



**Annual Information Form**  
**For the Year Ended December 31, 2009**

**March 31, 2010**

## TABLE OF CONTENTS

	Page
DEFINITIONS.....	1
CONVENTIONS.....	2
ABBREVIATIONS.....	2
EQUIVALENCIES.....	2
FORWARD-LOOKING STATEMENTS.....	3
NON-GAAP MEASURES.....	6
CORPORATE STRUCTURE.....	6
GENERAL DEVELOPMENT OF THE BUSINESS.....	7
DESCRIPTION OF THE BUSINESS.....	11
PROFORMA STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION.....	17
DIVIDENDS.....	19
DESCRIPTION OF CAPITAL STRUCTURE.....	20
MARKET FOR SECURITIES.....	20
PRIOR SALES.....	20
ESCROW AND TRANSFER RESTRICTIONS ON SECURITIES.....	21
DIRECTORS AND OFFICERS.....	21
AUDIT COMMITTEE.....	25
INDUSTRY CONDITIONS.....	26
RISK FACTORS.....	32
LEGAL PROCEEDINGS AND REGULATORY ACTIONS.....	40
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS.....	40
AUDITORS, TRANSFER AGENTS AND REGISTRARS.....	40
MATERIAL CONTRACTS.....	40
INTERESTS OF EXPERTS.....	41
ADDITIONAL INFORMATION.....	41
APPENDIX A ANGLE ENERGY INC. (THE “COMPANY”) AUDIT COMMITTEE MANDATE.....	A-1
APPENDIX B FORM 51-101F1 STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION.....	B-1
APPENDIX C FORM 51-101F2 REPORT OF RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR.....	C-1
APPENDIX D FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION.....	D-1
APPENDIX E CERTAIN STONEFIRE RESERVES DATA AND FINANCIAL INFORMATION.....	E-1

## DEFINITIONS

In this AIF the terms set forth below have the following meanings, unless the context requires or indicates otherwise:

“**ABCA**” means the *Business Corporations Act* (Alberta) R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

“**AECO**” means the natural gas delivery point in Southeast Alberta;

“**Affiliate**” has the meaning as set forth in the *Securities Act* (Alberta) R.S.A. 2000, c. S-4, as amended;

“**AIF**” means this annual information form;

“**Angle Energy**” or “**Company**” means Angle Energy Inc., a corporation governed by the laws of Alberta;

“**ARI**” means Angle Resources Inc., a wholly-owned subsidiary of the Company governed by the laws of Alberta;

“**API**” means American Petroleum Institute;

“**board**” or “**board of directors**” means the board of directors of Angle Energy;

“**COGE Handbook**” means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

“**common shares**” means common shares in the capital of Angle Energy Inc.;

“**Crown**” means the Government of Alberta;

“**ExxonMobil**” means ExxonMobil Canada Energy;

“**GAAP**” means Canadian generally accepted accounting principles;

“**GLJ**” means GLJ Petroleum Consultants Ltd.;

“**GLJ Report**” means the independent engineering report dated March 15, 2010 and prepared by GLJ on March 10, 2010, evaluating the crude oil, natural gas and NGLs reserves of the Company effective as of December 31, 2009;

“**GLJ Stonefire Report**” means the independent engineering report dated March 15, 2010 and prepared by GLJ on March 10, 2010, evaluating the crude oil, natural gas and NGLs reserves of Stonefire Energy Corp. effective as of December 31, 2009;

“**Harmattan Farm-in Agreement**” means the agreement dated April 9, 2005 between the Company and ExxonMobil;

“**IPO**” means the initial public offering completed by the Company on June 30, 2008;

“**NI 51-101**” means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*;

“**NI 52-110**” means National Instrument 52-110 – *Audit Committees*;

“**Normal Course Issuer Bid**” means the normal course issuer bid of the Company established on September 24, 2008 and terminated on September 23, 2009, which permitted the Company to purchase up to 2,997,700 common shares of the Company on the market subject to the rules of the TSX;

“**NRF**” means the New Royalty Framework announced by the Alberta government on October 25, 2007;

“**SEDAR**” means the System for Electronic Document Analysis and Retrieval;

“**Securities Act**” means the *Securities Act* (Alberta), R.S.A. 2000, c. S-4, as amended;

“**Stonefire**” means Stonefire Energy Corp., a wholly-owned subsidiary of the Company governed by the laws of Alberta;

“**Tax Act**” means the *Income Tax Act* (Canada) R.S.C. 1985, c.1 (5th Supp.);

“**TSX**” means the Toronto Stock Exchange;

“**United States**” or “**U.S.**” means the United States of America and includes its territories and possessions; and

“**WTI**” means West Texas Intermediate crude oil.

### CONVENTIONS

Certain other terms used but not defined in this AIF are defined in NI 51-101 and, unless the context otherwise requires, have the same meanings as ascribed to them in NI 51-101. Unless otherwise indicated, references in this AIF to “\$” or “dollars” are to Canadian dollars. All financial information with respect to the Company has been presented in Canadian dollars in accordance with GAAP.

### ABBREVIATIONS

The following abbreviations are used in this AIF.

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	One barrel equalling 34.972 Imperial gallons or 42 U.S. gallons	bcf	Billion cubic feet
		bcfe	Billion cubic feet equivalent
bbl/d	Barrels per day	m <sup>3</sup> /day	Cubic metres per day
boe	Barrels of oil equivalent	mcf	Thousand cubic feet
boe/d	Barrels of oil equivalent per day	mcf	Thousand cubic feet equivalent
mboe	Thousand barrels of oil equivalent	mcf/d	Thousand cubic feet per day
mmboe	Million barrels of oil equivalent	mmcf	Million cubic feet equivalent
mdbl	Thousand barrels	mmcf	Million cubic feet
mmdbl	Million barrels	mmcf/d	Million cubic feet per day
NGLs	Natural gas liquids, consisting of any one or more of ethane, propane, butane and condensate	mmbtu	Million British Thermal Units
		GJ/d	Gigajoules per day

**The use of the boe unit of measurement may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

### EQUIVALENCIES

To Convert From	To	Multiply by
Thousand cubic feet	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Barrels	Cubic metres	0.159

<b>To Convert From</b>	<b>To</b>	<b>Multiply by</b>
Cubic metres	Barrels	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
Gigajoules	Thousand cubic feet	1.055

### **FORWARD-LOOKING STATEMENTS**

Certain statements contained in this AIF constitute forward-looking statements. Forward-looking information is often, but not always, identified by the use of words such as “anticipate”, “believe”, “could”, “estimate”, “expect”, “forecast”, “guidance”, “intend”, “may”, “plan”, “predict”, “project”, “should”, “target”, “will”, or similar words suggesting future outcomes or language suggesting an outlook. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company’s presentation of forward-looking information is based on internally generated budgets relating to drilling plans and related costs, expected results from drilling as well as estimated royalties, operating costs and administrative expenses. Angle Energy bases the commodity pricing for budget purposes on a range of publicly available pricing forecasts and also considers general economic conditions. Management believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct. Such forward-looking statements should not be unduly relied upon.

In particular, this AIF contains forward-looking statements pertaining to the following:

#### *Production and Sales Rates*

During 2010, Angle Energy expects that production and sales of natural gas, NGLs and light crude oil will average between 9,300 and 9,500 boe/d. There are many factors that could result in production levels being less than anticipated, including: greater than anticipated declines in existing production due to poor reservoir performance, mechanical failures or inability to access production facilities; the unanticipated encroachment of water or other fluids into the producing formation; and, the inability to drill, complete and tie-in wells on schedule due to a lack of oilfield services being available on a cost efficient basis, poor weather, the inability to negotiate surface access with the landowners, or regulatory delays in obtaining all necessary drilling and production approvals.

#### *Production Mix*

The Company anticipates that its 2010 product volume mix will be approximately 67% natural gas, 28% NGLs and 5% light crude oil. This product volume mix differs from that realized in 2009 due to expected increased production from the Lone Pine Creek area, which has lower NGLs recoveries from the raw gas produced. This expectation may not be met if the wells are not drilled when expected (see “Drilling Program” below) or if the wells do not produce as expected (see “Production and Sales Rates” above).

#### *Commodity Prices*

For purposes of its forecast for 2010, the Company has assumed that the natural gas price at AECO for spot delivery will average \$5.50/mcf and that the crude oil price will average \$70/bbl Edmonton Par. There are many risks that may result in commodity prices being less than expected. The price of natural gas in North America is primarily related to the domestic supply and demand equation. Demand is primarily affected by heating requirements in winter and cooling requirements in summer, with warm winters and/or cool summers having a negative demand

influence. Supplies are generally domestic and respond to prices, but an increase in the deliverability of global NGLs into the North American market can also, at times, influence the supply situation.

The price of crude oil is set in U.S. dollars on the world market and is influenced by global supply and demand factors as well as exogenous events, such as terrorist activity in oil exporting countries. The current slowdown in economic growth due to recession in several of the world's major economies could further reduce both the demand and price for crude oil.

Canadian producers realize a Canadian dollar price for natural gas, NGLs and crude oil, all of which are determined in large part by the U.S. dollar price for such products adjusted for the U.S. to Canadian dollar exchange rate. The exchange rate is influenced by many factors, which have and will continue to result in high volatility.

#### *Royalty Rates*

Angle Energy expects that royalty rates during 2010 will average in the range of 25% to 27% of gross revenue, before realized or unrealized derivative gains or losses. This royalty rate expectation has resulted from the Company's view on commodity prices and increased sales from Crown lands. Total royalties are the combination of Crown royalties paid on Crown lands and freehold royalties paid on freehold lands. In addition, gross overriding royalties are payable on lands in which the Company has earned an interest by way of farm-in, whether the lands are Crown or freehold. Total royalties payable are a function of the mix between Crown and freehold lands as the rates are different.

The Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta. For new wells drilled between April 1, 2009 and March 31, 2011 on Crown lands, the program provides a credit of \$200 per metre drilled and caps royalties at 5% for the first 12 months of production up to a maximum of 500 mmcf of natural gas or 50 mbbbls of oil. As a result of the Government of Alberta's response to the recently released Competitiveness Review, this incentive will be made permanent as of January 1, 2011. The Government of Alberta also committed to reduce conventional oil and gas royalties from 50% to 40%, and from 50% to 36%, respectively. The complete royalty curves have not yet been released, and the Government of Alberta also indicated that it may make additional natural gas royalty changes as it completes its response to the Competitiveness Review. The Company will continue to monitor any further amendments to the incentive program and will update its plans as required. For a more detailed discussion of royalty rates, please refer to the section entitled "Industry Conditions".

#### *Operating Costs*

The Company expects operating and transportation costs to average in the range of \$5.80 to \$5.90/boe for 2010. Operating costs in the Lone Pine Creek area are expected to be higher than in the Harmattan and Ferrier areas, and as production from Lone Pine Creek grows in proportion to the Company's total, the blended operating costs are expected to increase.

Risks to operating cost increases relate to general oilfield service costs, which tend to increase in periods of high industry activity and decrease as activity levels decline.

#### *General and Administrative ("G&A") Costs*

Angle Energy anticipates that G&A expenses for 2010 will be approximately \$1.85 to \$1.95/boe, net of capitalized amounts. Risks that G&A costs will exceed this amount relate to higher than expected employee costs necessarily incurred by the Company to retain key employees in a competitive market, the need to hire more staff than originally anticipated and general cost inflation.

#### *Capital Expenditures*

Angle Energy expects to incur between \$101 million and \$107 million for capital expenditures in 2010, excluding the acquisition of Stonefire that was completed January 12, 2010, any potential future acquisition activity and the impact of the Crown drilling credit incentive program. Angle Energy's capital expenditures will consist of costs for drilling, completions, equipment, tie-ins, land and seismic. This is based on the assumption that the Company drills

33 gross wells during the year. The capital program during 2010 is flexible, depending on commodity prices and any changes to the Crown royalty incentive programs. Increases in capital costs from budgeted amounts can occur for the following reasons: general cost inflation in the industry resulting from high utilization rates; poor weather that can delay activity and subject the Company to stand-by charges; and problems encountered in drilling a well that can result in additional drilling time or, in some cases, losing the well entirely.

#### *Drilling Program*

The Company expects to drill 33 gross wells during 2010. The drilling program is a key assumption in the production estimates for the period discussed above. The risk that Angle Energy will not meet its drilling targets is attributable to the following: lack of access to drilling rigs and related equipment at sites; delays in obtaining landowner consent for surface access; and, delays in obtaining well licences and drilling permits.

#### *Drilling Success*

During 2010, the Company expects to add reserves from its drilling activities. In arriving at such expectations, Angle Energy undertakes a risking process where each well is assigned a probability of success and the expected reserves that would be added in a success case. The basis for such assessment is a combination of geological, geophysical and reservoir engineering analysis, including reviewing analog reserves in the area of interest. There are many risks that a well may not add the reserves anticipated, including: poor reservoir rock due to low permeability and/or low porosity that inhibits production; the non-existence of the targeted zone due to erosion; the lack of an effective reservoir seal, preventing the migration of hydrocarbons; presence of water in the zone; damage to the zone from the drilling process; and, competitive drainage from offsetting acreage not owned by the Company.

#### *Developing Future Prospects*

Angle Energy intends to continue generating and developing its own prospects and acquiring lands directly, as well as through farm-ins, as part of its business strategy. To do so requires that appealing opportunities become available within the timeframe suitable to the Company, that Angle Energy has the necessary human and financial resources to pursue and capture such opportunities, and that the Company is able to prevail over its competitors pursuing the same projects. Risks in achieving such growth plans relate to a lack of adequate staffing or capital, or to an overly competitive market where other industry participants are prepared to pay more for a prospect than what Angle Energy would consider prudent.

#### *Tax Horizon*

Angle Energy should not become taxable during 2010 based on the foregoing assumptions. Liability for current income tax is a function of the amount of revenue and expenses recognized for tax purposes, including deductions for capital expenditures. As such, taxable income is affected by many factors, including production levels, commodity prices and the level and classification for tax purposes of capital spending into one of several categories with each being deductible at different rates. The liability for current income tax could be higher than expected if revenues exceed Angle Energy's budget, if capital spending is lower than expected, or if a greater proportion of capital spending is allocated to a lower deduction category.

#### *Market Conditions*

Management is aware that equity market conditions may not always be conducive to raising funds through treasury issues of common shares. However, the Company has the financial capability to continue its 2010 capital program through funds from operations and available credit under the existing bank line without the need to access capital markets.

#### *General*

Statements relating to reserves are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future. For more information see Appendix B – *Statement of Reserves Data and Other Oil and Gas Information*.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors and assumptions set forth above and elsewhere in this AIF.

Undue reliance should not be placed on forward-looking statements. Such statements are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward-looking statements will not occur. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will in fact be realized. Actual results will differ, and the difference may be material and adverse to the Company and its shareholders.

**These factors should not be considered exhaustive. The reader is cautioned that these factors and risks are difficult to predict and that the assumptions used in the preparation of such information, although considered reasonably accurate at the time of preparation, may prove to be incorrect. Accordingly, readers are cautioned that the actual results achieved by the Company will vary from the information provided herein and the variations may be material. Consequently, there are no representations by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained in this AIF are made as of the date hereof, and the Company undertakes no obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.**

#### NON-GAAP MEASURES

In this annual information form there are references to the terms “netbacks”, “funds from operations”, “funds from operations per share”, “net debt” and “cash operating costs”, which are not recognized measures under Canadian GAAP. Angle Energy uses these measures to help evaluate its performance. Management considers that netbacks are an important measure as they demonstrate the Company’s profitability relative to current commodity prices. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates Angle Energy’s ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations has been defined by Angle Energy as net earnings plus the addition back of certain non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized gains/losses on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations and reclamation. Angle Energy also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Angle Energy’s determination of funds from operations may not be comparable to that reported by other companies nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. Angle Energy defines net debt as the sum of long term debt plus working capital, excluding risk management assets/liabilities and the related income tax effect. Net debt is used by Angle Energy’s management to monitor remaining availability under its credit facilities. Cash operating costs have been defined as the sum of operating expenses, transportation expenses, general and administrative and interest expenses.

For more information, see the Company’s management’s discussion and analysis of financial condition and results of operations for the year ended December 31, 2009, which includes a definition of “funds from operations” and reconciliation to cash provided by operating activities.

#### CORPORATE STRUCTURE

The Company was incorporated under the ABCA on January 23, 2004 under the name 1087577 Alberta Ltd. The Company changed its name to Angle Energy Inc. on March 26, 2004. On June 15, 2004, the Company amended its articles to create an unlimited number of preferred shares, issuable in series and to delete the share transfer restrictions. No amendments to the articles of the Company occurred in 2009.

The Company’s head office is located at Suite 700, 324 - 8<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 2Z2 and its registered and records office is located at Suite 2500, 450 - 1<sup>st</sup> Street S.W., Calgary, Alberta, T2P 5H1.

Angle Energy has a wholly-owned subsidiary named Angle Resources Inc. (“**ARI**”), which was incorporated in Alberta on July 8, 2008. Angle Energy and ARI entered into a partnership agreement, effective October 1, 2008, to form Angle Energy Partnership, a general partnership created under the laws of the Province of Alberta. On January 12, 2010, Angle Energy acquired all of the issued and outstanding Class A shares and Class B shares of Stonefire, pursuant to a take-over bid and subsequent compulsory acquisition. Stonefire also became a partner of Angle Energy Partnership on January 12, 2010. On March 31, 2010, Angle Energy wound-up Stonefire pursuant to the provisions of the ABCA. Angle Energy has no subsidiaries other than those noted above.

## GENERAL DEVELOPMENT OF THE BUSINESS

### History and Recent Developments

The Company was incorporated in 2004 as a “blind pool start up” which possessed no assets, other than an experienced senior management team.

The following table summarizes the growth of the business over the past six years.

Period	Equity Offerings \$ million <sup>(1)</sup>	Capital Expenditures \$ million	Wells Drilled		Average Production boe/d	Funds From Operations \$ million <sup>(2)</sup>
			Gross	Net		
2004	14.8	0.8	Nil	Nil	Nil	(0.3)
2005	30.3	25.2	9	8.0	14	(0.6)
2006	25.0	57.8	22	18.7	1,281	8.0
2007	8.9	59.1	19	16.6	3,334	29.7
2008	36.3	79.9	24	20.9	6,586	69.8
2009	76.4	64.6	13	11.9	7,528	40.2

#### Notes

- (1) Gross proceeds before share issue expense and all tax effects and includes common share purchases under the Normal Course Issuer Bid.
- (2) “Funds From Operations” is a non-GAAP measurement.

Initial equity was raised in June 2004 through a private placement for gross proceeds of approximately \$14.8 million. After this initial capitalization, the Company was the successful bidder to farm-in on specific ExxonMobil freehold lands in the Harmattan area of southwestern Alberta. The Harmattan Farm-in Agreement was signed in April 2005 and five commitment wells were drilled. After initial success at these wells and at a sixth well drilled on Crown land, a second equity financing was completed in 2005 for gross proceeds of approximately \$30.3 million. These funds were used to continue drilling on the Harmattan farm-in lands as well as on additional lands purchased in Crown sales. At the end of 2005, the Company was producing 35 boe/d from one well in the Harmattan area.

A number of pipeline tie-ins were completed in early 2006 to increase the Company’s production to over 700 boe/d from four wells in the Harmattan area. Subsequent financings in 2006 for gross proceeds of approximately \$25 million were completed to fund drilling, completion and pipeline construction for the ongoing program in Harmattan and the initial program in Ferrier. By the end of 2006, the Company had drilled 31 gross (26.7 net) wells and was producing in excess of 3,500 boe/d from 11 wells in Harmattan with 11 wells to tie-in.

The Company went on to drill 19 gross (16.6 net) wells in 2007, bringing the corporate total to 50 gross wells drilled (43.3 net) since inception. Production averaged 3,334 boe/d in 2007. The Company exited the year at a stable rate of 4,800 boe/d from 28 wells, with 80% of production coming from the Harmattan area and 20% of production attributed to the Ferrier area. Significant branch pipelines in both Harmattan and Ferrier were constructed in 2007 at 100% working interest, allowing for production control and efficient tie-in cycle times of less than 90 days on average for subsequent drilling. These pipelines cost approximately \$7 million, representing 13% of overall capital expenditures in 2007. The Company completed an equity financing in December 2007 for gross proceeds of approximately \$8.9 million to maintain a debt to cash flow ratio of less than 1.0.

During 2008 the Company drilled 24 gross (20.9 net) wells at an average working interest of 87% at a 74% net success rate, bringing the corporate total to 74 gross wells drilled (64.2 net) since inception. Harmattan provided

approximately two-thirds of the Company's production in 2008 with 14 gross (12.9 net) wells drilled in this area during the year with a net success ratio of 74%. The Company's year-end exit rate in this area was in excess of 4,900 boe/d producing from 39 wells. Ferrier grew to one-third of total corporate production in 2008 through the drilling of 10 gross (8.0 net) wells with a net success ratio of 75%. Exit production from this region was in excess of 2,600 boe/d producing from 14 wells. The Company continued its growth profile into 2008 with average yearly production of 6,586 boe/d and averaged 7,628 boe/d in the fourth quarter. In June 2008 Angle Energy completed an IPO and listed the common shares for trading on the TSX. Angle Energy raised approximately \$31 million by way of its IPO.

On December 18, 2008, Angle Energy completed a brokered private placement offering of 1,888,000 common shares, issued on a flow-through basis pursuant to the Tax Act, at a price of \$5.30 per share for gross proceeds of approximately \$10 million, which included the over-allotment option of 567,000 shares exercised prior to closing. Angle Energy used the proceeds from the offering to fund its exploration program specifically in the Deanne area in West Central Alberta and to preserve its financial flexibility for potential acquisition opportunities.

### **Developments in 2009**

During 2009 the Company drilled 13 gross (11.9 net) wells at an average working interest of 92% at a 66% net success rate, bringing the corporate total to 87 gross wells drilled (76.1 net) since inception. Harmattan provided approximately two-thirds of the Company's production in 2009 with 2 gross (2.0 net) wells drilled in this area during the year with a net success ratio of 100%. The Company's average production rate in this area was 4,900 boe/d producing from 42 wells. Ferrier contributed one-third of total corporate production in 2009 through the drilling of 6 gross (4.9 net) wells with a net success ratio of 80%. Average production from this region was 2,615 boe/d producing from 30 wells. The Company continued its growth profile into 2009 with average yearly production of 7,528 boe/d which is a 14% increase over 2008.

On May 8, 2009, Angle Energy entered into a purchase and sale agreement with a public oil and gas entity to acquire certain producing assets together with associated facility interests and undeveloped land, within Angle Energy's Ferrier core area, for an aggregate cash purchase price of approximately \$22.5 million, subject to closing adjustments. The assets, at the time of purchase, consisted of approximately 550 boe/d, 7,430 net acres of land (of which 3,350 net acres were undeveloped) and a 25% working interest in a gas gathering pipeline and a compression facility. The acquisition is adjacent to and complements the Company's existing production in the area.

The transaction closed on June 1, 2009 with an effective date of April 1, 2009. The volumes acquired as at the closing date of the acquisition were restricted to 140 boe/d from 550 boe/d due to a fire at Imperial Oil Limited's Everdell Complex that occurred late evening on May 25, 2009. Imperial Oil declared force majeure and informed Angle Energy in June 2009, that plant repair and recovery was not expected to occur in 2009. Accordingly, the Company proceeded to re-route production to an Angle Energy-owned facility with subsequent processing at the Keyera Strachan Complex, with full recovery of the acquisition volumes achieved in late September 2009. The Ferrier acquisition does not constitute a "significant acquisition" for the Company in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*.

On May 21, 2009, the Altagas Harmattan Complex (the "**Plant**"), located approximately 80 kilometres northwest of Calgary, near the town of Sundre, Alberta, experienced a significant restriction due to a failure at the Plant's condensate stabilizer. As a result, Angle Energy had production at the Plant inlet curtailed to 27% of the Corporation's normal throughput to this facility. Restoration of normal operations occurred on May 24, 2009. This outage yielded a total negative effect to Angle Energy of approximately 150 boe/d in the second quarter of 2009.

### **Significant Acquisitions**

On November 20, 2009, Angle Energy and Stonefire, a then TSX Venture Exchange listed company, jointly announced that they entered into an acquisition agreement (the "**Stonefire Agreement**") pursuant to which Angle Energy made an offer to acquire all of the outstanding shares of Stonefire (the "**Stonefire Acquisition**") for a purchase price of \$2.00 per class A share and \$10.00 per class B share. On January 12, 2010, Angle Energy acquired all of the issued and outstanding securities of Stonefire by way of a take-over bid and a subsequent compulsory acquisition under the ABCA of those remaining shares which were not tendered for sale pursuant to Angle Energy's offer. Pursuant to the Stonefire Acquisition, Angle Energy acquired a concentrated asset base in the

greater Edson area of west central Alberta. The acquired properties are consistent with Angle Energy's existing high quality asset base, and had the following attributes, as of November 20, 2009, the date of announcement:

- Production of approximately 1,225 boe/d, consisting of 70% natural gas, 15% light crude oil and 15% natural gas liquids.
- Production is high working interest and is operated; working interests in both production and undeveloped land of 79% and 73%, respectively.
- Reserves as at September 1, 2009 of 3.4 million boe proven and 6.4 million boe proven plus probable. Reserve life index of 7.6 years on proven reserves and 14.3 years on proven plus probable reserves.
- Operating costs of less than \$4.60 per boe (less than \$6.00 per boe including transportation), with approximately 75% of production processed through a company-owned natural gas plant.
- Undeveloped land of 20,000 net acres with an internal value of \$5.5 million.
- Significant opportunity portfolio on Stonefire's lands, with greater than 30 potential horizontal locations, and over 20 completion opportunities in existing wellbores. Stonefire's land base is 60 gross sections at an approximate 73% average working interest with only vertical wells drilled to date.

The total consideration paid by Angle Energy for Stonefire was approximately \$75 million, which included the assumption of approximately \$28.4 million of net debt and transaction costs. The acquisition of Stonefire constitutes a "significant acquisition" for the Company in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. The Company intends to file a Business Acquisition Report (National Instrument 51-102F4) within the prescribed time period.

### **Management Appointments**

On April 8, 2009, Angle Energy announced several executive changes and appointments within its management team. Ms. Heather Christie-Burns was appointed as President while retaining her position as Chief Operating Officer. Ms. Christie-Burns became responsible for key decision making regarding operations and overall direction of the Company and communications with shareholders and the public market. Mr. Gregg Fischbuch is primarily responsible for prospect development as well as strategic corporate planning and will continue to provide guidance as Chief Executive Officer. In addition, on April 8, 2009 Mr. Matthew Mazuryk was appointed as Vice President, Engineering and on September 28, 2009 Graham Cormack was appointed as Vice President, Operations.

### **New Credit Facilities**

On April 17, 2009, Angle Energy closed its new syndicated banking facility. This revolving committed credit facility consisted of a \$70 million revolving extendible syndicated facility and a \$10 million revolving extendible operating facility, thereby enhancing the Company's financial flexibility for the continued development of its core areas and in seeking additional growth opportunities and strategic acquisitions. Subsequent to the establishment of this credit facility it was amended pursuant to an agreement dated December 14, 2009. The amendment occurred in two stages: first, on December 14, 2009, the amount of the syndicated facility was increased to \$88 million; and second, on January 12, 2010, upon the satisfaction of certain conditions relating to the Stonefire Acquisition, the amount of the syndicated facility was increased to \$110 million. The amount of the credit facility is subject to a borrowing base test performed on a semi-annual basis by the lenders, based primarily on reserves and using commodity prices estimated by the lenders as well as other factors. In March 2010, the semi-annual review was completed, and Angle Energy will have its syndicated revolving credit facility increased to a total of \$120 million.

### **Equity Placements**

On May 26, 2009, Angle Energy completed a brokered private placement of 6,666,724 special warrants at a price of \$4.50 per special warrant for gross proceeds of approximately \$30 million, which included an over-allotment option of 2,222,224 special warrants which was exercised prior to closing. Each special warrant entitled the holder thereof

to receive one common share in the capital of the Company on the exercise or deemed exercise of the special warrant.

On June 2, 2009, the Company obtained a final receipt in connection with the filing of a final short form prospectus with respect to the qualification of distribution of 6,666,724 common shares issuable pursuant to the exercise or deemed exercise of the special warrants. The special warrants were deemed exercised on June 9, 2009 resulting in the issuance of 6,666,724 common shares. The proceeds from the special warrant offering were used primarily to fund the Ferrier acquisition described above and to a lesser extent, development drilling at Ferrier.

On December 15, 2009, Angle Energy completed a public offering of 7,535,000 common shares at a price of \$5.85 per common share for gross proceeds of approximately \$44.1 million, which included an over-allotment option of 685,000 common shares that was exercised prior to closing. Further, on December 15, 2009, Angle Energy issued 107,500 common shares pursuant to a non-brokered private placement at a price of \$5.85 per share for gross proceeds of \$628,875. The proceeds from these equity issuances were used to fund the acquisition of Stonefire in January of 2010.

In total the Company has accessed capital by way of private and public equity placements and has raised approximately \$191.7 million (gross proceeds) since inception in 2004 to present. As at December 31, 2009, Angle Energy has invested \$287.4 million in property and equipment funded by a combination of bank debt, net proceeds from issuance of common shares and other equity instruments such as warrants, and cash flow from operations.

#### **Expected Capital Expenditure Program for 2010**

On November 20, 2009, Angle Energy announced its expanded capital expenditure program for 2010. Angle Energy has a high quality producing asset base with over 180 non-contingent, high working interest drilling locations targeting liquids-rich natural gas in the Wabamun, Elkton, Ellerslie, Notikewin, Falher and Mannville formations and light crude oil in the Cardium and Pekisko zones. In 2010, Angle Energy plans to significantly expand its drilling and capital expenditure plans over 2009 levels, due to recent exploration success in the Lone Pine Creek area, Angle Energy's Cardium light oil project at Ferrier and other opportunities. In addition, capital will be directed towards the expanded portfolio of opportunities related to the Stonefire Acquisition.

The Company has approved a 2010 capital expenditure budget of between \$94 and \$96 million, including credits expected to be received from the Crown drilling credit incentive program, but excluding the costs of the Stonefire Acquisition, which are expected to amount to approximately \$75 million. Highlights of the Company's expanded capital program, which includes the Stonefire Acquisition, include the drilling of up to 33 gross wells during 2010, 75% of which are expected to be horizontal targets. By area, the drilling includes: up to 12 horizontal wells in Lone Pine Creek (Wabamun); up to 6 horizontal wells in Harmattan (Elkton and Mannville); up to 9 horizontal and vertical wells in Ferrier (Ellerslie and Cardium); and up to 6 horizontal wells in the acquired greater Edson area (Notikewin and Falher). Of the 9 wells planned in Ferrier, 6 horizontal wells will target light oil in the Cardium formation. Including the Stonefire Acquisition, Angle Energy anticipates that this increased capital program will elevate production to the 10,000 boe/d level during the second half of 2010.

In the latter part of 2009 the Company began the transition of moving from conventional drilling and completion techniques to horizontal drilling and emerging multi-fracture technologies on completions in order to increase recovery and productivity on Angle Energy's extensive asset base. The Company was successful in exploration drilling in the Lone Pine Creek area, which is expected to provide horizontal development drilling moving into 2010. In addition, the Company was successful in its first horizontal drilling on the light oil bearing sands in the Cardium zone at Ferrier. Due to this success Angle Energy expects increased focus on light oil drilling in Ferrier and Harmattan into 2010.

Angle Energy has high working interests, infrastructure control, and operatorship in virtually all of its project areas which will allow the Company to govern and quickly adjust its capital expenditure plans as required in response to any material change in commodity prices.

## DESCRIPTION OF THE BUSINESS

### General

Angle Energy is a growth-oriented, exploration-focused producer. Angle Energy's primary focus areas are located in Alberta.

### Business Objective and Strategy

Strategic financial planning, with attention to capital structure, has played a key role in Angle Energy's success. The Company has always maintained a view that a simple capital structure is desirable, that equity issues should provide a platform for initial project growth and that debt is an instrument best used for later stage development or for opportunistic acquisitions in appropriate environments.

The Company prefers to drill in areas where it can complete multi-well projects at high working interest and operate the resulting production. Additionally, there should be available access to existing infrastructure to transport and process the products produced. Once some or all of these factors have been reviewed and subsequently satisfied, the Company will pursue a strategy of acquiring lands upon which to drill. These lands may be acquired through direct Crown purchases, freehold farm-ins, industry farm-ins or asset acquisitions.

Prior to 2009, all of the Company's reserves had been added through drilling as the Company had not previously made either a material property or any corporate acquisitions. As noted above, in 2009 the Company purchased assets in the Ferrier region and, in 2010, in the Edson area through the Stonefire Acquisition. These transactions reflect the Company's strategy of actively canvassing the market for acquisitions that will add exploration and development opportunities in areas where Company management has a demonstrated ability.

While the timing of an acquisition can be difficult to anticipate given its inherently opportunistic nature, the Company continues to actively search for acquisitions that will provide additional opportunities. The Company is well positioned to execute a sizable acquisition given its size of operation and financial strength.

### Principal Areas

The following is a description of the material oil and natural gas properties, pipelines, facilities and installations in which the Company has an interest. The production data noted below represents the Company's share of sales volumes before deduction of royalties. In addition to the properties held by the Company on December 31, 2009, the material properties, pipelines and installations acquired by the Company pursuant to the Stonefire Acquisition on January 12, 2010, are also described below.

#### *Harmattan, Alberta*

Harmattan is located approximately 80 kilometres northwest of Calgary near the town of Sundre, Alberta. Approximately 65% of Angle Energy's production in 2009 was derived from this area. Accordingly, this area also represents approximately 15% of the Company's 2009 capital activity. This is Angle Energy's foundation asset that began development in early 2005 through a strategic farm-in with ExxonMobil, accessing 60 sections of land in return for a 12-well commitment. Angle Energy's Harmattan area possesses a number of operating advantages, including year round access, medium depth drilling (approximately 2,500 metres or less) and multi-zone stacked targets of proven commercially productive zones. The area contains massive historical natural gas pools and has several large underutilized gas processing plants that offer very competitive processing rates. Production in this area is largely attributed to medium depth Mannville sands or from slightly deeper targets in the Elkton carbonate formation, both of which are predominantly gas with a high degree of associated NGLs. Angle Energy owns or has access to 307 kilometres of 2-D and 374 square kilometres of 3-D seismic data that will aid in the future development and exploration of the area.

To December 31, 2009, the Company has drilled 56 gross (51.7 net) wells in the Harmattan area. As at December 31, 2009, the Company's Harmattan property consisted of 55,302 controlled net acres of land and 11,435 mboe of Angle Energy-interest proved plus probable reserves. Production during the fourth quarter of 2009 averaged 4,500 boe/d from 42 wells. During 2009 Angle Energy drilled 2 gross (2.0 net) wells in the Harmattan region and was

successful on both wells. The Company owns 79 kilometres of extensive gas gathering systems, a 20 mmcf/d gas facility in the area with an average 96% working interest and near 100% operatorship. This extensive gas gathering infrastructure installation, which was completed in late 2007, allows Angle Energy to promptly tie-in successful wells and direct the production into mid-stream operated processing facilities, thereby maintaining operational control. The Company's first success in 2005 in the Ellerslie member resulted in the delineation of an approximate township-sized pool extension, using a bypassed pay concept based on historical well logs. Later that year, the Company discovered a significant Elkton pool. The Mannville 'B' pool was discovered in March 2008 with delineation drilling that proceeded throughout the year. This is also a large, township-sized pool producing primarily liquids-rich natural gas plus light sweet crude oil. These are high quality reservoirs with deep basin-like characteristics, including entrained NGLs, no produceable water and a predictable decline curve, resulting in long-life production and a premium production base.

The Company currently has an inventory of 85 to 180 high working interest drilling locations on the Harmattan property. During 2010 the Company expects to drill six horizontal wells at an all-in cost of drilling through tie-in of \$3.5 million per well.

#### *Ferrier, Alberta*

Located approximately 12 kilometres south of Rocky Mountain House, Alberta, Ferrier is Angle Energy's second-largest producing property and has experienced rapid growth since commencing operations in 2006. The targets in this area include the Ellerslie, Glauconitic and Ostracod formations. Angle Energy controls the infrastructure it uses in this gas prone area and, like Harmattan, the gas contains a high degree of NGLs with no produceable water.

Initial entry to the area was made pursuant to a farm-in agreement in 2006 on 3.5 sections of land owned by a major exploration and production company with additional lands being purchased in Crown sales. Area drilling began in May 2005 and the completion of key infrastructure in October 2007 allowed initial production to begin in November 2007, increasing to 20% of Angle Energy's total production by December 2007. Five wells were on production in this area as at year-end 2007 with an exit rate for the area of 1,000 boe/d.

Through continued successes and production gains in 2008, Ferrier became a true core area for Angle Energy, comprising one-third of corporate production. In late 2007, the Company drilled a significant extension of an existing 60 bcf gas pool in an Ellerslie channel, and in early 2008 further extended the pool with the drilling of two additional wells. During drilling operations conducted in the third quarter of 2008, Angle Energy extended an Ostracod channel and continues to follow up both of these liquids-rich natural gas charged channels. In June 2009 Angle Energy acquired certain producing assets together with associated facility interests and undeveloped land within Angle Energy's Ferrier core area. The acquired properties complement, and are adjacent to, Angle Energy's existing production in the area. As at December 31, 2009, the Company's Ferrier property consisted of 29,392 controlled net acres of land and 6,556 mboe of Angle Energy-interest proved plus probable reserves. Production during the fourth quarter of 2009 averaged 2,896 boe/d from 30 wells, which is transported through the Company's gathering pipelines and compressors enroute to a mid-stream operated gas processing facility. Angle Energy's production from this highly competitive area is comprised of 72% natural gas and 28% NGLs and a small amount of light crude oil. During 2009 the Company drilled 6 gross (4.9 net) wells in the Ferrier region and was successful on 5 gross (3.9 net) wells for a net success ratio of 80%. A major compression project was completed in October 2008 with a raw gas throughput capacity of 18 mmcf/d and can easily be expanded to allow for increased future production from the area.

Angle Energy currently has an inventory of 35 to 90 drilling locations on the Ferrier property. During 2010, Angle Energy expects to drill a total of nine wells in the Ferrier area, and in the first quarter of 2010, expects to drill one well targeting the Ellerslie channel sand and three horizontal wells targeting the Cardium light oil bearing sands.

#### *Lone Pine Creek, Alberta*

The Lone Pine Creek area, which was acquired through a farm-in with ExxonMobil along with selective Crown land purchases, is located 20 kilometres east of the Company's Harmattan core area. Angle Energy's objective is to extend the Lone Pine Creek natural gas Wabamun pools, which have historically produced a cumulative 500 bcf of natural gas since their discovery in the mid-1950s, into underexplored areas to the north and south. Angle Energy's technical team has had previous success extending one of these pools to the south.

Lone Pine Creek consists of 27,882 controlled net acres of land at 100% working interest with initial production commencing in the fourth quarter of 2009. The Company's technical team has used substantial production history, 30 kilometres of 2-D and 304 square kilometres of 3-D seismic data as well as pressure data to define this prospect. The historic existing pool is a high quality reservoir with prolific individual wells, but contains approximately 5% H<sub>2</sub>S gas at target depths of 2,200 metres, and is expected to yield 20 bbls/d of NGLs per mmcf of natural gas produced.

Angle Energy began exploration drilling at Lone Pine Creek in the third quarter of 2009. The first well, located in the southernmost area of the Company's owned and controlled lands, was drilled vertically and encountered 12 metres of pay at an average 6% porosity in the Crossfield Wabamun formation. The reservoir pressures measured were high and results were encouraging as this proved the presence of a gas charged reservoir. The lower permeability revealed by the flow test, combined with the thick pay encountered, indicated that horizontal drilling exploitation would be a favourable application for the adjacent lands. During the fourth quarter of 2009 the Company's second exploratory well, located on the northernmost extent of the land block, was a successful horizontal drill completed using an acid wash and was subsequently tied in. In December 2009, Angle Energy spud the second horizontal well that was completed in February 2010. Multi-stage acid fracturing was used in the completion operations, which yielded substantially better flow results than the acid wash technique. In February 2010, the Company spud two additional horizontal wells in the area.

There are four large gas plants in the area with ample excess processing capacity available, and as a result, Angle Energy has been in discussions with several parties regarding the possible tie-in of its future production.

Due to the potential sour nature of the gas in this area, the Company continues to proactively address the safety issues by conducting environmental and community consultations to ensure operations will proceed in a safe manner. The project area is comprised of over 50 contiguous sections of land at 100% working interest with a potential drilling inventory of 30 to 40 wells (one well per section), representing approximately three years of development. Angle Energy has budgeted 12 Wabamun gas horizontal wells in the project area in 2010, four of which are scheduled to be drilled during the first quarter of 2010 at an all-in cost of drilling through tie-in of \$3.5 million per well.

#### *Edson, Alberta*

The Edson area, including the Edson, Bronson and McLeod producing regions, is located approximately 3 kilometres east of the town of Edson, Alberta. These properties, which were acquired in early January 2010 through the purchase of Stonefire, feature high working interest production and undeveloped land as well as owned and controlled infrastructure. This acquisition complements Angle Energy's operating strategy of focusing in areas where it can own and operate its facilities, where gas plants have excess capacity and processing fees are attractive. The Edson region will be one of Angle Energy's primary development focus areas in 2010.

Edson consists of 27,928 controlled net acres of land at 72% working interest and will initially contribute 1,100 boe/d to the Company's total corporate production. The area has proven resource exploitation potential using horizontal wells with multi-stage fracture completions in several liquids-rich, sweet gas reservoirs, including the Cardium, Notikewin, Falher, Bluesky and Rock Creek. Continued development and exploration will be aided by 189 kilometres of 2-D and 36 square kilometres of 3-D seismic data. To date, the exploration has been conducted using vertical wells, but in the first quarter of 2010, Angle Energy commenced drilling its first horizontal well in the area. Wells are in the 1,800 to 2,400-metre vertical depth range, similar to the drilling depths at Harmattan. The Company owned infrastructure can be expanded to facilitate future production growth. Angle Energy has a 100% ownership interest in a 5.5 mmcf/d (1,000 boe/d) gas plant at Edson that processes approximately 75% of the Company's current production in the area. Plant capacity is currently being expanded to 17 mmcf/d to meet future production needs at a cost of approximately \$2.5 million.

Angle Energy has identified a significant opportunity portfolio on the Edson lands with 25 to 35 horizontal locations and more than 20 completion opportunities in existing wellbores. The cost to drill, complete and tie-in vertical wells in the area is approximately \$1.8 million with initial production rates ranging from 100 to 150 boe/d and recoverable reserves per well of approximately 1.5 bcf. Horizontal wells in the area are being drilled at an all-in cost of drilling through tie-in of approximately \$3.5 million with initial production rates in the 250 boe/d range and recoverable

reserves of 2 to 4 bcf per well. During 2010, Angle Energy expects to drill a total of six horizontal wells in the Edson area, and in the first quarter of 2010, expects to drill two wells targeting the Notikewin and Cardium areas.

## **Emerging Projects**

### *Deanne, Alberta*

The Deanne exploration prospect is located approximately 24 kilometres southwest of Rocky Mountain House, Alberta and is primarily targeting the southwestern portion of the Hoadley barrier bar, an extensive Glauconitic deep basin reservoir that has yielded significant historical reserves. The prospect is approximately 3,600 metres in depth. There are two gas processing plants with 20 mmcf/d available capacity within 2 to 3 kilometres of this prospect.

Intended unrisks recoverable reserve targets range from 3 to 15 bcf at Deanne. Due to the depth of drilling and an over-pressured reservoir, each well costs approximately \$4.0 million to drill and \$3.0 million to complete. During 2010, Angle Energy does not expect to conduct further exploration tests on this property due to the costs related to the drilling depth and the anticipated natural gas pricing.

### *Pembina, Alberta*

The Company's Pembina property is located 60 kilometres north of the Ferrier core producing area. Angle Energy's primary target at Pembina is the Nordegg sand, a medium depth conventional natural gas reservoir that typically yields wells with initial productivity of 1 mmcf/d or greater. During 2009, other industry players were also targeting the Cardium oil bearing sands. Gas gathering infrastructure and processing facilities are in place with available capacity.

At December 31, 2009, Angle Energy's Pembina property consisted of 10,656 controlled net acres of land acquired through a farm-in and selective Crown purchases. During the first quarter of 2009, Angle Energy drilled 2 gross (2.0 net) exploratory wells and cased both wells for completion. The target Nordegg sand was encountered, but was low in permeability and did not yield commercial results upon testing. The two wells tested separate seismic features and were stand-alone plays with neutral impact to the prospectivity of the land block. Angle Energy does not expect to conduct another exploration test on this property in 2010, but will review the prospectivity of its land for Cardium oil potential.

## **Exploration Risks with Emerging Projects**

Exploration drilling involves substantial risk and no assurance can be given that drilling will prove successful in establishing commercially recoverable reserves. While the Company is of the view that its personnel have the skills and that the Company will have the resources to achieve its objectives, participation in the exploration for and the development of oil and natural gas has a number of inherent risks. See "Risk Factors" for a discussion of exploration risk.

## **Trends and Cycles**

Market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions throughout 2008 and 2009, have caused significant volatility to commodity prices. Although global economic conditions began stabilizing in the latter half of 2009, the United States and global credit and financial markets have not yet recovered. A climate of greater economic volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions persists. These factors have negatively impacted the Company's valuations and will impact the performance of the global economy going forward.

The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that climate change legislation will have on the sector by the June 22, 2007 amendments to the *Tax Act* (the "**SIFT Amendments**") relating to income trusts and other "specified investment flow-through" entities ("**SIFTS**"), by the October 25, 2007 proposal of the Alberta government relating to the New Royalty Framework ("**NRF**"), and by the subsequent changes to maximum conventional oil and gas royalty rates and new royalty curves to be implemented as part of the Alberta government's March 11, 2010 response to its Competitiveness Review ("**Competitiveness**

**Review**”). The combined impacts of the NRF and the Competitiveness Review are still being determined and will vary company to company based on the percentage of production in Alberta, their commodity mix and depths of production, among other things. The combined effects of the NRF and the Competitiveness Review may also impact investor sentiment to investment in the Province of Alberta. The amount and degree of these impacts have yet to be determined.

Under the SIFT Amendments, SIFTs will be liable for tax at tax rates that approximate those applicable to corporations commencing in January 2011, provided that the SIFT experiences only “normal growth” and no “undue expansion” before then, in which case the tax could be imposed prior to the January 2011 deadline. Although the SIFT Amendments will not affect the method in which Angle Energy will be taxed, it may have an impact on the ability of a SIFT to purchase producing assets from oil and gas exploration and production companies (as well as the price that a SIFT is willing to pay for such an acquisition) thereby affecting the exploration and production companies’ ability to be sold to a SIFT, which has been a key “exit strategy” in recent years for oil and gas companies. This may be a benefit for junior and mid-sized companies as they may compete with SIFTs for the acquisition of oil and gas properties from such producers. However, it may also limit such companies’ abilities to sell producing properties or pursue an exit strategy.

Commodity prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns. Prolonged increases or decreases in the price of oil and gas could significantly impact the Company. As a result of the Company operating a high degree of capital projects, management is able to control the timing of projects to balance to its expected cash flow and remain in a solid fiscal position. There is a strong relationship between energy commodity prices and access to both equipment and personnel. High commodity prices also affect the cost structure of services which may impact the Company’s ability to accomplish drilling, completion and equipping goals. Changes in the Alberta new royalty framework implemented in January 2009 had a negative impact on the oil and gas industry, including the Company. See Appendix B – *Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions* for a detailed discussion of such impact. In addition, weather patterns are unpredictable and can cause delays in implementing and completing field projects.

It is likely that in the future, the Company may consider raising additional capital through debt and equity financings in order to fully realize the Company’s strategic goals and business plans. The Company’s ability to raise additional capital will depend on a number of factors, such as general economic and market conditions that are beyond the Company’s control. If the Company is unable to obtain additional financing or to obtain it on favourable terms, the Company may be required to forego attractive business opportunities. However, as the operator of virtually all of its projects at a high working interest position, the Company is able to be flexible in the timing of operations to ensure a continued strong financial position. The Company is committed to maintaining a strong balance sheet combined with an adaptable capital expenditures program that can be adjusted to capitalize on or reflect acquisition opportunities or a tightening of liquidity sources, if necessary.

The oil and gas business is cyclical by nature, due to the volatility of oil and gas commodity pricing as described above. Additionally, seasonal interruptions in drilling and construction operations can occur but are expected and accounted for in the budgeting and forecasting process.

### **Competitive Conditions**

Angle Energy actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than Angle Energy. The Company’s competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

Some of Angle Energy’s customers and potential customers are themselves exploring for oil and natural gas, and the results of such exploration efforts could affect the Company’s ability to sell or supply oil or gas to these customers in the future. Angle Energy’s ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry

partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment. Alberta provincial land sales are a competitive bid process and the Company assesses its interpretation of the value of such lands and then submits a bid. Field equipment availability is competitive and the Company continues to gain access to it through prior agreements and contacts. Hiring and retaining technical and administrative personnel continues to be a competitive process. To meet this challenge, the Company rewards existing employees and provides opportunities for new staff to participate in the equity of the Company. Angle Energy believes its distinct competitive advantage is through its scientific, integrated approach in generating drilling prospects.

#### *Economic Dependence*

The Company is not substantially dependent on any contract or license, such as a contract to sell the major part of its products or services or to purchase the majority of its goods, services or raw materials, or any franchise or licence or other agreement to use a patent, formula, trade secret, process or trade name upon which its business depends.

#### *Change to Contracts*

There is no aspect of the Company's business that the Company reasonably expects to be affected by renegotiation or termination of contracts or sub-contracts.

#### **Price Risk Management**

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

- world market forces, including the ability of OPEC to set and maintain production levels and prices for crude oil;
- political conditions, including the risk of hostilities in the Middle East and other regions throughout the world;
- increases or decreases in crude oil quality and market differentials;
- the impact of changes in the exchange rate between Canada and U.S. dollars on prices received by the Company for its crude oil and natural gas;
- North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;
- global and domestic economic and weather conditions;
- the impact of tax and incentive regime to credit risk;
- the price and availability of alternative fuels; and
- the effect of energy conservation measures and government regulations.

Fluctuations in commodity prices, quality differentials and foreign exchange and interest rates, among other factors, are outside of management's control. To mitigate a portion of these risks, the Company actively evaluates price risk management activities.

#### **Revenue Sources**

For the year ended December 31, 2009, natural gas accounted for 49% (2008 – 55%) and oil and NGLs accounted for 51% (2008 – 45%) of Angle Energy's revenue before royalties. Production is sold to marketers at delivery points in or close to the producing field.

## **Seasonal Considerations**

Certain properties in Northern Alberta are accessible only during winter months. The majority of Angle Energy's properties are accessible year round, except during spring break-up. Major facilities through which Angle Energy's production is processed may temporarily be shut down for a short period of time during the year to conduct repair and maintenance operations.

## **Substantial Capital Requirements**

The Company anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Company's revenues or reserves decline, the Company may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash 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. Moreover, future activities may require the Company to alter its capitalization significantly. Transactions involving the issuance of securities may be dilutive. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's financial condition, results of operations or prospects. See "Risk Factors" for further discussion of capital requirements.

## **Employees**

As at December 31, 2009, the Company had 26 full-time employees and 3 consultants and plans to modestly increase that number of employees during 2010. The Company's technical staff focuses on identifying exploration and development oil and gas drilling prospects and evaluating the probability of encountering economically recoverable hydrocarbons.

## **Environmental Protection**

The Company is subject to a range of environmental regulations, as are its competitors in the oil and gas industry. To ensure that the Company complies with its environmental obligations the board of directors monitors Company environmental policies and procedures through an Environmental, Health and Safety Committee. In 2009 the Company adopted a corporate environmental policy, which commits the Company to environmental protection through effective project planning and implementation, energy conservation and waste management. The Company has also adopted a corporate procedures manual that provides employees with detailed instructions on how they are to fulfill the Company's responsibilities at an operational level (e.g. procedures to follow in the event of a spill). In addition to this the Corporation employs an environmental compliance manager whose job is to ensure that the Company's practices and procedures are implemented in the Company's operations.

As the environmental regulations applicable to the Company are also applicable to its competitors, environmental protection did not affect the competitive position of the Company in 2009; nor did the Company incur any material environmental protection or regulatory costs out of the ordinary course of business in 2009. For a further discussion of the Company's environmental policies see "Industry Conditions" and "Risk Factors".

## **Social or Environmental Policies**

As noted, the Company places stringent standards on environmental protection and has an Environmental, Health and Safety Committee that provides oversight to management in the environmental area. All necessary employees are trained and educated on environmental policies as such policies pertain to their particular roles. The Company adheres to all government regulations and policy directives. For a further discussion of the Company's environmental and safety policies see "Industry Conditions" and "Risk Factors".

## **PROFORMA STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION**

The following tables set forth a consolidated statement of reserve data for Angle Energy and Stonefire on a proforma basis. Although the Stonefire Acquisition did not occur until January 12, 2010, the proforma tables set out

below aggregate the reserves of Angle Energy and Stonefire as they were at December 31, 2009. For details of Angle Energy's reserves as they were at December 31, 2009 without the reserves attributable to Stonefire, see Appendix B – *Statement of Reserves Data and Other Oil and Gas Information*. For information regarding reserves attributable to Stonefire as they were at December 31, 2009, see Appendix E - *Certain Stonefire Reserves Data and Financial Information*.

Definitions used for reserves categories in this AIF, unless otherwise indicated, are as presented in the COGE Handbook, as specified under NI 51-101. Certain relevant terms and definitions from the COGE Handbook are reproduced in Appendix B – *Statement of Reserves Data and Other Oil and Gas Information*.

### **Summary of Proforma Oil and Gas Reserves Effective December 31, 2009**

The following table outlines the light and medium crude oil (combined) and gas reserves of both Angle Energy and Stonefire on a forecasted pricing basis, by product type on a gross (before royalties) and net (after royalties) basis:

	Light and medium crude oil (combined)		Natural Gas		NGLs		boe	
	Gross (mdbl)	Net (mdbl)	Gross (mmcf)	Net (mmcf)	Gross (mdbl)	Net (mdbl)	Gross (mboe)	Net (mboe)
Proved								
Developed producing	443	308	43,309	32,068	4,251	2,754	11,912	8,406
Developed non-producing	54	40	1,600	1,314	139	92	459	351
Undeveloped	135	112	9,204	8,169	690	514	2,359	1,987
Total proved	631	460	54,112	41,552	5,080	3,359	14,730	10,744
Probable	571	424	47,299	38,291	2,978	1,942	11,433	8,748
Total proved plus probable	1,202	884	101,412	79,843	8,059	5,301	26,163	19,492

### **Net Present Values of Proforma Future Net Revenue**

The following tables outlines the net present values of future net revenue of both Angle Energy's and Stonefire's reserves at December 31, 2009 at various discount rates on a before tax and after tax basis and on a forecasted pricing basis:

	Before Income Taxes				
	Discounted At				
	0%	5%	10%	15%	20%
(000s)	(\$)	(\$)	(\$)	(\$)	(\$)
Proved					
Developed producing	298,169	242,634	205,761	179,629	160,165
Developed non-producing	11,048	8,611	6,940	5,734	4,827
Undeveloped	56,085	40,318	30,154	23,198	18,202
Total proved	365,302	291,563	242,855	208,560	183,193
Probable	330,941	200,423	135,296	98,070	74,597
Total proved plus probable	696,242	491,986	378,151	306,631	257,790

#### **Note**

(1) Figures may not add due to rounding.

	<b>After Income Taxes</b>				
	Discounted At				
	0%	5%	10%	15%	20%
(000s)	(\$)	(\$)	(\$)	(\$)	(\$)
Proved					
Developed producing	265,489	217,450	185,482	162,746	145,747
Developed non-producing	8,214	6,279	4,958	4,008	3,298
Undeveloped	41,684	29,175	21,074	15,516	11,519
Total proved	315,387	252,903	211,514	182,270	160,564
Probable	248,326	148,656	98,875	70,374	52,380
Total proved plus probable	563,713	401,559	310,389	252,644	212,944

**Note**

(1) Figures may not add due to rounding.

**Total Proforma Future Net Revenue**

The following table provides a breakdown of the various components of total future net revenue on an undiscounted basis for proved and proved plus probable reserves:

			Operating	Capital	Well	Future Net	Future	Future Net
	Revenue	Royalties	Costs	Development	Abandonment	Revenue	Income	Revenue
(000s)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
Proved	755,876	197,258	160,986	27,332	4,999	365,302	49,914	315,387
Total probable	695,963	158,216	159,685	44,862	2,259	330,941	82,614	248,326
Total proved plus probable	1,451,839	355,475	320,671	72,193	7,257	696,242	132,529	563,713

**Note**

(1) Figures may not add due to rounding.

**Net Present Value of Proforma Future Net Revenue by Production Group (Forecast Prices and Costs)**

	Production Group	Future Net Revenue	Future Net Revenue
		Before Income Taxes <sup>(3)</sup> (discounted at 10%/year) (\$000s)	Before Income Taxes <sup>(3)</sup> (discounted at 10%/year) (\$/boe)
Proved	Conventional light and medium crude oil <sup>(1)</sup>	17,189	47.60
	Conventional natural gas <sup>(2)</sup>	225,666	21.74
Total proved		242,855	22.60
Proved plus probable	Conventional light and medium crude oil <sup>(1)</sup>	30,140	44.89
	Conventional natural gas <sup>(2)</sup>	348,011	18.49
Total proved plus probable		378,151	19.40

**Notes**

- (1) Including solution gas and other by-products.
- (2) Including by-products but excluding solution gas.
- (3) Unit values of \$/boe are based on Company Net Reserves.

**DIVIDENDS**

The Company has never paid dividends on its common shares. The Company currently intends to retain earnings to finance the expansion of its business and accordingly does not anticipate paying dividends in the foreseeable future. Future decisions to pay dividends on the common shares will be made by the board on the basis of the earnings and financial requirements of the Company as well as other conditions existing at such time.

## DESCRIPTION OF CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of common shares and preferred shares, issuable in series, of which 54,779,598 common shares and no preferred shares are issued and outstanding as at the date of this AIF.

### Common Shares

The holders of common shares are entitled to one vote per share at all meetings of shareholders of the Company, except meetings at which only holders of a specified class of shares are entitled to vote. In addition, the holders of common shares are entitled to receive dividends if, as and when declared by the board of directors of the Company and to receive the remaining property and assets of the Company upon dissolution, subject to the prior rights and privileges attaching to any other class of shares of the Company.

### Preferred Shares

Preferred shares may from time-to-time be issued in one or more series. Prior to the issuance of a series of preferred shares, the board of directors of the Company may fix the number of preferred shares which are to comprise the series as well as the designation, rights, privileges, restrictions and conditions attached to each series.

## MARKET FOR SECURITIES

### Trading Price and Volume

Angle Energy's common shares have been listed and posted for trading on the TSX under the trading symbol "NGL" since the Company's IPO in June 2008. The following table sets forth the market price ranges and the trading volumes of the common shares of the Company for the year ended December 31, 2009, as reported by the TSX:

	Price Range (\$ per share)		Volume
	High	Low	
January	4.07	3.40	653,318
February	3.65	3.12	1,457,685
March	4.10	3.03	1,222,719
April	3.93	3.55	1,483,075
May	5.05	3.76	1,441,040
June	4.95	4.16	1,436,445
July	4.59	3.76	800,883
August	4.67	4.25	1,945,361
September	5.45	4.20	2,451,578
October	5.80	5.00	1,849,653
November	6.33	5.45	4,146,587
December	6.83	5.74	2,153,130

### PRIOR SALES

During the financial year ended December 31, 2009, the Company granted 2,547,750 options exercisable into 2,547,750 common shares of the Company, the particulars of which are set forth in the following table:

Date of Grant	Number and Type of Securities Issued <sup>(1)</sup>	Average Exercise Price (\$)
August 7, 2009	334,000 Options <sup>(2)</sup>	4.43
August 7, 2009	274,750 Options <sup>(2)</sup>	5.30
August 7, 2009	150,000 Options <sup>(2)</sup>	6.25
August 7, 2009	86,500 Options <sup>(2)</sup>	6.44
August 7, 2009	1,127,500 Options	4.43
September 15, 2009	150,000 Options	5.19
September 28, 2009	250,000 Options	5.05
November 18, 2009	100,000 Options	6.00
December 1, 2009	75,000 Options	6.02

#### Notes

- (1) Each option entitles the holder thereof to acquire one common share, on the terms and conditions set forth in the Company's stock option plan and expires five years from the date of issuance. For further details, see the "Compensation Discussion and Analysis" in the Company's meeting information circular, dated March 30, 2010.
- (2) Issued in connection with the collapse of the Company's share appreciation rights plan. For further details, see the "Compensation Discussion and Analysis" in the Company's meeting information circular, dated March 30, 2010.

### ESCROW AND TRANSFER RESTRICTIONS ON SECURITIES

There are no securities subject to escrow or that are subject to any contractual restrictions on transfer.

### DIRECTORS AND OFFICERS

#### Current Directors and Officers

The current directors of the Company are Gregg Fischbuch, Noralee Bradley, Clarence Chow, John Gareau, Edward Muchowski and Timothy Dunne. Each person elected as a director of the Company will hold office until the close of the next annual meeting of the shareholders or until his or her successor is duly elected or appointed or his or her office is earlier vacated in accordance with the ABCA and the articles and by-laws of the Company. The current executive officers of the Company are Gregg Fischbuch, Stuart Symon and Heather Christie-Burns; the non-executive officers are Graham Cormack, Matthew Mazuryk, Glen Richardson, Elizabeth More and Heather Post.

The following table sets forth the name, province and country of residence of each director and officer, the date each first became a director or officer of the Company, the current principal occupation, the business or employment of each director and officer and their principal occupation, business or employment over the past five years, and the number of common shares beneficially owned, or controlled or directed, directly or indirectly, by each of them as at March 31, 2010:

Name and Province/Country of Residence and Position with the Company	Principal Occupation(s)	Date Appointed as Director or Officer	Shares Beneficially Owned or Controlled as of the date of this AIF	Principal Occupation in Past Five Years
Gregg Fischbuch <sup>(5)</sup> <i>Alberta, Canada</i>  <i>Chief Executive Officer and Director</i>	Chief Executive Officer Angle Energy	March 4, 2004	4,265,427	Chief Executive Officer of Angle Energy since April 2004; prior thereto, President of Angle Energy (April 2004 to April 2009); prior thereto, Senior Vice President, Business Development of Brooklyn Energy Corp. (March 2003 to March 2004).

<b>Name and Province/Country of Residence and Position with the Company</b>	<b>Principal Occupation(s)</b>	<b>Date Appointed as Director or Officer</b>	<b>Shares Beneficially Owned or Controlled as of the date of this AIF</b>	<b>Principal Occupation in Past Five Years</b>
Stuart Symon <i>Alberta, Canada</i>  <i>Vice President, Finance Chief Financial Officer and Corporate Secretary</i>	Vice President, Finance Chief Financial Officer and Corporate Secretary Angle Energy	February 23, 2006	204,407	Chief Financial Officer of Angle Energy since February 2006; prior thereto, Chief Financial Officer of White Fire Energy Ltd. (April 2005 to February 2006); prior thereto, Chief Financial Officer of Lightning Energy Ltd. (April 2004 to April 2005); prior thereto, Chief Financial Officer of Brooklyn Energy Corp. (December 2001 to March 2004).
Heather Christie-Burns <i>Alberta, Canada</i>  <i>President and Chief Operating Officer</i>	President and Chief Operating Officer Angle Energy	March 31, 2004	535,178	President and Chief Operating Officer of Angle Energy since April 2009; prior thereto, Chief Operating Officer of Angle Energy since March 2004.
Elizabeth More <i>Alberta, Canada</i>  <i>Vice President, Exploration</i>	Vice President, Exploration Angle Energy	September 8, 2008	34,920	Vice President, Exploration of Angle Energy since September 2008; prior thereto, Vice President, Exploration for Flagship Energy Inc. (November 2002 to March 2005).
Glen Richardson <i>Alberta, Canada</i> <i>Vice President, Land</i>	Vice President, Land Angle Energy	September 8, 2008	203,420	Vice President, Land of Angle Energy since September 2008; prior thereto, Land Manager for Angle Energy (August 2007 to September 2008); prior thereto, Land Manager for Yangarra Resources Ltd. (September 2005 to August 2007); prior thereto, Senior Landman for Penn West Petroleum Ltd. (January 2003 to July 2005).
Graham Cormack <i>Alberta, Canada</i>  <i>Vice President, Operations</i>	Vice President, Operations Angle Energy	September 28, 2009	13,558	Vice President, Operations of Angle Energy since September, 2009; prior thereto, Senior Vice President, Engineering and Operations of StarCor Energy (end of 2008 to September 2009); prior thereto, Vice President, Engineering and Operations and a Founder of E4 and E3 Energy Inc. (September 2002 through 2008).
Matthew Mazuryk <i>Alberta, Canada</i>  <i>Vice President, Engineering</i>	Vice President, Engineering Angle Energy	April 8, 2009	10,346	Vice President, Engineering of Angle Energy since April 2009; prior thereto, Manager of Engineering of Angle Energy (August 2008 to April 2009); prior thereto, Manager of Engineering, Monterey Exploration Ltd. (October 2006 to July 2008); prior thereto, Manager of Engineering, Harvest Energy Trust (2004 to 2006).

Name and Province/Country of Residence and Position with the Company	Principal Occupation(s)	Date Appointed as Director or Officer	Shares Beneficially Owned or Controlled as of the date of this AIF	Principal Occupation in Past Five Years
Heather Post <i>Alberta, Canada</i>  <i>Controller</i>	Controller Angle Energy	January 22, 2009	7,655	Controller of Angle Energy since June 2008; prior thereto, Assistant Controller at Barnwell of Canada, Limited (July 2006 to June 2008); prior thereto, Senior Accountant at KPMG LLP (January 2004 to July 2006).
Noralee Bradley <sup>(3)(4)</sup> <i>Alberta, Canada</i>  <i>Director</i>	Partner at the Calgary office of Osler, Hoskin & Harcourt LLP, a national law firm	June 15, 2004	180,055	Partner at the Calgary office of Osler, Hoskin & Harcourt LLP, a national law firm, since January 2006; prior thereto, partner with Bennett Jones LLP, a national law firm.
Clarence Chow <sup>(1)(2)(6)</sup> <i>Alberta, Canada</i>  <i>Director</i>	President CGS Asset Management Ltd.	June 28, 2004	1,793,100	President, CGS Asset Management Ltd. since March 2008; prior thereto, President, AGS Capital Management Ltd. (since 2003).
John Gareau <sup>(1)(3)(7)</sup> <i>Alberta, Canada</i>  <i>Director</i>	Retired; corporate director and independent businessman	June 15, 2004	399,500	Corporate director and independent businessman.
Edward Muchowski <sup>(2)(4)(8)</sup> <i>Alberta, Canada</i>  <i>Director</i>	Corporate director and independent businessman	June 15, 2004	750,833	Corporate director and independent businessman.
Timothy Dunne <sup>(1)(3)(9)</sup> <i>Alberta, Canada</i>  <i>Director</i>	Corporate director and independent businessman	March 29, 2006	155,646	Corporate director and independent businessman.

#### Notes

- (1) Member of the Audit Committee.
- (2) Member of the Reserves Committee.
- (3) Member of the Corporate Governance and Compensation Committee.
- (4) Member of the Environmental, Health and Safety Committee
- (5) Includes 1,347,633 common shares held by an associate and a corporation controlled by Mr. Fischbuch.
- (6) Includes 1,793,100 common shares held by AGS Energy Fund II L.P., a group of investment funds of which Mr. Chow is Manager.
- (7) Includes 58,500 common shares held by an associate and a corporation controlled by Mr. Gareau.
- (8) Includes 5,000 common shares held by an associate of Mr. Muchowski.
- (9) Includes 9,420 Shares held by an associate of Mr. Dunne.

The directors and senior officers of the Company as a group beneficially own, directly or indirectly, or exercise control or direction over, an aggregate of 8,554,045 common shares. As at March 31, 2010, the directors and senior officers of the Company, as a group, beneficially own, or control or direct, directly or indirectly, 16% of the outstanding common shares.

## **Corporate Cease Trade Orders**

No current director or executive officer is, or has been within 10 years prior to the date of this AIF, a director, chief executive officer or chief financial officer of any company that

- (a) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation and that was in effect for a period of more than 30 consecutive days, that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer of the relevant company; or
- (b) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation and that was in effect for a period of more than 30 consecutive days, that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

## **Penalties or Sanctions**

None of Angle Energy's director, executive officer, or shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company have been subject to

- (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or
- (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

## **Bankruptcies**

Except as set forth in this AIF, no current director, executive officer or shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company is, or has within 10 years prior to the date of this AIF:

- (a) been a director or executive officer of any company that, while that person was acting in that capacity, or 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; or
- (b) become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Mr. Edward Muchowski, a director of Angle Energy, is a former director of Calgary New Holland Sales & Service Ltd., a private corporation that was incorporated under the ABCA and which was petitioned into bankruptcy proceedings under the *Bankruptcy and Insolvency Act* (Canada) in December 2000. Mr. Muchowski was not a director at this time; however, he was a director within one year thereof.

## **Conflicts of Interest**

There are no existing material conflicts of interest between Angle Energy or its subsidiaries and any of their directors and officers. However, certain directors and officers of the Company are, and may continue to be, directors, officers or shareholders of other oil and gas companies whose operations may, from time to time, be in

direct competition with those of the Company or with entities which may, from time to time, provide financing to, or make equity investments in competitors of the Company. In accordance with the ABCA, such directors and officers will be required to disclose all conflicts of interest as such conflicts arise. If a conflict of interest arises at a meeting of the board, any director in a conflict will disclose his interest and abstain from voting on such matter.

## **AUDIT COMMITTEE**

### **Audit Committee Charter**

The Company's audit committee mandate is attached as Appendix A.

### **Composition of the Audit Committee**

The audit committee of Angle Energy (the "**Audit Committee**") is currently comprised of three directors: Mr. Timothy Dunne (Chairman), Mr. John Gareau and Mr. Clarence Chow. All members of the Audit Committee are considered "independent" (as determined under National Instrument 52-110 *Audit Committees*) ("**NI 52-110**") and are financially literate.

### **Relevant Education and Experience**

Each member of the Audit Committee has served in senior positions within their respective organizations and/or served as directors of public and private companies, which has afforded them the opportunity to gain familiarity with financial matters relevant to Angle Energy.

*John M.F. Gareau*  
*Director*

Mr. Gareau has over 50 years of experience in the oil and gas industry. Mr. Gareau was a director of Moxie Exploration Ltd. from November 1999 until July 2003. In addition, Mr. Gareau was a director of Vision 2000 Exploration Ltd. from June 1997 until November 2004 and a director of Kensington Energy Ltd. from April 1995 until February 2005. Mr. Gareau was also a director of TriGas Exploration Inc. from 1995 through 2000. Mr. Gareau obtained his Bachelor of Science degree from McGill University in 1952 and is a member of the Canadian Association of Petroleum Landmen.

*Clarence Y. Chow*  
*Director*

Mr. Chow has over 30 years of experience in managing and operating private and publicly traded junior oil and gas companies. He is currently the President and director of CGS Asset Management Ltd., a company which engages in investing in the oil and gas industry. He is also a director of a number of private oil and gas companies. Mr. Chow served as the President of Justinian Explorations Ltd. He obtained a Bachelor of Science degree in Chemical Engineering from the University of Alberta in 1977 and completed his executive business training at the Richard Ivey Business School, University of Western Ontario. Mr. Chow is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and is also a former Chairman of the Canadian Petroleum Institute.

*Timothy V. Dunne*  
*Director*

Mr. Dunne has over 20 years of experience as Vice President, Finance and Chief Financial Officer in the oil and gas industry. Mr. Dunne was the CFO for Defiant Resources Corporation (formerly Defiant Energy Corporation) from 1998 to 2005. Mr. Dunne was also the Vice President, Finance and Chief Financial Officer of Barrington Petroleum Ltd. from 1993 through 1998 and the Chief Financial Officer of Joss Energy Ltd. from 1985 through 1993. Mr. Dunne was admitted to the membership Institute of Chartered Accountants in England and Wales in 1975 and subsequently admitted into fellowship in 1980.

### Reliance on Certain Exemptions

Since the commencement of Angle Energy's most recently completed financial year, the Company has not relied on the exemptions contained in section 2.4 (*De Minimis Non-audit Services*), section 3.2 (*Initial Public Offerings*), section 3.4 (*Events Outside Control of Member*), section 3.5 (*Death, Disability or Resignation of Audit Committee Member*) or Part 8 of NI 52-110 (*Exemptions*).

### Reliance on the Exemptions in Subsection 3.3(2) or Section 3.6

Since the commencement of Angle Energy's most recently completed financial year, Angle Energy has not relied on the exemptions contained in subsection 3.3(2) (*Controlled Companies*) or section 3.6 (*Temporary Exemption for Limited and Exceptional Circumstances*) of NI 52-110.

### Reliance on Section 3.8

Since the commencement of Angle Energy's most recently completed financial year, Angle Energy has not relied on section 3.8 (*Acquisition of Financial Literacy*) of NI 52-110.

### Audit Committee Oversight

Since the commencement of the Company's most recently completed fiscal year, the board of directors has adopted all recommendations of the Audit Committee with respect to the nomination or compensation of an external auditor.

### Pre-Approval Policies and Procedures

The Company has not adopted specific policies and procedures for the engagement of non-audit services. The Audit Committee reviews the engagement of non-audit services as required.

### Fees Charged by External Auditors

The following table sets out the aggregate fees billed by Angle Energy's external auditors in each of the last two fiscal years for the category of fees described:

	2009	2008
Audit Fees <sup>(1)</sup>	90,000	\$80,000
Audit-Related Fees <sup>(2)</sup>	52,500	\$46,990
Tax Fees <sup>(3)</sup>	27,620	\$34,020
All Other Fees	157,000 <sup>(5)</sup>	\$115,260 <sup>(4)</sup>

#### Notes

- (1) The services comprising the fees under this category consisted of those matters related to the preparation of Angle Energy's annual audited financial statements for the years ended December 31, 2009 and December 31, 2008.
- (2) The fees set forth in this category consisted of fees charged by Angle Energy's auditors in connection with review engagements of interim financial statements.
- (3) The services comprising the fees under this category consisted of tax advice and compliance, which included the preparation and filing of annual tax returns.
- (4) The services comprising the fees under this category for the year ended December 31, 2008 consisted of services rendered in connection with equity private placements, the IPO and consulting.
- (5) The services comprising the fees under this category for the year ended December 31, 2009 consist of services rendered in connection with equity private placements, tax due diligence on acquisitions and IT internal control documentation.

### INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations. Controls relating to land tenure, exploration, development, production, refining, transportation and marketing, among other things, are imposed by legislation and regulation enacted by various levels of government. The pricing and taxation of oil and natural gas is regulated by agreements among the governments of Canada and Alberta. It is not expected

that any of these controls or regulations will affect the operations of Angle Energy in a manner materially different than they would affect other oil and gas corporations of similar size. All current legislation is a matter of public record and Angle Energy is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry. All controls and regulations that relate to the oil and gas industry should be carefully considered by investors contemplating investing in or currently invested in this industry.

### **Pricing and Marketing of Oil and Natural Gas**

In Canada the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which means that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. Specific prices depend in part on oil quality, prices of competing fuels, distance to market, value of refined products, the balance of supply and demand and other contractual terms. While exporters are free to negotiate prices and other terms with purchasers, crude oil exported from Canada is subject to regulation by the National Energy Board of Canada (“NEB”). Crude oil must be exported pursuant to either an export order or an export licence from the NEB. Crude oil exports for a term less than one year for light and medium crude, or two years for heavy crude, may be made pursuant to an export order. Any oil export made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB, which requires the approval of the Governor in Council (i.e. federal cabinet).

The price of natural gas is also determined by negotiation between buyers and sellers and natural gas exported from Canada is also subject to regulation by the NEB and the Government of Canada. While exporters are free to negotiate prices and other terms with purchasers, natural gas must be exported pursuant to either an export order or an export licence from the NEB. Natural gas exports for a term of less than two years, or for a term of two to 20 years in quantities of not more than 30,000 m<sup>3</sup>/day, may be made pursuant to an NEB export order. Any natural gas export to be made pursuant to a contract longer than two years or in excess of 30,000 m<sup>3</sup>/day requires an exporter to obtain an export licence from the NEB, which requires the approval of the Governor in Council.

The Government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

### **Pipeline Capacity**

Interprovincial and international natural gas pipelines are regulated by the NEB and provide the opportunity for firm pipeline capacity. Interprovincial and international crude oil pipelines are also regulated by the NEB and operate on a common carrier basis. The NEB has allowed some crude oil pipelines to meet common carrier obligations by providing firm contract service. Depending upon the pipeline, there is therefore some apportionment risk (i.e. risk of pro-rationing capacity) relating to crude oil service that is not subject to firm contracts, which may affect the ability to produce and market oil production.

### **The North American Free Trade Agreement**

The North American Free Trade Agreement (“NAFTA”) among the governments of Canada, the United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. NAFTA parties are generally prohibited from imposing minimum or maximum import and export price restrictions. However, import price restrictions are allowed to the extent that such restrictions are allowed by the anti-dumping and anti-subsidy provisions of the *General Agreement on Tariffs and Trade*.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to

ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

## **Provincial Royalties and Incentives**

### *General*

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. From time to time non-public transactions create other royalties and royalty-like interests. These are often referred to as overriding royalties, gross overriding royalties, net profit interests or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal.

With the elimination of the corporate surtax effective, January 1, 2008, and other rate reductions initially introduced in the October 2007 Economic Statement, the federal corporate income tax rate has or will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009, 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

### *Alberta*

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil and gas reserves in Alberta. Oil produced from horizontal extensions commenced at least five years after the well was originally spudded may qualify for a royalty reduction. A 24 month, 8,000 m<sup>3</sup> exemption is available to production from a well that has not produced for a 12 month period, if resuming production after February 1, 1993. As well, oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992 is entitled to a 12 month royalty exemption (to a maximum of \$1 million). Oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

Natural gas produced from qualifying exploratory gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 is eligible for a royalty exemption for a period of 12 months, up to a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

The Alberta government in August 2006 introduced the Innovative Energy Technologies Program (the “**IETP**”) to promote producers’ investment in research, technology and innovation with royalty reductions. The final deadline for IETP applications was September 30, 2008.

On October 25, 2007, the Government of Alberta unveiled the NRF. The NRF introduced new royalties for conventional oil, natural gas and bitumen on January 1, 2009 that are linked to price and production levels and apply to both new and existing oil sands projects and conventional oil and gas activities. The Alberta government supplemented the NRF on April 10, 2008 with two, five-year royalty programs, which also came into effect on

January 1, 2009: the *Deep Oil Exploratory Well Regulation* and the *Natural Gas Deep Drilling Regulation*. These regulations are designed to encourage the continued development of deep, high-cost oil and gas reserves.

Royalties payable pursuant to Crown petroleum and natural gas leases are assessed on a sliding scale where the rate changes depending on oil or natural gas prices and the level of production. The NRF for conventional oil operates on a sliding rate formula containing separate elements that account for oil price and well production. Royalty rates for conventional oil range up to 50 percent, with rate caps once the price of conventional oil reaches \$115.75 per barrel. As part of its response to the release of its long-anticipated Competitiveness Review on March 11, 2011, the Alberta Government committed to reduce the maximum conventional oil royalty from 50% to 40%. The royalty curves reflecting these changes will be finalized and announced by May 31, 2010. Accordingly, the precise prices at which maximum royalties apply have not yet been determined.

Under the NRF, natural gas royalties are also set by a sliding rate formula sensitive to price, production volume and measured well depth. New natural gas royalty rates range from 5 percent to 50 percent with rate caps once the price of natural gas reaches \$17.75/GJ. Royalties for natural gas liquids are set at 40 percent for pentanes and 30 percent for butanes and propane. Similar to conventional crude royalties, as part of the Alberta government's response to the Competitiveness Review the maximum conventional natural gas royalty will be reduced from 50% to 36%, and new royalty curves reflecting these changes will be finalized and announced by May 31, 2010. The Alberta government also indicated that further changes may be made to the natural gas royalty rates.

To spur new drilling the Alberta government announced a transitional royalty option on November 19, 2008, to apply to wells spudded between November 19, 2008 and December 31, 2013, if the company so elects. However, as part of the Competitiveness Review response as of January 1, 2011, wells will no longer be able to elect the transitional royalty option. Wells that have already selected the transitional regime will be allowed to switch to the general royalty regime, with new royalty curves, at that time.

On March 3, 2009, in response to economic conditions the Alberta government announced a temporary royalty program designed to stimulate drilling activity. The program offers \$200 in royalty credits per meter drilled on new conventional oil and natural gas wells. To qualify, a well must be a conventional oil and gas well on Crown mineral rights, spudded between April 1, 2009 and April 1, 2010, and finish drilling within the same time frame. The maximum credit is dependent upon a sliding scale formula depending on production size and Crown royalties paid between April 1, 2009 and March 31, 2010. Producers with less than 10,000 boe/d of production are eligible for a maximum credit of 50% on qualifying Crown royalties paid. In addition, all new wells that commence initial production of conventional oil and natural gas on Crown leases between April 1, 2009 and March 31, 2010 will pay a maximum royalty of 5% for 12 calendar months, 50,000 barrels of oil production or 500 mcm of natural gas production, whichever is reached first. On June 25, 2009 the eligibility for each of these programs was extended by an additional year. The latter 5% maximum royalty program will be made permanent as of January 1, 2011, as part of the Competitiveness Review response.

Under the NRF, Angle Energy's average royalty rate may increase based on pricing and or increased productivity from new wells. These recent changes could have a negative impact on net earnings, funds from operations, cash flow from operating activities, operating netbacks, and reserve values, which could create uncertainty as to the recoverability of the carrying value of Angle Energy's petroleum and natural gas assets. Nonetheless, Angle Energy expects the economics of production from its properties will be acceptable under the new royalty regime. This is due, in part, to the potential decreased industry activity leading to reduced costs of services, which would offset the potential nominal decline in rates of return due to a higher royalty.

## **Land Tenure**

Crude oil and natural gas located in the Western Canadian provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

## Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean up orders.

The Province of Alberta's environmental legislation is the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), the *Oil and Gas Conservation Act* ("**OGCA**") and directives and guidelines issued by both Alberta Environment ("**AENV**") and the Energy Resources Conservation Board ("**ERCB**"). The EPEA, OGCA and AENV/ERCB directives impose environmental standards with respect to releases of effluents and emissions, including reporting and monitoring obligations, and impose significant penalties for non-compliance. For example, regulations enacted under the EPEA target sulphur oxide and nitrous oxide emissions from oil and gas operations. In addition, the greenhouse gas emissions ("**GHGs**") intensity reduction requirement of the *Specified Gas Emitters Regulation* implemented under the *Climate Change and Emissions Management Act* (Alberta) came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of GHGs a year must reduce their emissions intensity by 12% from their baseline intensity level. This threshold is expected to decline in the future to 50,000 tonnes. If the emissions intensity target is not met through improvements in operations, compliance tools include: per tonne payments into the climate change emissions management fund; purchase of Alberta-based offsets or purchase emission performance credits from a different Alberta facility. Failure to comply with these regulations results in a penalty of \$200 per tonne of GHGs over the allowable GHG intensity limit. Angle Energy does not operate a facility emitting 50,000 tonne/yr of GHGs.

Angle Energy will meet its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA, the OGCA and similar legislation in other jurisdictions in which it operates. Angle Energy believes that it is in material compliance with applicable environmental laws and regulations. It also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Protocol, was passed by the House of Commons on February 14, 2007, requiring Canada to reduce GHGs to 6% below 1990 levels. However, the federal government has largely abandoned its intention to comply with its Kyoto Protocol obligations.

On April 26, 2007, the Federal Government released its *Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution* regulatory framework, supplementing it on March 10, 2008, with *Turning the Corner – Taking Action to Fight Climate Change* (the "**Turning the Corner Plan**"). The Turning the Corner Plan envisaged an intensity-based GHG reduction framework. However, the Federal Government has subsequently indicated that it now instead expects to implement a cap-and-trade GHG reduction framework similar to legislation proposed in the United States.

On December 19, 2009, Canada signed the Copenhagen Accord, the outcome of the 2009 United Nations Climate Change Conference (the "**Copenhagen Summit**") that committed signatory countries to take individual GHG reduction steps. On January 31, 2010 Canada registered its commitment under the Copenhagen Accord to reduce its GHG emissions by 17% from 2005 levels by 2020, adopting the same target as the United States, subject to the United States enacting GHG reduction legislation. It is not clear when federal regulations or legislation to take this step will be enacted.

Prior the Copenhagen Summit, the United States and Canada agreed to a preliminary “clean energy strategy dialogue” and staffed an associated working group. The United States House of Representatives has passed the *American Clean Energy and Security Act*, and it is now before the United States Senate, which in turn has passed the *Clean Energy Jobs and American Power Act*. Each piece of legislation contemplates a cap-and-trade GHG reduction regime. However, it is unclear if the Senate will be able to pass into law one or a combination of the two Acts. If Canada harmonizes with the United States on GHG and climate change policy, this may result in increased costs or reduced revenue to Angle Energy.

Given the evolving nature of the climate change issue, the regulation of GHGs and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on Angle Energy and its operations and financial condition at this time. However, if climate change regulations comparable to the Turning the Corner Update standards are implemented (e.g. a production threshold of 10,000 boe/d and the obligation to reduce emissions equivalent to an 18% emissions intensity reduction) then compliance would represent an additional cost that would negatively affect Angle Energy.

## **Trends**

There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Recently, liquefied natural gas shipments to North America have also resulted in natural gas supply and natural gas pricing being based more on factors other than supply and demand in North America. Changes to any of these or other factors create price volatility.

Crude oil is influenced by the world economy and Organization of the Petroleum Exporting Countries’ ability to adjust supply to world demand. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East. Political events trigger large fluctuations in price levels.

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar may negatively impact production revenues from Canadian producers and further increases in the value of the Canadian dollar would exacerbate this negative impact. Such increases may also negatively impact the future value of such entities’ reserves as determined by independent evaluators.

Another trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the overall North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that climate change legislation will have on the sector, by the June 22, 2007 SIFT Amendments to the Tax Act, by the October 25, 2007 proposal of the Alberta government relating to the NRF, and by the subsequent changes to maximum conventional oil and gas royalty rates and new royalty curves to be implemented as part of the Alberta government’s March 11, 2010 response to its Competitiveness Review. The combined impacts of the NRF and the Competitiveness Review are still being determined and will vary company to company based on the percentage of production in Alberta, their commodity mix and depths of production, among other things. The combined effects of the Competitiveness Review and the NRF may also impact upon investor sentiment to investment in the Province of Alberta. The amount and degree of these impacts have yet to be determined.

Under the SIFT Amendments, SIFTs will be liable for tax at tax rates that approximate those applicable to corporations commencing in January 2011, provided that the SIFT experiences only “normal growth” and no “undue expansion” before then, in which case the tax could be imposed prior to the January 2011 deadline. Although the SIFT Amendments will not affect the method in which Angle Energy will be taxed, it may have an impact on the ability of a SIFT to purchase producing assets from oil and gas exploration and production companies (as well as the price that a SIFT is willing to pay for such an acquisition) thereby affecting the exploration and production companies’ ability to be sold to a SIFT, which has been a key “exit strategy” in recent years for oil and gas companies. This may be a benefit for junior and mid-sized companies as they will compete with SIFTs for the acquisition of oil and gas properties from such producers. However, it may also limit such companies’ abilities to sell producing properties or pursue an exit strategy.

The operations of Angle Energy are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. Angle Energy is committed to meeting its responsibilities to protect the environment and Angle Energy will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. Angle Energy believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment. However, it is not currently possible to quantify any such increased expenditures and it is not anticipated that Angle Energy’s competitive position will be adversely affected by current or future environmental laws and regulations governing its oil and natural gas operations.

## **RISK FACTORS**

The following are certain risk factors related to Angle Energy, its business, and the ownership of the securities of Angle Energy which investors should carefully consider. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in the AIF. If any event arising from the risk factors set forth below occurs, Angle Energy’s business, prospects, financial condition, results of operation or cash flows and in some cases its reputation could be materially adversely affected.

### **Exploration, Development and Production Risks**

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Angle Energy depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Angle Energy may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Angle Energy’s reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that Angle Energy will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Angle Energy may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Angle Energy.

Future oil and natural 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. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating 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 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.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas

releases and 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, Angle Energy is not fully insured against all of these risks, nor are all such risks insurable. Although Angle Energy maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Angle Energy could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

### **Risks Associated with Acquisitions**

Acquisitions of oil and gas properties or companies are based in large on engineering, environmental and economic assessments made by the acquiror, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Company. All such assessments involve a measure of geologic, engineering, facility operations, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

Although title and environmental reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that any unforeseen defects in the change of title will not arise to defeat the Company's title to certain assets or that environmental defects or deficiencies do not exist.

### **Volatility of Market Price of Common Shares**

The market price of the common shares may be volatile. The volatility may affect the ability of holders to sell the common shares at an advantageous price. Market price fluctuations in the common shares may be due to the Company's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by the Company or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "Forward-Looking Statements". In addition, in 2008 and 2009 the market price for securities in the stock markets, including the TSX, experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market prices of the common shares of the Company.

### **Failure to Realize Anticipated Benefits of Acquisition and Disposition, including the Ferrier and Stonefire Acquisitions**

Angle Energy makes acquisitions and dispositions of businesses and assets in the ordinary course of business. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. On June 1, 2009 and January 12, 2010, the Company completed the Ferrier and Stonefire acquisitions, respectively, in furtherance of its business and to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits including, among other things, production and reserves growth and potential cost savings. Achieving the benefits of the Ferrier and Stonefire acquisitions and future acquisitions the Company may complete depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses, assets and operations with those of Angle Energy. The integration of the acquired businesses and assets requires the dedication of management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may cause disruptions which may adversely affect the Company's ability to achieve the anticipated benefits

of this and future acquisitions. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that Angle Energy can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of Angle Energy, if disposed of, could be expected to realize less than their carrying value on the financial statements of Angle Energy.

### **Volatility of Commodity Prices**

Oil and natural gas prices fluctuate significantly in response to regional, national and global supply and demand factors beyond the control of Angle Energy. Political and economic developments around the world can affect world oil and natural gas supply and prices. Any prolonged period of low oil and natural gas prices could result in a decision by Angle Energy to suspend or terminate exploration, as it may become uneconomic to explore for and/or produce oil or natural gas at such prices.

### **Operational Matters**

The ownership and operation of oil and natural gas wells, pipelines and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to Angle Energy's properties and possible liability to third parties. Angle Energy intends to employ prudent risk management practices and maintain suitable liability insurance, where available. Angle Energy may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities could have a material adverse effect on Angle Energy, its operations and financial condition.

### **Reliance on Operators, Management and Key Personnel**

Successfully exploring for, developing and commercializing oil and gas interests depends on a number of factors, not the least of which is the technical skill of the personnel involved. Angle Energy's success will be, in part, dependent on the performance of its key managers and consultants. Failure to retain the managers and consultants, or to attract or retain additional key personnel, with the necessary skills and experience could have a materially adverse impact upon Angle Energy's growth and profitability. Angle Energy does not carry key person insurance. In addition, Angle Energy may not be the operator of certain oil and gas properties in which it acquires an interest. To the extent Angle Energy is not the operator of its oil and gas properties, Angle Energy will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators.

### **Reserve Replacement**

Angle Energy's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Angle Energy successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Angle Energy may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Angle Energy's reserves will depend not only on Angle Energy's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Angle Energy's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas. Competition may also be presented by alternate fuel sources.

### **Reserve Estimates**

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and cash flows to be derived therefrom, including many factors beyond Angle Energy's control. The information concerning reserves and associated cash flow set forth in this AIF represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves

attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Angle Energy's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based, in part, on the assumed success of the 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 evaluation.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material. Many of Angle Energy's producing wells have a limited production history and thus there is less historical production on which to base the reserves estimates. In addition, a significant portion of Angle Energy's reserves may be attributable to a limited number of wells and, therefore, a variation in production results or reservoir characteristics in respect of such wells may have a significant impact upon Angle Energy's reserves.

In accordance with applicable securities laws, GLJ has used forecast price and cost estimates in calculating reserve quantities. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the GLJ Report and the GLJ Stonefire Report, and such variations could be material. The GLJ Report and the GLJ Stonefire Report are based in part on the assumed success of activities Angle Energy intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the GLJ Report and the GLJ Stonefire Report will be reduced to the extent that such activities do not achieve the level of success assumed in the GLJ Report and the GLJ Stonefire Report.

The GLJ Report and the GLJ Stonefire Report are effective as of a specific effective date and have not been updated and thus do not reflect changes in Angle Energy's resources since that date.

#### **Additional Funding Requirements and Liquidity Risk**

Angle Energy's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Angle Energy may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities or to fully realize the Company's strategic goals and business plans. If Angle Energy's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Angle Energy's ability to expend the necessary capital to replace its reserves or to maintain its production. If Angle Energy'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 favourable terms. To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets or operations may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Continued uncertainty in domestic and international credit markets could materially affect the Company's ability to access sufficient capital for its capital expenditures and acquisitions and, as a result, may have a material adverse effect on the Company's ability to execute its business strategy and on its financial condition. There can be no assurance that financing will be available or sufficient to meet these requirements or for other corporate purposes or, if financing is available, that it will be on terms appropriate and acceptable to us. The Company cannot predict the size of future issuance of equity or the issuance of debt or the effect, if any, that future issuance and sales of the Company's securities will have on the market price of its common shares. In addition, future financings or other transactions involving the issuance of securities of the Company may be dilutive to existing shareholders.

## **Hedging**

From time to time the Company 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, the Company will not benefit from such increases and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements.

## **Environmental Concerns**

The oil and natural gas industry is subject to environmental regulations pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or other penalties as well as the responsibility to remedy environmental problems caused by Angle Energy's operations. See "*Industry Conditions — Environmental Regulation*". Should Angle Energy be unable to fully fund the cost of remedying an environmental problem, Angle Energy might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Angle Energy to incur costs to remedy such discharge. Although Angle Energy believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Angle Energy's financial condition, results of operations or prospects. See "*Industry Conditions – Environmental Regulation*".

## **Regulatory**

Oil and gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government and may be amended from time to time. See "*Industry Conditions*". Angle Energy's operations may require licences from various governmental authorities. There can be no assurance that Angle Energy will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its projects. It is not expected that any of these controls or regulations will affect the operations of Angle Energy in a manner materially different from how they would affect other oil and natural gas companies of similar size.

## **New Alberta Royalty Regime**

On October 25, 2007, the Albert government released the NRF. This introduced new royalties for conventional oil, natural gas and bitumen on January 1, 2009 that are linked to price and production levels and apply to both new and existing oil sands projects and conventional oil and gas activities. The Alberta government supplemented the NRF on April 10, 2008, with two, five-year royalty programs, that also came into effect on January 1, 2009: the Deep Oil Exploratory Well Regulation and the Natural Gas Deep Drilling Regulation. These are designed to encourage the continued development of deep, high-cost oil and gas reserves.

On March 3, 2009, in response to economic conditions the Alberta government announced a temporary royalty program designed to stimulate drilling activity. A drilling royalty credit will offer \$200 in royalty credits per meter drilled on new conventional oil and natural gas wells. To qualify, a well must be a conventional oil and gas producing well drilled on Crown mineral rights, spudded between April 1, 2009 and April 1, 2010, and finish drilling within the same time frame.

On June 25, 2009, the Alberta government announced a one year extension to the above drilling stimulus program and announced that it was undertaking an overall competitiveness review by consulting industry and coordinating between different government departments. The government announced its response to the competitiveness review results on March 11, 2010. One of the major outcomes is that royalty curves for conventional oil and gas will be released by May 31, 2010. The maximum royalty rates will be reduced from 50% to 40% for oil and 36% for gas. The temporary stimulus “front end” royalty for the first year of production for each of oil and gas wells will be made permanent instead of ending on March 31, 2011. Eligibility for the NRF “transition” royalty regime will end on January 1, 2011, although wells that have already elected that regime can opt into the new royalty curves as of that date.

Under the NRF, and despite the forthcoming new royalty curves, Angle Energy’s average royalty rate may increase based on pricing and or increased productivity from new wells. These recent changes could have a negative impact on net earnings, funds from operations, cash flow from operating activities, operating netbacks, and reserve values, which could create uncertainty as to the recoverability of the carrying value of Angle Energy’s petroleum and natural gas assets. Nonetheless, Angle Energy expects the economics of production from its properties will be acceptable under the new royalties. This is due, in part, to the potential decreased industry activity leading to reduced costs of services, which would offset the potential nominal decline in rates of return due to a higher royalty.

### **Climate Change Legislation**

Canada is a signatory to the United Nations Framework Convention on Climate Change. Canada has ratified the Kyoto Protocol established thereunder and is thereby required to establish legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other GHGs. However, it is largely thought that the federal government has abandoned its intent to comply with its Kyoto Protocol obligations, will align itself with the GHG and climate change policy to come from the new administration in the United States under President Obama. Both Canada and the United States have committed to the same GHG reduction targets as part of the Copenhagen Accord agreed to at the Copenhagen Summit. While the United States Senate has several pieces of climate change legislation before it, it is not clear if they will be passed. The Federal Government has indicated that future federal legislation will depend upon the outcome of United States efforts. This will likely be different than the previously released Turning the Corner Plan, although the scope and timing of new regulations remains uncertain. Angle Energy’s exploration and production facilities and other operations and activities emit a small amount of GHGs which may subject Angle Energy to legislation in Canada regulating emissions of greenhouse gases.

The Province of Alberta implemented the *Specified Gas Emitters Regulation* under its *Climate Change Emissions Management Act* on July 1, 2007. This regulation requires facilities which emit in excess of 100,000 tonnes of greenhouse gases per year to reduce their emissions intensity by 12% from a baseline derived from the average of 2003-2005 emissions. This threshold is expected to be reduced to 50,000 tonnes in the near to medium term. Angle Energy is not classified as a Large Industrial Emitter under the Alberta legislation and as such, to date, the Company will not be subject to costs of complying with these emissions regulations.

### **Global Financial Crisis**

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in the third and fourth quarters of 2008 and continued into 2009, causing a loss of confidence in the broader United States and global credit and financial markets. Although capital markets appear to be stabilizing a climate of volatility, illiquidity, wide credit spreads, a lack of price transparency, credit losses and tight credit conditions persists. These factors have and may continue to negatively impact the Company’s valuations.

### **Forward-Looking Information May Prove Inaccurate**

Investors are cautioned not to place undue reliance on forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumptions and uncertainties are found in this AIF under the heading “*Forward-Looking Statements*”.

### **Investment Returns**

Angle Energy has never paid a dividend nor made a distribution on any of its securities. Further, Angle Energy may never achieve a level of profitability that would permit payment of dividends or making other forms of distributions to security holders. In any event, given the stage of the Angle Energy’s development, it will likely be a long period of time before Angle Energy could be in a position to make dividends or distributions to its investors. The payment of any future dividends by Angle Energy will be at the sole discretion of the board of directors of Angle Energy. In this regard, Angle Energy currently intends to retain earnings to finance the expansion of its business and does not anticipate paying dividends in the foreseeable future.

### **Competition**

There is strong competition relating to all aspects of the oil and natural gas industry. Angle Energy will actively compete for capital, skilled personnel, access to 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 will have greater technical and financial resources than Angle Energy.

### **Availability of Equipment and Qualified Personnel and Related Costs**

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment and qualified personnel in the particular areas where such activities will be conducted. Demand for such limited equipment and qualified personnel may affect the availability of such equipment and qualified personnel to Angle Energy and may delay Angle Energy’s exploration and development activities. In addition, the costs of qualified personnel and equipment in the area where Angle Energy’s assets are located are very high due to the availability of, and demands for, such qualified personnel and equipment in the area.

### **Management of Growth**

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

### **Title to Properties**

Although 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 of Angle Energy, which could result in a reduction of the revenue received by Angle Energy.

### **Potential Conflicts of Interest**

Certain of the directors of Angle Energy are also directors or officers of corporations which are in competition to the interests of Angle Energy. No assurances can be given that opportunities identified by such board members will be provided to Angle Energy. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as applicable under the ABCA.

### **Changes in Legislation**

There can be no assurance that income tax laws, other laws or government incentive programs relating to the oil and gas industry will not be changed in a manner that will adversely affect Angle Energy. The NRF and new forthcoming royalty curves from the government’s competitiveness review have not been fully implemented and there is uncertainty as to the final form it will take. There can be no assurance that tax authorities having

jurisdiction will agree with how Angle Energy calculates its income for tax purposes or that such tax authorities will not change their administrative practices to the detriment of Angle Energy.

### **Seasonality and Climate**

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may result in limited access and, as a result, reduced operations or a cessation of operations.

Municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment during periods of wet weather, thereby reducing activity levels. Also, certain oil and natural 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 Angle Energy.

### **Borrowing and Further Issuance of Debt**

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

From time to time, Angle Energy 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 Angle Energy's debt levels above industry standards. Neither Angle Energy's articles nor its by-laws limit the amount of indebtedness that Angle Energy may incur. The level of Angle Energy's indebtedness from time to time could impair Angle Energy's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

### **Aboriginal Claims**

Aboriginal peoples have claimed Aboriginal and treaty rights to portions of Western Canada. Angle Energy is not aware that any claims have been made in respect of Angle Energy's assets; however, if a claim arose and was successful this could have an adverse effect on Angle Energy and its operations.

### **Third-Party Credit Risk and Delays**

Angle Energy is or may be exposed to third-party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production, suppliers and other parties. In the event such entities fail to meet their contractual obligations to Angle Energy, such failures could have a material adverse effect on Angle Energy and its funds from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Angle Energy's ongoing capital program, potentially delaying the program and the result of such program until Angle Energy finds a suitable alternative partner.

In addition to the usual delays in payments by purchasers of oil and natural gas to Angle Energy or to the operators, and the delays by operators in remitting payment to Angle Energy, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale of delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of Angle Energy in a given period and expose Angle Energy to additional third party credit risks.

### **Limitations of Insurance**

Angle Energy's involvement in the exploration for and development of oil and gas properties may result in Angle Energy becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards.

Although Angle Energy has obtained insurance in accordance with industry standards to address such 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, Angle Energy 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 Angle Energy. The occurrence of a significant event that Angle Energy is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Angle Energy's financial position, results of operations or prospects.

### **Alternatives to and Changing Demand for Petroleum Products**

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. Angle Energy cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on Angle Energy's business, financial condition, results of operations and cash flows.

### **LEGAL PROCEEDINGS AND REGULATORY ACTIONS**

To the knowledge of the Company, there are no legal proceedings and regulatory actions material to the Company to which the Company is a party or of which any of its properties are the subject matter, nor are any such proceedings known to the Company to be contemplated.

Since incorporation, there have not been any penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, and the Company has not entered into any settlement agreements before a court relating to securities legislation or with a securities regulatory authority.

### **INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

Other than as disclosed in this AIF, to the knowledge of the directors and officers of the Company, none of the directors or executive officers of the Company, nor any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the voting rights attached to all outstanding voting securities of the Company, nor any of their respective associates or affiliates, has or has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years or during the Company's current year or in any proposed transaction which has materially affected or is reasonably expected to materially affect the Company.

Noralee Bradley, the Chairman of the Company, is a partner of Osler, Hoskin & Harcourt LLP, which law firm provides legal services to the Company.

### **AUDITORS, TRANSFER AGENTS AND REGISTRARS**

The auditor of the Company is KPMG LLP, Chartered Accountants, Calgary, Alberta. KPMG LLP, Chartered Accountants was first appointed by the board to be the Company's auditor in February 2008.

The registrar and transfer agent for common shares of the Company is Valiant Trust Company at its principal office in Calgary, Alberta with a branch office in Toronto, Ontario. The register of transfers of common shares is located at the office of Valiant Trust Company in Calgary, Alberta.

### **MATERIAL CONTRACTS**

Except for the Stonefire Agreement and as disclosed elsewhere in this AIF, and except for contracts entered into in the ordinary course of business, no material contracts were entered into by the Company during the most recently completed financial year, nor are any material contracts in effect that were entered into prior to the beginning of the most recently completed financial year.

## **INTERESTS OF EXPERTS**

Reserve estimates contained in this AIF are derived from a report prepared by GLJ, an independent reserves evaluator. As at the date hereof, to the knowledge of the Company, neither GLJ nor its officers, directors, employees or consultants beneficially own, directly or indirectly, any of the outstanding common shares of the Company. In addition, none of the officers, directors, employees or consultants of GLJ are currently expected to be elected, appointed or employed as a director, officer or employee of the Company or any of its associates or affiliates.

As of the date of this AIF, KPMG LLP, Chartered Accountants have reported that they are independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

Other than as set out above, no other experts (whose profession or business gives authority to a report, valuation, statement or opinion made by them) were named in any securities disclosure document filed by the Company in the most recently completed financial year.

## **ADDITIONAL INFORMATION**

Additional information regarding Angle Energy may be found on SEDAR at [www.sedar.com](http://www.sedar.com). Additional information, including directors' and officers' remuneration and indebtedness, the principal holders of common shares and the securities authorized for issuance under equity compensation plans, is contained in the Company's information circular relating to the annual meeting of shareholders to be held May 26, 2010, or any adjournment thereof. Additional financial information is provided in the annual audited financial statements of the Company and the management's discussion and analysis for the financial year ended December 31, 2009.

**APPENDIX A  
ANGLE ENERGY INC.  
(THE “COMPANY”)  
AUDIT COMMITTEE MANDATE**

**General**

The board of directors of the Company (the “**Board**”) will establish an audit committee (the “**Audit Committee**”). The primary role of the Audit Committee is to assist the Board in fulfilling its oversight responsibilities regarding the following:

- the accuracy and completeness of the Company’s financial statements;
- the internal control and financial reporting systems of the Company;
- the selection and activities of the Company’s external auditor;
- communicating directly with the Company’s internal and external auditors;
- the development of the Company’s risk management strategy;
- the Company’s compliance with legal and regulatory requirements; and
- any additional duties set out in this Mandate or otherwise delegated to the Audit Committee by the Board.

**Composition and Operation**

The Board will in each year appoint at least three Directors as members of the Audit Committee. All of the members of the Audit Committee must be “independent” directors as such term is defined from time to time under the requirements or guidelines for audit committee service under applicable securities laws and the rules of any stock exchange on which the Company’s securities are listed for trading.

All members of the Audit Committee must be financially literate. While the Board shall determine from time to time the definition of, and criteria for, financial literacy, this shall, at a minimum, include the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company’s financial statements.

Directors who are not members of the Audit Committee may attend all or any part of meetings of the Audit Committee, but shall not vote.

**Mandate**

The Audit Committee shall have the following duties:

*Financial Reporting and Disclosure*

Review the audited annual financial statements as prepared by management in conjunction with the external auditors, related management discussion and analysis of operations and financial results (“**MD&A**”) and earnings press releases for submission to the Board for approval.

Such reviews shall be conducted prior to the release of any summary of financial results or the filing of such reports with the applicable regulatory authority.

Review the unaudited quarterly financial statements, the related MD&A and earnings press releases for submission to the Board for approval.

Review with management and the external auditor significant accounting practices employed by the Company and disclosure issues, including complex or unusual transactions, judgmental areas such as reserves or estimates, significant changes to accounting principles, and alternative treatments under Canadian GAAP for material transactions. This review process must be undertaken in order to have reasonable assurance that the financial statements are complete, do not contain any misrepresentations, and present fairly the Company's financial position and the results of its operations in accordance with Canadian GAAP.

Confirm through discussions with management that Canadian GAAP and all applicable laws or regulations related to financial reporting and disclosure have been complied with.

Review any actual or anticipated litigation or other events, including tax assessments, which could have a material current or future effect on the Company's financial statements, and the manner in which these have been disclosed in the financial statements.

Discuss with management the effect of any off-balance sheet transactions, arrangements, obligations and other relationships with unconsolidated entities or other persons that may have a material effect on the Company's financial condition, results of operations, liquidity, capital expenditures, capital resources, or revenues and expenses.

Satisfy itself that adequate procedures are in place for the review of the Company's public disclosure of financial information extracted from the Company's financial statements and periodically assess the adequacy of those procedures.

#### *Oversight of Internal Controls*

Review and assess the adequacy and effectiveness of the Company's system of internal control and management information systems through discussions with management and the external auditor.

Oversee system of internal control by:

- consulting with the external auditor regarding the adequacy of the Company's internal controls;
- monitoring policies and procedures for internal accounting, financial control and management information, electronic data control and computer security;
- obtaining from management adequate assurances that all statutory payments and withholdings have been made; and
- taking other actions as considered necessary.

Oversee investigations of alleged fraud and illegality relating to the Company's finances and any resulting actions.

Establish procedures for the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls or auditing matters, the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters, and for the protection from retaliation of those who report such complaints in good faith.

#### *External Auditor Appointment and Removal*

Recommend the appointment or replacement of the external auditor to the Board, who will consider the recommendation prior to submitting the nomination to the securityholders for their approval. If a change in external auditors is proposed, the Audit Committee shall review the reasons for the change and any other significant issues related to the change including the response of the incumbent auditors and inquire on the qualifications of the proposed auditors before making its recommendation to the Board.

Review management's plans for an orderly transition to a new external auditor, if required.

Pre-approve, in accordance with applicable law, any non-audit services to be provided to the Company by the external auditor, with reference to compatibility of the service with the external auditor's independence.

Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor.

#### *External Auditor Liaison*

The external auditor will report directly to the Audit Committee.

Overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company.

Resolve any disagreements between management and the external auditor regarding financial reporting.

Review all other material written communications between the external auditor and management, including the post-audit management letter containing the recommendations of the external auditor, management's response and, subsequently, follow-up identified weaknesses.

Meet with the external auditor independently from management and without management present at least annually to discuss and review specific issues; and as appropriate with respect to any significant matters that the auditor may wish to bring to the Audit Committee for its consideration.

#### *External Audit Review*

Review with management, and make recommendations to the Board, regarding the compensation of the external auditor. In making a recommendation with respect to compensation, the Audit Committee shall consider the number and nature of reports issued by the external auditor, the quality of internal controls, the size, complexity and financial condition of the Company, and the extent of other support provided by the Company to the external auditor.

Review with management the terms of the external auditor's engagement, accountability, experience, qualifications and performance. Evaluate the performance of the external auditor.

Review the audit plan and scope of the external audit with the external auditor and management, and consider the nature and scope of the planned audit procedures.

Discuss with the external auditor any significant changes required in the approach or scope of their audit plan, management's handling of any proposed adjustments identified by the external auditor, and any actions or inactions by management that limited or restricted the scope of their work.

Review, independently of management, and without management present, the results of the annual external audit, the audit report thereon and the auditor's review of the related MD&A, and discuss with the external auditor the quality (not just the acceptability) of accounting principles used, any alternative treatments of financial information that have been discussed with management, the ramifications of their use and the auditor's preferred treatment, and any other material communications with management.

Engage the external auditor to review all interim financial statements and review the results of the auditor's review of the interim financial statements and the auditor's review of the related MD&A independent, and without the presence, of management.

Review any other matters related to the external audit that are to be communicated to the Audit Committee under generally accepted auditing standards or that relate to the external auditor.

Review with management and the external auditor any correspondence with regulators or governmental agencies, employee complaints or published reports that raise material issues regarding the Company's financial statements or accounting policies.

At least annually, and before the external auditor issues its report on the annual financial statements, review and confirm the independence of the external auditor through discussions with the auditor on its relationship with the Company, including details of all non-audit services provided. Consider the safeguards implemented by the external auditor to minimize any threats to their independence, and take action to eliminate all factors that might impair, or be perceived to impair, the independence of the external auditor. Consider the number of years the lead audit partner has been assigned to the Company, and consider whether it is appropriate to recommend to the Board a policy of rotating the lead audit partner more frequently than every five years, as is required under the rules of the Canadian Public Accountability Board.

#### *Risk Management*

Review and assess the adequacy of the Company's risk management policies and procedures with respect to the Company's principal business risks.

Review and assess the adequacy of the implementation of appropriate systems to mitigate and manage the risks, and report regularly to the Board.

Review the Company's insurance program.

#### *Regulatory Compliance*

Review with management the Company's relationship with regulators and the timeliness and accuracy of Company filings with regulatory authorities.

#### *Related Party Transactions*

Review with management all related party transactions and the development of policies and procedures related to those transactions.

#### *Board Relationship and Reporting*

Review and assess the adequacy of the Audit Committee Mandate annually and submit such amendments as the Audit Committee proposes to the Board.

Oversee appropriate disclosure of the Audit Committee's Mandate, and other information required to be disclosed by applicable legislation, in the Company's AIF and all other applicable disclosure documents, including any management information circular of the Company distributed in connection with the solicitation of proxies from the Company's securityholders.

Report regularly to the Board on Audit Committee activities, issues and related recommendations.

### **Audit Committee Procedure**

#### *Chair*

The Board will in each year appoint a chairman of the Audit Committee (the "**Audit Committee Chair**"). In the Audit Committee Chair's absence, or if the position is vacant, the Audit Committee may select another member as Audit Committee Chair.

#### *Meetings*

The Audit Committee shall meet at the request of the Audit Committee Chair, but in any event it will meet at least four times a year. Notices calling meetings shall be sent to all Audit Committee members, to the Chief Executive Officer of the Company (the "**CEO**"), to the Audit Committee Chair and to all other directors. The external auditor or any member of the Audit Committee may call a meeting of the Audit Committee.

### *Quorum*

A majority of members of the Audit Committee, present in person, by teleconference, or by videoconference will constitute a quorum.

### *Removal and Vacancy*

A member may resign from the Audit Committee, and may be removed and replaced at any time by the Board, and will automatically cease to be a member as soon as the member ceases to be a director. The Board will fill vacancies in the Audit Committee by appointment from among the directors in accordance with this Mandate. Subject to quorum requirements, if a vacancy exists on the Audit Committee, the remaining members will exercise all its powers.

### *Experts and Advisors*

In order to carry out its duties, the Audit Committee may retain or appoint, at the Company's expense, such independent counsel and other experts and advisors, as it deems necessary. In so doing, the Audit Committee has the authority to set and pay the compensation for such advisors. In addition, the Audit Committee shall provide notice to the Board of its actions in this regard.

### *Access*

The Audit Committee may have access to and direct contact with any employee, contractor, supplier, customer or other person that is engaged in any business relationship with the Company to confirm information or to investigate any matter within the Audit Committee Mandate.

### *Secretary and Minutes*

The Audit Committee Chair shall appoint a secretary for each meeting to keep minutes of such meeting. The minutes of the Audit Committee will be in writing and duly entered into the books of the Company and shall be available to all members of the Board.

**APPENDIX B**  
**FORM 51-101F1**  
**STATEMENT OF RESERVES DATA AND**  
**OTHER OIL AND GAS INFORMATION**

In accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*, GLJ Petroleum Consultants Ltd (“**GLJ**”) prepared a report (the “**GLJ Report**”) dated March 15, 2010 and prepared March 10, 2010. The GLJ Report evaluated, as at December 31, 2009, the Company’s oil, NGLs and natural gas reserves, other than reserves attributable to Stonefire. The tables below are a summary of the oil, NGLs and natural gas reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Report based on forecast price and cost assumptions. The tables summarize the data contained in the GLJ Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. **The net present value of future net revenue attributable to the Company’s reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by GLJ. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company’s reserves estimated by GLJ represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in this Appendix. The recovery and reserve estimates of the Company’s oil, NGLs and natural gas reserves provided in this Appendix are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided in this AIF. Because this Appendix sets out the Company’s reserve data and other oil and gas information as it was at December 31, 2009, Stonefire reserve data and other oil and gas information is not included in this Appendix. For an estimate of the consolidated reserves of Angle Energy and Stonefire, see “Proforma Statement of Reserves Data and Other Oil and Gas Information” in the AIF. For an estimate of the reserves of Stonefire alone, see Appendix E –*Certain Stonefire Reserves Data and Financial information.***

The GLJ Report is based on certain factual data supplied by the Company and GLJ’s opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company’s petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to GLJ and accepted without any further investigation. GLJ accepted this data as presented and neither title searches nor field inspections were conducted. All statements relating to the activities of the Company for the year ended December 31, 2009 include a full year of operating data on the properties of the Company.

**Notes and Definitions**

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

Development and Production Status of Reserves

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

“**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 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.

“**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.

“**possible reserves**” are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

“**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.

“**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.

“**reserves**” are 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 (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

“**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.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

#### Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- (b) at least a 50 percent probability that the quantities recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

#### GLJ Report Terms

The following terms, used in the preparation of the GLJ Report and this document, have the following meanings:

“**associated gas**” means the gas cap overlying a crude oil accumulation in a reservoir.

“**Company**” or “**Angle Energy**” means Angle Energy Inc.

“**constant prices and costs**” means

- (a) the Company’s prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), the Company's prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

**"crude oil"** or **"oil"** means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

**"development costs"** means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
- (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;
- (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
- (d) provide improved recovery systems.

**"development well"** means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

**"exploration costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as **"geological and geophysical costs"**);
- (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
- (c) dry hole contributions and bottom hole contributions;
- (d) costs of drilling and equipping exploratory wells; and
- (e) costs of drilling exploratory type stratigraphic test wells.

**"exploratory well"** means a well that is not a development well, a service well or a stratigraphic test well.

**“field”** means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to denote localized geological features, in contrast to broader terms such as “basin”, “trend”, “province”, “play” or “area of interest”.

**“future prices and costs”** means future prices and costs that are:

- (a) generally accepted as being a reasonable outlook of the future;
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

**“future income tax expenses”** means future income tax expenses estimated (generally, year-by-year):

- (a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
- (b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;
- (c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and
- (d) applying to the future pre-tax net cash flows relating to the reporting issuer’s oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

**“future net revenue”** means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using or forecast prices and costs.

**“gross”** means:

- (a) in relation to the Company’s interest in production or reserves, its “company gross reserves”, which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;
- (b) in relation to wells, the total number of wells in which the Company has an interest; and
- (c) in relation to properties, the total area of properties in which the Company has an interest.

**“natural gas”** means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

**“natural gas liquids”** means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

**“net”** means

- (a) in relation to the Company’s interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company’s royalty interests in production or reserves;

- (b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and
- (c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

**"non-associated gas"** means an accumulation of natural gas in a reservoir where there is no crude oil.

**"operating costs"** or **"production costs"** means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

**"production"** means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

**"property"** includes:

- (a) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;
- (b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and
- (c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

**"property acquisition costs"** means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

- (a) costs of lease bonuses and options to purchase or lease a property;
- (b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;
- (c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

**"proved property"** means a property or part of a property to which reserves have been specifically attributed.

**"reservoir"** means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

**"service well"** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

**"solution gas"** means natural gas dissolved in crude oil.

**"stratigraphic test well"** means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) "exploratory type" if not drilled into a proved

property; or (b) “development type”, if drilled into a proved property. Development type stratigraphic wells are also referred to as “evaluation wells”.

“**support equipment and facilities**” means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

“**unproved property**” means a property or part of a property to which no reserves have been specifically attributed.

“**well abandonment costs**” means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

## **PART 1: RELEVANT DATES**

The date of the report by GLJ is March 15, 2010 and the preparation date in that report is March 10, 2010. As of the preparation date, Angle Energy and its independent reserves evaluator, GLJ, are not aware of any new information (other than commodity pricing assumptions which may differ from those used in this analysis) which could materially impact this evaluation.

The effective date of the reserves estimates and revenue projection in this report is December 31, 2009.

Estimates of reserves and projections of production were generally prepared using data current to December 31, 2009. No drilling results were used past December 31, 2009. The Company has provided GLJ with a representation letter confirming that complete and correct information has been provided to GLJ.

## **PART 2: DISCLOSURE OF RESERVES DATA**

In 2003, Canadian Securities Administrators implemented new standards of disclosure for reporting issuers engaged in upstream oil and gas activities. Further amendments to these standards were implemented on December 31, 2007. National Instrument 51-101 (“**NI 51-101**”) establishes a regime of continuous disclosure for oil and gas companies and includes specific reporting requirements.

In conjunction with NI 51-101, the Standing Committee on Reserves Evaluation of the Calgary Chapter of the Society of Petroleum Evaluation Engineers and the Standing Committee on Reserves Definitions of the Canadian Institute of Mining, Metallurgy and Petroleum developed the Canadian Oil and Gas Evaluation Handbook (“**COGE Handbook**”) to serve as the guidelines for conducting reserves evaluations and reporting the results thereof. Canadian securities regulators require reporting issuers to comply with the COGE Handbook, as amended from time to time.

Based on an independent engineering evaluation conducted by GLJ effective December 31, 2009 and prepared in accordance with NI 51-101, the Company had proved plus probable reserves of 20.03 million barrels of oil equivalent.

The Company’s light and medium crude oil (combined), natural gas and natural gas liquids reserves quantities and future net revenues were determined by GLJ utilizing GLJ’s price forecast as of January 1, 2010. The future net revenues shown below are based on the current Alberta oil royalty regulations and are prior to provision for currency hedging, interest, debt service charges, general and administrative costs and insurance. It should not be assumed that the discounted future net revenues estimated represent the fair market value of the reserves. No attempt was made to evaluate possible reserves.

The light and medium crude oil (combined), natural gas and natural gas liquids reserves quantities and future net revenues set out herein are dependent upon a number of assumptions and estimates. They are also subject to risks and uncertainties regarding oil prices, including the impact of proposed Crown royalty changes, any impact of announced or potential environmental legislation or sanctions that may be imposed and various other factors outlined herein and in the annual disclosure documents of the Company. There is no assurance that the price and cost assumptions set out below will be attained and variances could be material. The reserve quantities provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

All of the Company's properties, reserves and production are located in the province of Alberta.

The use of the boe unit of measurement may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

## Item 2.1 Reserves Data – Forecast Prices and Costs

### Summary of Oil and Gas Reserves Effective December 31, 2009

The following table outlines the light and medium crude oil (combined) and gas reserves of the Company on a forecasted pricing basis, by product type on a gross (before royalties) and net (after royalties) basis:

	Light and medium crude oil (combined)		Natural Gas		NGLs		boe	
	Gross (mdbl)	Net (mdbl)	Gross (mmcf)	Net (mmcf)	Gross (mdbl)	Net (mdbl)	Gross (mboe)	Net (mboe)
Proved								
Developed producing	220	160	35,064	25,256	3,970	2,583	10,034	6,952
Developed non-producing	54	40	1,553	1,277	137	91	450	344
Undeveloped	135	112	6,533	5,704	602	451	1,826	1,513
Total proved	408	312	43,151	32,238	4,709	3,124	12,309	8,809
Probable	261	206	29,736	22,758	2,507	1,633	7,724	5,632
Total proved plus probable	669	518	72,887	54,996	7,216	4,757	20,033	14,442

### Net Present Values of Future Net Revenue

The net present values of future net revenue of the Company's reserves at December 31, 2009 at various discount rates on a before tax and after tax basis and on a forecasted pricing basis, are outlined below:

	Before Income Taxes				
	Discounted At				
	0%	5%	10%	15%	20%
(000s)	(\$)	(\$)	(\$)	(\$)	(\$)
Proved					
Developed producing	240,454	195,674	166,090	145,165	129,585
Developed non-producing	10,753	8,357	6,718	5,538	4,652
Undeveloped	42,452	30,609	23,014	17,828	14,104
Total proved	293,660	234,640	195,822	168,531	148,341
Probable	204,549	121,341	81,025	58,377	44,245
Total proved plus probable	498,209	355,981	276,847	226,907	192,586
	After Income Taxes				
	Discounted At				
	0%	5%	10%	15%	20%
(000s)	(\$)	(\$)	(\$)	(\$)	(\$)
Proved					
Developed producing	216,526	177,340	151,379	132,944	119,160
Developed non-producing	7,995	6,090	4,793	3,863	3,168
Undeveloped	31,477	22,104	16,057	11,913	8,934
Total proved	255,998	205,534	172,229	148,720	131,263
Probable	153,588	90,053	59,255	41,925	31,096
Total proved plus probable	409,585	295,587	231,484	190,645	162,359

### Total Future Net Revenue

The following table provides a breakdown of the various components of total future net revenue on an undiscounted basis for proved and proved plus probable reserves:

	Revenue	Royalties	Operating Costs	Capital Development Costs	Well Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Tax Expenses	Future Net Revenue After Income Taxes
(000s)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
Proved	619,391	171,179	129,723	20,821	4,008	293,660	37,662	255,998
Total probable	460,647	120,284	110,304	24,193	1,316	204,549	50,962	153,588
Total proved plus probable	1,080,038	291,463	240,027	45,015	5,324	498,209	88,624	409,585

### Net Present Value of Future Net Revenue by Production Group (Forecast Prices and Costs)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes <sup>(3)</sup> (discounted at 10%/year) (\$000s)	Future Net Revenue Before Income Taxes <sup>(3)</sup> (discounted at 10%/year) (\$/boe)
Proved	Conventional light and medium crude oil <sup>(1)</sup>	8,142	39.94
	Conventional natural gas <sup>(2)</sup>	187,681	21.81
Total proved		195,822	22.23
Proved plus probable	Conventional light and medium crude oil <sup>(1)</sup>	11,066	38.88
	Conventional natural gas <sup>(2)</sup>	265,781	18.77
Total proved plus probable		276,847	19.17

#### Notes

- (1) Including solution gas and other by-products.
- (2) Including by-products but excluding solution gas.
- (3) Unit values of \$/boe are based on Company Net Reserves.

### PART 3: PRICING ASSUMPTIONS

#### Item 3.1: Constant Prices and Company Average Prices in 2009

Constant price runs are not included as supplemental disclosure.

#### Item 3.2: Forecast Prices Used in Estimates

The forecast reference prices as at December 31, 2009 used in preparing the Company's reserves data are provided in the table below.

The economic parameters, as determined by GLJ, assumed in preparing the forecast prices and costs reserves report are outlined below.

#### Natural Gas Price Forecast – Effective January 1, 2010

Year	AECO		Alberta Plant Gate			
	NIT Spot	Spot	Then Current	ARP	Aggregator	Alliance
	Then Current	Constant 2010 \$				
	(\$CDN/mmbtu)	(\$/mmbtu)	(\$/mmbtu)	(\$/mmbtu)	(\$/mmbtu)	(\$/mmbtu)
2004	6.88	7.46	6.70	6.31	6.16	6.39
2005	8.58	9.19	8.42	8.30	8.27	8.29
2006	7.16	7.45	6.96	6.57	6.36	6.34
2007	6.65	6.74	6.43	6.20	6.13	5.86
2008	8.16	8.13	7.92	7.88	8.06	7.84

Year	AECO		Alberta Plant Gate				
	NIT Spot		Spot		ARP	Aggregator	Alliance
	Then	Current	Constant 2010 \$	Then			
	(\$/CDN/mmbtu)	(\$/mmbtu)	(\$/mmbtu)	(\$/mmbtu)	(\$/mmbtu)	(\$/mmbtu)	(\$/mmbtu)
2009		4.20	4.01	3.99	3.99	4.18	3.30
2010 Q1		5.63	5.43	5.43	5.26	5.20	4.59
2010 Q2		5.74	5.53	5.53	5.37	5.30	4.75
2010 Q3		5.74	5.53	5.53	5.37	5.30	4.85
2010 Q4		6.74	6.52	6.52	6.33	6.25	5.81
2010 Full Year		5.96	5.75	5.75	5.58	5.51	5.00
2011		6.79	6.45	6.58	6.38	6.30	6.02
2012		6.89	6.42	6.68	6.48	6.40	6.12
2013		6.95	6.34	6.73	6.53	6.45	6.17
2014		7.05	6.32	6.84	6.63	6.55	6.37
2015		7.16	6.29	6.94	6.73	6.65	6.53
2016		7.42	6.39	7.20	6.99	6.90	6.78
2017		7.95	6.72	7.72	7.49	7.41	7.28
2018		8.52	7.07	8.29	8.04	7.95	7.82
2019		8.69	7.08	8.47	8.21	8.12	7.99
2020		+2%/yr	7.08	+2%/yr	+2%/yr	+2%/yr	+2%/yr

*Crude Oil and NGL Liquids Price Forecast – Effective January 1, 2010*

Year	Inflation	Bank of Canada Average	West Texas Intermediate Light Crude Oil at Cushing Oklahoma		Light Crude Oil (40° API, 0.3%S) at Edmonton	Alberta Natural Gas Liquids (Then Current Dollars)			
			Constant 2010 \$	Then Current	Then Current	Spec Ethane	Edmonton Propane	Edmonton Butane	Edmonton Pentanes Plus
			(\$/bbl)	(\$/bbl)	(\$/CDN/bbl)	(\$/CDN/bbl)	(\$/CDN/bbl)	(\$/CDN/bbl)	(\$/CDN/bbl)
2004	1.8	0.770	46.08	41.38	52.96	--	34.70	39.97	53.94
2005	2.2	0.826	61.87	56.58	69.02	--	43.04	51.80	69.57
2006	2.0	0.882	70.84	66.22	73.21	--	43.85	60.17	75.41
2007	2.2	0.935	75.88	72.39	77.06	--	49.56	61.78	77.38
2008	2.4	0.943	102.35	99.64	102.89	--	58.38	75.33	104.78
2009	0.3	0.880	61.66	61.56	66.43	--	37.58	47.31	67.99
2010 Q1	2.0	0.950	80.00	80.00	83.26	18.88	52.46	64.11	84.93
2010 Q2	2.0	0.950	80.00	80.00	83.26	19.25	52.46	64.11	84.93
2010 Q3	2.0	0.950	80.00	80.00	83.26	19.25	52.46	64.11	84.93
2010 Q4	2.0	0.950	80.00	80.00	83.26	22.70	52.46	64.11	84.93
2010 Full Year	2.0	0.950	80.00	80.00	83.26	20.02	52.46	64.11	84.93
2011	2.0	0.950	81.37	83.00	86.42	22.88	54.45	66.54	88.15
2012	2.0	0.950	82.66	86.00	89.58	23.24	56.43	68.98	91.37
2013	2.0	0.950	83.87	89.00	92.74	23.43	58.42	71.41	94.59
2014	2.0	0.950	85.00	92.00	95.90	23.79	60.42	73.84	97.82
2015	2.0	0.950	85.00	93.84	97.84	24.15	61.64	75.33	99.79
2016	2.0	0.950	85.00	95.72	99.81	25.06	62.88	76.85	101.81
2017	2.0	0.950	85.00	97.64	101.83	26.88	64.15	78.41	103.86
2018	2.0	0.950	85.00	99.59	103.88	28.84	65.45	79.99	105.96
2019	2.0	0.950	85.00	101.58	105.98	29.46	66.77	81.60	108.10
2020	2.0	0.950	85.00	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

The above price forecast as at January 1, 2010 was provided by GLJ, the Company's independent reserve evaluator.

Angle Energy's weighted average prices received in 2009 after quality/heating value differentials were \$61.74 per barrel of oil, \$4.06 per Mcf of natural gas and \$34.46 per barrel of NGLs.

On October 25, 2007, the Alberta government announced a new royalty framework (“NRF”) and on March 11, 2010 announced its response to its Competitiveness Review report (“**Competitiveness Review**”). The NRF introduced new royalties for conventional oil, natural gas and bitumen on January 1, 2009 that are linked to price and production levels and apply to both new and existing oil sands projects and conventional oil and gas activities. The Competitiveness Review reduced the maximum royalty rates on conventional oil and gas production, committed to updating the conventional oil and gas royalty curves accordingly, and made permanent some previously temporary incentive programs. Under the NRF and the Competitiveness Review changes, Angle Energy’s average royalty rate may change based on commodity pricing and productivity from new wells. Subsequent to the October 25, 2007 announcement, the Alberta government announced a transitional royalty option on November 19, 2008. It will apply to wells spudded between November 19, 2008 and December 31, 2013, if the company so elects, although as a result of the Competitiveness Review eligibility to elect the transitional option will end on January 1, 2011 in light of the royalty curve changes. The NRF will apply for all wells as of January 1, 2014. The transitional royalty program has been incorporated in the reserve estimations as presented, where future drilling could benefit.

On March 3, 2009, in response to economic conditions the Alberta government announced a temporary royalty program designed to stimulate drilling activity. A drilling royalty credit will offer \$200 in royalty credits per meter drilled on new conventional oil and natural gas wells. To qualify, a well must be a conventional oil and gas producing well drilled on Crown mineral rights, spudded between April 1, 2009 and April 1, 2010, and finish drilling within the same time frame. The maximum credit is dependent upon a sliding scale formula depending on production size and 2008 Crown royalties paid. Producers with less than 10,000 boe/d of production are eligible for a maximum credit of 50% of Crown royalties paid between April 1, 2009 and March 31, 2010. In addition, all new wells that commence initial production of conventional oil and natural gas on Crown leases between April 1, 2009 and March 31, 2010 will pay a maximum royalty of 5% for 12 calendar months, 50,000 barrels of oil production or 500 mcm of natural gas production, whichever is reached first. On June 25, 2009 the eligibility for each of these programs was extended by an additional year. The latter 5% maximum royalty program will be made permanent as of January 1, 2011, as part of the Competitiveness Review response.

## RECONCILIATION OF CHANGES IN RESERVES

	Natural Gas			NGLs		
	Proved	Probable	Proved plus Probable	Proved	Probable	Proved plus Probable
	(mcm)	(mcm)	(mcm)	(mbbls)	(mbbls)	(mbbls)
December 31, 2008	40,039	15,682	55,720	4,715	1,812	6,528
Technical	1,303	(1,989)	(686)	243	(155)	88
Exploration						
discoveries	1,181	465	1,646	30	12	42
Drilling extensions	5,826	14,587	20,413	504	764	1,268
Improved recovery	524	128	652	38	9	47
Acquisitions	3,890	864	4,754	272	64	336
Production	(9,612)	--	(9,612)	(1,093)	--	(1,093)
December 31, 2009	43,151	29,736	72,887	4,709	2,507	7,216

  

	Light Crude Oil			Total		
	Proved	Probable	Proved plus Probable	Proved	Probable	Proved plus Probable
	(mcm)	(mcm)	(mcm)	(mbbls)	(mbbls)	(mbbls)
December 31, 2008	74	47	121	11,462	4,473	15,935
Technical	114	39	153	575	(448)	127
Exploration						
discoveries	--	--	--	227	89	316
Drilling extensions	135	151	286	1,610	3,346	4,956
Improved recovery	75	12	87	200	43	243
Acquisitions	63	12	75	983	220	1,203
Production	(53)	--	(53)	(2,748)	--	(2,748)
December 31, 2009	408	261	669	12,309	7,724	20,033

## Reserves Reconciliation

### *Reconciliation of Reserves by Principal Product Type Based on Forecast Prices and Costs*

The following table sets forth a reconciliation of the changes in total company working interest reserve volumes as at December 31, 2009 against such reserves as at December 31, 2008 based on the forecast prices and costs assumptions:

#### Notes

- (1) Figures may not add due to rounding.
- (2) The Company has no unconventional reserves (including, for example, bitumen, synthetic crude oil, coalbed methane), nor any heavy oil.

## **PART 5: ADDITIONAL INFORMATION RELATING TO RESERVES DATA**

### **Item 5.1: Undeveloped Reserves**

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook.

At December 31, 2009, 14.8% of Angle Energy's total proved reserves and 45.2% of Angle Energy's total probable reserves were undeveloped. Undeveloped reserves are attributable to activity scheduled over 2010.

The timing of initial undeveloped reserves assignments as at December 31, 2009 over the prior three years in the forecast prices and costs case is indicated in the attached table from the GLJ Report.

#### **Company Gross Reserves First Attributed By Year**

Product Type	Units	Prior	2006	2007	2008	2009
<i>Proved Undeveloped</i>						
Light & Medium Oil	mdbl	0	0	75	0	135
Heavy Oil	mdbl	0	0	0	0	0
Natural Gas	mmcf	0	2,378	383	1,610	5,159
Natural Gas Liquids	mdbl	0	465	38	205	437
Total: Oil Equivalent	mboe	0	861	176	474	1,431
<i>Probable Undeveloped</i>						
Light & Medium Oil	mdbl	0	0	99	0	151
Heavy Oil	mdbl	0	0	0	0	0
Natural Gas	mmcf	0	8,747	3,916	3,131	14,213
Natural Gas Liquids	mdbl	0	1,430	358	307	712
Total: Oil Equivalent	mboe	0	2,895	1,110	829	3,232

Proved and probable undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. In general, once proved and/or probable undeveloped reserves are identified they are scheduled into the Company's development plans. Currently, the Company plans to develop its proved and probable undeveloped reserves within two years. However, if the economic climate is not conducive to developing these reserves within two years, the Company may, in its discretion, defer the development into the future. There are a number of factors that could result in delays or cancelled development plans. These factors would include, but are not limited to, changing economic and technical conditions, surface access issues and the availability of services. For further discussion of the Company's development plans see "General Development of the Business - Expected Capital Expenditures Program for 2010" and "Description of the Business".

### **Item 5.2: Significant Factors or Uncertainties**

The process of evaluating reserves is inherently complex. It requires significant judgment and decision-making on the basis of the available geological, geophysical, engineering and economic data. These estimates may change

substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. Factors and assumptions that affect these reserve estimates include, among other things: (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 become available, reserve 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 reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The evaluated oil and gas properties of the Company have no material extraordinary risks or uncertainties beyond those that are inherent in an oil and gas producing company.

**Item 5.3: Future Development Costs**

The following table details the development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves of the Company as set forth in the GLJ report:

(\$000s) Year	Total Proved Reserves using forecast prices and costs	Total Proved Plus Probable Reserves using forecast prices and costs
2010	20,311	39,075
2011	510	5,940
2012	0	0
2013	0	0
2014	0	0
Total Undiscounted	20,821	45,015
Total Discounted at 10%	19,808	42,405

The Company's source of funding for future development costs of its reserves will be derived from a combination of working capital, funds from operations, debt and new equity. Management does not anticipate that the costs of funding referred to above will materially affect the Company's disclosed reserves and future net revenues or will make the development of any of the Company's properties uneconomic.

**PART 6: OTHER OIL AND GAS INFORMATION**

**Item 6.1: Oil and Gas Properties and Wells**

The producing assets of the Company are in the Harmattan, Ferrier, and Lone Pine Creek areas of Alberta. Most of the exploratory lands of the Company are in the Deanne and Pembina areas of Alberta.

For a description of the material oil and natural gas properties, pipelines, facilities and installations in which the Company has an interest, please refer to the section entitled "Description of the Business", in the AIF to which this Appendix B – *Statement of Reserves Data and Other Oil and Gas Information* is attached.

## Producing and Non-producing Wells

The following table sets forth the number and status of wells in which the Company had a working interest as at December 31, 2009:

	Light and Medium Crude Oil (Combined) Wells				Natural Gas Wells			
	Producing		Non-Producing <sup>(1)</sup>		Producing		Non-Producing <sup>(1)</sup>	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	11	9.4	7	6.9	63	49.7	12	10.2
Total	11	9.4	7	6.9	63	49.7	12	10.2

### Note

(1) Of the 19 non-producing wells in which Angle Energy has an interest, 5 have been assigned proven or probable reserves in the GLJ Report.

### Item 6.2: Properties with No Attributed Reserves

The following table summarizes as of December 31, 2009 the Angle Energy's undeveloped lands. No reserves have been attributed to these lands:

	Acres		
	Gross	Net	Net Acres Expiring Within One Year
Alberta	106,076	98,966	14,371

### Item 6.3: Forward Contracts

As at December 31, 2009, the Company had fixed the price applicable to future production through the following contract:

Natural Gas	Volume	Pricing Point	Strike Price	Term
Fixed Price/Financial	5,000 GJ/d	AECO	CDN\$5.535/GJ	Apr.1/10 – Oct.31/10

### Item 6.4: Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment costs for wells for which proved plus probable reserves have been assigned in the GLJ Report and that are expected to be incurred by the Company for the years indicated in the forecast prices and costs case of that report.

(\$000s)	Well Abandonment Costs	
	Undiscounted	Discounted at 10%
2010	0	0
2011	33	30
2012	42	35
Remainder	5,249	772
Total	5,324	837

The well abandonment costs in respect of wells for which reserves have been assigned in the GLJ Report using forecast prices is \$5,324 (undiscounted) and \$837 (discounted at 10%). 100% of such amounts were deducted as abandonment costs in estimating the Company's future net revenue as disclosed above.

The Company estimates the costs to abandon and reclaim all of its shut-in and producing wells in each of its operating areas using the Alberta Energy Utilities Board methodology, which averages the cost of abandonment and reclamation by well type in each specific geographic region. Abandonment and reclamation costs have been estimated for the end of the life of the wells. Costs to abandon and reclaim pipelines, surface leases and facilities are expected to be offset in part by proceeds from the sale of surface equipment. The Company 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 cash flow.

## Abandonment & Reclamation Costs

The Company estimates its abandonment and reclamation costs for surface leases, wells, facilities and pipelines by referencing the current cost of such operations in the industry. As at December 31, 2009, the Company estimates its total undiscounted net cost for 92.8 net wells and surface leases net of salvage value would be \$1,997,000 and would expect to incur \$426,000 in the next three years. As at December 31, 2009, and using a 10% discount factor, the Company estimates its total discounted net cost would be \$986,000 and would expect to incur \$298,000 in the next three years. The Company does not expect to incur any material abandonment and reclamation costs for facilities and pipelines in the next three years.

### Item 6.5: Tax Horizon

#### *Tax Horizon*

The Company is not expected to pay income taxes for 2009, its most recently completed financial year. During 2010 the Company will unlikely be taxable given the current price environment and the capital spending plans.

### Item 6.6: Costs Incurred

The following table outlines the costs incurred by Angle Energy during the financial year ended December 31, 2009 in respect of acquisitions, dispositions and capital expenditures:

	Year Ended December 31, 2009 (\$000)
<b>Nature of Cost Incurred</b>	
Property Acquisition (Divestiture) Costs	
Proved Properties	22,451
Unproved Properties	0
Exploration	12,707
Development	29,417
Total	64,575

### Item 6.7: Exploration and Development Activities

Angle Energy participated in the drilling and completion of 13 gross (11.9 net) wells in 2009. The following table summarizes the Company's drilling results:

	Exploration		Development		Total	
	Gross (#)	Net (#)	Gross (#)	Net (#)	Gross (#)	Net (#)
2009						
Natural gas and NGLs	2	2.0	7	5.9	9	7.9
Dry and abandoned	3	3.0	1	1.0	4	4.0
Total wells	5	5.0	8	6.9	13	11.9
Success rate (%)		40		86		66
Average working interest (%)		100		86		92

For the year ended December 31, 2009, Angle drilled 13 gross (11.9 net) wells of which 2 gross (2.0 net) development wells were at Harmattan, 6 gross (4.9 net) development wells were at Ferrier, 1 gross (1.0 net) exploration well was at Deanne, 2 gross (2.0 net) exploration wells were at Pembina and 2 gross (2.0 net) exploration wells were at Lone Pine Creek. The Company's success rate is calculated on a net working interest completion basis.

**Item 6.8: Production Estimates**

The following table is a summary of the gross (prior to royalties) volume of the Company's estimated production for 2010, which is reflected in the estimate of future net revenue in the GLJ Report based on forecast prices and costs.

Reserve Category	Conventional Light and Medium Oil (bbl/d)	Conventional Natural Gas (mcf/d)	Natural Gas Liquids (bbl/d)	Oil Equivalent (boe/d)
Proved producing	174	20,753	2,199	5,832
Total proved	245	23,698	2,462	6,656
Total proved plus probable	310	27,365	2,683	7,554

As at December 31, 2009, Angle Energy's forecast estimates of production include contributions from one property, Harmattan, that exceed 55% of the Company's total production. In the proved producing category, Harmattan is forecast to contribute 3613 boe/d of the Company's gross 5,832 boe/d or 62%. In the total proved category, Harmattan is forecast to contribute 3,889 boe/d of the Company's gross 6,656 boe/d or 58%. In the total proved plus probable category, Harmattan is forecast to contribute 4,164 boe/d of the Company's gross 7,554 boe/d or 55%. The Ferrier property materially represents the remaining portions of the forecast production in all categories as the Carson Creek property contributes less than 1% overall.

**Item 6.9: Production History**

The following tables set forth Angle Energy's daily sales volumes, netbacks and capital expenditures for the periods indicated:

	<b>2009</b>			
	<b>(3 months ended)</b>			
	Dec 31	Sept 30	Jun 30	Mar 31
<b>Average Daily Production</b>				
Light Crude Oil (bbl/d)	184	85	146	163
Gas (Mcf/d)	26,335	26,710	25,899	26,390
NGL (bbl/d)	2,873	3,015	3,009	3,084
Combined (boe/d)	7,446	7,552	7,472	7,645
<b>Average Price Received</b>				
Light Crude Oil (\$/bbl)	75.64	69.62	54.35	48.23
Gas (\$/Mcf)	4.71	3.23	3.63	4.70
NGL (\$/bbl)	41.51	32.42	29.68	34.51
Combined (\$/boe)	34.53	25.16	25.60	31.19
<b>Royalties</b>				
Light Crude Oil (\$/bbl)	0.54	0.23	0.33	0.41
Gas (\$/Mcf)	0.30	0.08	0.13	0.82
NGL (\$/bbl)	5.53	4.52	4.17	5.28
Combined (\$/boe)	7.88	5.22	5.26	10.61
<b>Operating expenses</b>				
Combined (\$/boe)	4.39	4.89	4.21	4.46
Transportation (\$/boe)	0.36	0.36	0.35	0.36
<b>Netback Received</b>				
Combined (\$/boe)	21.90	14.69	15.78	15.76
<b>Capital Expenditures (\$000s)</b>				
Land and seismic	2,362	881	896	673
Drilling and completion	3,966	4,972	3,680	12,515
Facilities and equipment	546	3,133	1,642	4,189
Geological and geophysical	842	300	82	216
Property acquisitions	-	-	22,451	-
Corporate acquisitions	-	-	-	-
Other	568	210	269	182
<b>Total</b>	<b>8,284</b>	<b>9,496</b>	<b>29,020</b>	<b>17,775</b>

## Production by Area

The table below indicates the production volumes by area from the Company's oil and natural gas properties for the year ended December 31, 2009:

	Conventional Light and medium crude oil (combined) <i>(bbl/d)</i>	Conventional Natural Gas <i>(mcf/d)</i>	NGLs <i>(bbl/d)</i>	Equivalent Barrels <i>(boe/d)</i>
Alberta				
Harmattan	130	15,006	2,269	4,900
Ferrier	14	11,254	725	2,615
Lone Pine Creek	-	74	1	13
Total	144	26,334	2,995	7,528

## Other Oil and Natural Gas Information

### Landholdings

The Company's developed and undeveloped landholdings as at December 31, 2009 are set forth in the following table:

Acres	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta	106,076	98,966	45,061	37,602	151,137	136,568
Total	106,076	98,966	45,061	37,602	151,137	136,568

**APPENDIX C  
FORM 51-101F2  
REPORT OF RESERVES DATA BY  
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR**

To the board of directors of Angle Energy Inc. (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 10, 2010	Canada	-	276,847	-	<b>276,847</b>

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 15, 2010.

*(signed) "Jodi L. Anhorn"*  
Jodi L. Anhorn, M.Sc., P.Eng.  
Vice-President

**APPENDIX D**  
**FORM 51-101F3**  
**REPORT OF MANAGEMENT AND DIRECTORS**  
**ON RESERVES DATA AND OTHER INFORMATION**

Management of Angle Energy Ltd. (the “**Company**”) is 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 is presented herein.

The Reserves Committee of the Board 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.

Dated March 15, 2010

(signed) “Gregg Fischbuch”

Gregg Fischbuch  
Chief Executive Officer and Director

(signed) “Heather Christie-Burns”

Heather Christie-Burns  
President and Chief Operating Officer

(signed) “Edward Muchowski”

Edward Muchowski  
Director

(signed) “Clarence Chow”

Clarence Chow  
Director

**APPENDIX E**  
**CERTAIN STONEFIRE RESERVES DATA**  
**AND FINANCIAL INFORMATION**

The Company is disclosing certain Stonefire reserves data and financial information because, for the purposes of National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*, the Stonefire Acquisition constitutes a material change that, had it occurred on or before the effective date of the AIF, would have resulted in a significant change in the information contained in the AIF. The information set out in the GLJ report (the “**GLJ Stonefire Report**”) in this appendix, dated March 15, 2010 and prepared March 10, 2010 is the basis for the Company’s expectation that its reserves data and other information will be affected by the Stonefire Acquisition in the manner contemplated in the AIF.

The tables below are a summary of the oil, NGLs and natural gas reserves of Stonefire, as at December 31, 2009, and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Stonefire Report, based on forecast price and cost assumptions. The tables summarize the data contained in the GLJ Stonefire Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. **The net present value of future net revenue attributable to Stonefire’s reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by GLJ. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Stonefire’s reserves estimated by GLJ represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are substantially the same as those summarized in Appendix B. The Stonefire recovery and reserve estimates are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided in this AIF.**

The GLJ Stonefire Report is based on certain factual data supplied by the Company and GLJ’s opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company’s petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to GLJ and accepted without any further investigation. GLJ accepted this data as presented and neither title searches nor field inspections were conducted. All statements relating to the activities of the Company for the year ended December 31, 2009 include a full year of operating data on the properties of the Company.

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. Terms used in this appendix, such as “proved” and “probable” are defined in Appendix B.

**Reserves Data – Forecast Prices and Costs**

**Summary of Oil and Gas Reserves Effective December 31, 2009**

The following table outlines the light and medium crude oil (combined) and gas reserves of the Company on a forecasted pricing basis, by product type on a gross (before royalties) and net (after royalties) basis:

	Light and medium crude oil (combined)		Natural Gas		NGLs		boe	
	Gross (mdbl)	Net (mdbl)	Gross (mmcf)	Net (mmcf)	Gross (mdbl)	Net (mdbl)	Gross (mboe)	Net (mboe)
Proved								
Developed producing	223	148	8,244	6,812	281	171	1,878	1,454
Developed non-producing	0	0	47	37	2	1	10	7
Undeveloped	0	0	2,671	2,464	88	62	533	473
Total proved	223	148	10,962	9,314	371	234	2,421	1,934
Probable	310	218	17,563	15,533	471	309	3,709	3,116
Total proved plus probable	533	366	28,524	24,847	842	543	6,130	5,050

### **Net Present Values of Future Net Revenue**

The net present values of future net revenue of the Company's reserves at December 31, 2009 at various discount rates on a before tax and after tax basis and on a forecasted pricing basis, are outlined below:

	<b>Before Income Taxes</b>				
	Discounted At				
	0%	5%	10%	15%	20%
(000s)	(\$)	(\$)	(\$)	(\$)	(\$)
Proved					
Developed producing	57,714	46,960	39,671	34,464	30,580
Developed non-producing	294	254	222	196	174
Undeveloped	13,633	9,709	7,140	5,370	4,098
Total proved	71,642	56,924	47,033	40,030	34,852
Probable	124,060	76,806	52,047	37,519	28,223
Total proved plus probable	195,701	133,730	99,080	77,549	63,075

	<b>After Income Taxes</b>				
	Discounted At				
	0%	5%	10%	15%	20%
(000s)	(\$)	(\$)	(\$)	(\$)	(\$)
Proved					
Developed producing	48,941	40,102	34,100	29,801	26,587
Developed non-producing	219	189	165	146	129
Undeveloped	10,157	7,051	5,010	3,599	2,584
Total proved	59,317	47,343	39,275	33,546	29,300
Probable	92,990	56,877	37,889	26,721	19,565
Total proved plus probable	152,307	104,220	77,164	60,267	48,864