduled meeting following such pre-approval.

Reporting Obligations

(l) The Audit Committee shall be responsible for reviewing the disclosure contained in Anderson's annual information form as required by Form 52-110F1 *Audit Committee Information Required in an AIF* attached to MI 52-110. If management of Anderson solicits proxies from shareholders of Anderson for the purpose of recommending persons to be elected as directors of Anderson, the Audit Committee shall be responsible for ensuring that Anderson's information circular includes a cross-reference to the sections in Anderson's annual information form that contain the information required by Form 52-110F1.

Auditor Oversight and Independence

(m) The Audit Committee shall be responsible for:

(i) ensuring compliance by Anderson's external auditors with the requirements set forth in National Instrument 52-108 *Auditor Oversight*;

(ii) ensuring that Anderson's external auditors are participants in good standing with the Canadian Public Accountability Board ("CPAB") and participate in the oversight programs established by the CPAB from time to time and that the external auditors have complied with any restrictions or sanctions imposed by the CPAB as of the date of the applicable auditor's report relating to Anderson's annual audited financial statements; and

(iii) obtaining from the external auditors of Anderson a formal written statement describing in detail all of the relationships between the external auditors and Anderson, determining whether the non-audit services performed by the external auditors during the year have impacted their independence, ensuring that no relationship between the external auditors and Anderson exists which may affect the independence of the external auditors and taking appropriate action to ensure the independence of the external auditors.

Authority of the Audit Committee

(n) The Audit Committee shall have the authority:

(i) to engage independent counsel and other advisors as it determines necessary to carry out its duties;

(ii) to set and pay the compensation for any advisors employed by the Audit Committee; and

(iii) to communicate directly with the internal (if any) and external auditors of Anderson.

Internal Controls, Information Systems and Risk Management

(o) The Audit Committee shall review with the external auditors of Anderson the adequacy of internal control procedures and management information systems and make inquiries to management of Anderson and the external auditors of Anderson about significant risks and exposures to Anderson that may have a material adverse impact on Anderson's financial statements and about the efforts of the management of Anderson to mitigate such risks and exposures.

Supervision of Certification of Annual Filings and Interim Filings

(p) The Audit Committee shall be responsible for supervising the preparation and filing of each annual certificate in Form 52-109F1 and each interim certificate in Form 52-109F2 to be signed by each of the Chief Executive Officer and Chief Financial Officer of Anderson in accordance with the requirements set forth under Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings* as amended from time to time ("MI 52-109"). These certificates require each of the Chief Executive Officer and the Chief Financial Officer of Anderson to certify, among other things, that, based on their knowledge:

(i) the annual filings and interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made with respect to the period covered by the annual filings or interim filings; and

(ii) the annual financial statements and the interim financial statements of Anderson, together with the other financial information included in the annual filings or interim filings, fairly present in all material respects the financial condition, results of operations and cash flows of Anderson as of the date and for the periods presented in the annual filings or interim filings.

(q) The Audit Committee is responsible for ensuring that management of Anderson establishes and maintains disclosure controls and procedures for Anderson that are designed to provide reasonable assurance that material information relating to Anderson, including its consolidated subsidiaries, is made known to management of Anderson by others within those entities, particularly during the period in which the annual filings or interim filings are being prepared and that management of Anderson establishes and maintains internal control over financial reporting for Anderson that has been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Anderson's generally accepted accounting principles. The Audit Committee is also responsible for ensuring that management of the Corporation evaluates the effectiveness of Anderson's disclosure controls and procedures as of the end of the period covered by the annual filings and has caused Anderson to disclose in the annual management's discussion and analysis its conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation. The terms "annual filings," "interim filings," "disclosure controls and procedures" and "internal control over financial reporting" shall have the meanings set forth under MI 52-109.

(r) The Audit Committee is also responsible for monitoring any changes in Anderson's internal control over financial reporting and for ensuring that any change that occurred during Anderson's most recent interim period that has materially affected, or is reasonably likely to materially affect, Anderson's internal control over financial reporting is disclosed in Anderson's annual management's discussion and analysis.

Other

(s) The Audit Committee must review and approve Anderson's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of Anderson.

(t) The Audit Committee shall monitor policies and procedures relating to directors' and officers' expenses and the reimbursement thereof and relating to any prerequisites paid to directors and officers.

5. Administrative Matters

The following general provisions shall have application to the Audit Committee:

(a) A quorum of the Audit Committee shall be the attendance of a majority of members thereof present in person or by telephone. No business may be transacted by the Audit Committee except at a meeting of its members at which a quorum of the Audit Committee is present or by a resolution in writing signed by all the members of the Audit Committee. Meetings of the Audit Committee shall be held at least quarterly and more often as the Chair of the Audit Committee may determine or upon the request of the Board, a member of the Audit Committee, an officer of Anderson or the external auditors of Anderson.

(b) Any member of the Audit Committee may be removed or replaced at any time by resolution of the Board. The Board, upon recommendation of the Corporate Governance Committee, may fill vacancies on the Audit Committee by appointment from among the members of the Board. If and whenever a vacancy shall exist on the Audit Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Audit Committee shall hold such office until the close of the annual meeting of shareholders of Anderson next following the date of appointment as a member of the Audit Committee or until a successor is duly appointed. Any member of the Board who has served as a member of the Audit Committee may be re-appointed as a member of the Audit Committee following the expiration of his or her term.

(c) The Audit Committee may invite such officers, directors and employees of Anderson and its subsidiary entities as it may see fit from time to time to attend at meetings of the Audit Committee and to assist thereat in the discussion of matters being considered by the Audit Committee. The external auditors of Anderson shall appear before the Audit Committee when requested to do so by the Audit Committee. The Audit Committee shall meet with the external auditors of Anderson independent of management of Anderson at least annually and at such other times as the Chair of the Audit Committee may determine or upon the request of a member of the Audit Committee or the external auditors of Anderson.

(d) The time at which and the place where the meetings of the Audit Committee shall be held, the calling of meetings and the procedure at such meetings shall be determined by the Audit Committee, having regard to the by-laws of Anderson. Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee and to the external auditors of Anderson who shall be entitled to attend and to be heard at each meeting of the Audit Committee. A meeting of the Audit Committee may be held at any time without notice if all of the members are present or, if any members are absent, those absent have waived notice or otherwise signified their consent in writing to the meeting being held in their absence.

(e) The Chair shall preside at all meetings of the Audit Committee. In the absence of the Chair, the other members of the Audit Committee shall appoint one of their members to act as Chair for the particular meeting.

(f) The Audit Committee shall report to the Board on such matters and questions relating to the financial position of Anderson and its subsidiary entities as the Board may from time to time refer to the Audit Committee.

(g) The members of the Audit Committee shall, for the purpose of performing their duties, have the right to inspect all the books and records of Anderson and its subsidiary entities and to discuss such books and records that are in any way related to the financial position of Anderson and its subsidiary entities with the officers, directors and employees of Anderson and its subsidiary entities and with the external auditor of Anderson.

(h) The Chair of each meeting of the Audit Committee shall appoint a person to act as recording secretary to keep the minutes of the meeting. The recording secretary need not be a member of the Audit Committee.

(i) Minutes of the Audit Committee will be recorded and maintained and signed by the Chair and the secretary of the meeting. The Chair of the Audit Committee will report to the Board on the activities of the Audit Committee and/or the minutes will promptly be circulated to the members of the Board who are not members of the Audit Committee or otherwise made available at the next meeting of the Board.

(j) Unless the Audit Committee has been provided with express instructions from the Board, the Audit Committee shall function primarily to make assessments and determinations with respect to the purposes mandated herein and its decisions shall serve as recommendations for consideration by the Board.