

Argosy Energy Inc.
Management Discussion and Analysis
And
Unaudited Interim Condensed Consolidated Financial Statements
March 31, 2011

Management Discussion and Analysis

The following discussion and analysis (“MD&A”) reports on the financial condition and the results of operations of Argosy Energy Inc. (“Argosy” or the “Company”), was prepared on, and is dated June 10, 2011 and is to be read in conjunction with the accompanying unaudited interim consolidated financial statements and related notes for the three month period ended March 31, 2011 as well as the audited consolidated financial statements and related notes and MD&A for the year ended December 31, 2010.

Description of Business

Argosy was formed pursuant to a Plan of Arrangement between Accrete Energy Inc. (“Accrete”), Pengrowth Energy Trust, Pengrowth Company, Pengrowth Energy Partnership and Argosy (“the Arrangement”) on December 31, 2008 and is a junior energy company focused on the acquisition, exploration, exploitation and development of oil and natural gas in Alberta in western Canada.

On May 14, 2010, Argosy acquired 100% of the issued and outstanding shares of its only subsidiary, Radius Resources Corp. (Radius), as part of a restructuring process undertaken by Radius. Radius has oil and gas operations primarily focused in the Ante Creek area of Alberta.

As at March 31, 2011, there were 20,042,888 (15,536,939 at December 31, 2010) common shares, 1,341,235 (1,847,183 at December 31, 2010) common share purchase warrants and 1,858,000 (1,433,000 at December 31, 2010) stock options outstanding. As at the date of this MD&A there are 20,243,622 common shares and 1,858,000 stock options outstanding. The Company exercised its option to accelerate the expiry date of common share purchase warrants that were outstanding and all unexercised common share purchase warrants outstanding at May 13, 2011 expired on May 13, 2011.

Additional information may be found on the Company’s web site at www.argosyenergy.com and on the SEDAR web site at www.sedar.com.

Argosy’s shares trade on the Toronto Stock Exchange (“TSX”) under the symbol GSY.

Basis of Presentation

The interim consolidated financial statements have been prepared in accordance with International Accounting Standard 34 “Interim Financial Reporting” in accordance with International Financial Reporting Standards (“IFRS”). This is the first time that the Company has reported its financial statements under IFRS. The Company utilized standards and interpretations thereof that are expected to be effective as at December 31, 2011, the date of the Company’s first annual report under IFRS. The effective date of the Company’s transition to IFRS was January 1, 2011. Previously the Company prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles (“Canadian GAAP or “CGAAP”). The adoption of IFRS did not have any effect on the Company’s operations, strategic decisions or cash flow from operations before changes in non-cash working capital.

The IFRS policies that have been adopted together with reconciliations between CGAAP and IFRS have been provided in the notes to the unaudited consolidated financial statements for the three month period ended March 31, 2011. Additional information in respect to the adoption of IFRS is provided in this MD&A.

The reporting and functional currency is the Canadian dollar.

The Company evaluates its performance based on net earnings, net backs and cash flow. The Company considers cash flow a key measure as it illustrates the Company’s ability to meet obligations necessary to repay debt and fund future growth through capital investment. Cash flow per share is presented using the weighted average shares outstanding in a manner consistent with that used to calculate earnings per share.

In addition, net debt is a term used by the Company to describe one of the measures used by Company management to monitor the remaining availability of its credit facilities. Net debt is calculated by the Company by subtracting current assets values from the sum of current liabilities including bank debt without consideration of current values of derivative instruments.

The terms “cash flow” and “netbacks” should not be considered an alternative to, or more meaningful than cash flow from operating activities as prescribed by IFRS or CGAAP as an indicator of the Company’s performance. Argosy’s definition of cash flow and/or netbacks may not be comparable to that reported by other companies. The term “net debt” is not prescribed by IFRS.

The following reconciles cash flow provided by operating activities, the most comparable IFRS measure to cash flow used in this MD&A:

\$ Thousands	Three Months Ended March 31,	
	2011	2010
Cash flow provided by operating activities (IFRS)	732	(3,019)
Net changes in non-cash working capital	(217)	4,111
Cash flow (not prescribed - IFRS)	515	1,092

The following table reconciles field and corporate netback to income before taxes, the most comparable IFRS measure:

\$ Thousands	Three Months Ended March 31,	
	2011	2010
Loss and comprehensive loss (IFRS)	(439)	(127)
Future income taxes	107	737
Depletion, depreciation and accretion	773	1,161
Finance expense	122	235
Realized gain on derivative instruments	(22)	21
Unrealized (gain) loss on derivative instruments	-	(775)
Corporate netback (not prescribed - IFRS)	541	1,252
General and administrative expense	1,072	882
Field netback (not prescribed - IFRS)	1,613	2,134

Barrel of Oil (“BOE”) Conversion

In this MD&A production data is commonly stated in barrels of oil equivalent using a six (6) to one (1) conversion ratio when converting thousands of cubic feet of natural gas to barrels of oil and a one (1) to one (1) conversion ratio for natural gas liquids. An oil equivalency of six (6) to one (1) thousand cubic feet of natural gas is based on energy equivalent at the burner tip and does not represent a value equivalency at the well head.

Forward-Looking Statements

Certain statements included or incorporated herein constitute forward-looking statements. These statements relate to future events or the future performance of Argosy. All statements other than statements of historical fact are forward-looking.

Such forward-looking statements or information are provided for the purpose of providing information about management’s current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment

decisions. Forward-looking statements are often, but not always, identified by the use of words such as “seek”, “continue”, “might”, “may”, “will”, “should”, “could”, “anticipate”, “believe”, “expect”, “intend”, “plan”, “estimate”, “budget”, “forecast”, “predict”, “project”, “potential”, or the negative of these terms and similar expressions. In addition, these financial statements and accompanying management discussion may contain forward-looking statements attributed to third party industry sources. 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.

Forward-looking statements include, but are not limited to, statements with respect to:

The performance characteristics of Argosy’s oil and natural gas properties; oil and natural gas production levels; the quantity of oil and natural gas reserves; the performance characteristics of oil and natural gas properties; projection of market prices; other trends of the capital markets; the size of and future net revenues from Argosy’s oil and natural gas reserves; capital expenditure programs; supply and demand for oil and natural gas and commodity prices; financial conditions; industry conditions; capital expenditure programs; drilling plans; expectations regarding the Argosy’s ability to raise capital and to continually add to reserves through acquisitions, exploration and development; treatment under governmental regulatory regimes and tax laws; estimated tax pool balances; future land expiries; governmental regulations; anticipated IFRS elections and the impact of the conversion to IFRS and realization of the anticipated benefits of acquisitions and dispositions.

In addition, statements relating to “reserves” or “resources” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described can be profitably produced in the future.

The forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond the Company’s control and which would cause results to differ materially from those expressed in the forward-looking statements contained in these financial statements and accompanying management discussion. These risks and uncertainties may include, but are not limited to:

general economic conditions in Canada, the United States and globally; industry conditions, including fluctuations in the price of oil and natural gas; governmental regulation of the oil and gas industry, including environmental regulation; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; volatility of commodity prices; environmental risks; fluctuation in foreign exchange or interest rates; liabilities inherent in oil and gas operations; geological, technical, drilling and processing problems; unanticipated operating events which can reduce production or cause production to be shut in or delayed; failure to obtain industry partner and other third party consents and approvals, when required; stock market volatility and market valuations; competition for, among other things, capital, acquisitions of reserves, undeveloped land, skilled personnel, and equipment and facilities; the need to obtain required consents, permits or approvals from regulatory authorities; competition for, among other things, capital, acquisition of reserves, undeveloped land, skilled personnel and equipment and facilities; the lack of availability of qualified personnel or management; uncertainties associated with estimating oil and natural gas reserves; aboriginal land claims; stock market volatility; the implementation of International Financial Reporting Standards and the other factors considered under “Risks”.

Readers are cautioned that the foregoing lists should not be considered to be exhaustive. Readers are also cautioned that these factors and risks are difficult to predict and that the preparation of financial statements in accordance with Canadian GAAP requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Forward-looking statements and other information contained herein concerning the oil and gas industry and Argosy’s general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which Argosy believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While Argosy is not aware of any misstatements regarding any industry data

presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

The foregoing summary of assumptions and risks relating to forward-looking information is provided in this MD&A in order to provide readers with a more complete perspective on the Company's future operations and may not be appropriate for other purposes. Although the assumptions used in the preparation of such information and statements are considered reasonably accurate by the Company at the time of preparation, they may prove to be incorrect. Accordingly, readers are cautioned that the actual results achieved will vary from the information provided herein and the variations may be material.

Investors should not place undue reliance on forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. These forward-looking statements are made as of the date of this date or as of the date specified in any documents that may be incorporated by reference into the financial statements and accompanying management discussion, as the case may be.

Operating Summary

Average Daily Production

	3 Months Ended March 31,	
	2011	2010
Oil (bbl/d)	83	25
NGL (bbl/d)	63	95
Total Oil/NGL (bbl/d)	146	120
Gas (mcf/d)	3,537	5,006
Total (boe/d) ⁽¹⁾	736	954

(1) The reader is cautioned that the use of the term boe's ("barrels of oil equivalent") may be misleading particularly when used in isolation. A boe conversion of 6 mcf to 1 boe may not represent a value equivalency at the wellhead.

The production included in the table above includes the production from Radius' Ante Creek property from the date of acquisition on May 14, 2010 to December 31, 2010. The Company sold its Saxon property effective August 1, 2010.

Production averaged 770 bbl/day for the 4th quarter of 2010. The decrease to 736 bbl/day for the 1st quarter of 2011 occurred as a result of natural production declines.

The decrease in production for the period ended March 31, 2011 versus the period ended March 31, 2010 was due to the loss of the production that occurred on the sale of the Saxon property and natural declines in natural gas production at Claresholm and Ante Creek. The decrease was offset in part by production from Ante Creek and production from a well at Pouce Coupe that was put on stream in February, 2011.

Natural Gas Sales Volumes (mcf/d)

	3 Months Ended March 31,	
	2011	2010
Ante Creek	109	-
Atlee-Buffalo	22	31
Claresholm	3,157	3,833
Edson	249	432
Saxon	-	710
Total	3,537	5,006

The decrease in production for the 1st quarter 2011 as compared to the 1st quarter 2010 occurred because of natural declines and the sale of the Saxon property. These declines were offset by production from Radius' Ante Creek property.

Natural gas production for the 4th quarter 2010 was 3,909 mcf/day. The decrease to 3,537 mcf/day for the 1st quarter of 2011 quarter was attributable to natural production declines.

Crude Oil Sales volumes (bbl/d)

	3 Months Ended March 31,	
	2011	2010
Ante Creek	34	-
Claresholm	24	25
Pouce Coupe	25	-
Total	83	25

The increase in oil production for the 1st quarter of 2011 versus the 1st quarter of 2010 is due to production from Radius' Ante Creek property and from a well at Pouce Coupe that was put on stream in February, 2011.

Oil production for the 4th quarter 2010 was 54 bbl/day. The increase is due to the addition of production from a well at Pouce Coupe that was put on stream in February, 2011.

Natural Gas Liquids Sales Volumes (bbl/d)

	3 Months Ended March 31,	
	2011	2010
Ante Creek	3	-
Claresholm	51	62
Edson	9	24
Saxon	-	9
Total	63	95

The decrease to 63 bbl/day for the 1st quarter 2011 from the 95bbl/day that was recorded for the 1st quarter of 2010 was attributable to the disposition of the Saxon property together and natural production declines.

Natural gas liquids production for the 1st quarter remained relatively constant when compared to 4th quarter 2010 production that totaled 64 bbl/day.

Product Prices

Natural Gas Prices (\$/mcf)

	3 Months Ended March 31,	
	2011	2010
Ante Creek	4.39	-
Atlee-Buffalo	3.87	4.95
Claresholm	4.27	5.46
Edson	4.07	5.10
Saxon	-	5.12
Average Price	4.26	5.38

Benchmark AECO C spot prices averaged \$3.77 for the quarter ended March 31, 2011 and \$4.92 for the quarter ended March 31, 2010. Certain liquids are recombined to Company production giving it a higher heating content resulting in a premium over the benchmark price being received.

Natural gas prices averaged \$4.18 per mcf for the 4th quarter 2010.

Crude Oil Sales Prices (\$/bbl)

	3 Months Ended March 31,	
	2011	2010
Ante Creek	83.82	-
Claresholm	88.82	79.27
Pouce Coupe	85.93	-
Average Price	85.92	79.27

Benchmark Edmonton Par prices averaged \$ 88.65 for the quarter ended March 31, 2011 and \$81.02 for the quarter ended March 31, 2010.

Company prices were consistent with Edmonton Par prices for the most part.

Oil prices average \$75.01 per barrel for the 4th quarter of 2010.

Natural Gas Liquids (“NGL”) Sales Prices (\$/bbl)

	3 Months Ended March 31,	
	2011	2010
Ante Creek	57.41	-
Claresholm	73.44	68.41
Edson	73.05	69.10
Saxon	-	83.66
Average Price	72.70	69.95

NGL prices tend to move in tandem with oil prices. Saxon natural gas liquids contain more condensate than those in Edson and Claresholm, and therefore it commands a higher price.

NGL prices averaged \$65.21 for the 4th quarter 2010.

Revenue**Total Sales
(\$ thousands)**

	3 Months Ended March 31,	
	2011	2010
Oil	641	175
NGL	413	595
Gas	1,355	2,423
Total	2,409	3,193

Revenue decreased due to a decrease in natural gas production primarily as a result of the sale of its Saxon property and declines at Claresholm together with a decrease in natural gas prices. This was offset in part by increases in production from Radius’ Ante creek properties, oil production from Pouce Coupe and an increase in oil prices.

Argosy’s go forward strategy is to increase its oil sales relative to natural gas sales. This process was initiated with the acquisition of the Ante Creek property in 2010. The Company has drilled for oil at Pouce Coupe and Claresholm and is operating an oil enhanced recovery pilot project at Claresholm with the object being to significantly increase oil production.

Natural Gas Sales Revenue
(\$ thousands)

	3 Months Ended March 31,	
	2011	2010
Ante Creek	44	-
Atlee-Buffalo	7	14
Claresholm	1,213	1,883
Edson	91	198
Saxon	-	328
Total	1,355	2,423

Natural gas volumes decreased due to natural declines at Claresholm, the sale of the Saxon property and a decline in natural gas pricing. This was offset in part by the addition of production from Radius' Ante Creek property.

Natural gas sales revenue for the 4th quarter 2010 was \$1,501,000. Natural gas sales revenue decreased mainly because of normal production declines at Claresholm.

Crude Oil Sales Revenue
(\$ thousands)

	3 Months Ended March 31,	
	2011	2010
Ante Creek	256	-
Claresholm	196	175
Pouce Coupe	189	-
Total	641	175

Oil sales increased because of production from Radius' Ante Creek property, production from Pouce Coupe and an increase in oil prices.

Oil sales for the 4th quarter 2010 were \$374,000. The increase to \$641,000 occurred because of the addition of the Pouce Coupe production and an increase in oil prices.

Argosy's go forward strategy is to increase its oil sales relative to natural gas sales.

Natural Gas Liquids (NGL) Sales Revenue
(\$ thousands)

	3 Months Ended March 31,	
	2011	2010
Ante Creek	13	-
Claresholm	340	380
Edson	60	152
Saxon	-	63
	413	595

In general, natural gas liquids sales revenue decreased because of the sale of the Saxon property and declines at Claresholm which were offset in part by the addition of production from Radius' Ante Creek property and a slight increase in commodity pricing.

Royalties

(\$ thousands except rate information)

Area	3 Months Ended March 31,			
	2011		2010	
	Rate	Total \$	Rate	Total \$
Ante Creek	7%	21	-	-
Atlee-Buffalo	4%	1	1%	1
Claresholm	6%	106	17%	425
Edson	13%	21	24%	85
Pouce Coupe	5%	10	-	-
Saxon	-	-	3%	11
Total	7%	159	16%	522

Royalty expense comprises royalties paid to the Province of Alberta, freehold land owners and overriding royalty owners for the right to produce the oil and natural gas owned by them.

Royalty expense has decreased with decreased sales volumes and Crown royalty rates.

In March 2010 the Province of Alberta revised its deep drilling credit program. A Crown royalty credit of \$625 per meter is available for wells drilled that are deeper than 2000 meters (formerly 2,500 meters) to 3,500 meters. This credit is deducted from royalties paid on the individual well. However, the royalty rate in respect of that production cannot be reduced to a rate that is lower than 5%.

The older wells in the Claresholm area also enjoy a lower Crown royalty rate because of their low production volumes and because gas cost allowance is applied to them to reflect the Company's investment in the Claresholm processing facilities.

In addition, the Province of Alberta reduced the royalty rates to 5% on the first year of production on new natural gas and conventional oil wells up to a maximum of 50,000 bbl of oil and 500,000 mcf of natural gas.

The Edson wells are subject to gross overriding royalties in addition to those levied by the Crown.

For the period ended March 31, 2011, Crown royalties were \$52,000(\$371,000 in 2010), gross overriding royalties were \$45,000(\$83,000 in 2010), and freehold royalties were \$61,000(\$68,000 in 2010).

Royalties for the 4th quarter 2010 averaged 7% which is comparable with those recorded for the 1st quarter of 2011.

Production and Transportation Expenses

(\$ thousands except per boe information)

Area	3 Months Ended				
	March 31,				
	2011		2010		
	\$/boe	Total \$	\$/boe	Total \$	
Ante Creek	12.66	62	-	-	
Atlee-Buffalo	10.88	3	13.82	6	
Claresholm	9.24	501	5.72	372	
Edson	5.16	25	7.70	68	
Pouce Coupe	20.55	46	-	-	
Saxon	-	-	7.89	91	
Total	9.62	637	6.27	537	

On a year over year basis, production and transportation expenses increased on a per boe basis. Claresholm operating costs have increased in absolute terms because as they age, more work is required to maintain, or at least partially offset, normal declines. The decline in volumes also causes fixed costs to be spread over fewer units which in turn lead to an increase in per unit costs.

A portion of Ante Creek production is not operated by the Company and is oil production that requires trucking.

Claresholm natural gas is processed in a Company operated processing plant. Atlee Buffalo, Edson and Ante Creek natural gas is processed by third party processors hence the cost of processing is higher. Edson is relatively remote which in and of itself leads to higher operating and transportation costs but to date in 2011, operations have been relatively trouble free.

Start up costs caused the Pouce Coupe operating costs to be high relative to such costs incurred at the Company's other areas.

Atlee Buffalo volumes are very low and even minor repair and maintenance items have a significant impact on the rate per boe. Over all though, Atlee Buffalo is not material.

Operating costs averaged \$9.34 per barrel for the three months ended December 31, 2010. The increase to \$9.62 for the 1st quarter 2011 basically results from colder weather operation.

Field and Corporate Netbacks

Field Netback

	3 Months Ended March 31,	
	2011	2010
\$/boe		
Ante Creek	46.51	-
Atlee-Buffalo	11.36	15.45
Claresholm	21.09	25.11
Edson	23.57	22.86
Pouce Coupe	60.79	-
Saxon	-	25.39
Field Netback	24.37	24.85

Field netbacks for quarter ended March 31, 2011 decreased slightly from those recorded in the 1st quarter last year.

Significantly reduced royalties costs at Claresholm, the Company's most significant property, almost offset the decrease in 1st quarter 2011 natural gas prices and the increase in 1st quarter 2011 operating expenses.

Field netbacks for the 4th quarter of 2010 averaged \$19.81 per barrel. The increase is due to the addition of oil production at Pouce Coupe and Ante Creek.

Corporate Netback (\$ thousands)

	3 Months Ended March 31,	
	2011	2010
Field Netback	1,613	2,134
General and Administrative after acquisition and disposition costs	1,072	882
Corporate Netback	541	1,252

Corporate netback decreased because of decreased volumes and increased general and administrative costs.

Field netback basically decreased due to decreased volumes due to the disposition of the Saxon property and natural declines.

General and administrative expenses represent costs which are relatively fixed except for acquisition and disposition costs. No acquisition or disposition costs were incurred in the 1st quarter 2011 while \$40,000 of such costs was incurred in the 1st quarter of 2010. The increase in general and administrative cost was due the reinstatement of salaries that had been reduced in June 2009 as well as an increase in professional fees due to the increase in complexity of the Company following the acquisition of Radius.

The corporate netback for the 4th quarter of 2010 was \$834 after deducting \$250,000 of acquisition and disposition costs incurred in that quarter. The decrease in corporate netback for the 1st quarter of

2011 versus the 4th quarter of 2010 was due to decreased natural gas volumes that was caused by natural declines mainly at Claresholm offset in part by an increase in production revenues at Pouce Coupe.

General and Administrative Expense
(\$ thousands)

	3 Months Ended March 31,	
	2011	2010
Salary & Benefits, net	642	496
Share Based Payments	53	88
General Office Expenses	457	327
Acquisition and disposition Related Costs	-	40
	1,152	951
Recoveries	(80)	(69)
Total	1,072	882

The increase in salary & benefits arose because of the reinstatement of salaries that had been curtailed since June 2009 and for most of 2010. General office expenses increased due to increases in professional fees caused by the increased complexities arising from the acquisition of Radius.

The adoption of IFRS on January 1, 2010 required that the Company account for acquisition and disposition related costs as expenses in the periods in which the costs were incurred and the services received. In 2010, \$40,000 of costs related to the Radius acquisition was expensed.

General and administrative expense amounted to \$1,252,000 for the 4th quarter 2010. The 4th quarter of 2010 included \$250,000 of costs related to the acquisition of Radius and the disposition of the Saxon property. Once that is factored in, General and administrative costs incurred in the 1st quarter of 2011 were very comparable with those recorded for the 4th quarter of 2010.

Approximately \$74,000 (\$63,000 in 2010) of direct salary costs related to geological and geophysical personnel have been capitalized for the period ended March 31, 2011. No other salary or overhead charges are capitalized.

Finance Expenses

Finance expenses under IFRS include accretion on decommissioning obligations and interest on the Company's credit facilities. Under CGAAP, finance expenses included only interest expense and the accretion on the decommissioning obligations was included in depreciation, depletion and accretion.

Argosy utilized its operating line of credit, funds from share issuances and property divestitures as well as cash flow from operating activities to fund its capital program.

Interest expense for the period ended March 31, 2011 was \$92,000 versus \$217,000 in 2010. The decrease was related to a decrease in bank debt to \$10,781,000 for the first quarter of 2011 from \$20,264,000 for the first quarter 2010 which occurred because of the share issuance in the 1st quarter of 2011. The effective average interest rates were 3.4% for the first quarter of 2011 versus 4.3% for the first quarter of 2010. Bank debt decreased significantly due to the issuance on February 2, 2011 of 4,000,000 shares for gross proceeds of \$12,550,000 and from the exercise of 505,949 common share purchase warrants for gross proceeds of \$1,138,000 during the first quarter of 2011.

Accretion expense for the period ended March 31, 2011 was \$32,000 versus \$17,000 in 2010. The increase in accretion expense is primarily related to the Radius acquisition.

Stock-Based Compensation

Stock-based compensation is accounted for using the fair value method using the Black-Scholes model to calculate the value at the date of the grants. Under IFRS, stock based compensation expense is recognized over the vesting periods on a graded basis which results in higher charges to stock based compensation in the early years of each grant. Forfeitures were estimated at 2% per year. Under CGAAP, the Company recognized stock based compensation on a straight line basis over the vesting period of the individual grant.

As at March 31, 2011 there were 1,858,000 options outstanding. In the 1st quarter of 2011, 425,000 options with an exercise price of \$2.40 were granted. The fair value of the options granted in 2011 was estimated to be \$556,000 (\$1.36 per option granted).

Depletion and Depreciation

Under IFRS, depletion and depreciation expense is computed on a unit of production basis based on proved and probable reserves on an area basis instead of on proved reserves only on a company wide basis as was the case under CGAAP. Depletion and depreciation on a boe basis varies from period by period primarily because of changes in proved plus probable reserves in the reserve base as well as changes in costs subject to depletion and depreciation, including future development costs.

Impairment of Property and equipment

Under IFRS, the Company is required to perform impairment testing at the Cash Generating Unit ("CGU") level. A CGU is the smallest identifiable grouping of assets that generates independent cash inflows. Such impairment testing is based on discounted cash flows from the respective CGU. Impairment is recorded if the CGU's carrying amount is greater than the value of the discounted cash flows expected to be derived from it.

The Company elected to use the IFRS 1 deemed cost exemption on the adoption of IFRS at January 1, 2010. Under that exemption, net costs were allocated to CGU's based on reserve volumes and then the CGU's were tested for impairment. The Company tested the Claresholm, Edson, Saxon, Ante Creek and Pouce Coupe CGUs for impairment.

The recoverable amount of the CGUs was estimated based on the higher of the value in use and the fair value less costs to sell. The estimate of fair value less costs to sell was determined using a discount rate of 12 percent and forecasted cash flows, with escalating prices and future development costs, as obtained from the reserve report. The prices used to estimate the fair value less cost to sell are those used by independent industry reserve engineers.

As a result of this process, an impairment of \$9.7 million was recognized at January 1, 2010. This was comprised of impairments of \$1.6 million of the Edson, \$.7 million of the Saxon and \$7.4 million of the Claresholm CGU's.

In addition, as a result of continued weakness in natural gas pricing the Company tested the same CGUs for impairment at September 30 and December 31, 2010. As a result of this process, an impairment of \$20.1million was recognized in the second half of the year ended December 31, 2010. This was comprised of impairments of \$2.0million of the Edson and \$18.1million of the Claresholm CGU's.

There were no indicators of impairment during the first three months of 2011 therefore the Company was not required to test for impairment. There were no firm indicators of impairment reversal during 2011 because commodity prices have remained relatively constant.

The Company booked a gain of \$6.2 million in the 3rd quarter of 2010 upon the sale of its interests at Saxon for proceeds of \$16.7million.

Income Taxes

Argosy has approximately \$46 million of income tax pools and \$4 million of operating loss carry-forwards at March 31, 2010 and does not anticipate being cash taxable in 2011.

Cash Flow

Cash flow for the period ended March 31, 2011 was \$515,000 (\$0.03 per share) versus \$1,092,000 (\$0.08 per share) for the equivalent period last year.

Cash flow decreased because of decreased volumes and increased general and administrative costs.

Sensitivities

The Company is in the process of exploiting its oil opportunities with a view to increasing oil production relative to natural gas. If the Company is successful, the impact of oil production and changes in oil prices is expected to have more impact whereas changes in natural gas volumes and prices are expected to have less impact on financial results. The following analysis was prepared by applying various pricing, volume and interest rate assumptions to the Company's 2011 forecast.

<u>\$ Thousand</u>	Cash Flow and Pretax Earnings
Forecast of impact on Company estimates for the year ended December 31, 2011	
Change in Canadian crude oil of \$1/bbl	411
Change in natural gas price of \$0.10 / mcf	309
Change in natural gas liquids price of \$1 / bbl	208
Change in interest rate of 1%	160
Change in production of crude oil of 100 bbl/day	2,977
Change in production of natural gas liquids of 100 bbl/day	2,127
Change in production of natural gas production of 1,000 mcf/day	1,507

Capital Expenditures

(\$ thousands)	3 Months Ended March 31, 2011
Drilling and completions ⁽¹⁾	6,617
Geology and geophysical	402
Equipping and tie-ins	988
Land and producing property acquisitions, net	5,296
Office equipment	24
Total expenditures	13,327

⁽¹⁾ Included in drilling and completions expenditures are drilling expenditures related to the 1 (1 net) oil wells at Pouce Coupe spudded in 2010.

The Company finished drilling and completed a 100% owned oil well at Pouce Coupe during the first quarter of 2011. The Company also drilled and completed a 100% one oil well and commenced drilling a second 100% owned oil well at Claresholm. The Company also purchased 10.25 sections of 100% owned land in the Claresholm area and 1 section of land in the Edson area during the first quarter of 2011.

Quarterly Financial Information

Three Months Ended (\$000's) except per share data)	Mar. 31, 2011	Dec. 31, 2010	Sept. 30, 2010	June 30, 2010	Mar. 31, 2010	Dec. 31, 2009(2)	Sept. 30, 2009(2)	June 30, 2009(2)
Total assets	55,287	42,808	49,536	69,536	64,424	73,989	71,650	66,969
Total sales boe/d)	736	770	924	1,098	954	724	823	935
Total sales \$	2,409	2,260	2,456	3,064	3,193	2,297	1,827	2,255
Cash flow (1)	515	397	597	1,037	1,092	(16)	347	78
Net income (loss)	(268)	(9,166)	(3,616)	3,065	(127)	(1,757)	(1,257)	(1,726)
Net income (loss) per share basic	(0.03)	(0.58)	(0.23)	0.20	(0.01)	(0.11)	(0.21)	(0.30)
Net income (loss) share diluted	(0.03)	(0.58)	(0.23)	0.19	(0.01)	(0.11)	(0.21)	(0.30)
Capital expenditures	13,327	5,056	2,222	1,009	5,375	3,685	287	600
Working capital; (deficiency)	(13,889)	(13,577)	(8,377)	(23,607)	(22,096)	(21,153)	(20,197)	(25,958)
Shareholders' equity	37,220	25,332	33,549	37,634	33,548	38,950	36,199	31,509

Notes:

(1) This financial information has been extracted from Argosy's unaudited quarterly and audited annual financial statements prepared in accordance with the accounting principles as outlined in the notes to the consolidated financial statements for 2011 and 2010 except for "cash flow" which is a non-prescribed measure under IFRS and previous to that, CGAAP.

(2) Argosy's IFRS transition date was January 1, 2010, therefore 2009 comparative information was calculated in accordance with CGAAP has not been restated.

Factors That Have Caused Variations Over the Quarters

The variations in the Company's revenues, net earnings and cash flow are generally caused by fluctuations in realized market prices for oil and natural gas and in production volumes caused by drilling activity offset by production declines.

Total assets and shareholders' equity increased and working capital deficiency decreased between June 30, 2009 and September 30, 2009 because of an issue of 4,800,000 common shares for gross proceeds of \$6,000,000.

Total assets, total sales and net income increased between March 31, 2010 and June 30, 2010 because of the acquisition of Radius Resources Inc. for a cash consideration of \$2,629,588 and the issuance of 748,000 Argosy common shares at a deemed price of \$0.70 per share. A pretax gain of \$2,228,000 was recorded on the acquisition in the quarter ended June 30, 2010 because the assigned values of the assets acquired exceeded the sum of the cash consideration and the value of the shares issued. A portion of the cash required was offset by the issuance of 500,000 shares for gross proceeds of \$1,000,000 in the period.

Total assets, total sales, revenue and working capital deficiency decreased significantly between June 30, 2010 and September 30, 2010 because the Company sold its interests in the Saxon area for gross cash proceeds of \$16,710,000.

Total assets increased and working capital deficiency decreased in the first quarter 2011 because the company issued 4,000,000 shares for gross proceeds of \$12,550,000. The funds were used in part to fund the Company's drilling and land acquisition activities primarily in the Claresholm area.

Liquidity and Capital Resources

	\$ <u>(thousands)</u>
2011 Exploration and development program funding	
Cash, Beginning of period	93
Cash flow	515
Change in non-cash working capital	3,879
Decrease in Bank Debt	(3,567)
Issue of Capital Stock	12,702
Cash, end of period	<u>(295)</u>
Net capital expenditures	<u>13,327</u>

Argosy normally endeavors to fund its capital expenditure program from internally generated cash flow, debt, farm-ins, farm outs and additional equity or other funding if available on favorable terms. However the Company may, from time to time, rationalize assets that are deemed superfluous to its needs.

In January 2011, 255,949 warrants to purchase common shares were exercised for gross proceeds of \$575,885. In March 2011, 250,000 warrants to purchase common shares were exercised for gross proceeds of \$562,500. In May 2011, 200,734 warrants to purchase common shares were exercised for gross proceeds of \$451,652. In February 2011, the Company issued 4,000,000 common shares for gross proceeds of \$12,550,000. The Company closed the sale of certain lands in the Ante Creek area for proceeds of approximately \$4,500,000 in April 2011. The Company's Bank has increased the credit limits from \$20 million to \$22 million on its Revolving Operating Demand Loan Facility and from \$4 million to \$8 million on its Acquisition/Development Demand Loan Facility as of its scheduled review of the Company's credit facilities in May 2011.

The foregoing financing activities together with expected cash flow should provide sufficient funds to fund the Company's short term growth.

Funding for medium to long term growth will be dependent on future exploration success, commodity prices and capital markets.

Commodity prices and production volumes have a large impact on the ability of the Company to finance its capital program. Commodity prices and production volumes affect Argosy's ability to generate adequate cash flow. Moreover, bank financing is dependent on the value of the Company's reserves which are in turn affected by commodity prices, production volumes and drilling success.

It should be noted that a prolonged period of low commodity prices would negatively affect cash flow from operations and would likely result in a reduction in the amount of cash flow available for investment in drilling programs which would in turn negatively impact future production volumes and reserves. A prolonged period of low commodity prices may also negatively affect the availability of funds that might be available by way of bank financing because the bank financing is dependent on the value of the Company's reserves. The value of the Company's reserves would be negatively impacted by commodity pricing and lower production volumes.

A prolonged period of low commodity prices may also negatively affect the availability of funds that might be available in the equity markets as well. Future activities may require Argosy to alter its capitalization significantly through the issuance of additional capital stock.

At March 31, 2011 the Company's credit facilities comprised a Revolving Operating Demand Loan Facility with a credit limit of \$20,000,000 and an Acquisition/Development Demand Facility with a credit limit of \$4,000,000. At that date the Company had drawn \$8,997,338 against the Revolving Operating Demand Loan Facility and nil against the Acquisition/Development Demand Facility.

The Revolving Operating Demand Loan Facility bears interest at Bank prime plus a percentage determined quarterly ranging from .75% to 2.5% greater than the Bank's prime rate in accordance with the Bank's pricing grid. The Bank's pricing grid is dependent on the Company's debt to cash flow ratio where debt is defined by the Bank as working capital deficit, consolidated long-term debt including capital leases and retractable preferred shares which are retractable at the option of the holder and cash flow is defined by the Bank as net earnings, depletion, depletion and accretion, future income taxes and other charges to income not requiring a cash payment calculated for the most recently completed quarter and annualized. The application of the Bank's pricing grid resulted in a rate was approximately 2.5% over the Bank's prime rate.

The Revolving Operating Demand Loan Facility has no specific terms of repayment aside from the Bank's right of demand and periodic review. The Acquisition/Development Demand Loan requires unspecified monthly principal repayments over the engineering half life of the reserves being financed as determined by the Bank

The Acquisition/Development Demand Loan Facility is restricted to the acquisition of proved non-producing/undeveloped petroleum and natural gas reserves and/or development of proved producing/undeveloped petroleum and natural gas reserves, bears interest at a rate which is 0.5% higher than the Revolving Operating Demand Loan and bears a standby fee of between 0.25% and 0.5% on the undrawn portion of the loan facility.

Security for the facilities includes a general assignment of book debts, a \$75,000,000 debenture with a first floating charge over all assets with a negative pledge and an undertaking to provide fixed charges on the Company's major producing reserves at the request of the bank.

A covenant to the Revolving Operating Demand Loan Facility requires that the Company maintain a working capital ratio, exclusive of bank indebtedness, of at least 1 to 1. For purposes of this calculation, the undrawn availability under the Revolving Operating Demand Loan Facility is added to current assets. A covenant to the Revolving Operating Demand Loan facility requires that the Company limit hedging activities to 50% of actual production.

There is no similar working capital requirement for the Acquisition/Development Demand Loan.

There is no debt to equity requirements related to either of the facilities.

The Company was in compliance with all debt covenants at March 31, 2011.

The last scheduled review of the Company's borrowing limits occurred in May 2011. The next review is scheduled for November 2011. There can be no assurance that other amounts or terms will not change at the next scheduled bank review of the Company's borrowing limits. The Company's Bank increased the credit limits from \$20 million to \$22 million on its Revolving Operating Demand Loan Facility and from \$4 million to \$8 million on its Acquisition/Development Demand Loan Facility as a result of its review of the Company's borrowing limits in May 2011. There were no other material changes made to the Company's banking arrangements as a result of that review.

Contractual Obligations

The Company's banking commitments are outlined in *Liquidity and Capital Resources*.

In 2011 the Company issued 1,000,000 common flow through shares at an issuance price of \$3.70 per share. The tax deductions related to these flow through shares will be renounced to flow through shareholders. The Company incurred the \$3,700,000 of qualifying Canadian Exploration Expenditures required to fulfill its flow through obligation in the first quarter of 2011.

The Company has entered into various commitments related to the leasing of office premises. The payments due under such leases are as follows:

Contractual obligations (\$ thousands)	2011	2012	2013	2014	2015	Thereafter
Office Premises	556	808	879	609	-	-

Risk Management

There have been no changes in risk from those described in the Management's Discussion and Analysis for the year ended December 31, 2010.

The most important business risks that face Argosy in the Canadian oil and gas industry together with its strategies to mitigate such risks are as follows:

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by Argosy will result in new discoveries of oil or natural gas in commercial quantities. Without the continual addition of new reserves, any existing reserves that Argosy may have at any particular time and the production there from will decline over time as such existing reserves are depleted. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

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

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. 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.

In order to mitigate such exploration risk, the Company has employed seasoned and highly skilled employees and consultants and it operates in areas in which it has technical and operating expertise. The Company uses the latest technology to further reduce risk and increase the probability of success.

The Company operates most of its production and this allows it to a great extent to control the timing and costs in the areas in which it operates. Programs can thus be expanded or contracted on a timely basis in response to changing parameters. In this time of extreme market volatility, Argosy has cautiously moved forward with its exploration and development plans as capital has become available see Liquidity and Capital Resources.

Oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on Argosy and its future results of operations, liquidity and financial condition.

The Company carries insurance to protect itself from catastrophic events and management reviews its coverage at least annually to ensure that the insurance policies that are in place are adequate.

The Company follows all environmental and industry regulations and has formal procedures to ensure that this occurs. Such procedures are communicated to all personnel and contractors.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world and North American demand, supply and other factors, all of which are beyond the control of Argosy. Market prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the volume of Argosy's oil and gas reserves. Argosy may also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Argosy's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to Argosy are in part determined by the value of the underlying reserves of Argosy. A sustained material decline in prices from historical average prices could result in a significant decrease in the value of Argosy's reserves, thus reducing the bank credit available to Argosy, and could require that a portion of any existing bank debt of Argosy be repaid, may require the curtailment of capital programs and may result failure of the Company to meet its contractual obligations. In addition to establishing markets for its oil and natural gas, Argosy must also successfully market its oil and natural gas to prospective buyers.

The Company has attempted from time to time to mitigate commodity price risk through the use of various financial derivative contracts classified as "held for trading" to manage volatility of commodity gas prices. These contracts can only be undertaken upon approval by the Board of Directors. The Company's banking documents limit such activities to 50% of actual production.

The Company has no derivative contracts outstanding at March 31, 2011. The derivative contracts that were outstanding at December 31, 2010 expired on March 31, 2011. During the 3 months ended March 31, a total of \$155,980 was actually received in respect to the derivative contracts that had been outstanding during the quarter and that was recorded as a realized gain.

The marketability and price of oil and natural gas which may be acquired or discovered by Argosy will be affected by numerous factors beyond its control. Argosy will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by Argosy. The ability of Argosy to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines which deliver oil and natural gas to commercial markets. Argosy will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to

operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Argosy has limited direct experience in the marketing of oil and natural gas. Argosy employs the services of an outside marketing firm. The Company reviews the credit worthiness of that firm from time to time.

All of the Company's petroleum and natural gas production is marketed under standard industry terms. The industry has a pre-arranged monthly settlement day for payment of revenues from all buyers of crude oil and natural gas. This occurs on the 25th day following the month in which the production is sold. As a result, the Company collects sales revenues in a predetermined, timely and organized manner. Management monitors purchaser credit positions to mitigate any potential credit losses. To the extent the Company has joint interest activities with industry partners, the Company must collect, on a monthly basis, partners' share of capital and operating expenses. These collections are subject to normal industry credit risk. The Company attempts to mitigate risk from joint venture receivables by obtaining partner approval of capital projects prior to expenditure and collects in advance for significant amounts related to partners' share of capital expenditures in accordance with the industry operating procedures. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners. However, the Company does have the ability to withhold production from joint venture partners in the event of non-payment.

Substantial Capital Requirements – Liquidity

Argosy has a significant inventory of undrilled prospects. It could make substantial capital expenditures for exploration, development and production of oil and natural gas reserves in connection with these prospects. From time to time, Argosy may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Argosy to forfeit its interest in certain properties, to miss certain acquisition opportunities, to fail to meet its flow through obligations and/or to reduce or terminate its operations. If Argosy's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Argosy's ability to expend the necessary capital to replace its reserves or to maintain its production. 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 Argosy. As a consequence the Company may consider other sources of debt with different characteristics than existing bank debt, adjust exploration and development capital expenditures and dispose of assets. Moreover, future activities may require Argosy to alter its capitalization significantly. The inability of Argosy to access sufficient capital for its operations could have a material adverse effect on Argosy's financial condition, results of operations or prospects as well as its ability to meet its flow through obligations. A recurrence of the global economic slowdown of 2008 and 2009, the scarcity of credit and volatile capital markets may exacerbate Argosy's liquidity risk.

Argosy's Bank has been provided with security over substantially all of the assets of Argosy. The Bank reviews the engineering values underlying such security from time to time using its own forecast of commodity prices and production. A sustained decline in prices could reduce the value of the Bank's security thereby reducing the amount of credit available to the Company and could possibly result in a portion of the bank indebtedness to be repaid. Furthermore, there is a risk that the lines of credit may not be renewed on terms that would be favorable to the Company, if at all. This risk is also particularly important given the current volatile capital markets.

The availability of bank credit is generally reducing and related costs are increasing. As a consequence the Company may consider other sources of debt with different characteristics than existing bank debt, adjust exploration and development capital expenditures and dispose of assets. Equity financing may not be readily available to junior oil and gas producers given current market conditions.

If Argosy becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, or if the value of the underlying security, as determined by the Bank, is less than that which

would be acceptable to it, the Bank may demand payment and it may foreclose on or sell Argosy's properties. The proceeds of any such sale would be applied to satisfy amounts owed to Argosy's Bank and other creditors and only the remainder, if any, would be available to Argosy.

Management has strictly controlled capital, non-essential expense and administrative spending and continues to pursue financing opportunities to fund its future prospects. In fact, in spite of the economic slowdown that has characterized the period of time since its inception the Company has managed to raise significant amounts of capital. In 2009, 2010 and 2011 it raised funds aggregating approximately \$27 million by way of private placements and short form prospectus offerings. Share capital increased from 5,858,834 common shares outstanding at December 31, 2008 to 20,042,888 common shares and 1,341,235 common share purchase warrants outstanding at March 31, 2011.

In addition, the Company sold its Saxon property in the third quarter of 2010 for gross proceeds of \$16.7million. Further, the Company rationalized certain property interests in the Ante Creek area in April of 2011. The decision to rationalize these properties came as a result of reviews of the Company's exploration projects and operational activities.

The following financings were completed since December 31, 2008:

In September 2009 the Company issued 4,800,000 special warrants at a price of \$1.25 per special warrant for total proceeds of \$6,000,000 by way of private placement. In October 2009, 4,800,000 common shares were issued to holders of these special warrants on basis of one common share for each special warrant held.

In December 2009, the Company completed a private placement of 1,750,000 flow-through common shares and 875,000 warrants to purchase common shares of the Company for gross proceeds of \$3,498,223. At the same time it completed a private placement of 444,363 common shares and 222,182 warrants to purchase common shares of the Company for gross proceeds of \$801,637. Each common share purchase warrant entitles the holder to purchase a common share of the Company for \$2.25 per share for 18 months from the time of issuance.

In March 2010, the Company completed a private placement of 1,500,004 common shares and 750,002 common share purchase warrants for gross proceeds of \$2,700,008. . Each common share purchase warrant entitles the holder to purchase a common share of the Company for \$2.25 per share for 18 months from the time of issuance.

In May 2010 the Company completed a private placement of 500,000 flow-through common shares for gross proceeds of \$1,000,000.

In January 2011, 255,949 warrants to purchase common shares were exercised for gross proceeds of \$575,885.

In February 2011, the Company closed a bought deal issue of 3,000,000 common shares by way of short form prospectus for total proceeds of \$8,850,000. At the same time it closed a bought deal issue of 1,000,000 flow through common shares by way of short form prospectus for gross proceeds of \$3,700,000.

In March 2011, 250,000 warrants to purchase common shares were exercised for gross proceeds of \$562,500.

In May 2011, 200,734 warrants to purchase common shares were exercised for gross proceeds of \$451,652.

Outlook

The Company is in the midst of a process that will result in the change of its focus from natural gas projects to those that can deliver quality, low cost oil production and reserve additions. Fortunately, Argosy is ideally positioned to take advantage of this situation.

Argosy currently expects to drill 12 wells in 2011, with 9 expected to be development wells and 3 expected to be exploratory wells. To date in 2011, 3 (3 net) oil wells have been drilled and cased.

At Claresholm Argosy has extended the Exshaw/Bakken resource play currently being developed just south of the US Canadian border in Northern Montana onto its lands., The Company drilled one vertical well in the 4th quarter of 2010 that established oil in two horizons. The upper Banff horizon was completed for vertical production late in 2010. However, the Company is of the opinion that the oil bearing reservoirs found are more ideally suited to horizontal development. One Banff horizontal well was drilled and completed and a second lower Big Valley well was spudded in the first quarter of 2011 and is awaiting completion. The Company is still evaluating the results of this drilling. It will direct additional capital budget funds to oil well drilling in the Claresholm area if the proposed multistage fracing technology proves to be economic for these reservoirs.

An enhanced oil recovery pilot project has been implemented in the Pearce area at Claresholm. If pressure is restored and maintained, capital spending will be focused on this area later in 2011.

At Pouce Coupe, the Company has drilled a horizontal oil well to the Boundary Lake formation. The well was spudded in December 2010, completed in January 2011 and was put on stream in February 2011. This well promises to be an important contributor to the Company's cash flow in 2011 once its production rate stabilizes.

At Ante Creek, recent industry drilling directly offsetting the Company's lands, has validated the production potential of production from the Montoney formation of which 70% is light oil. The Company has identified 11 horizontal locations on its 100% working interest lands. It has also identified a deeper horizontal target which it hopes to test by re-entering a suspended cased well bore.

Critical Accounting Estimates

The Company's consolidated financial statements have been prepared in accordance with IFRS.

Management is required to make appropriate decisions in respect to assumptions and estimates that impact the reported amounts balance sheet and income statement items. As the determination of accounts receivable, accounts payable, revenues and expenses is dependent upon future events, the preparation of these financial statements requires the use of estimates and assumptions which have been made using careful judgment. Areas requiring the use of management estimates include estimates of revenues, royalties and production costs at a specific reporting date but for which actual revenues and costs have not yet been received, estimates on capital projects which are in progress or recently been completed where actual costs have not been received at a specific reporting date, collectability of accounts receivable, recoverability of petroleum and natural gas interests, rates of depletion and depreciation, accrued liabilities, determination of decommissioning liabilities, the assessment of impairment of oil and gas assets, assumptions used in the calculation of stock-based compensation, allocation of proceeds for units between common shares and warrants, the classification of the Company's derivative contracts and the determination of the valuation allowance for future tax assets.

Amounts recorded for depreciation and depletion, and amounts used for impairment test calculations are based on estimates of oil and natural gas reserves. The company's credit facilities are also based on such estimates. The Company's reserve estimates are reviewed annually by an independent engineering firm. By their nature, these estimates of reserves and future cash flows are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

Management believes the estimates are reasonable within reasonable limits of materiality and within the framework of the significant accounting policies adopted by the Company; however, actual results could differ from those estimates and could impact future results of operations and cash flows.

The Company ensures that the individuals with the most knowledge of the activity are responsible for the estimate. Estimates and assumptions used in this regard are reviewed by management for reasonableness on a regular basis and past estimates are compared to actual results in order to make informed decisions on future estimates.

In the opinion of management, these financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

As time passes, new information may be gleaned or circumstances may change and this may cause the estimates to change materially from the current estimates.

Management believes the estimates are reasonable, however, actual results could differ from those estimates and could impact future results of operations and cash flows.

Disclosure Controls and Internal Controls over Financial Reporting

Argosy's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") to provide reasonable assurance that (i) material information relating to the Company and its consolidated subsidiaries is made known to Argosy's Chief Executive Officer and Chief Financial Officer by others; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Argosy's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision, Internal Controls over Financial Reporting ("ICFR") to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The control framework Argosy's that officers used to design the ICFR is the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations.

No material changes in Argosy's ICFR were identified during the three months ended March 31, 2011 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting. There were no material changes to ICFR as a result of the transition to IFRS.

It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's DC&P and ICFR provide a reasonable level of assurance that they are effective, such controls and procedures cannot provide absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud. Furthermore, ICFR has inherent limitations no matter how well designed such controls may be. Control systems can provide reasonable, not absolute, assurance that the objectives of the control system are met.

The Company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of March 31, 2011, that the Company's disclosure controls and procedures as at such date are effective to provide reasonable assurance that material information related to the Company, including its consolidated subsidiary, is made known to them by others within those entities.

IFRS

The Company adopted IFRS effective January 1, 2011. The Company's financial results for the first quarter of 2011 together with the results of the comparative periods in 2010 are reported using the IFRS principles. Certain selected comparative historical data for periods prior to 2010 is reported using CGAAP principles. Refer to the notes to the unaudited interim consolidated financial statements for further reconciliations of the impact of the transition to IFRS from CGAAP as well as a listing of the significant accounting policies adopted by the Company.

The following table outlines a reconciliation of the Company's CGAAP to IFRS consolidated statement of financial position as at January 1, December 31, 2010 and March 31, 2010:

\$ thousands	As at January 1, 2010						
	CGAAP	E&E	Impairment	Onerous Contracts	Flow through shares	Share based payments	IFRS
Current assets	6,784	-	-	-	-	-	6,784
Note receivable	1,300	-	-	-	-	-	1,300
Exploration & evaluation assets	-	8,177	-	-	-	-	8,177
Property, plant and equipment	65,806	(8,177)	(9,704)	-	-	-	47,925
Total assets	73,890	-	(9,704)	-	-	-	64,186
Current liabilities	28,036	-	-	37	341	-	28,414
Decommissioning liabilities	973	-	-	-	-	-	973
Deferred income taxes	5,931	-	(2,426)	(155)	-	-	3,350
Onerous contracts	-	-	-	583	-	-	583
Shareholders' equity	38,950	-	(7,278)	(465)	(341)	-	30,866
Total liabilities and shareholders' equity	73,890	-	(9,704)	-	-	-	64,186

As at December 31, 2010

(\$000's)	Canadian GAAP	Impairment	E&E Assets	Depletion and depreciation	Gain on Sale	Onerous contracts	Share – based payments	Flow through Shares	IFRS
ASSETS									
Current Assets	2,679	-	-	-	-	-	-	-	2,679
Exploration and evaluation assets	-	-	3,275	-	-	-	92	-	3,367
Property, plant and equipment	60,387	(29,804)	(3,275)	3,170	6,284	-	-	-	36,762
	63,066	(29,804)	-	3,170	6,284	-	92	-	42,808
LIABILITIES AND EQUITY									
Current liabilities	16,101	-	-	-	-	155	-	-	16,256
Onerous contracts Decommissioning obligations	-	-	-	-	-	427	-	-	427
Deferred tax liability	1,432	-	-	-	-	-	-	-	1,432
	4,134	(7,451)	-	793	1,571	(145)	59	400	(639)
Shareholders' Equity:	21,667	(7,451)	-	793	1,571	437	59	400	17,476
	41,399	(22,353)	-	2,377	4,713	(437)	33	(400)	25,332
	63,066	(29,804)	-	3,170	6,284	-	92	-	42,808

As at March 31, 2010

(\$000's)	Canadian GAAP	Impairment	E&E Assets	Depletion and depreciation	Onerous contracts	Share – based payments	IFRS
ASSETS							
Current Assets	2,739	-	-	-	-	-	2,739
Notes Receivable	1,300	-	-	-	-	-	1,300
Exploration and evaluation assets	-	-	8,387	-	-	16	8,403
Property, plant and equipment	69,335	(9,704)	(8,387)	738	-	-	51,982
	73,374	(9,704)	-	738	-	16	64,424
LIABILITIES AND EQUITY							
Current liabilities	24,798	-	-	-	37	-	24,835
Onerous contracts Decommissioning obligations	-	-	-	-	573	-	573
Deferred tax liability	1,037	-	-	-	-	-	1,037
	6,822	(2,426)	-	185	(150)	-	4,431
Shareholders' Equity:	32,657	(2,426)	-	185	460	-	30,876
	40,717	(7,278)	-	553	(460)	16	33,548
	73,374	(9,704)	-	738	-	16	64,424

The following table outlines a reconciliation of the Company's CGAAP to IFRS consolidated statement of operations for the year ended December 31, 2010:

(\$000's)	Canadian GAAP	Impairment	Gain on Sale of Property	Depletion and Depreciation	Onerous Contracts	Share – based payments	Deferred income taxes	IFRS
Oil and gas sales	10,973	-	-	-	-	-	-	10,973
Royalties	(786)	-	-	-	-	-	-	(786)
Revenue, net of royalties	10,187	-	-	-	-	-	-	10,187
Realized gain on derivative contract	371	-	-	-	-	-	-	371
Unrealized gain on derivative contract	486	-	-	-	-	-	-	486
Gain on acquisition – Radius Resources Corp.	2,633	-	-	-	-	-	-	2,633
Gain on sale of property and equipment	-	-	6,284	-	-	-	-	6,284
	13,677	-	6,284	-	-	-	-	19,961
Operating expenses	2,526	-	-	-	-	-	-	2,526
Depletion and depreciation	8,013	-	-	(3,249)	-	-	-	4,764
Impairment of property, plant and equipment	-	20,100	-	-	-	-	-	20,100
General and administrative expenses, including stock based compensation	4,614	-	-	-	(37)	(238)	-	4,339
Income/(loss) from operating activities	(1,476)	(20,100)	6,284	3,249	37	238	-	(11,768)
Financing expenses including accretion	(805)	-	-	(79)	-	-	-	(884)
Loss before taxes	(2,281)	(20,100)	6,284	3,170	37	238	-	(12,652)
Deferred income taxes	1,050	5,025	(1,571)	(793)	(9)	(59)	(835)	2,808
Loss and comprehensive loss for the year	(1,231)	(15,075)	4,713	2,377	28	179	(835)	(9,844)

The following table outlines a reconciliation of the Company's CGAAP to IFRS consolidated statement of operations for the period March 31, 2010:

(\$000's)	Canadian GAAP	Depletion and Depreciation	Onerous contracts	Share –based payments	Flow through shares	IFRS
Oil and gas sales	3,193	-	-	-	-	3,193
Royalties	(522)	-	-	-	-	(522)
Revenue, net of royalties	2,671	-	-	-	-	2,671
Realized loss on derivative contracts	(21)	-	-	-	-	(21)
Unrealized gain on derivative instruments	775	-	-	-	-	775
	3,425	-	-	-	-	3,425
Operating expenses	537	-	-	-	-	537
Depletion and depreciation	1,917	(756)	-	-	-	1,161
General and administrative expenses, including stock based compensation	929	-	(7)	(40)	-	882
Income from operating activities	42	756	7	40	-	845
Financing expenses including accretion	(217)	(18)	-	-	-	(235)
Income before taxes	(175)	738	7	40	-	610
Deferred income tax	16	185	2	-	534	737
Loss and comprehensive loss for the period	(191)	553	5	40	(534)	(127)

On transition to IFRS, on January 1, 2010 the Company used the exemption in respect to Full Cost Accounting allowed pursuant to IFRS 1 *First Time Adoption of International Reporting Standards*.

On transition to IFRS on January 1, 2011, the Company used the IFRS 1 exemption that allowed it to apply IFRS prospectively in respect to property and equipment by utilizing its reserve volumes at the transition date to allocate its full cost pool to CGU's and to exploration and evaluation assets, with the provision that an impairment As a result of applying the IFRS 1 exemption for deemed cost at January 1, 2010, the Company was required to test all of its cash generating units for impairment. The Company tested the Claresholm, Edson, Saxon, Ante Creek and Pouce Coupe CGUs for impairment.

In addition, as a result of continued weakness in natural gas pricing the Company tested the same CGUs for impairment at September 30 and December 31, 2010. At March 31, 2011, there was no material change in the forward curve for natural gas prices and there was an increase in oil and natural gas liquids prices from December 31, 2010, therefore the Company did not test for impairment of its CGUs, or reverse any of the impairments previously recognized.

The recoverable amount of the CGUs was estimated based on the higher of the value in use and the fair value less costs to sell. The estimate of fair value less costs to sell was determined using a discount rate of 12 percent and forecasted cash flows, with escalating prices and future development costs, as obtained from the reserve report. The prices used to estimate the fair value less cost to sell are those used by independent industry reserve engineers.

The impairment losses recognized in each CGU were as follows:

(\$ 000's)	Claresholm	Edson	Saxon	Ante Creek	Pouce Coupe	Other	Total
Impairment loss at January 1, 2010	7,461	1,561	677	-	-	5	9,704
Year ended December 31, 2010	18,090	1,981	-	-	-	29	20,100
	25,551	3,542	677	-	-	34	29,804

Carrying value

January 1, 2010	38,948	7,244	1,590	-	-	143	47,925
December 31, 2010	25,788	5,509	-	4,415	1,411	90	36,762

New standards and interpretations not yet adopted:

The Company is currently reviewing the following new and revised accounting pronouncements that have been issued but are not yet effective to determine if they may have an impact on the Company:

IFRS 9 – Financial Instruments. In November 2009, the IASB published IFRS 9 “Financial Instruments” which covers the classification and measurement of financial assets as part of its project to replace IAS 39 “Financial Instruments: Recognition and Measurement.” IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity managed its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. In October 2010, additional requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to own credit risk out of profit or loss and recognize the change in other comprehensive income.

IFRS 9 will become effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. The implementation of the issued standard is not expected to have a significant impact on the Company’s financial position or results.

IAS 12 – Income Taxes. IAS 12 “Income Taxes” was amended on December 20, 2010 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through the sale of the asset. The amendment to IAS 12 is effective for reporting periods beginning on or after January 1, 2012. The Company is currently evaluating the impact of this amendment to its financial statements.

Transactions with Related Parties

The Company has not entered into any transactions with related parties, nor did it have any balances outstanding with related parties at year end.

Off Balance Sheet Arrangements

The Company has not entered into any off-balance sheet transactions.

Argosy Energy Inc.
Condensed Consolidated Statements of Financial Position
Unaudited

(\$ Thousands)	March 31, 2011	December 31, 2010 (Note 16)	January 1, 2010 (Note 16)
ASSETS			
Current assets			
Cash	295	93	4,300
Accounts receivable and accruals	1,200	1,411	2,011
Prepaid expenses and deposits	1,028	1,041	473
Fair value derivative contracts (note 13)	-	134	-
	2,523	2,679	6,784
Note receivable – Radius Resources Corp. (note 14)	-	-	1,300
Exploration and evaluation assets (note 8)	13,795	3,367	8,177
Property, plant and equipment (note 7)	38,956	36,762	47,925
	55,274	42,808	64,186
LIABILITIES			
Current liabilities			
Accounts payable and accruals	7,189	3,537	5,955
Fair value of derivative contracts (note 13)	-	-	352
Onerous Contract	226	155	37
Flow Through Shares	-	-	341
Bank indebtedness (note 11)	8,997	12,564	21,729
	16,412	16,256	28,414
Onerous Contracts	347	427	583
Decommissioning obligations (note 9)	1,534	1,432	973
Deferred tax liability (asset)	(89)	(639)	3,350
	18,204	17,476	33,320
SHAREHOLDERS' EQUITY			
Share capital (note 12)	61,858	49,737	45,837
Contributed surplus	1,758	1,702	1,292
Deficit	(26,546)	(26,107)	(16,263)
	37,070	25,332	30,866
	55,274	42,808	64,186

Subsequent events – notes 11, 12 and 15.

See accompanying notes to unaudited interim condensed consolidated financial statements.

Argosy Energy Inc.
Condensed Consolidated Statements of Operations Income (Loss) and
Comprehensive Income (Loss)
Unaudited

(\$ Thousands except for per share information)	Three Months Ended	
	2011	March 31, 2010 (note 16)
Revenue:		
Oil and gas sales	2,409	3,193
Royalties	(159)	(522)
Revenue, net of royalties	2,250	2,671
Realized gain (loss) on derivative contracts (note 13)	22	(21)
Unrealized gain on derivative contracts (note 13)	-	775
	2,272	3,425
Operating expenses	637	537
Depletion and depreciation	773	1,161
General and administrative	1,072	882
Income (loss) from operating activities	(210)	845
Finance expenses	122	235
Income (loss) before taxes	(332)	610
Deferred income tax reduction	(107)	(737)
Loss and comprehensive loss for the period	(439)	(127)
Basic and diluted income (loss) per share (note 12)	(0.02)	(0.01)

Subsequent events – notes 11, 12 and 15.

See accompanying notes to unaudited interim condensed consolidated financial statements.

Argosy Energy Inc.
Condensed Consolidated Statements of Changes in Shareholders' Equity
Unaudited

(\$ Thousands except number of common shares)	Number Of Common Shares	Share Capital	Contributed Surplus	Deficit	Total Shareholder's Equity
Balance at January 1, 2010 (note 12 and 16)	12,853,197	45,837	1,292	(16,263)	30,866
Issued pursuant to private placement	1,500,004	2,699	-	-	2,699
Share based payments	-	-	110	-	110
Income for the period	-	-	-	(127)	(127)
Balance at March 31, 2010 (notes 12and 16)	14,353,201	48,536	1,402	(16,390)	33,548
Balance at January 1, 2011 (note 12 and 16)	15,536,939	49,737	1,702	(26,107)	25,332
Issued pursuant to prospectus	4,000,000	11,800	-	-	11,800
Issued pursuant to private placement	505,949	1,138	-	-	1,138
Share issuance costs, net of tax	-	(817)	-	-	(817)
Share Based Payments	-	-	56	-	56
Income for the period	-	-	-	(439)	(439)
Balance at March 31, 2011 (notes 12 and 16)	20,042,888	61,858	1,758	(26,546)	37,070

Subsequent events – notes 11, 12 and 15.

See accompanying notes to unaudited interim condensed consolidated financial statements

Argosy Energy Inc.
Condensed Consolidated Statements of Cash Flows
Unaudited

(\$ Thousands)	Three Months Ended	
	2011	2010 (note 17)
Cash provided by (used in):		
Cash provided by (used in) Operations		
Income (loss) for the period	(439)	(127)
Adjustments for:		
Share based payments	52	88
Onerous contracts	(9)	(9)
Deferred income tax	(107)	737
Unrealized (gain) on derivative contracts	-	(775)
Depletion and depreciation	773	1,161
Accretion	31	17
Changes in non-cash working capital (note 6)	217	(4,111)
	732	(3,019)
Investing		
Property, plant and equipment additions, net	(13,327)	(5,375)
Changes in non-cash working capital (note 6)	3,662	4,326
	(9,665)	(1,049)
Financing		
Increase (decrease in) Bank indebtedness	(3,567)	(2,931)
Proceeds from issue of share capital, net of issue costs	12,702	2,699
	9,135	(232)
Increase (decrease) in cash	202	(4,300)
Cash – beginning of period	93	4,300
Cash – end of period	295	-
Supplemental Information :		
Interest paid in cash	92	217

Subsequent events – notes 11, 12 and 15.

See accompanying notes to unaudited interim condensed consolidated financial statements

Argosy Energy Inc.
Notes to the Unaudited Interim Condensed Consolidated Financial Statements
For the Three Months Ended March 31, 2011 and 2010

Reporting entity

Argosy Energy Inc. (“Argosy” or the “Company”) is an independent public Company engaged in the acquisition, exploration, exploitation, development and production of crude oil and natural gas from its principal producing properties at Claresholm and Edson in Alberta, Canada.

On May 14, 2010, Argosy acquired 100% of the issued and outstanding shares of Radius Resources Corp. (Radius) which became and remains the Company’s only subsidiary. Radius has oil and gas operations primarily focused in the Ante Creek area of Alberta, Canada.

1. Basis of preparation

Statement of compliance

The unaudited interim condensed consolidated financial statements (the “financial statements”) have been prepared in accordance with International Accounting Standard 34 *Interim Financial Reporting*. These are the Company’s first International Financial Reporting Standards (“IFRS”) unaudited interim condensed financial statements for part of the period covered by the first IFRS annual financial statements. IFRS 1 *First-time Adoption of International Accounting Reporting Standards* has been applied. The unaudited interim condensed consolidated financial statements do not include all of the information required for full annual financial statements.

The Company’s significant accounting policies under IFRS are presented in note 3. These policies have been retrospectively and consistently applied except where specific exemptions permitted an alternative treatment on transition to IFRS in accordance with IFRS 1. The impact of the adoption of the new standards, including reconciliations presenting the change from previous GAAP to IFRS as at January 1, 2010, as at and for the three month period ended March 31, 2010 and as at and for the year ended December 31, 2010 is presented in note 16.

These unaudited interim condensed consolidated financial statements were approved for issue by the Company’s Board of Directors on June 14, 2011.

Basis of measurement

The unaudited interim condensed consolidated financial statements have been prepared on the historical cost basis except for derivative financial instruments, which are measured at fair value. The methods used to measure fair values are disclosed in note 3.

Functional and presentation currency

The unaudited interim condensed consolidated financial statements are presented in Canadian dollars which is the Company and its subsidiary’s functional currency.

Use of Estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Significant areas where estimation uncertainty and critical judgments are applied include valuation of financial instruments, valuation of property, plant and equipment, impairment losses, depletion and depreciation, decommissioning obligations, onerous contracts, deferred taxes and measurement of stock-based compensation.

Reserve estimates impact a number of the areas referred to above, in particular, the valuation of property, plant and equipment and the calculation of depletion and depreciation.

2. Significant accounting policies

The accounting policies set out below have been applied consistently to all periods presented in these unaudited interim condensed consolidated financial statements, and have been applied consistently by the Company and its subsidiary.

a. Basis of consolidation:

Subsidiaries

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the interim condensed unaudited consolidated financial statements from the date that control commences until the date that control ceases.

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their recognized amounts (generally fair value) at the acquisition date. The excess of the cost of acquisition over the recognized amounts of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair values of the net assets of the subsidiary acquired, a bargain purchase gain is recognized immediately in the consolidated statement of income.

Jointly controlled operations and jointly controlled assets

Many of the Company's oil and natural gas activities involve jointly controlled assets. The unaudited interim condensed consolidated financial statements include the Company's share of these jointly controlled assets and the proportionate share of the relevant revenue and related costs.

Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the unaudited interim condensed consolidated financial statements.

b. Financial instruments:

Non-derivative financial instruments.

Non-derivative financial instruments comprise cash, accounts receivable and accruals, accounts payables and accruals and bank indebtedness. Non-derivative financial instruments are recognized initially at fair value, plus, for instruments not classified as “fair value through profit or loss”, any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

Cash

Cash comprise cash on hand, term deposits and other short-term highly liquid investments with original maturities of three months or less and is measured similar to other non-derivative financial instruments.

Other

Other non-derivative financial instruments, comprising accounts receivable and accruals, accounts payable and accruals and bank indebtedness are measured at amortized cost using the effective interest method, less any impairment losses. The Company nets all transaction costs incurred in relation to the acquisition of a financial asset or liability, against the related financial asset or liability. Bank indebtedness is recorded net of issue costs and are presented net of deferred interest payments, with interest recognized in earnings on an effective interest basis.

Derivative financial instruments.

The Company has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as “fair value through profit or loss” and are recorded on the statement of financial position at fair value. Transaction costs are recognized in profit or loss when incurred.

The Company accounts for forward physical delivery sales contracts, which are entered into and held for the purpose of delivery or receipt of non-financial items in accordance with expected sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statement of financial position. Settlements on these physical sales contracts are recognized in oil and natural gas revenue.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at “fair value through profit or loss”. Changes in the fair value of separable embedded derivatives are recognized immediately in profit or loss.

Share capital.

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and stock options are recognized as a deduction from equity, net of any tax effects.

c. Property, plant and equipment:

i. Recognition and measurement

Exploration and evaluation expenditures

Pre-license costs are recognized in the statement of operations and comprehensive loss as incurred. The Company has not incurred any such costs.

Exploration and evaluation costs, including the costs of acquiring undeveloped land and drilling costs are initially capitalized until the drilling of the well is complete and the results have been evaluated. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved reserves are determined to exist. If proved and or probable reserves are found, the drilling costs and associated undeveloped land are tested for impairment and transferred to property, plant and equipment. The cost of undeveloped land that expires or any impairment recognized during a period, is charged as additional depletion and depreciation expense unless it is related to a viable Cash Generating Unit ("CGU") in which case such costs will transferred to the applicable CGU.

Exploration and evaluation assets are assessed for impairment if sufficient data exists to determine technical feasibility and commercial viability, and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

ii. Development and production costs.

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGU's for impairment testing.

The Company has grouped its development and production assets into the Claresholm, Edson, Saxon, Ante Creek and Pouce Coupe CGU's.

The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, was determined using the IFRS 1 deemed cost election, whereby the costs at transition were allocated to CGU's based on reserve volumes and tested for impairment. The Company chose to allocate its costs based on proved plus probable reserves volumes. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized as separate line items in profit or loss.

ii Subsequent costs.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

iii. Depletion and depreciation.

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the quarter to the related proved and probable reserves, taking into account estimated future development and decommissioning costs necessary to bring those reserves into production and potential salvage values. These estimates are reviewed by independent reserves engineers at least annually. Proved and probable reserves are estimated using independent reserves evaluator reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proved component of proved and probable reserves are 90 percent and 10 percent, respectively. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- a reasonable assessment of the future economics of such production;
- a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered proved and probable if producibility is supported by either actual production or a conclusive formation test. The area of reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proved and probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir, or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

For other assets, depreciation is recognized in profit or loss over the estimated useful lives of each part of an item of property, plant and equipment using the declining balance method at

rates between 20% and 30% per annum. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term.

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

d. Leased assets:

Operating leases are not recognized on the Company's statement of financial position. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease. Onerous leases are recognized in the accounts over the terms of the respective leases by reference to forecast cash outlays net of projected recoveries.

e. Impairment:

Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

Non-financial assets.

The carrying amounts of the Company's non-financial assets, other than deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or the CGU. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

Fair value less cost to sell is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The fair value less cost to sell of oil and gas assets is generally determined as the net present value of the estimated future cash flows expected to arise from the continued use of the CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account.

These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGU's are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit on a pro rata basis. Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists.

An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

f. Share-based payments

The grant date fair value of equity-settled options granted to employees is recognized as stock-based compensation expense, within general and administrative expenses, with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

g. Provisions – onerous contracts

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

h. Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditures required to settle the present obligation at the date of the statement of financial position. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The credit adjusted interest rate is used in connection with the calculation of such future cash flows. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the asset retirement obligations are charged against the provision to the extent the provision was established.

i. Revenue

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party and collection is reasonably assured. This is generally at the time product enters the pipeline. Revenue is presented both before and after royalties payable to the Crown and others. Transportation costs are netted from revenue where title transfers prior to transport on applicable sales pipelines and the transportation is held by and charged by the purchaser. Other transportation and processing fees and included in operating expenses. Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

j. Finance expense

Finance expense comprises interest expense on borrowings and accretion of the discount on decommissioning obligations.

k. Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity. Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes.

Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

l. Earnings per share

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

m. New standards and interpretations not yet adopted:

The Company is currently reviewing the following new and revised accounting pronouncements that have been issued but are not yet effective to determine if they may have an impact on the Company:

IFRS 9 – Financial Instruments. In November 2009, the IASB published IFRS 9 “Financial Instruments” which covers the classification and measurement of financial assets as part of its project to replace IAS 39 “Financial Instruments: Recognition and Measurement.” IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity managed its financial instruments in the context of its business model and the

contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. On October 2010, additional requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to own credit risk out of profit or loss and recognize the change in other comprehensive income.

IFRS 9 will become effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. The implementation of the issued standard is not expected to have a significant impact on the Company's financial position or results.

IAS 12 – Income Taxes. IAS 12 “Income Taxes” was amended on December 20, 2010 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through the sale of the asset. The amendment to IAS 12 is effective for reporting periods beginning on or after January 1, 2012. The Company is currently evaluating the impact of this amendment to its financial statements.

n. Flow through shares

Periodically, the Company finances a portion of its exploration and development activities through the issuance of flow-through shares. The resource expenditure deductions for income tax purposes related to exploratory development activities are renounced to investors in accordance with tax legislation. Flow-through shares issued are recorded in share capital at the fair value of common shares on the date of issue. The premium received on issuing flow-through shares is initially recorded as a deferred credit. As qualifying expenditures are incurred, the premium is reversed and a deferred income tax liability is recorded. The net amount is then recognized as deferred income tax expense.

3. Determination of Fair Value

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) Property, plant and equipment and E&E assets

The fair value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions, being 12% for 2011 (2010 – 12%). The market value of other items of property, plant and equipment is based on the quoted market prices for similar items. Similarly, property, plant and equipment are recognized at fair value in a business combination.

- (ii) Cash and cash equivalents, accounts receivable and accruals and accounts payable and accruals

The fair value of cash and cash equivalents, accounts receivable and accruals and accounts payable and accruals is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At March 31, 2011 and December 31, 2010, the fair value of these balances approximated their carrying value due to their short term to maturity.

- (ii) Bank indebtedness

The fair value of bank loans approximates their carrying value, as they bear interest at floating rates and the premium charged at March 31, 2011 and December 31, 2010 was indicative by the Company's current credit spreads.

- (iii) Derivatives

The fair value of forward contracts and swaps is derived from quoted prices received from financial institutions and is based on published forward price curves as at the measurement date, using the remaining notional contracted oil and natural gas volumes.

- (iv) Stock options

The fair value of employee stock options is measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behavior), expected dividends, and the risk-free interest rate (based on government bonds).

The Company classified the fair value of its financial instruments measured at fair value according to the following hierarchy based on the amount of observable inputs used to value the instrument:

Level 1 – observable inputs such as quoted prices in active markets;

Level 2 – inputs, other than the quoted market prices in active markets, which are observable, either directly and/or indirectly; and

Level 3 – unobservable inputs for the asset or liability in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The fair value of the derivative contracts used for risk management as shown in the consolidated statements of financial position as at March 31, 2011 and December 2010 is measured using level 2. During the periods ended March 31, 2011 and 2010, there were no transfers between level 1, level 2 and level 3 classified assets and liabilities.

4. Financial Risk Management

The Board of Directors oversees managements' establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as credit risk, liquidity risk and market risk.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. All of the Company's operations are conducted in Canada. The Company's exposure to credit risk is influenced mainly by the individual characteristics of each purchaser or joint venture partner.

All of the Company's petroleum and natural gas production is marketed under standard industry terms. The industry has a pre-arranged monthly settlement day for payment of revenues from all buyers of crude oil and natural gas. This occurs on the 25th day following the month in which the production is sold. As a result, the Company collects sales revenues in a predetermined and organized manner. Management monitors purchaser credit positions to mitigate any potential credit losses. To the extent the Company has joint interest activities with industry partners, the Company must collect, on a monthly basis, partners' share of capital and operating expenses. These collections are subject to normal industry credit risk. The Company attempts to mitigate risk from joint venture receivables by obtaining partner approval of capital projects prior to expenditure and collects in advance for significant amounts related to partners' share of capital expenditures in accordance with the industry operating procedures. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners, however, the Company does have the ability to withhold production from joint venture partners in the event of non-payment. The Company's credit risk is limited to the carrying amount of its accounts receivable, which are due primarily from other entities involved in the oil and gas industry. These amounts are subject to the same risks as the industry as a whole. The Company had no material trade accounts receivable deemed uncollectible. The carrying amount of cash and accounts receivable represent the maximum credit exposure.

The maximum exposure to credit risk at the dates captioned below is as follows:

	Carrying Amount		
	March 31, 2011	December 31, 2010	January1, 2010
Cash and cash equivalents	295	93	4,300
Accounts receivable and accruals	1,200	1,411	2,011
	1,495	1,504	6,311

The maximum exposure to credit risk for accounts receivable and accruals at the reporting date by type of customer was:

	Carrying Amount		
	March 31, 2011	December 31, 2010	January1, 2010
Oil and natural gas marketers	1,189	1,249	989
Joint venture partners	5	153	1,022
Other	6	9	-
	1,200	1,411	2,011

As at March 31, 2011, December 31, 2010 and January 1, 2010, the Company's accounts receivable and accruals was aged as follows:

	Carrying Amount		
	March 31, 2011	December 31, 2010	January 1, 2010
Not past due by less than 90 days	1,184	1,343	1,999
Past due by less than 120 days	16	68	12
Past due by more than 120 days	-	-	-
Total	1,200	1,411	2,011

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

Liquidity risk

Liquidity risk relates to the risk the Company will encounter should it have difficulty in meeting obligations associated with the financial liabilities as they fall due.

The financial liabilities on the statement of financial position consist of accounts payable, accrued liabilities, and bank indebtedness. Accounts payable consists of invoices payable to trade suppliers relating to the office and field operating activities and its capital spending program. The Company processes invoices within a normal payment period. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month. The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. The Company uses authorizations for expenditures on both operated and non operated projects to further manage capital expenditures.

The Company anticipates it will continue to have adequate liquidity to fund its financial liabilities and its commitments through its future funds from operations, financings and available bank debt. The Company has revolving reserves-based credit facilities which are reviewed regularly by its lenders. These facilities are described in note 12.

The Company was not in default on its bank debt or any of its other financial liabilities.

All financial liabilities are due within one year.

Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return. The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors and those limitations set by lenders in credit agreements.

Currency risk

Prices for oil are determined in global markets and generally denominated in United States dollars. Natural gas prices obtained by the Company are influenced by both U.S. and Canadian demand and the corresponding North American supply, and recently, by imports of liquefied natural gas. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the U.S. dollar will reduce the prices received by the Company for its petroleum and natural gas sales.

There were no financial instruments denominated in U.S. dollars at March 31, 2011 or December 31, 2010.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank loans fluctuates with the interest rates posted by the lenders. The Company has not entered into any mitigating interest rate hedges or swaps.

Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by both the relationship between the Canadian and U.S. dollar and world economic events that dictate the levels of supply and demand. From time to time, the Company has entered into financial derivative contracts to mitigate such risks. The Company has no such contracts outstanding at March 31, 2011.

Capital management

The Company's objective in the course of the management of the Company's capital structure is to maintain a flexible capital structure that will allow it to execute on its capital expenditure program, which includes expenditures on oil and gas activities that may or may not be successful, optimize the cost of capital and maintains investor, creditor and market confidence.

The Company considers that its capital structure comprises share capital and warrants aggregating \$61,858,000.

The Company monitors its capital structure and makes adjustments when possible. Business conditions including current economic trends, the underlying risk characteristics of the Company's assets, the depth and breadth of its exploration and development portfolio, the desired pace of investment, the availability of farm ins and farm outs, current and forecasted energy prices, the potential bank credit that could be obtained as a result of reserve growth and forecasted debt levels are all factors that the Company uses as inputs to its capital management process.

In order to maintain or adjust its capital structure, the Company may issue new common voting shares if available on favorable terms and/or renegotiate the terms of its banking facilities. The Company may also consider other sources of debt with different characteristics than existing bank indebtedness, adjust exploration and development capital expenditures and acquire or dispose of assets. Equity financing may not be readily available to junior oil and gas producers given current market conditions. The availability of bank credit is generally reducing and related costs are increasing. A covenant to the Revolving Operating Demand Loan facility requires that the Company maintain a working capital ratio, exclusive of bank indebtedness, of at least 1 to 1. For purposes of this calculation, the undrawn availability under the facility is added to current assets. The Company was in compliance with this debt covenant at March 31, 2011 and at December 31, 2010. There is no similar working capital requirement for the Acquisition/Development Demand Loan. There is no debt to equity requirements related to either of the facilities. The credit facilities are subject to regular reviews by its Bank. The last such review was held in April 2011 with the next scheduled for November 2011.

A covenant to the Revolving Operating Demand Loan Facility requires that the Company limit hedging activities to 50% of actual production.

There were no changes in the Company's approach to capital management during the period.

Neither the Company nor its subsidiary is subject to externally imposed capital requirements.

5. Finance Expenses

Finance expenses are comprised of:

(\$ 000's)	March 31,	
	2011	2010
Interest and financing costs on bank indebtedness	92	217
Accretion on decommissioning obligations	31	17
Total	123	234

6. Supplemental Cash Flow Information

Changes in non-cash working capital are comprised of:

(\$ 000's)	March 31,	
	2011	2010
Source (Use) of cash or cash equivalents		
Accounts receivable and accruals	211	108
Prepaid expenses and deposits	15	57
Accounts payable and accruals	3,653	44
Total	3,879	209
Related to:		
Operations	217	(4,117)
Financing	-	-
Investing	3,662	4,326
Total	3,879	209

7. Property, Plant and Equipment

Depletion and depreciation, impairment of property plant and equipment and any eventual reversal thereof are recognized as separate line items in the unaudited consolidated statement of income.

Property, plant and equipment (\$ 000's)	At cost or deemed cost		
	Oil and Gas Assets	Other	Total
January 1, 2010	87,547	187	87,734
Additions	23,057	84	23,141
Disposals	(15,724)	-	(15,724)
December 31, 2010	94,880	271	95,151
Additions	2,812	62	2,874
Disposals	-	-	-
March 31, 2011	97,692	333	98,025

Accumulated depletion and depreciation
and impairment losses

(\$ 000's)	Oil and Gas		Total
	Assets	Other	
January 1, 2010	30,098	7	30,105
Impairment loss at January 1, 2010	9,704	-	9,704
January 1, 2010	39,802	7	39,809
Disposal	(6,283)	-	(6,283)
Depletion and depreciation	4,756	7	4,763
Impairment loss during the period	20,100	-	20,100
December 31, 2010	58,375	14	58,389
Depletion and depreciation	677	3	680
March 31, 2011	59,052	17	59,069

Carrying amounts
(\$ 000's)

	Oil and Gas		Total
	Assets	Other	
January 1, 2010	47,745	180	47,925
December 31, 2010	36,505	257	36,762
March 31, 2011	38,640	316	38,956

8. Exploration and evaluation assets

Exploration and evaluation assets consist of the Company's exploration projects which are pending the determination of proved or probable reserves. Costs primarily consist of undeveloped land and drilling costs until the drilling of the well is complete and the results have been evaluated. The cost of undeveloped land that expires or any impairment recognized during a period, is charged as additional depletion and depreciation expense unless it is related to a viable Cash Generating Unit ("CGU") in which case such costs will be transferred to the applicable CGU and assessed for impairment. Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

(\$ 000's)

Balance January 1, 2010	8,177
Additions	1,378
Radius acquisition	-
Saxon disposition	(4,994)
Transfers to property, plant and equipment	(1,194)
Lease expiries	-
Balance December 31, 2010	3,367
Additions	10,774
Transfers to property, plant and equipment	(252)
Lease expiries	(94)
Balance March 31, 2011	13,795

9. Decommissioning Obligations

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and gathering systems.

The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be \$1,534,000 as at March 31, 2011 (December 31, 2010 – \$1,432,000) based on an undiscounted inflation-adjusted total future liability of \$3,747,000 million (December 31, 2010 – \$3,457,000). These payments are expected to be made over the next 25 years with the majority of costs to be incurred between 2012 and 2030. The discount factor, being the risk free credit adjusted rate related to the liability, ranged from 7.0% to 8.5% (December 31, 2010 – 7.0% to 8.5%) depending on the estimated timing of the future obligation.

10. Impairment

As a result of applying the IFRS 1 exemption for deemed cost at January 1, 2010, the Company was required to test all of its cash generating units for impairment. The Company tested the Claresholm, Edson, Saxon, Ante Creek and Pouce Coupe CGUs for impairment.

In addition, as a result of continued weakness in natural gas pricing the Company tested the same CGUs for impairment during the second half of 2010 and recognized impairments totaling \$20,100,000 at that time.

At March 31, 2011, there was no material change in the forward curve for natural gas prices and there was an increase in oil and natural gas liquids prices from December 31, 2010, therefore the Company did not test for impairment of its CGUs, or reverse any of the impairments previously recognized.

The recoverable amount of the CGUs was estimated based on the higher of the value in use and the fair value less costs to sell. The estimate of fair value less costs to sell was determined using a discount rate of 12 percent and forecasted cash flows, with escalating prices and future development costs, as obtained from the reserve report. The prices used to estimate the fair value less cost to sell are those used by independent industry reserve engineers.

The impairment losses recognized in each CGU were as follows:

(\$ 000's)	Claresholm	Edson	Saxon	Ante Creek	Pouce Coupe	Other	Total
Impairment loss:							
January 1, 2010	7,461	1,561	677	-	-	5	9,704
Year ended							
December 31, 2010	18,090	1,981	-	-	-	29	20,100
	25,551	3,542	677			34	29,804
Carrying values:							
January 1, 2010	38,948	7,244	1,590	-	-	143	47,925
December 31, 2010	25,788	5,509	-	4,415	1,411	90	36,762
March 31, 2011	25,640	5,015	-	4,834	3,379	88	38,956

11. Bank Indebtedness

Amounts outstanding:

(\$000's)	March 31, 2011	December 31, 2010	January 1, 2010
Revolving operating demand loan	8,997	12,564	21,729
Acquisition/development demand loan	-	-	-
	8,997	12,564	21,729

At March 31, 2011 the Company's credit facilities comprised a Revolving Operating Demand Loan Facility with a credit limit of \$20,000,000 and an Acquisition/Development Demand Facility with a credit limit of \$4,000,000.

The Revolving Operating Demand Loan Facility bears interest at Bank prime plus a percentage determined quarterly ranging from .75% to 2.5% greater than the Bank's prime rate in accordance with the Bank's pricing grid. The Bank's pricing grid is dependent on the Company's debt to cash flow ratio where debt is defined by the Bank as working capital deficit, consolidated long term debt including capital leases and retractable preferred shares which are retractable at the option of the holder and cash flow is defined by the Bank as net earnings, adjusted for depletion, depletion and accretion, future income taxes and other charges to income not requiring a cash payment calculated for the most recently completed quarter and annualized. The application of the Bank's pricing grid resulted in a rate which is 2.5% greater than the Bank's prime rate.

The Revolving Operating Demand Loan Facility has no specific terms of repayment aside from the Bank's right of demand and periodic review. The Acquisition/Development Demand Loan Facility requires unspecified monthly principal repayments over the engineering half life of the reserves being financed as determined by the Bank.

The Acquisition/Development Demand Loan Facility is restricted to the acquisition of proved non-producing/undeveloped petroleum and natural gas reserves and/or development of proved producing/undeveloped petroleum and natural gas reserves, bears interest at a rate which is 0.5% higher than the Revolving Operating Demand Loan Facility and bears a standby fee of between 0.25% and 0.5% on the undrawn portion of the loan facility.

Security for the facilities includes a general assignment of book debts, a \$75,000,000 debenture with a first floating charge over all assets with a negative pledge and an undertaking to provide fixed charges on the Company's major producing reserves at the request of the bank.

A covenant to the Revolving Operating Demand Loan Facility requires that the Company limit hedging activities to 50% of actual production.

A covenant to the Revolving Operating Demand Loan Facility requires that the Company maintain a working capital ratio, exclusive of bank indebtedness, of at least 1 to 1. For purposes of this calculation, the undrawn availability under the Revolving Operating Demand Loan Facility is added to current assets. The Company was in compliance with this debt covenant at December 31, 2010. There is no similar working capital requirement for the Acquisition/Development Demand Loan. There is no debt to equity requirements related to either of the facilities.

The last scheduled review of the Company's borrowing limits occurred in April 2011 at which time the credit limit under the Revolving Operating Demand Loan Facility was increased to \$22 million and the credit limit under the Acquisition/Development Demand Loan Facility was increased to \$8 million.

There can be no assurance that other amounts or terms will not change at the next review scheduled in November 2011.

12. Share Capital

Share capital comprises:
000's \$

	March 31, 2011	December 31, 2010	December 31, 2009
Common voting shares	61,471	49,204	45,521
Warrants	387	533	316
Total	61,858	49,737	45,837

Common Voting Shares

Authorized:

An unlimited number of common voting shares and an unlimited number of preferred shares issuable in series for which the directors may fix, among other things, the rights, privileges, restrictions, conditions, voting rights, rates, method of calculation and dates of payment of dividends and terms of redemption, purchase and conversion if any, and any other provisions.

Issued and outstanding, Common Voting Shares:

	Number of Shares	\$ 000's
Balance, December 31, 2009	12,853,197	45,521
Issued by way of private placement	1,500,004	2,483
Issued by way of private placement, flow through common shares	500,000	1,000
Premium on private placement, flow through shares		(100)
Issued in connection with the acquisition of Radius Resources Inc.	748,000	524
Share issuance costs, net of tax		(26)
Received and cancelled on settlement of Radius debt (Note 6)	(64,262)	(198)
Balance, December 31, 2010	15,536,939	49,204
Exercise warrants	505,949	1,284
Issued by way of short form prospectus – common shares	3,000,000	8,850
Issued by way of short form prospectus – flow through common shares	1,000,000	3,700
Premium on short form prospectus issue , flow through common shares		(750)
Share issuance costs, net of tax	-	(817)
Balance, March 31, 2011	20,042,888	61,471

On February 11, 2011, the Company closed a bought deal issue of 3,000,000 common shares by way of short form prospectus for total proceeds of \$8,850,000. At the same time it closed a bought deal issue of flow through common shares by way of short form prospectus for gross proceeds of \$3,700,000.

The implied premium on the flow through common shares was computed to be \$0.75 per share or \$750,000 in total.

The qualifying exploration and development expenditures were made prior to March 31, 2011.

Warrants:

	Number of Warrants	\$ 000's
Balance, January 1, 2010	1,097,180	316
Private Placement	750,003	217
Balance December 31, 2010	1,847,183	533
Warrants exercised	(505,949)	(146)
Balance March 31, 2011	1,341,234	387

Each whole Argosy warrant issued in connection with the December financing entitled the holder thereof to receive one Argosy share at an exercise price of \$2.25 per share for a period of 18 months. The exercise period of the Argosy warrants may be accelerated in the event that the 20-day trading volume weighted average price of the Argosy shares meets or exceeds \$3.00 during the period such warrants remaining remain outstanding.

The allocation of the issue price of units between common shares and share purchase warrants was based on fair values of the common shares and warrants. The fair market value of the common shares was based on the closing price of the Company's shares on the TSX on the closing date. The common share purchase warrants were valued using a Black-Scholes model using the following assumptions:

- Share price \$1.27
- Exercise price \$2.25
- Time to expiry 1.5 years
- Risk free rate 1.3%
- Volatility 83%

The 20-day trading volume weighted average price of the Argosy exceeded \$3.00 as at April 29, 2011. Accordingly, the Company served notice to the remaining warrant holders that expiry date of the warrants was accelerated to May 13, 2011. A total of 200,734 warrants were exercised prior to the accelerated expiry date for proceeds of \$451,652. The holders of 1,183,385 warrants did not exercise their warrants by the end of the accelerated expiry date. Those warrants that were not exercised by the end of the accelerated expiry date were cancelled.

Per share calculations:

The following reconciles the weighted average number of common shares outstanding used in calculating net loss per common share ("EPS"):

	Three months ended		Year ended
	March 31,		December 31,
	2011	2010	2010
Weighted average common voting shares outstanding - basic	18,321,592	13,253,198	7,099,884
Effect of dilutive stock options	-	-	-
Effect of dilutive warrants	-	-	-
Weighted average common voting shares outstanding - diluted	18,321,592	13,253,198	7,099,884

Diluted EPS excludes the effect of stock options and warrants because their inclusion would be anti-dilutive.

Stock Options

Options outstanding:

Under the terms of the Argosy Energy Inc. 2008 Incentive Stock Option Plan, (the "plan"), directors, officers, employees are eligible to be granted options to purchase common shares.

The following tables summarize information about stock options outstanding at March 31, 2011:

Balance, December 31, 2008	580,000
Granted	473,000
Forfeited	(3,000)
Balance, January 1, 2010	1,050,000
Granted	403,000
Forfeited	(20,000)
Balance December 31, 2010	1,433,000
Granted 2011	425,000
Balance, March 31, 2011	1,858,000

Grant Price (\$/Share)	Repriced	Options Outstanding	Remaining Contractual Life	Number Exercisable (Vested)
4.60	1.28 ⁽¹⁾	571,000	2.25 Years	571,000
1.20	n/a	465,000	3.75 Years	310,000
0.91	n/a	377,000	4.08 Years	125,667
0.79	n/a	20,000	4.42 Years	6,667
2.40	n/a	425,000	4.92 years	141,667
		1,858,000		1,155,001

Grant Price	\$4.60/\$1.28 ⁽¹⁾	\$1.20	\$0.91	\$0.79	\$2.40
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Fair value at grantor repricing date	\$4.60/\$1.20	\$1.20	\$0.91	\$0.79	\$2.40
Fair value for stock based compensation cost	\$1,345,000	\$373,000	\$222,000	\$9,800	578,000
Expected forfeiture rate	2%	2%	2%	2%	2%
Risk free interest rate	4.5%	1.3%	3.5%	2.29%	2.39%
Expected life	5 years	5 years	5 years	5 years	5 years
Expected volatility	46%/83%	83%	76%	75%	75%
Expected dividend yield	-	-	-	-	-

(1) At a special meeting held on October 6, 2009, the shareholders of the Company approved the repricing from \$4.60 to \$1.28

Stock based compensation expense of \$4,000 was capitalized for the 3 months ended March 31, 2011 (\$134,000 for the 12 months ended December 31, 2010 and \$22,000 for the 3 months ended March 31, 2010).

13. Derivative Contracts

Derivative contracts were designated as “fair value through profit and loss” and recorded at the estimated fair market value.

All derivative contracts held by the Company expired on March 31, 2011.

As at December 31, 2010, the following derivative contracts were outstanding:

Type of Hedge	Commodity Hedged	Volume	Price	Period	Fair Value \$ 000	Unrealized Gain(Loss) \$ 000
Financial fixed price bought put	Natural Gas	2,000 GJ/day	Cdn \$5.00 /Gj	January 1, 2010 to March 31, 2011	134	289
Financial fixed price sold call	Natural Gas	2,000 GJ/day	Cdn \$7.70/Gj	January 1, 2010 to March 31, 2011	-	197
					134	486

Note: A gigajoule (GJ) converts to a mcf at the rate of 1.055056 GJs per mcf.

The fair-value level of the Company’s derivative contracts at December 31, 2010 was as follows:

(000’s)	Fair Value	Level 1	Level 2	Level 3
Financial fixed price bought put	-	-	-	-
Financial fixed price sold call	134	-	134	-
	134	-	134	-

14. Note receivable Radius Resources Corp. (“Radius”)

Pursuant to the terms of the farm-in agreement, Radius agreed to pay \$1,300,000 towards drilling costs to earn a 50% working interest in two wells that were spudded in the Saxon area in late December 2009.

The funds advanced were only to be used to pay for and were only advanceable against Radius’ share of costs under the farm in agreement. The advances are evidenced by a promissory note that was repayable on demand, was unsecured and was interest free.

On May 14, 2010, Argosy acquired all of the issued and outstanding shares of Radius as part of a Proposal put forward by Radius pursuant to the provisions of the Bankruptcy and Insolvency Act (BIA) (the “Proposal”). As the note receivable was unsecured and because the Proposal was made pursuant to the BIA, the amount was extinguished and an amount of \$1,300,000 was charged to property and equipment.

In November 2010, Argosy received \$1,208 cash and 64,262 common shares of Argosy in respect to the final settlement of the note receivable pursuant to the Proposal. The common shares so received were returned to treasury and cancelled and a credit of \$198,000 was booked as a reduction to property and equipment.

15. Subsequent Events

A scheduled review of the Company's borrowing limits was made in April 2011 at which time the credit limit under the Revolving Operating Demand Loan Facility was increased to \$22 million and the credit limit under the Acquisition/Development Demand Loan Facility was increased to \$8 million.

The 20-day trading volume weighted average price of the Argosy exceeded \$3.00 as at April 29, 2011. Accordingly, the Company served notice to the remaining warrant holders that expiry date of the warrants was accelerated to May 13, 2011. A total of 200,734 warrants were exercised prior to the accelerated expiry date for proceeds of \$451,652. The holders of 1,183,385 warrants did not exercise their warrants by the end of the accelerated expiry date. Those warrants that were not exercised by the end of the accelerated expiry date were cancelled.

16. Reconciliation from Canadian GAAP to IFRS

These are the Company's first interim condensed consolidated financial statements for the period covered by the first annual consolidated financial statements to be prepared in accordance with IFRS. The accounting policies in note 3 have been applied in preparing the unaudited interim condensed consolidated financial statements for the three months ended March 31, 2011, the comparative information presented in these interim condensed consolidated financial statements for both the three months ended March 31, 2010 and the year ended December 31, 2010 and in the preparation of the opening IFRS statement of financial position at January 1, 2010.

Statement of financial position at the date of IFRS transition – January 1, 2010:

(\$000's)	Canadian GAAP	Impairment (Note b)	E&E Assets (Note c)	Onerous contracts (Note d)	Share – based payments (Note e)	Flow through Shares (Note f)	IFRS
ASSETS							
Current Assets:							
Cash and cash equivalents	4,300	-	-	-	-	-	4,300
Accounts receivable and accruals	2011	-	-	-	-	-	2,011
Prepaid expenses and deposits	473	-	-	-	-	-	473
	6,784	-	-	-	-	-	6,784
Notes Receivable	1,300	-	-	-	-	-	1,300
Exploration and evaluation assets	-	-	8,177	-	-	-	8,177
Property, plant and equipment	65,806	(9,704)	(8,177)	-	-	-	47,925
	73,890	(9,704)	-	-	-	-	64,186
LIABILITIES AND EQUITY							
Current liabilities:							
Accounts payable and accruals	5,955	-	-	-	-	-	5,955
Fair value of derivative contracts	352	-	-	-	-	-	352
Flow through shares	-	-	-	-	-	341	341
Bank indebtedness	21,729	-	-	-	-	-	21,729
Onerous contracts	-	-	-	37	-	-	37
	28,036	-	-	37	-	341	28,414
Onerous contracts Decommissioning obligations	-	-	-	583	-	-	583
Deferred tax liability	973	-	-	-	-	-	973
	5,931	(2,426)	-	(155)	-	-	3,350
	34,940	(2,426)	-	465	-	341	33,320
Shareholders' Equity:							
Share capital	45,333	-	-	-	-	504	45,837
Contributed surplus	1,184	-	-	-	108	-	1,292
Deficit (note h)	(7,567)	(7,278)	-	(465)	(108)	(845)	(16,263)
	38,950	(7,278)	-	(465)	-	(341)	30,866
	73,890	(9,704)	-	-	-	-	64,186

Statement of financial position – March 31, 2010:

(\$000's)	Canadian GAAP	Impairment (Note b)	E&E Assets (Note c)	Depletion and depreciation (Note c)	Onerous contracts (Note d)	Share – based payments (Note e)	Flow through Shares (Note f)	IFRS
ASSETS								
Current Assets:								
Cash and cash equivalents	-	-	-	-	-	-	-	-
Accounts receivable and accruals	1,901	-	-	-	-	-	-	1,901
Prepaid expenses and deposits	415	-	-	-	-	-	-	415
Fair value of derivative contracts	423	-	-	-	-	-	-	423
	2,739	-	-	-	-	-	-	2,739
Notes Receivable	1,300	-	-	-	-	-	-	1,300
Exploration and evaluation assets	-	-	8,387	-	-	16	-	8,403
Property, plant and equipment	69,335	(9,704)	(8,387)	738	-	-	-	51,982
	73,374	(9,704)	-	738	-	16	-	64,424
LIABILITIES AND EQUITY								
Current liabilities:								
Accounts payable and accruals	5,999	-	-	-	-	-	-	5,999
Bank indebtedness	18,799	-	-	-	-	-	-	18,799
Onerous contracts	-	-	-	-	37	-	-	37
	24,798	-	-	-	37	-	-	24,835
Onerous contracts	-	-	-	-	573	-	-	573
Decommissioning obligations	1,037	-	-	-	-	-	-	1,037
Deferred tax liability	6,822	(2,426)	-	185	(150)	-	-	4,431
	32,657	(2,426)	-	185	460	-	-	30,876
Shareholders' Equity:								
Share capital	47,157	-	-	-	-	-	1,379	48,536
Contributed surplus	1,318	-	-	-	-	84	-	1,402
Deficit (note h)	(7,758)	(7,278)	-	553	(460)	(68)	(1,379)	(16,390)
	40,717	(7,278)	-	553	(460)	16	-	33,548
	73,374	(9,704)	-	738	-	16	-	64,424

Statement of financial position at the date of IFRS transition –December 31, 2010:

(\$000's)	Canadian GAAP	Impairment (Note b)	E&E Assets (Note c)	Depletion and depreciation (Note c)	Gain on Sale (Note c)	Onerous contracts (Note d)	Share – based payments (Note e)	Flow through Shares (Note f)	IFRS
ASSETS									
Current Assets:									
Cash and cash equivalents	93	-	-	-	-	-	-	-	93
Accounts receivable and accruals	1,411	-	-	-	-	-	-	-	1,411
Prepaid expenses and deposits	1,041	-	-	-	-	-	-	-	1,041
Fair value of derivative contracts	134	-	-	-	-	-	-	-	134
	2,679	-	-	-	-	-	-	-	2,679
Exploration and evaluation assets	-	-	3,275	-	-	-	92	-	3,367
Property, plant and equipment	60,387	(29,804)	(3,275)	3,170	6,284	-	-	-	36,762
	63,066	(29,804)	-	3,170	6,284	-	92	-	42,808
LIABILITIES AND EQUITY									
Current liabilities:									
Accounts payable and accruals	3,537	-	-	-	-	-	-	-	3,537
Bank indebtedness	12,564	-	-	-	-	-	-	-	12,564
Onerous contracts	-	-	-	-	-	155	-	-	155
	16,101	-	-	-	-	155	-	-	16,256
Onerous contracts Decommissioning obligations	-	-	-	-	-	427	-	-	427
Deferred tax liability	1,432	-	-	-	-	-	-	-	1,432
	4,134	(7,451)	-	793	1,571	(145)	59	400	(639)
	21,667	(7,451)	-	793	1,571	437	59	400	17,476
Shareholders' Equity:									
Share capital	48,457	-	-	-	-	-	-	1,280	49,737
Contributed surplus	1,740	-	-	-	-	-	(38)	-	1,702
Deficit (note h)	(8,798)	(22,353)	-	2,377	4,713	(437)	71	(1,680)	(26,107)
	41,399	(22,353)	-	2,377	4,713	(437)	33	(400)	25,332
	63,066	(29,804)	-	3,170	6,284	-	92	-	42,808

Reconciliation of unaudited consolidated statement of operations and comprehensive loss for the three month period ended March 31, 2010

(\$000's)	Canadian GAAP	Depletion and Depreciation (Note c)	Onerous contracts (Note d)	Share –based payments (Note e)	Flow Through Shares (Note f)	IFRS
Oil and gas sales	3,193	-	-	-	-	3,193
Royalties	(522)	-	-	-	-	(522)
Revenue, net of royalties	2,671	-	-	-	-	2,671
Realized loss on derivative contracts	(21)	-	-	-	-	(21)
Unrealized gain on derivative instruments	775	-	-	-	-	775
	3,425	-	-	-	-	3,425
Operating expenses	537	-	-	-	-	537
Depletion and depreciation	1,917	(756)	-	-	-	1,161
General and administrative expenses, including stock based compensation	929	-	(7)	(40)	-	882
Income (loss) from operating activities	42	756	7	40	-	845
Financing expenses including accretion	(217)	(18)	-	-	-	(235)
Income (loss) before taxes	(175)	738	7	40	-	610
Deferred income tax	16	185	2	-	534	737
Income (loss) and comprehensive loss for the period	(191)	553	5	40	(534)	(127)

Reconciliation of unaudited consolidated statement of operations and comprehensive loss for the year ended December 31, 2010

(\$000's)	Canadian GAAP	Impairment (Note b)	Gain on Sale of Property	Depletion and Depreciation (Note c)	Onerous Contracts (Note d)	Share –based payments (Note e)	Deferred income taxes	IFRS
Oil and gas sales	10,973	-	-	-	-	-	-	10,973
Royalties	(786)	-	-	-	-	-	-	(786)
Revenue, net of royalties	10,187	-	-	-	-	-	-	10,187
Realized gain on derivative contract	371	-	-	-	-	-	-	371
Unrealized gain on derivative contract	486	-	-	-	-	-	-	486
Gain on acquisition – Radius Resources Corp.	2,633	-	-	-	-	-	-	2,633
Gain on sale of property and equipment	-	-	6,284	-	-	-	-	6,284
	13,677	-	6,284	-	-	-	-	19,961
Operating expenses	2,526	-	-	-	-	-	-	2,526
Depletion and depreciation	8,013	-	-	(3,249)	-	-	-	4,764
Impairment of property, plant and equipment	-	20,100	-	-	-	-	-	20,100
General and administrative expenses, including stock based compensation	4,614	-	-	-	(37)	(238)	-	4,339
Income (loss) from operating activities	(1,476)	(20,100)	6,284	3,249	37	238	-	(11,768)
Financing expenses including accretion	(805)	-	-	(79)	-	-	-	(884)
Income (loss) before taxes	(2,281)	(20,100)	6,284	3,170	37	238	-	(12,652)
Deferred income tax	1,050	5,025	(1,571)	(793)	(9)	(59)	(835)	2,808
Income (loss) and comprehensive loss for the year	(1,231)	(15,075)	4,713	2,377	28	179	(835)	(9,844)

Notes to reconciliations

- (a) IFRS 1 – Deemed Cost. The Company applied the IFRS 1 exemption whereby the value of its opening plant, property and equipment at January 1, 2010 was deemed to be equal to the net book value as determined under Canadian GAAP and the corresponding CGUs were tested for impairment. The Company chose to allocate its costs to its CGUs based on proved plus probable reserves volumes.
- (b) IAS 36 Adjustments – Impairment of Assets. Under Canadian GAAP, impairment of nonfinancial assets is assessed on the basis of an asset's estimated undiscounted future cash flows compared with the asset's carrying amount and if impairment is indicated, discounted cash flows are prepared to quantify the amount of the impairment. Under IFRS, impairment is assessed based on

recoverable amount (greater of value in use or fair value less costs to sell) compared with the asset's carrying amount to determine the recoverable amount and measure the amount of the impairment. In addition, under IFRS, where a non-financial asset does not generate largely independent cash inflows, the Company is required to perform its test at cash generating unit level, which is the smallest identifiable grouping of assets that generates largely independent cash inflows. Canadian GAAP impairment is based on undiscounted cash flows using asset groupings with both independent cash inflows and cash outflows. As a result of this impairment testing at cash generating unit level, the Company recognized an impairment of \$9.7million at January 1, 2010 with a corresponding reduction to retained earnings. For the three months ended March 31, 2010 and the year ended December 31, 2010 the Company recognized additional impairments of \$20.1 million based its estimate of the fair value less costs to sell in the second half of 2011 with a corresponding reduction in property, plant and equipment as a result of declines in the forward natural gas price curves.

(c) IAS 6 and 16 Adjustments – Property, Plant and Equipment. Depletion and depreciation.

Under Canadian GAAP the Company used the full cost method of oil and gas accounting whereby all costs relating to the exploration for and development of petroleum and natural gas reserves were capitalized and included with property and equipment. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities.

IFRS 6 requires that E&E costs must be separated from PP&E into tangible or intangible pools according to the nature of the assets acquired. These costs include acquisition of rights to explore, exploration drilling, carrying costs of unproved properties, and any other activities relating to evaluation of technical feasibility and commercial viability of extracting an oil and gas resource. Application of this policy impacted the financial statements significantly. The opening balance sheet adjustment for this policy change reclassified \$8.2 million at January 1, 2010, \$3.3 million at December 31, 2010 and \$8.4 million at March 31, 2010 from PP&E to intangible E&E. This adjustment had no impact on net loss.

Upon transition to IFRS, the Company adopted a policy of depleting and depreciating oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion and depreciation policy under Canadian GAAP was based on units of production over proved reserves. In addition, depletion and depreciation was calculated on the Canadian full cost pool under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on individual components. There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the policy as discussed above. For the three months ended March 31, 2010, the use of proved plus probable reserves as well as the lower net book value due to the transition impairment of the Claresholm, Edson and Saxon CGUs resulted in a decrease to depletion of \$0.74 million (year ended December 31, 2010 – \$0.79 million) with a corresponding increase to property, plant and equipment.

IFRS requires that gains or losses be reported on the disposition of property, plant and equipment. Under Canadian GAAP, gains or losses on disposition of property, plant and equipment were only reported when the disposition resulted in more than a 20 percent change in the depletion rate. As a result of this requirement, the Company reported a gain of \$6.3 million during the three months ended September 30, 2010 (year ended December 31, 2010 – \$6.3 million) with an increase in property, plant and equipment where the proceeds were originally recorded under Canadian GAAP. IFRS also requires that the capitalization of general and administrative costs be limited to directly attributable costs. Under Canadian GAAP, a reasonable allocation of general and administrative costs to property, plant and equipment was acceptable. The Company's previous policy was congruent with this.

(d) IAS 37 Adjustments – Provisions, Contingent Liabilities and Contingent Assets.

Consistent with IFRS, decommissioning obligations (asset retirement obligations under Canadian GAAP) were measured under Canadian GAAP based on the estimated cost of decommissioning, discounted to their net present value upon initial recognition.

Under Canadian GAAP accretion of the discount was included in depletion and depreciation. Under IFRS, it is included in finance expenses.

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by estimating the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the liability. The unwinding of the discount is recognized as finance cost.

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under the contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on the assets associated with that contract.

A provision for \$620,000 was booked on adoption of IFRS to recognize the effect of onerous office leases.

(e) IFRS 2 Adjustments – Share-based Payments.

Under Canadian GAAP, the Company recognized an expense related to stock-based compensation on a straight-line basis through the date of full vesting and incorporated a forfeiture multiple, which was optional under Canadian GAAP. Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate. Upon transition to IFRS, this resulted in a \$0.1 million increase in contributed surplus with a corresponding decrease in retained earnings. For the three months ended March 31, 2010, the Company reduced the amount of stock-based compensation expense by \$40,000 (year ended December 31, 2010 – \$0.2 million). In addition, under Canadian GAAP, stock-based compensation was disclosed separately on the consolidated statement of operations and comprehensive loss. Under IFRS, stock-based compensation is included in general and administrative expenses.

(f) Flow Through Shares

Under Canadian GAAP, the Company recorded the deferred tax impact on renouncement of flow through shares against share capital. Under IFRS, the Company is required to record a premium liability when the flow through shares are issued, which is relieved upon qualifying expenditures being incurred, with the difference going to deferred tax expense. As a result of this change in the treatment of deferred taxes, at transition, the Company recorded an additional \$0.5 million to share capital with a corresponding reduction in retained earnings for flow through shares that had been previously issued and fully renounced at transition.

(g) IAS 12 Adjustments – Income Taxes

The aforementioned changes increased (decreased) the net deferred tax liability as follows based on a tax rate of 25 percent:

(\$000's)	December		
	31, 2010	March 31, 2010	January1, 2010
Impairment of property plant and equipment	(7,451)	(2,426)	(2,426)
Depletion and depreciation	793	185	-
Gain on sale of property, plant and equipment	1,571	-	-
Onerous contracts	(145)	(150)	(155)
Flow through shares	400	-	-
Stock based compensation	59	-	-
<u>Decrease in deferred tax liabilities</u>	<u>(4,773)</u>	<u>(2,391)</u>	<u>(2,581)</u>

Under Canadian GAAP, the Company was required to present its future income tax assets and liabilities in the same current and long-term classification from which the timing differences arose. There is no such requirement under IFRS, therefore the Company reclassified \$112,000 at March 31, 2010 and \$36,000 at December 31, 2010 from current future income tax assets to the deferred tax asset. The effect on the consolidated statements of operations and comprehensive loss for the three months ended March 31, 2010 and the year ended December 31, 2010 was to decrease the previously reported tax charge for the period by \$13.0 million and \$30.2 million, respectively.

(h) The adoption of IFRS had the following effect on the Company's deficit:

	December 31, 2010	March 31, 2010	January1, 2010
Impairment of property, plant and equipment	(29,804)	(9,704)	(9,704)
Flow through shares	(1,280)	(1,379)	(846)
Depletion and depreciation	3,170	738	-
Gain on sale of property, plant and equipment	6,284	-	-
Deferred taxes	4,773	2,391	2,581
Onerous contracts	(582)	(610)	(619)
Stock based compensation	130	(68)	(108)
Total change	(17,309)	(8,632)	(8,696)

(i) Adjustments to cash flow

The reconciling items enumerated in this footnote have no material impact on cash flows generated by the Company.