ZARGON OIL AND GAS LTD.

2012 ANNUAL FINANCIAL REPORT

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ABBREVIATIONS

BA-CDOR	Banker's Acceptances – Canadian Dealer Offered Rate
bbl	Barrel
bbl/d	Barrels per day
boe	Barrels of oil equivalent (6 mcf is equivalent to 1 bbl)
boe/d	Barrels of oil equivalent per day
btu	British thermal units
gj	Gigajoule
gj/d	Gigajoules per day
m	Thousand
mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
mm	Million
mmbtu	Million British thermal units
AECO	Alberta gas trading price
AESO	Alberta Electric Systems Operator
API	American Petroleum Institute
ASP	Alkaline Surfactant Polymer
DRIP	Dividend Reinvestment Plan
LIBOR	London Interbank Offered Rate
NYMEX	New York Mercantile Exchange
WTI	West Texas Intermediate

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is a review of Zargon Oil & Gas Ltd.'s 2012 financial results and should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2012 and 2011. The 2012 and 2011 consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, which are also generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada. All amounts are in Canadian dollars unless otherwise noted. All references to "Zargon" or the "Company" refer to Zargon Oil & Gas Ltd.

In the MD&A, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of gas to one barrel of oil. In certain circumstances, natural gas liquid volumes have been converted to a thousand cubic feet equivalent ("mcfe") on the basis of one barrel of natural gas liquids to six thousand cubic feet of gas. Boes and Mcfes may be misleading, particularly if used in isolation. A conversion ratio of one barrel to six thousand cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion ratio on a 6:1 basis may be misleading as an indication of value.

The following are descriptions of additional GAAP measures used in this MD&A:

- *The MD&A contains the term "funds flow from operating activities" ("funds flow"), which should not be considered an alternative to, or more meaningful than, "cash flows from operating activities" as determined in accordance with IFRS as an indicator of the Company's financial performance. This term does not have any standardized meaning as prescribed by IFRS and, therefore, the Company's determination of funds flow from operating activities may not be comparable to that reported by other companies. The Company evaluates its performance based on net earnings and funds flow from operating activities. The Company considers funds flow from operating activities to be a key measure as it demonstrates the Company's ability to generate the cash necessary to pay dividends, repay debt and to fund future capital investment. It is also used by research analysts to value and compare oil and gas companies, and it is frequently included in published research when providing investment recommendations.*

The following are descriptions of non-GAAP measures used in this MD&A:

- *The Company also uses the term "debt net of working capital" or "net debt". Debt net of working capital, as presented, does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures for other entities. Debt net of working capital, as used by the Company, is calculated as bank debt plus the full future face value of the convertible debenture of $57.50 million and any working capital deficit excluding unrealized derivative assets/liabilities.*

- *Operating netbacks per boe equal total petroleum and natural gas sales per boe adjusted for realized derivative gains and/or losses per boe, royalties per boe, operating expenses per boe and transportation expenses per boe. Operating netbacks are a useful measure to compare the Company's operations with those of its peers.*

- *Funds flow netbacks per boe are calculated as operating netbacks less general and administrative expenses per boe, transaction costs per boe, interest and financing charges per boe, interest on the convertible debenture per boe, asset retirement expenditures per boe, cash portion of exploration and evaluation, other expense per boe and current income taxes per boe. Funds flow netbacks are a useful measure to compare the Company's operations with those of its peers.*

References to “production volumes” or “production” in this document refer to sales volumes.

Forward-Looking Statements – This document offers our assessment of Zargon’s future plans and operations as at March 12, 2013, and contains forward-looking statements including:

- *our expectations for operating costs and transportation costs referred to under the heading “Detailed Financial Analysis”;*
- *our expectations for general and administrative expenses referred to under the heading “Detailed Financial Analysis”;*
- *our expectations for our taxes payable referred to under the heading “Detailed Financial Analysis”;*
- *our expectations for our total asset retirement obligations referred to under the heading “Detailed Financial Analysis”;*
- *our expectations for our plans with respect to our Little Bow ASP project and the results therefrom referred to under the headings “Detailed Financial Analysis”, “Liquidity and Capital Resources”, “Risk Factors” and “Outlook”;*
- *our expectations for use of funds from the issuance of convertible unsecured subordinated debentures and bank line referred to under the heading “Liquidity and Capital Resources”;*
- *our dividend policy referred to under the heading “Liquidity and Capital Resources”;*
- *our expected sources of funds for dividends referred to under the headings “Liquidity and Capital Resources”, “Risk Factors” and “Outlook”;*
- *our expected sources of funds for capital expenditures referred to under the headings “Liquidity and Capital Resources” and “Risk Factors”;*
- *our expectations for our borrowing costs, standby fees and debt levels referred to under the heading “Liquidity and Capital Resources”;*
- *our expectations for our budgeted 2013 field capital and ASP capital referred to under the heading “Risk Factors”; and*
- *our expectations for production volumes referred to under the heading “Outlook”.*

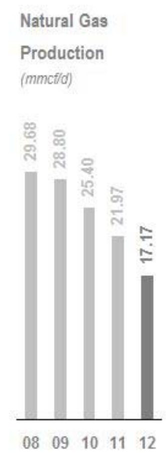
Such statements are generally identified by the use of words such as “anticipate”, “continue”, “estimate”, “expect”, “forecast”, “may”, “will”, “project”, “should”, “plan”, “intend”, “believe” and similar expressions (including the negatives thereof). By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including such as those relating to results of operations and financial condition, general economic conditions, industry conditions, changes in regulatory and taxation regimes, volatility of commodity prices, escalation of operating and capital costs, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel. Risks are described in more detail in our Annual Information Form, which is available on our website and at www.sedar.com. Forward-looking statements are provided to allow investors to have a greater understanding of our business.

You are cautioned that the assumptions, including among other things, future oil and natural gas prices; future capital expenditure levels (including ASP); future production levels; future exchange rates; the cost of developing and expanding our assets; our ability to obtain equipment in a timely manner to carry out development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition, our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our development and acquisition activities used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievements could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. The forward-looking information contained in this document is expressly qualified by this cautionary statement. Our policy for updating forward-looking statements is that Zargon disclaims, except as required by law, any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

This MD&A has been prepared as of March 12, 2013.

2012 HIGHLIGHTS

- For calendar 2012, oil and liquids production averaged 5,255 barrels of oil and liquids per day, a four percent decrease from the preceding year as production additions from our 2012 drilling and exploitation activities were offset by property dispositions. Calendar 2012 natural gas production averaged 17.17 million cubic feet per day, a 22 percent decrease from 2011 reflecting production shut-ins as well as natural declines. Total 2012 production averaged 8,117 barrels of oil equivalent per day, an 11 percent decrease from the prior year.
- Funds flow from operating activities in 2012 of $56.66 million ($1.91 per basic share) were seven percent lower than the $60.67 million ($2.11 per basic share) recorded in the prior year.
- Zargon declared cash dividends totalling $1.08 per common share during 2012 for a total of $31.95 million ($27.35 million net of the DRIP). These cash dividends (net of the DRIP) were equivalent to a payout ratio of 48 percent of funds flow from operating activities.
- Net capital expenditures for the year totalled $30.25 million; consisting of $64.69 million of exploitation and development programs and $0.06 million of administrative assets which was offset by $34.50 million of net property dispositions. The $64.69 million of exploitation and development programs include $6.48 million of ASP project costs. During the year, Zargon drilled 27.8 net wells yielding 26.8 net oil wells and 1.0 net abandonment.
- Zargon's December 31, 2012 debt, net of working capital (excluding unrealized derivative assets/liabilities) and using the full future face value of the convertible debenture of $57.50 million, of $113.18 million, was approximately 2.0 times 2012 funds flow from operating activities, and was up three percent from the 2011 year end net debt of $109.50 million. At December 31, 2012, Zargon had approximately $128.55 million of unutilized credit facilities available.



Financial Highlights

($ millions, except for per share amounts)	**2012**	2011	2010 [5]
Gross petroleum and natural gas sales	**157.95**	191.53	179.47
Funds flow from operating activities	**56.66**	60.67	72.92
Per share – basic [1]	**1.91**	2.11	3.10
Cash flows from operating activities	**58.87**	73.26	61.67
Per share – basic [1]	**1.99**	2.55	2.62
Net earnings/(loss)	**(5.38)**	10.38	(12.88)
Per share – diluted [1]	**(0.18)**	0.36	(0.49)
Total assets	**445.11**	470.69	472.25
Net capital expenditures [2]	**30.25**	48.65	69.22
Long term bank debt	**35.74**	92.70	115.29
Convertible debentures [3]	**57.50**	–	–
Cash dividends/distributions [4]	**27.35**	38.14	47.35

(1) *For the convenience of the reader, the comparative information presented in this schedule refers to common shares although, for the pre-corporate conversion period, these items were trust units.*

(2) *Amounts include capital expenditures for corporate and property acquisitions acquired for cash consideration, equity issuances and net debt assumed.*

(3) *Amount is the full future face value of the convertible debentures.*

(4) *Cash dividends/distributions represent the cash portion only and do not include equity issued through the DRIP, which commenced in April 2010.*

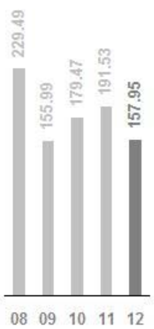
(5) *2010 amounts have been restated to be IFRS compliant.*

Production Highlights

	2012	2011	2010
Oil and liquids production (bbl/d)	**5,255**	5,468	5,645
Natural gas production (mmcf/d)	**17.17**	21.97	25.40
Production (boe/d)	**8,117**	9,130	9,879
Oil weighting (%)	**65**	60	57

DETAILED FINANCIAL ANALYSIS

Petroleum and Natural Gas Sales
($ millions)



Gross Petroleum and Natural Gas Sales

Zargon derives its revenue from the production and sale of petroleum (oil and natural gas liquids) and natural gas. Gross petroleum and natural gas sales, exclusive of the impact of financial risk management contracts, decreased 18 percent to $157.95 million in 2012 from $191.53 million in 2011, primarily due to lower commodity prices as well as a decrease in production. For 2012, the relative weighting of production revenue from oil and liquids increased to 91 percent (86 percent in 2011) and nine percent came from the sale of natural gas (14 percent in 2011). Average production volumes in 2012 decreased to 8,117 barrels of oil equivalent per day compared to the prior year's 9,130 barrels of oil equivalent per day. Of the 8,117 barrels of oil equivalent per day of production volumes in 2012, 65 percent was oil and liquids (35 percent natural gas), as compared to 60 percent in 2011.

Natural gas production in 2012 decreased 22 percent, and oil and liquids production decreased four percent from 2011 levels. Oil and liquids production declines were due in part to second quarter 2012 oil property sales, a limited drilling program and naturally occurring production declines. Natural gas production declines continued as a result of a planned multi-year strategy to de-emphasize the natural gas business. The average field price of oil and liquids received by Zargon decreased to $75.07 per barrel in 2012, down nine percent from $82.09 per barrel in 2011. The average Zargon realized field price of natural gas was $2.16 per thousand cubic feet in 2012, a 37 percent decrease from $3.45 per thousand cubic feet realized in 2011.

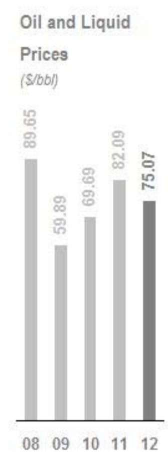
Pricing

Average for the period	**2012**	2011	2010
Natural Gas:			
NYMEX average daily spot price ($US/mmbtu)	**2.75**	4.00	4.39
AECO average daily spot price ($Cdn/mmbtu)	**2.39**	3.63	4.01
Zargon realized field price before the impact of financial risk management contracts ($Cdn/mcf) (1)	**2.16**	3.45	3.87
Zargon realized field price before the impact of physical and financial risk management contracts ($Cdn/mcf) (1)	**2.16**	3.45	3.84
Zargon realized field price after the impact of physical and financial risk management contracts ($Cdn/mcf) (1)	**2.18**	3.45	3.87
Zargon realized natural gas field price differential (1) (2)	**0.23**	0.18	0.14
Zargon realized natural gas field price differential before the impact of physical and financial risk management contracts	**0.23**	0.18	0.17
Crude Oil:			
WTI ($US/bbl)	**94.21**	95.10	79.54
Edmonton par price ($Cdn/bbl)	**86.15**	95.06	77.51
Zargon realized field price before the impact of financial risk management contracts ($Cdn/bbl)	**75.07**	82.09	69.69
Zargon realized field price after the impact of financial risk management contracts ($Cdn/bbl)	**75.02**	76.19	69.95
Zargon realized oil field price differential (3)	**11.08**	12.97	7.82

(1) *Zargon was not subject to any natural gas financial risk management contracts for 2011 or 2010.*

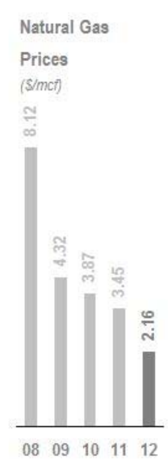
(2) *Calculated as Zargon's realized field price ($Cdn/mcf) as compared to AECO average daily spot price ($Cdn/mmbtu). There were no financial risk management contracts in place for natural gas in either 2011 or 2010.*

(3) *Calculated as Zargon's realized field price before the impact of financial risk management contracts ($Cdn/bbl) as compared to Edmonton par price ($Cdn/bbl).*



Petroleum (Oil and Natural Gas Liquids) Pricing

Zargon's field oil and natural gas liquids prices are adjusted at the point of sale for transportation charges and oil quality differentials from an Edmonton light sweet crude price that fluctuates with world commodity prices. The 2012 Edmonton par price was impacted by an $8.00 Cdn. per barrel negative differential to the WTI pricing index, which compares to the 2011 year of $0.98 Cdn. per barrel positive differential. In 2012, Zargon's average oil and liquids field price, exclusive of the impact of financial risk management contracts, decreased nine percent to $75.07 per barrel from $82.09 per barrel in 2011 and was eight percent higher than the $69.69 per barrel received in 2010. The field price differential for Zargon's average blended 27 degree API crude stream was $11.08 per barrel less than the 2012 Edmonton reference crude price, which compares to the 2011 differential of $12.97 per barrel and the 2010 differential of $7.82 per barrel.



Natural Gas Pricing

The average field natural gas price for 2012 decreased to $2.16 per thousand cubic feet, which is 37 percent lower than the 2011 average of $3.45 per thousand cubic feet (before the impact of financial risk management contracts) and 44 percent lower than the 2010 average of $3.87 per thousand cubic feet (before the impact of financial risk management contracts). Historically, Zargon's field prices have shown a small discount to the benchmark AECO average daily price due to transportation tariffs beyond the Zargon sales point. The 2012 field price differential for Zargon's natural gas was a discount of $0.23 per thousand cubic feet, compared to discounts of $0.18 and $0.17 per thousand cubic feet (exclusive of the impact of physical and financial risk management contracts) in 2011 and 2010, respectively. In 2012 and

2011, there were no fixed price physical contracts, which are normally treated as part of natural gas production revenue and natural gas pricing. In 2010, the fixed price physical contracts created a gain of $0.33 million, equivalent to an increase of $0.04 per thousand cubic feet.

Royalties

Royalties include payments made to the Crown, freehold owners and third parties. Reported royalties also include the cost of the Saskatchewan Resource Surcharge ("SRC") and the cost of North Dakota state oil production/extraction taxes. During 2012, total royalties were $30.14 million, a decrease of 11 percent from $33.96 million in 2011. The variations in royalty rates generally track changes in production volumes and prices. As a percentage of gross sales, royalties were 19.1 percent in 2012 compared to 17.7 percent in 2011 and 17.8 percent in 2010. On a commodity basis, natural gas royalties averaged 15.3 percent in 2012, an increase from the previous year's average of 10.4 percent relating to adjustments to the Gas Cost Allowance. Oil royalties averaged 19.4 percent, up slightly from the prior year rate of 19.0 percent. Total royalty rates increased due to a higher mix of oil production.

During 2012, 58 percent (2011 – 56 percent) of the total royalties were paid to provincial and state governments, with the remainder paid to freehold owners and other third parties. The SRC charges were $1.00 million in 2012, a decrease from $1.19 million in the prior year and a decrease from $1.30 million in 2010. North Dakota state oil production/extraction taxes decreased to $0.93 million in 2012 from $1.19 million in the prior year primarily due to lower oil prices as well as lower oil production volumes.

Risk Management Activities

Zargon's commodity price risk management policy, which is approved by the Board of Directors, allows for the sale of up to a 60 percent maximum of its estimated before royalty production volumes for each commodity up to a 30 month period with the purpose of reducing volatility in the financial results and to stabilize and hedge further cash flows against an unpredictable commodity price environment, with an emphasis on protecting downside risk. Because our risk management strategy is protective in nature and is designed to guard the Company against extreme effects on funds flow from sudden falls in prices and revenue, upward price spikes tend to produce overall risk management losses.

Zargon also has two five year interest rate swaps on a total of $40 million of borrowing with an average effective interest rate of 1.69 percent plus stamping fee (currently at 2.50 percent) and a physical electricity rate hedge effective in 2013. The Company does not have any natural gas swaps outstanding at December 31, 2012.

For 2012, the total realized derivative loss was $0.14 million; compared to a loss of $11.83 million in 2011 and a gain of $0.47 million in 2010. For 2012, there was a $0.10 million loss (equivalent to a decrease of $0.03 per barrel) from oil financial risk management transactions, a $0.15 million gain (equivalent to an increase of $0.05 per barrel) from natural gas financial risk management transactions and a $0.19 million loss (equivalent to a decrease of $0.07 per barrel) from interest rate swaps. Oil swaps are settled against the NYMEX WTI pricing index, natural gas swaps are settled against the AECO pricing index and interest rate swaps are settled against the Bankers' Acceptance-Canadian Dealer Offer Rate ("BA-CDOR").

Zargon's management considers financial risk management contracts to be effective on an economic basis, but does not designate these contracts as hedges for accounting purposes, and, accordingly, an unrealized gain or loss on these contracts is recorded based on the fair value (mark-to-market) of the contracts at year end. The 2012 net unrealized derivative gain totalled $9.90 million, which compares to an $8.45 million net unrealized derivative gain in 2011 (2010 – $10.80 million loss). Specifically, the 2012 net unrealized derivative gain resulted from financial oil contract gains ($9.50 million) and financial interest rate swap gains ($0.40 million). These non-cash unrealized derivative gains or losses are generated by the change over the reporting period in the mark-to-market valuation of Zargon's risk management contracts. Realized and unrealized gains/losses on risk management contracts are included in "gain/loss on derivatives" in the consolidated statement of earnings and their fair value is reflected in "derivative assets" or "derivative liabilities" on the consolidated balance sheet statement.

The electricity rate hedge is a physical contract and, therefore, is not mark-to-marketed and will be included as part of operating costs starting January 1, 2013. As a result of the contract being a physical contract, there are no realized and unrealized gains or losses on the contract.

As at December 31, 2012, the Company had the following outstanding commodity, interest and electricity rate risk management contracts:

Commodity Financial Risk Management Contracts:

	Rate	Weighted Average Price	Range of Terms
Oil swaps	500 bbl/d	$103.12 US/bbl	Jan. 1/13 – Mar. 31/13
	600 bbl/d	$100.12 US/bbl	Jan. 1/13 – Jun. 30/13
	1,200 bbl/d	$99.31 US/bbl	Jan. 1/13 – Dec. 31/13
	200 bbl/d	$97.90 US/bbl	Jan. 1/13 – Jun. 30/14
	200 bbl/d	$93.80 US/bbl	Apr. 1/13 – Dec. 31/13
	200 bbl/d	$96.20 US/bbl	Jul. 1/13 – Jun. 30/14

Interest Rate Financial Risk Management Contracts:

	Notional Value	Interest Rate (1)	Range of Terms
Interest rate swaps	$20,000,000/month	1.640%	Jan. 1/13 – Jul. 26/16
	$20,000,000/month	1.731%	Jan. 1/13 – Aug. 26/16

(1) *Excludes the current stamping fee of 2.50 percent for each swap.*

Electricity Physical Risk Management Contract:

	Rate	Price	Range of Terms
Electricity forward	1.5 MW/d	$54.81/MWh	Jan. 1/13 – Dec. 31/15

Operating Expenses and Transportation Expenses

Zargon's operating expenses decreased 15 percent to $47.28 million in 2012 from $55.58 million in 2011 due to lower production and a focus on reducing operating expenses in 2012. Transportation expenses decreased eight percent to $1.57 million from $1.70 million in 2011. On a per unit of production basis, operating expenses decreased five percent to $15.92 per barrel of oil equivalent from $16.68 in 2011 and transportation expenses increased two percent to $0.52 per barrel of oil equivalent from $0.51 per barrel of oil equivalent. A significant portion of the decrease in operating expenses stem from Zargon's cost containment activities which Zargon will continue to implement in 2013. For 2013, Zargon forecasts that the summation of operating and transportation expenses will be approximately $16.50 per barrel of oil equivalent.

Natural gas operating expenses in 2012 dropped 25 percent to $1.99 per thousand cubic feet from $2.64 per thousand cubic feet in 2011, due mainly to the shut-ins from Zargon's comprehensive operating cost review.

Oil operating and transportation expenses increased in 2012 to $18.90 per barrel, an increase of five percent from $18.06 per barrel in 2011. The primary reason for the increase is a reduction of oil production volumes in stable cost operations.

Operating Netbacks

The average oil and liquids price received, after realized derivative gains/losses, in 2012 of $75.02 per barrel was two percent lower than the $76.19 per barrel received in 2011. The average natural gas price received, after realized derivative gains/losses, in 2012 of $2.18 per thousand cubic feet was 37 percent below the $3.45 per thousand cubic feet received in 2011. Oil and liquids netbacks at $41.52 per barrel were down slightly from $42.57 per barrel in 2011 due to lower prices and production volumes. Natural gas netbacks decreased to a $0.14 loss per thousand cubic feet from $0.45 per thousand cubic feet in

2011, as natural gas prices continued to decline and certain natural gas wells were shut-in. On a barrel of oil equivalent basis, overall 2012 operating netbacks remained flat at $26.53 compared to $26.54 in 2011.

Operating Netbacks

	2012		2011	
	Oil and Liquids ($/bbl)	**Natural Gas ($/mcf)**	Oil and Liquids ($/bbl)	Natural Gas ($/mcf)
Sales	**75.07**	**2.16**	82.09	3.45
Royalties	**(14.60)**	**(0.33)**	(15.56)	(0.36)
Realized gain/(loss) on derivatives	**(0.05)**	**0.02**	(5.90)	–
Operating expenses	**(18.09)**	**(1.99)**	(17.21)	(2.64)
Transportation expenses	**(0.81)**	**–**	(0.85)	–
Operating netbacks	**41.52**	**(0.14)**	42.57	0.45

General and Administrative Expenses

Gross general and administrative expenses ("G&A") decreased 16 percent in 2012 to $16.76 million from $19.92 million in 2011. On a per unit of production basis, net G&A expenses decreased four percent to $4.56 per barrel of oil equivalent compared to $4.74 per barrel of oil equivalent in 2011 and $4.23 in 2010. Zargon completed a staff reorganization in the first and second quarters of 2012 as part of its cost containment activities. Zargon will continue to review G&A expenses in 2013 as part of the cost containment review. Trending downwards from 2011, the 2012 decreased G&A expenses on a per unit of production basis was primarily due to a reduction in Zargon's total employees. G&A expenses also include one-time employment related costs of $0.61 million or $0.20 per barrel of oil equivalent. For 2013, Zargon forecasts that G&A expenses, exclusive of transaction costs or other one-time adjustments will be approximately $4.50 per barrel of oil equivalent.

General and Administrative Expenses

($ millions, except as noted)	**2012**	2011	2010
Gross general and administrative expenses	**16.76**	19.92	19.27
Overhead recoveries	**(3.21)**	(4.11)	(4.03)
Net general and administrative expenses	**13.55**	15.81	15.24
Net expense after recoveries ($/boe)	**4.56**	4.74	4.23
Number of office employees at year end	**45**	64	59

Transaction Costs

Transaction costs include legal and consulting fees associated with business combinations such as property acquisitions/divestitures and corporate acquisitions, as well as fees associated with corporate reorganizations. IFRS 3 "Business Combinations" requires that transaction costs associated with business combinations be expensed in the consolidated statements of earnings and comprehensive income. For the year ended December 31, 2012, transaction costs were $0.04 million, or $0.01 per barrel of oil equivalent, and were comprised of legal and consulting fees associated with property acquisitions and divestitures during the year. For the year ended December 31, 2011, transaction costs were $0.16 million or $0.05 per barrel of oil equivalent and were comprised of legal and consulting fees associated with property acquisitions and divestitures during the year.

Interest and Financing Charges on Long Term Bank Debt

A portion of Zargon's borrowings are through its syndicated bank credit facilities. Interest and financing charges were $3.06 million or $1.03 per barrel of oil equivalent compared to $5.23 million or $1.57 per barrel of oil equivalent in 2011 and $4.89 million in 2010. The decrease in interest and financing charges is a result of a convertible debenture financing which reduced the average outstanding bank debt, proceeds from the second quarter property dispositions and lower interest rates due to lower debt pricing levels. Zargon's effective interest and financing charge rate was 5.1 percent on an average outstanding bank debt of $59.98 million in 2012, compared to 5.5 percent on an average bank debt of $94.68 million in 2011, and 4.9 percent on an average bank debt of $99.50 million in 2010. The decrease in the 2012 average and year end bank debt levels was the result of the property divestiture program in the second quarter of 2012 and a convertible debenture financing which reduced the average outstanding debt. At year end 2012, Zargon's bank debt, net of working capital (excluding unrealized derivative assets/liabilities) and including the full $57.50 million convertible debentures, totalled $113.18 million, up three percent from $109.50 million at December 31, 2011. The increase in net debt at the end of 2012 is due to an active fourth quarter drilling program and the decreased cash flows throughout the year. To further protect Zargon's future cash flows, Zargon has two interest rate swaps. For more information on Zargon's credit facilities, see the "Long Term Bank Debt" section of this report.

Interest on Convertible Debentures

Zargon has borrowings through its convertible debentures, which were issued in May 2012. Interest is payable semi-annually and payments commenced in December 2012 at a rate of six percent, calculated on the gross proceeds of $57.50 million. The interest charges for 2012 were $2.31 million or $0.78 per barrel of oil equivalent. For more information on Zargon's convertible debentures, see the "Convertible Debentures" section of this report.

Current Taxes

Current income taxes for 2012 were $0.57 million compared to $2.75 million in 2011. When compared to prior periods, current income taxes decreased $2.18 million from 2011 as a result of increased United States ("US") field drilling expenditures in North Dakota. In addition, the decrease from prior year partially related to withholding taxes. In 2011 and 2010, US dividends were declared from Zargon's US subsidiary to its parent corporation, which, including the tax provision for the flow-through share audit, totalled $1.22 million of withholding taxes on US dividends declared in 2011 and $0.22 million of withholding taxes on US dividends declared in 2010.

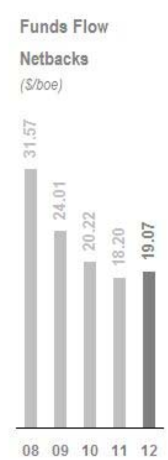
Zargon is subject to normal course income tax audits by Canadian and US taxation authorities. During the fourth quarter of 2010, the Canada Revenue Agency ("CRA") commenced a flow-through share audit of a predecessor company from a prior corporate acquisition. During the first quarter of 2011, Zargon recorded a $1.27 million provision which was comprised of a $0.92 million charge to current income tax expense and a $0.35 million charge to interest expense for the related Part XII.6 tax with respect to this ongoing flow-through share audit. The interest expense related to the Part XII.6 tax has been paid to the CRA and the remaining provision is $0.88 million.

Tax pools as at December 31, 2012 were approximately $313 million, down from the $346 million of tax pools available to Zargon at the end of 2011. This 10 percent decrease is due primarily from 2012 second quarter property dispositions. The Company is a taxable entity under the Income Tax Act (Canada); however, based on the current forward commodity strip, these tax pools are calculated to effectively shelter the Company from paying cash taxes in Canada beyond 2016.

For Canadian income tax purposes, all 2012 cash dividends paid or to be paid on Zargon's common shares are designated as "eligible dividends".

Corporate Netbacks

Despite lower commodity prices, operating netbacks in 2012 were similar to 2011 due mainly to the cost containment program focused on the reduction of operating expenses and general and administrative expenses as well as a decreased loss on realized derivative contracts. On a barrel of oil equivalent basis, revenue of $53.16 in 2012 was seven percent lower than 2011, while operating netbacks remained flat at $26.53 and funds flow netbacks increased five percent to $19.07 per barrel of oil equivalent.



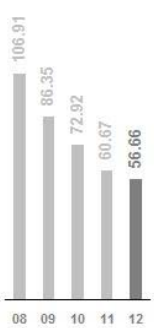
Corporate Netbacks

($/boe)	**2012**	2011	2010 [1]
Gross petroleum and natural gas sales	**53.16**	57.47	49.77
Royalties	**(10.14)**	(10.19)	(8.86)
Realized derivative gain/(loss)	**(0.05)**	(3.55)	0.13
Operating expenses	**(15.92)**	(16.68)	(12.77)
Transportation expenses	**(0.52)**	(0.51)	(0.32)
Operating netbacks	**26.53**	26.54	27.95
General and administrative expenses	**(4.56)**	(4.74)	(4.23)
Exploration and evaluation expenses	**–**	–	(0.22)
Transaction costs [1]	**(0.01)**	(0.05)	(0.35)
Interest and financing charges	**(1.03)**	(1.57)	(1.35)
Interest on convertible debentures	**(0.78)**	–	–
Asset retirement expenditures	**(0.89)**	(1.16)	(0.99)
Current income taxes	**(0.19)**	(0.82)	(0.59)
Funds flow netbacks	**19.07**	18.20	20.22

(1) 2010 amounts have been restated to be IFRS compliant.

Funds Flow from Operating Activities

($ millions)

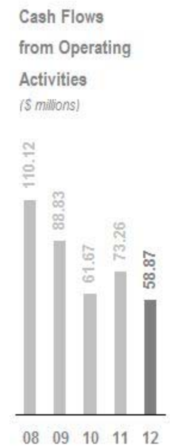


Funds Flow from Operating Activities (see note at the beginning of the MD&A)

In 2012, decreased revenue was partially offset by a decrease in operating expenses and general and administrative expenses due to the cost containment program, a decreased loss of realized derivative contracts and lower royalties to result in a seven percent decrease in funds flow from operating activities to $56.66 million, compared to $60.67 million in 2011 and $72.92 million in 2010. The corresponding funds flow per basic share was $1.91 in 2012, a nine percent decrease from $2.11 in 2011 and a 38 percent decrease from $3.10 in 2010. The basic per share statistics reflect a three percent increase in the weighted average outstanding shares to 29.61 million in 2012 from 28.63 million in 2011. The 2011 weighted average outstanding shares were also 22 percent higher than the 2010 amount of 23.53 million.

The following table summarizes the variances in funds flow from operating activities between 2012 and 2011. It demonstrates that the variance (decrease in funds flow from operating activities) was caused primarily by reduced production volumes and a decrease in oil and natural gas prices that more than offset the decrease in realized derivative losses, royalties, operating expenses and general and administrative expenses.

	$ Millions	$ Per Basic Common Share	Per Share Percent Variance
Funds flow from operating activities – 2011	**60.67**	**2.11**	**–**
Price variance	(12.77)	(0.43)	(20)
Volume variance	(20.81)	(0.69)	(32)
Realized derivative losses	11.69	0.39	19
Royalties	3.82	0.13	6
Expenses:			
Operating	8.30	0.28	13
Transportation	0.13	–	–
General and administrative	2.26	0.08	4
Transaction costs	0.12	–	–
Interest and financing charges	2.17	0.07	3
Interest on convertible debentures	(2.31)	(0.08)	(4)
Asset retirement expenditures	1.21	0.04	2
Current taxes	2.18	0.07	3
Weighted average common shares – basic	–	(0.06)	(3)
Funds flow from operating activities – 2012	**56.66**	**1.91**	**(9)**



Depletion and Depreciation

In 2012, Zargon's depletion and depreciation provision decreased five percent to $48.20 million, compared to $50.94 million in 2011. The lower charges reflect a six percent increase in the charge on a per barrel of oil equivalent basis due to lower volumes, property dispositions in the 2012 second quarter and the year end reserve evaluation. Depletion and depreciation charges calculated on a unit of production method are based on total proved and probable reserves with a conversion of six thousand cubic feet of natural gas being equivalent to one barrel of oil. The 2012 depletion calculation includes $21.59 million of future capital expenditures (excluding future ASP capital expenditures) to develop the Company's reserves, but excludes $19.97 million of unproven properties relating to E&E assets.

Zargon's depletion and depreciation, on a barrel of oil equivalent basis, increased six percent in 2012 to $16.22 from $15.29 in 2011 and increased 19 percent from the 2010 rate of $13.65.

Accretion of Asset Retirement Obligations and Convertible Debentures

For the year ended December 31, 2012, the non-cash accretion expense for asset retirement obligations was $2.77 million compared to $3.22 million in 2011 and $3.07 million in 2010. The year-over-year decreases are due to changes in the estimated future liability for asset retirement obligations as a result of a change in the discount rate. The significant assumptions used in this calculation are a risk-free rate of 2.5 percent, an inflation rate of two percent and payments to settle the retirement obligations occurring over the next 50 years, with the majority of the costs being incurred after 2021. At the end of the second quarter of 2012, the discount factor of 3.00 percent was reduced to 2.50 percent based on the Government of Canada long term bond rate. The estimated net present value of the total asset retirement obligation was $112 million as at December 31, 2012, based on a total future liability of $135 million.

The debt portion of Zargon's convertible debenture is also accreted over its term, up to the total maturity value of $57.50 million. Accretion on the convertible debenture for 2012 is $0.80 million.

Share-Based Compensation

Share-based compensation was $2.13 million in 2012, $0.08 million lower than the $2.21 million expense in 2011 due to the reduction in the number of employees. The decrease was the result of a number of share award forfeitures throughout the year. Zargon will continue to use fair value methodologies for future share award grants. These non-cash expenses will be recurring charges in future years if Zargon continues to grant employees and directors share awards.

In conjunction with the conversion to a corporation, Zargon's two original Trust Unit Rights Incentive Plans were amended and restated as Common Share Rights Incentive Plans. Under these plans, directors, officers, employees and other service providers of the Company possess rights to acquire common shares at their option of either the original exercise price or a "modified price" as calculated per the provisions of the relevant plan. The Common Share Rights Incentive Plan (2007) (the "Old Plan") provides for a modified price based on the increment of the amount by which monthly dividends/distributions exceed a monthly return of 0.833 percent of the Company's recorded net book value of oil and natural gas properties (as defined in the Old Plan). Under the Common Share Rights Incentive Plan (2009) (the "New Plan"), if the monthly dividend/distribution exceeds the monthly return of 0.833 percent of the Company's recorded net book value of oil and natural gas properties (as defined in the New Plan), the entire amount (not the increment) of the dividend/distribution is deducted from the original grant price. Rights granted under either Plan generally vest over a three-year period and expire approximately five years from the grant date. Zargon uses a fair value methodology to value these common share rights grants. No further common share rights will be granted under these plans.

In addition to their approval of the Plan of Arrangement on December 15, 2010, securityholders also approved a new share-based compensation plan ("Share Award Plan") effective January 1, 2011. Under the Share Award Plan, directors, officers, employees and other service providers are granted the right to receive a defined number of shares in the future, which increases commensurately with each dividend declared by the Company after the grant date. The awards vest equally over four years and expire five years after grant date. Holders may choose to exercise upon vesting or at any time thereafter, with forfeiture of any shares not exercised by the expiry date. The Company is authorized to issue up to an aggregate of 2.50 million share rights; however, the number of shares reserved for issuance upon exercise of the options shall not, at any time, exceed 10 percent of the aggregate number of the total outstanding shares. Zargon uses a fair value methodology to value the common share awards. At December 31, 2012, Zargon had 0.32 million of share awards outstanding.

Unrealized Foreign Exchange

Unrealized foreign exchange loss of $0.02 million in 2012 compared to a gain of $0.07 million in 2011. Gains and losses result from transactions in US dollars when they are translated into Canadian dollars. The volatility in the US/Cdn dollar has created non-cash translation gains/losses as recorded in Zargon's consolidated statement of earnings/(loss) and comprehensive income/(loss).

Gains on Disposal of Assets

As a result of the 2012 property dispositions, the Company is reporting gains of $20.82 million (2011 - $19.17 million) on disposals of capital assets in its statement of earnings.

Exploration and Evaluation Expenses

Exploration and evaluation expenses for 2012 were $6.54 million, and were $3.06 million higher than the $3.48 million incurred in 2011. Exploration and evaluation expenses were the result of land expiries in the year and increased due to expiries in west central and northern Alberta.

Impairment Loss

As at December 31, 2012, the Company tested its cash generating units ("CGUs") for impairment. Low crude oil and natural gas prices as well as the write off of certain natural gas reserves resulted in impairment of two Alberta CGUs and one Saskatchewan CGU out of the Company's eight CGUs. The exploration and evaluation ("E&E") assets associated with these CGUs were not included in this impairment test.

The recoverable amount of the CGUs was estimated based on their fair value less costs to sell. This estimate was determined using an after-tax discount rate of 10 percent and forecasted cash flows. The forecasted cash flows are prepared over the estimated life of the reserves in the CGUs. The prices used in this estimate are those used by independent reserve engineers.

Based on the assessment on December 31, 2012, the carrying amount of the three CGUs were determined to be $14.45 million lower than their recoverable amount, and an impairment loss was recognized. In addition to the December 31, 2012 impairment, the Company recognized impairment at June 30, 2012 of $22.87 million which totals to $37.32 million of impairment losses in 2012. In 2011, the Company determined there was $27.01 million in impairment and $8.14 million in reversals of impairment. No impairment losses from prior years were reversed in 2012.

Deferred Taxes

The provision for the deferred tax recovery for 2012 was $2.38 million when compared to a deferred tax expense of $3.12 million in 2011 and a recovery of $12.60 million in 2010. As a Trust, Zargon's deferred tax obligations were reduced, as distributions were 100 percent deductible. The 2012 deferred tax recovery, when compared to the 2011 prior year expense, is impacted by a net loss in 2012 compared to net earnings in 2011, which resulted from the decrease in gross petroleum and natural gas sales and a further impairment loss, partially offset by the gain on property dispositions and gain on unrealized derivatives.

Net Loss

Zargon's 2012 net loss was $5.38 million, a 152 percent decrease from the net earnings of $10.38 million in 2011. The 2010 net loss was $12.88 million. The net earnings/loss track the funds flow from operating activities for the respective periods modified by asset retirement expenditures and non-cash charges, which in 2012 were primarily related to depletion and depreciation, unrealized derivative gains, gains on disposal on properties, impairment losses and exploration and evaluation expense. On a per diluted share basis, the 2012 net loss was $0.18 compared to net earnings of $0.36 in 2011 and a net loss of $0.49 in 2010.

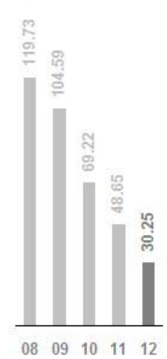
The 2012 net loss was a negative nine percent of funds flow from operating activities, a decrease over 2011 when the net earnings represented a positive 17 percent of funds flow from operating activities. The net loss was a negative 18 percent of funds flow from operating activities in 2010.

Net Earnings/ (Losses)
($ millions)

Capital Expenditures

Total net capital expenditures (including net property dispositions) in 2012 of $30.25 million decreased 38 percent from $48.65 million in 2011, while Zargon's field capital expenditure program decreased 10 percent in 2012 to $64.69 million from $71.66 million in 2011. Field capital expenditures include ASP project expenditures of $6.48 million in 2012 compared to $0.64 million in 2011. In 2012, Zargon drilled 34 gross (27.8 net) wells compared to 42 gross (35.3 net) wells in 2011. Drilling and completion expenditures decreased by 19 percent to $35.11 million due to less wells drilled in 2012. The 2012 drilling program yielded 26.8 net oil wells and 1.0 net abandoned well for a success ratio of 96 percent. Of the total 2012 field capital expenditures (excluding net property dispositions), $25.85 million were expended on Alberta Plains North, $17.48 million on Alberta Plains South and $21.36 million on Williston Basin properties. Additionally, $0.06 million was incurred corporately on leasehold improvements and administrative assets. These expenditures were partially offset by $34.50 million of net property dispositions.

Net Capital Expenditures
($ millions)



As noted in the February 20, 2013 press release, Zargon has sanctioned the construction of the ASP oil exploitation project facility at the Little Bow oil property in Alberta. The ASP project will entail the injection of large volumes of dilutive chemical solution into a partially depleted oil reservoir to recover incremental oil reserves.

Drilling Activity
(net wells)

Undeveloped Land
(thousand net acres)

Capital Expenditures

($ millions)	**2012**	2011	2010 [2]
Undeveloped land	**5.45**	6.24	6.93
Geological and geophysical (seismic)	**2.63**	4.15	2.58
Drilling and completion of wells	**35.11**	43.10	33.69
Well equipment and facilities	**15.02**	17.53	14.41
ASP project	**6.48**	0.64	–
Exploration and development	**64.69**	71.66	57.61
Property acquisitions	**2.27**	9.07	32.48
Property dispositions	**(36.77)**	(32.44)	(30.88)
Net property acquisitions/(dispositions)	**(34.50)**	(23.37)	1.60
Corporate acquisitions assigned to property and equipment [1]	**–**	–	9.36
Total net capital expenditures excluding administrative assets [1]	**30.19**	48.29	68.57
Administrative assets	**0.06**	0.36	0.65
Total net capital expenditures [1]	**30.25**	48.65	69.22

(1) Amounts include capital expenditures acquired for cash and equity issuances.

(2) 2010 amounts have been restated to be IFRS compliant.

PROPERTY ACQUISITIONS/DISPOSITIONS

During 2012, Zargon completed property acquisitions and dispositions totalling a net disposition of $34.50 million, which consisted of $2.27 million of acquisitions and $36.77 million of dispositions. Property dispositions were primarily related to the disposal of Manitoba assets and some producing areas in the Elswick, Saskatchewan area. There were no significant acquisitions during 2012.

LIQUIDITY AND CAPITAL RESOURCES

In 2012, the summation of the funds inflows coming from the funds flow from operating activities ($56.66 million), the net proceeds from the convertible debenture issuance of $54.65 million and the decrease in bank debt of $56.97 million were exceeded by the summation of the funds outflows pertaining to the net capital expenditure program ($30.25 million) and the cash dividends to shareholders ($27.35 million) by $3.26 million compared to $11.77 million in 2011.

Zargon's financing philosophy and the three sources of funding are as follows:

- Internally generated funds flow from operating activities provides the basic level of funding for the Company's annual capital expenditures program and for dividends/distributions to shareholders;
- Debt may be utilized for acquisitions or to expand capital programs when it is deemed appropriate. As at December 31, 2012, the Company had $165 million in syndicated committed credit facilities of which $128.55 million or 78 percent was unutilized. During the year, Zargon entered into a convertible debenture financing which resulted in net proceeds of $54.65 million which was used to pay down debt; and
- New equity, if available and if on favourable terms, can be utilized for acquisitions or to expand capital programs.

Cash Dividends/Distributions Analysis

($ millions)	**2012**	2011	2010 [2]
Cash flows from operating activities	**58.87**	73.26	61.67
Net earnings/(loss)	**(5.38)**	10.38	(12.88)
Cash dividends/distributions relating to the period [1]	**(27.35)**	(38.14)	(47.35)
Excess of cash flows from operating activities over cash dividends/distributions	**31.52**	35.12	14.32
Excess (shortfall) of net earnings over cash dividends/distributions	**(32.73)**	(27.76)	(60.23)

(1) Cash dividends/distributions represent the cash portion only and do not include equity issued through the DRIP, which commenced in April 2010.

(2) 2010 amounts have been restated to be IFRS compliant.

After Zargon converted to a Corporation on December 31, 2010, the monthly dividend was set at $0.14 per share compared to the monthly distribution of $0.18 per share in 2010. For the first nine months of 2011, Zargon maintained the monthly dividend of $0.14 per share, but this was reduced to $0.10 per share for the last three months of the year. For the first nine months of 2012, Zargon maintained the monthly dividend of $0.10 per share, but this was reduced to $0.06 per share for the last three months of the year. Management monitors the Company's dividend policy with respect to forecasted net cash flows, debt levels and capital expenditures. Zargon's cash dividends are discretionary to the extent that these dividends are in compliance with Section 43 of the Business Corporations Act (Alberta) and do not cause a breach of the financial covenants under Zargon's credit facilities. As a petroleum and natural gas company, Zargon's reserve base is depleted with production and Zargon, therefore, relies on ongoing exploration, development, exploitation and acquisition activities to replace reserves and to offset production declines. The success of these capital programs, along with commodity price fluctuations and the Company's ability to manage costs, are the main factors influencing the sustainability of the Company's dividends.

In response to continuing weakness in both spot and forward commodity price markets, wider differentials for Alberta and Williston Basin crude oil, and increased uncertainty in the capital and property disposition markets, the Board of Directors of Zargon on August 8, 2012 revised Zargon's monthly dividend policy from $0.10 per share to $0.06 per share which commenced in the fourth quarter of 2012.

These measures are intended to safeguard Zargon's financial and balance sheet strength. They provide additional flexibility required to continue to capitalize on Zargon's oil exploitation initiatives and to generate additional financing options for the construction and implementation of the Little Bow ASP tertiary oil recovery project.

For the year ended December 31, 2012, cash flows from operating activities (after changes in non-cash working capital) of $58.87 million exceeded cash dividends of $27.35 million. In the year ended December 31, 2011, cash flows from operating activities (after changes in non-cash working capital) of $73.26 million exceeded cash dividends of $38.14 million.

For the year ended December 31, 2012, cash dividends of $27.35 million exceeded a net loss of $5.38 million. The net loss included significant non-cash charges, particularly unrealized risk management gains, gains on disposal of properties, impairment losses, exploration and evaluation expenses and depletion and depreciation that do not impact cash flows. For the year ended December 31, 2011, cash dividends of $38.14 million exceeded net earnings of $10.38 million. The net loss also includes fluctuations in deferred taxes due to changes in tax rates and rules. In the instances where dividends exceed net earnings/loss, a portion of the cash dividend paid may represent an economic return of the shareholders' capital.

For the year ended December 31, 2012, cash dividends and net capital expenditures totalled $57.60 million, which was $1.27 million lower than cash flows from operating activities (after changes in non-cash working capital) of $58.87 million. For the year ended December 31, 2011, cash dividends and net capital expenditures totalled $86.79 million, which was $13.53 million higher than cash flows from operating activities (after changes in non-cash working capital) of $73.26 million. Zargon relies on access to debt and capital markets to the extent cash dividends and net capital expenditures exceed cash flows from operating activities (after changes in non-cash working capital). Over the long term, Zargon expects to fund future cash dividends and capital expenditures with its cash flows from operating activities; however, it may fund acquisitions and growth through additional debt and equity issuances. In the crude oil and natural gas industry, because of the nature of reserve reporting, the natural reservoir declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities, therefore, maintenance capital is not disclosed separately from development capital spending.

Pursuant to the Dividend Reinvestment Plan ("DRIP"), Canadian shareholders are entitled to reinvest monthly cash dividends/distributions in additional shares of the Company. At the discretion of the Company, these additional shares will be issued from Treasury at 95 percent of the "weighted average closing price". For the purposes of the shares issued, the "weighted average closing price" is calculated as the weighted average trading price of shares for the five days prior to the dividend/distribution payment date. For 2012, the DRIP participation rate was 14 percent compared to a 2011 rate of 15 percent.

Capital Sources and Uses

($ millions)	**2012**	2011	2010 (2)
Funds flow from operating activities	**56.66**	60.67	72.92
Change in long term bank debt	**(56.97)**	(22.58)	38.71
Issuance of convertible debentures, net of transaction costs	**54.65**	–	–
Issuance of common shares	**0.11**	40.47	8.31
Cash dividends/distributions to shareholders/unitholders (1)	**(27.35)**	(38.14)	(47.35)
Changes in working capital and other	**3.15**	8.23	(3.37)
Total capital sources	**30.25**	48.65	69.22

(1) Cash distributions represent the cash portion only and do not include equity issued through the DRIP, which commenced in April 2010.

(2) 2010 amounts have been restated to be IFRS compliant.

Funds Flow from Operating Activities

It is anticipated that Zargon's 2013 exploration and development capital budget and cash dividends to shareholders will be financed through the Company's funds flow from operating activities and its credit facilities. Funds flow is partially influenced by production volumes, commodity prices and the US/Canadian dollar exchange rates. Zargon's 2013 estimated sensitivity to moderate fluctuations in these key business parameters is shown in the accompanying table.

Funds Flow Sensitivity Summary

	Change in 2013 Funds Flow ($ millions)	($/share)
Change of $1.00 US/bbl in the price of WTI oil	1.48	0.05
Change in oil production of 100 bbl/d	1.46	0.05
Change of $0.10 US/mcf in the price of NYMEX natural gas	0.46	0.02
Change in natural gas production of one mmcf/d	0.11	–
Change of $0.01 in the $US/$Cdn exchange rate	1.20	0.04

Long Term Bank Debt

On June 14, 2012, Zargon amended and renewed its syndicated committed credit facilities, the result of which was the reduction of the available facilities and borrowing base to $165 million. A $300 million demand debenture on the assets of the Company has been provided as security for these facilities. The facilities are fully revolving for a 377 day period with the provision for an annual extension at the option of the lenders and upon notice from Zargon's Management. The next renewal date is June 26, 2013. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving period. Repayment would not be required until the end of the non-revolving term, and, as such, these facilities have been classified as long term debt. These facilities continue to be available for general corporate purposes and the potential acquisition of additional oil and natural gas properties.

For the 2013 renewal, it is anticipated that Zargon's borrowing costs will remain approximately the same as general debt pricing, and standby fees are expected to remain unchanged along with expected debt levels. Unhedged interest rates fluctuate under the syndicated facilities with Canadian prime, US prime and US base rates plus an applicable margin between 50 basis points and 200 basis points (2011 – 50 and 200 basis points, respectively), as well as with Canadian banker's acceptance and LIBOR rates plus an applicable margin between 200 basis points and 350 basis points (2011 – 200 and 350 basis points, respectively).

At December 31, 2012, $35.74 million (December 31, 2011 - $92.70 million) had been drawn on the syndicated committed credit facilities with any unused amounts subject to standby fees. Zargon reviews its compliance with its bank debt covenants on a quarterly basis and is in compliance as at December 31, 2012.

In the normal course of operations, Zargon enters into various letters of credit. At December 31, 2012, the approximate value of outstanding letters of credit totalled $0.71 million (December 31, 2011 - $0.60 million).

Zargon's debt, net of working capital (excluding unrealized derivative assets/liabilities) of $113.18 million at December 31, 2012 was equivalent to 2.0 times 2012 funds flow from operating activities of $56.66 million. At December 31, 2011, the debt net of working capital (excluding unrealized derivative assets/liabilities) was $109.50 million, equivalent to 1.8 times 2011 funds flow from operating activities of $60.67 million.

Convertible Debentures

In addition to its long term bank debt, Zargon entered into a convertible unsecured subordinated debenture offering on a bought deal basis with an aggregate principal amount of $57.50 million at six percent interest, paid semi-annually which commenced December 31, 2012, and matures June 30, 2017. This offering was closed on May 1, 2012 with the over-allotment closed on May 4, 2012.

These debentures are convertible at the holder's option into Zargon's common shares at any time prior to the earlier of the maturity date and the date fixed for redemption at a conversion price of $18.80 per share, subject to adjustment in certain circumstances. On or after June 30, 2015 but prior to maturity, the debentures will be redeemable at Zargon's option at par plus accrued and unpaid interest, provided that the weighted average trading price of the shares on the Toronto Stock Exchange during the 20 consecutive trading days ending on the fifth trading day preceding the date on which notice of redemption is given is not less than 125 percent of the conversion price. Zargon shall provide not more than 60 nor less than 30 days prior notice of redemption.

Zargon Year End
Share Price
($/share)

Equity

At March 12, 2013, Zargon Oil & Gas Ltd. had 29.908 million common shares outstanding. Pursuant to the common share rights incentive plans and the share award plan, there are currently an additional 0.937 million common share incentive rights issued and outstanding.

During 2012, 14.92 million Zargon common shares traded on the Toronto Stock Exchange with a high trading price of $15.99 per share, a low of $7.25 per share and a closing price of $8.38 per share. The 2012 trading statistics show a 35 percent year-over-year decrease in trading volume and a 39 percent decrease in the closing share price. Zargon's market capitalization at year end 2012 was approximately $250 million, compared to approximately $400 million at the end of 2011.

Segmented Geographic Information

During 2012, approximately 92 percent (2011 – 92 percent) of Zargon's combined petroleum and natural gas revenue came from Western Canadian (Alberta, Saskatchewan and Manitoba) properties, with the remaining eight percent (2011 – eight percent) of revenue generated in the United States (North Dakota). This weighting is due to additional revenue generated from property acquisitions comprised of only Canadian oil and natural gas properties as well as a drilling program focused only in Canadian properties.

OFF BALANCE SHEET ARRANGEMENTS

The Company has no guarantees or off balance sheet arrangements, except for letters of credit which have been issued in the normal course of business of approximately $0.71 million as at December 31, 2012.

RELATED PARTY TRANSACTIONS

During the year, the Company paid $0.21 million (2011 – $0.25 million) for legal services to a law firm in which a Board member is a partner. All amounts were based on normal commercial terms and conditions.

ENVIRONMENTAL INITIATIVES IMPACTING ZARGON

There are no new material environmental initiatives impacting Zargon at this time.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

Zargon has certain contractual obligations relating to the lease of head office space, ASP related contracts and natural gas transportation sales contracts that extend for longer than one year as set out in the table below:

($ millions)	Total	2013	2014 to 2015	2016 to 2017	Thereafter
Head office lease and other	4.72	1.86	2.86	–	–
ASP related contracts	2.01	2.01	–	–	–
Natural gas transportation sales contracts	0.22	0.20	0.02	–	–
Total	6.95	4.07	2.88	–	–

RISK FACTORS

There are numerous factors, both known and unknown, that can cause actual results or events to differ materially from forecast results. Although some of these risks are discussed in this section and in the Annual Information Form, these factors should not be construed as exhaustive.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of Zargon depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Zargon may have at any particular time and production they will yield will decline over time as such existing reserves are depleted. A future increase of the Company's reserves will depend not only on its ability to develop and exploit any properties it may have from time to time, but also its ability to evaluate and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by Zargon.

Zargon's principal risks are finding and developing economic hydrocarbon reserves efficiently and being able to fund the capital program. The Company's need for capital will be both short term and long term in nature. Short term working capital will be required to finance accounts receivable and other similar short term assets, while the development of oil and natural gas properties and ASP projects requires large amounts of long term capital. Zargon has budgeted $40 million for field capital and $38 million for ASP capital in 2013. The capital program will be funded through a combination of anticipated funds flow from operations, proceeds from planned non-core asset dispositions and bank credit facilities. If any components of the business plan are missing, Zargon may not be able to execute the entire business plan.

Operational risks faced by Zargon include competition, environmental factors, reservoir performance uncertainties, access to qualified personnel, a complex regulatory and taxation environment and safety concerns.

The supply of service and production equipment at competitive prices is critical to Zargon's ability to add reserves at a competitive cost and produce the reserve in an economic and timely fashion. In periods of increased activity, these services and supplies can become difficult to obtain. Zargon attempts to mitigate this risk by developing strong long term relationships with suppliers and contractors.

Zargon attempts to manage its business risks. Zargon has an experienced, talented and highly motivated staff of oil and natural gas professionals. Zargon also operates almost all of its properties. This enables Zargon to control the timing, direction and costs related to the exploitation and development opportunities. Zargon's geological focus is on areas in which the prospects are well understood by management. Technological tools are regularly used to reduce risk and increase the probability of success.

We are subject to extensive regulation surrounding the health and safety of our people and the environment. We make every effort to comply with the regulations and, where less stringent than our standards, exceed applicable legal and other requirements. However, regulatory standards and community expectations are constantly evolving. As a result, we may be exposed to increased litigation, compliance costs and unforeseen environmental rehabilitation expenses despite our best efforts to work with governments and community groups to keep pace with regulations, laws and public expectations. Zargon complies with government regulations and has in place an up-to-date Emergency Response Plan. Environmental and safety policies and standards are adhered to and reviewed with all levels of management on a regular basis.

Zargon maintains an insurance program with policies encompassing property damage, business interruption, public and certain other liabilities and directors and officers' exposures. As part of our portfolio risk management policy, we regularly conduct an assessment of foreseeable loss potential, cash flow at risk, loss experience, claims received and insurance premiums paid and will make adjustments to the balance. The coverage provides a reasonable amount of protection from risk of loss; however, not all risks are foreseeable or insurable.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial, state and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating expenses. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition.

The financial risks of global credit conditions, equity availability from the capital markets, commodity prices, interest rates, royalty rates, government intervention and taxation levels in the oil and natural gas industry are largely beyond Zargon's control. The Company's approach to managing these risks is to maintain a prudent level of debt and to employ forecasting and budgeting projections. In addition, from time to time, Zargon may use financial instruments to reduce corporate risk in certain situations. For a listing of financial instruments, refer to Note 16, derivatives, in the audited consolidated financial statements for the year ended December 31, 2012.

Zargon's operational results and financial condition, and, therefore, the amount of capital expenditures and future dividend payments made to shareholders, are dependent on the prices received for oil and natural gas production. Natural gas production in the US continued to establish new production records during 2012 and as a consequence North American natural gas inventories are at record highs. Oil production in North Dakota continued to increase in 2012 which put a strain on pipeline capacity. Delays in pipeline construction have also negatively affected pipeline capacity. Natural gas prices declined in 2012 from 2011. Continued or decreasing natural gas prices will affect Zargon's cash flow, impacting Zargon's level of capital expenditures and may result in the shut-in of certain natural gas properties. Differentials on WTI to Edmonton par pricing increased in 2012 and contributed to lower realized prices. Any movement in oil and natural gas prices will have an effect on Zargon's ability to continue with its capital expenditure program and its ability to pay dividends. Future declines in oil and natural gas prices may result in future declines in, or elimination of, any future dividends. Oil and natural gas prices are determined by economic and, in some circumstances, political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions, impact prices. Zargon may manage the risk associated with changes in commodity prices by entering into oil or natural gas price risk management contracts. If Zargon engages in activities to manage its commodity price exposure, it may forego the benefits it would otherwise experience if commodity prices were to increase. In addition, commodity risk management contract activities could expose Zargon to losses. To the extent that Zargon engages in risk management activities related to commodity prices, it will be subject to credit risks associated with counterparties with which it contracts.

SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

Zargon has continuously refined and documented its management and internal reporting systems to ensure that accurate, timely, internal and external information is gathered and disseminated.

Zargon's financial and operating results incorporate certain estimates including:

- Estimated revenues, royalties and operating expenses on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- Estimated capital expenditures on projects that are in progress;
- Estimated depletion and depreciation charges that are based on estimates of oil and gas reserves that Zargon expects to recover in the future;

- Estimated fair values of risk management contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
- Estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures;
- Estimated future recoverable value of property, plant and equipment and goodwill and any associated impairment charges or recoveries;
- Estimated compensation expense under Zargon's share option and share award plans; and
- Estimated deferred tax assets and liabilities based on current tax interpretations, regulations and legislation that is subject to change.

Zargon has hired individuals and consultants who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

Zargon's leadership team's mandate includes ongoing development of procedures, standards and systems to allow Zargon staff to make the best decisions possible and ensuring those decisions are in compliance with Zargon's environmental, health and safety policies.

CHANGES IN ACCOUNTING POLICIES

The Company had no changes in accounting policies for the year ended December 31, 2012.

FUTURE CHANGES IN ACCOUNTING POLICIES

The Company's future changes in accounting policies are discussed in Note 4 to the Financial Statements.

DESIGN AND EVALUATION OF INTERNAL CONTROL OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS AND PROCEDURES

Zargon is required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings" and is required to make specific disclosures with respect to NI 52-109. These disclosures can be summarized as follows:

- The President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer have directed an evaluation of Disclosure Control and Procedures ("DC&P") and have concluded that DC&P are designed appropriately and are operating effectively as at December 31, 2012.
- The President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer have directed an evaluation of Internal Controls over Financial Reporting ("ICFR") and have concluded that ICFR are designed appropriately and are operating effectively as at December 31, 2012.
- Zargon reports that no changes were made to ICFR during 2012 that have materially affected, or are reasonably likely to materially affect the Company's ICFR.
- Zargon has no interests in proportionately consolidated entities or variable interest entities other than oil and gas joint ventures. Accordingly, the scope of the design of DC&P and ICFR have not been limited to exclude controls, policies and procedures with respect to proportionately consolidated entities or variable interest entities.
- Zargon has not limited the scope of the design of DC&P and ICFR with respect to any businesses/assets acquired in 2012.

Because of their inherent limitations, DC&P and ICFR may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well designed or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

OUTLOOK

With a promising internally generated portfolio of long-life oil exploitation projects, Zargon is well positioned to meet its value-creating and dividend generating objectives into 2013 and beyond. In particular, Zargon's Little Bow ASP tertiary oil project has the potential to provide significant and stable oil production volumes into the second half of this decade.

SUMMARY OF QUARTERLY RESULTS

	2012			
	Q1	Q2	Q3	**Q4**
Petroleum and natural gas sales ($ millions)	44.64	38.52	36.91	**37.88**
Net earnings/(loss) ($ millions)	(2.01)	10.54	(4.02)	**(9.88)**
Net earnings/(loss) per diluted share ($)	(0.07)	0.34	(0.14)	**(0.33)**
Funds flow from operating activities ($ millions)	13.52	12.37	14.35	**16.42**
Cash flows from operating activities ($ millions)	11.85	18.00	12.16	**16.85**
Cash flows from operating activities per diluted share ($)	0.40	0.57	0.41	**0.57**
Cash dividends ($ millions) (1)	7.45	7.45	7.75	**4.70**
Cash dividends declared per common share ($)	0.30	0.30	0.30	**0.18**
Net capital expenditures/(dispositions) ($ millions)	20.95	(26.85)	10.35	**25.79**
Total assets ($ millions)	473.69	446.41	440.77	**445.11**
Long term bank debt ($ millions)	107.37	24.14	27.58	**35.74**
Convertible debentures ($millions) (2)	–	57.50	57.50	**57.50**
Average daily oil and liquids production (bbl)	5,496	5,384	5,079	**5,065**
Average daily natural gas production (mmcf)	20.03	17.44	15.33	**15.93**
Average daily production (boe)	8,834	8,290	7,634	**7,720**
Average oil production weighting (%)	62	65	67	**66**
Average realized commodity field price before the impact of financial risk management contracts ($/boe)	55.53	51.06	52.55	**53.33**
Funds flow netback ($/boe)	16.82	16.39	20.43	**23.12**

(1) Cash dividends represent the cash portion only and do not include common shares issued through Zargon's Dividend Reinvestment Plan.

(2) Amount is full face value of the convertible debentures.

	2011			
	Q1	Q2	Q3	Q4
Petroleum and natural gas sales ($ millions)	46.94	48.47	44.99	51.13
Net earnings/(loss) ($ millions)	(9.11)	12.67	30.69	(23.87)
Net earnings/(loss) per diluted share ($)	(0.33)	0.43	1.05	(0.81)
Funds flow from operating activities ($ millions)	15.22	13.76	14.59	17.10
Cash flows from operating activities ($ millions)	23.47	13.06	13.75	22.97
Cash flows from operating activities per diluted share ($)	0.86	0.45	0.47	0.78
Cash dividends ($ millions) (1)	9.65	10.47	10.75	7.27
Cash dividends declared per common share ($)	0.42	0.42	0.42	0.30
Net capital expenditures/(dispositions) ($ millions)	20.36	8.02	(4.61)	24.88
Total assets ($ millions)	483.98	472.58	489.77	470.69
Bank debt ($ millions)	121.89	95.79	76.69	92.70
Average daily oil and liquids production (bbl)	5,893	5,034	5,330	5,619
Average daily natural gas production (mmcf)	21.92	21.91	22.10	21.96
Average daily production (boe)	9,546	8,686	9,014	9,278
Average oil production weighting (%)	62	58	59	61
Average realized commodity field price before the impact of financial risk management contracts ($/boe)	54.64	61.32	54.25	59.91
Funds flow netback ($/boe)	17.71	17.41	17.59	20.03

(1) Cash dividends represent the cash portion only and do not include common shares issued through Zargon's Dividend Reinvestment Plan.

FOURTH QUARTER 2012

During the fourth quarter of 2012, Zargon's petroleum and natural gas sales of $37.88 million were three percent higher than the previous quarter's sales. Production for the 2012 fourth quarter of 7,720 barrels of oil equivalent per day was one percent higher than the 2012 third quarter's production of 7,634 barrels of oil equivalent per day. Compared to the previous quarter, oil production remained consistent at 5,065 barrels per day due to new wells drilled in the fourth quarter offsetting production declines. Fourth quarter natural gas production increased four percent from the previous quarter to 15.93 million cubic feet per day due to well reactivations because of improving natural gas prices. Average field prices received during the fourth quarter, before the impact of financial risk management contracts, were $72.06 per barrel for oil and liquids, a one percent decrease compared to the 2012 third quarter and $2.93 per thousand cubic feet for natural gas, a 41 percent increase from the prior quarter. Zargon's field price differential for its crude oil stream increased to an $11.97 per barrel discount to the Edmonton reference crude oil price, an 11 percent increase from Zargon's average differential of $10.83 per barrel for the first nine months of 2012.

Funds flow from operating activities was $16.42 million in the fourth quarter, an increase of 14 percent or $2.07 million from the prior quarter. A comparative analysis of the primary factors that caused this quarter-over-quarter increase is as follows:

- Fourth quarter 2012 petroleum and natural gas sales of $37.88 million were three percent higher than the 2012 third quarter sales of $36.91 million. This sales increase was a result of the one percent increase in production over the third quarter.

- Royalties for the fourth quarter were $7.06 million, a decrease of $0.10 million from the prior quarter as the average royalty rate for the quarter decreased to 18.6 percent from the 2012 third quarter rate of 19.4 percent.
- Realized derivative gains were $2.62 million in the fourth quarter of 2012, a $1.60 million increase from the prior quarter's $1.02 million gain due to the weakening of oil prices. The fourth quarter derivative gains were comprised of gains realized on financial oil risk management contracts ($2.67 million), losses on financial natural gas risk management contacts ($0.01 million) and losses on financial interest rate swaps ($0.04 million).
- Operating expenses were $11.21 million for the quarter, seven percent higher than the third quarter of 2012. Transportation expenses were $0.50 million, a 62 percent increase over the prior quarter. On a per barrel of oil equivalent basis, operating expenses increased six percent to $15.79 in the fourth quarter of 2012 compared to $14.90 in the prior quarter and transportation expenses increased 59 percent to $0.70. This quarterly increase was due to higher electricity, repairs and maintenance costs and 13^{th} month adjustments.
- General and administrative expenses decreased in the fourth quarter by $0.37 million or 11 percent as compared to the third quarter of 2012 due to increased capital overhead recoveries from the fourth quarter drilling program.
- There were no transaction costs incurred in the fourth quarter or in the prior quarter.
- Interest and financing charges on long term bank debt were $0.50 million, a decrease of two percent or $0.01 million from the prior quarter. Due to higher capital expenditures in the fourth quarter, the average bank debt level increased 17 percent to $32.74 million compared to $27.87 million in the third quarter of 2012, resulting in higher debt servicing charges. Interest on convertible debentures was $0.86 million.
- Asset retirement expenditures reflect the actual amounts incurred to abandon and reclaim wells. These asset retirement expenditures totalled $0.72 million in the 2012 fourth quarter and increased slightly from the prior quarter amount of $0.71 million.
- Current income taxes of $0.29 million were $0.05 million higher than in the 2012 third quarter. The increase was primarily due to the 2012 fourth quarter drilling program in the US being delayed until the first half of 2013.

The net loss for the quarter was $9.88 million, an increased loss of $5.86 million compared to the prior quarter net loss of $4.02 million, mainly as a result of an impairment loss recognized in the fourth quarter that was partially offset by a decrease in unrealized derivative losses. The net loss tracks the funds flow from operating activities for the respective periods modified by asset retirement expenditures and non-cash charges, which included the following for the fourth quarter of 2012:

- Depletion and depreciation expense decreased by $0.29 million to $11.41 million in the 2012 fourth quarter. The decreased expense was due to an updated depletion and depreciation rate of $16.07 per barrel of oil equivalent, compared to the prior quarter's $16.66 per barrel of oil equivalent charge.
- Fourth quarter 2012 unrealized derivative losses of $1.06 million compared with third quarter unrealized derivative losses of $5.21 million. These unrealized losses result from the mark-to-market of financial risk management contracts at each period end. During the fourth quarter, unrealized derivative losses decreased compared to the prior quarter. These non-cash unrealized derivative losses are generated by the change over the reporting period in the mark-to-market valuation of Zargon's risk management contracts. In particular, higher year end futures resulted in unrealized risk management contract oil losses of $1.16 million, unrealized risk management contract natural gas gains of $0.01 million and interest rate swap gains of $0.09 million.
- Accretion of convertible debentures remained unchanged at $0.30 million compared to the prior quarter amount.

- The provision for accretion of asset retirement obligations for the 2012 fourth quarter was $0.70 million, up five percent from the prior quarter expense. The quarter-over-quarter increase is due to changes in the estimated future liability for asset retirement obligations as a result of wells added through Zargon's drilling program, inclusive of wells acquired/disposed of in the quarter and changes resulting from revisions to the timing and the amounts of the original estimates of undiscounted cash flows.
- Share-based compensation expense increased by $0.20 million during the fourth quarter of 2012 to $0.59 million, a four percent increase from the third quarter.
- Unrealized foreign exchange gains of $0.03 million in the 2012 fourth quarter compare to losses of $0.03 million for the prior quarter.
- Exploration and evaluation expenses in the fourth quarter were $2.08 million and were flat compared to the third quarter's $2.07 million. Exploration and evaluation expenses were the result of land expiries in the quarter.
- At the end of the fourth quarter, due to low commodity prices and the write off of certain natural gas reserves, three of the Company's eight CGUs were found to be impaired. The impairment was calculated to be a loss of $14.45 million. The E&E assets associated with these CGUs were not included in this impairment test.
- The deferred tax recovery was $3.54 million during the quarter compared to a deferred tax recovery of $1.48 million from the third quarter of 2012. The increase was due to the increase of losses before taxes of $13.13 million compared to the third quarter losses before taxes of $5.26 million.

Net capital expenditures were $25.79 million during the fourth quarter of 2012, compared to a prior quarter spend amount of $10.35 million. During the fourth quarter, Zargon drilled 15.0 net wells, which resulted in 15.0 net oil wells.

Fourth quarter cash dividends to shareholders of $0.06 per share per month totalled $4.70 million (after the effect of the DRIP program) and compared to the prior quarter's $0.10 per share per month dividend that totalled $7.75 million (net of the DRIP).

ADDITIONAL INFORMATION

Additional information regarding the Company and its business operations, including the Company's Annual Information Form, is available on the Company's SEDAR profile at www.sedar.com.

MANAGEMENT'S REPORT

The consolidated financial statements of Zargon Oil & Gas Ltd. were prepared by management in accordance with International Financial Reporting Standards. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the financial statements reliably report the Company's operations and that the Company's assets are safeguarded. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

Ernst & Young LLP, an independent chartered accountant firm, was appointed by a resolution of the shareholders to audit the consolidated financial statements of the Company and provide an independent opinion. They have conducted an independent examination of the Company's accounting records in order to express their opinion on the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through its Audit and Reserves Committee. The Audit and Reserves Committee, which consists of non-management directors, has met with Ernst & Young LLP and management in order to determine that management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Audit and Reserves Committee has reported its findings to the Board of Directors, who have approved the consolidated financial statements.

C.H. Hansen
President and Chief Executive Officer

J.B. Dranchuk
Vice President, Finance and Chief Financial Officer

Calgary, Canada
March 12, 2013

INDEPENDENT AUDITORS' REPORT

To the Shareholders of **Zargon Oil & Gas Ltd.**

We have audited the accompanying consolidated financial statements of Zargon Oil & Gas Ltd., which comprise the consolidated balance sheets as at December 31, 2012 and 2011, and the consolidated statements of earnings/(loss) and comprehensive income/(loss), changes in equity and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2012 and 2011 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Ernst & Young LLP

Chartered Accountants

Calgary, Canada
March 12, 2013

CONSOLIDATED BALANCE SHEETS

($ thousands)	Notes	**December 31, 2012**	December 31, 2011
ASSETS			
Trade and other receivables		**16,660**	22,373
Deposits and prepaid expenses		**1,715**	1,656
Derivatives	15,16	**4,514**	650
Total current assets		**22,889**	24,679
Long term deposits		**269**	418
Derivatives	15,16	**284**	327
Property, plant and equipment, net	5,7	**389,971**	410,667
Intangible exploration and evaluation assets	6	**19,968**	25,184
Goodwill	6	**2,969**	2,969
Deferred tax assets	17	**8,755**	6,443
Total non-current assets		**422,216**	446,008
Total assets		**445,105**	470,687
LIABILITIES			
Trade and other payables		**35,777**	37,450
Cash dividends payable	8	**1,656**	2,493
Provisions	9	**881**	881
Derivatives	15,16	**72**	5,826
Total current liabilities		**38,386**	46,650
Long term bank debt	10	**35,736**	92,703
Convertible debenture	11	**51,261**	–
Derivatives	15,16	**191**	519
Provisions	9	**112,283**	96,596
Deferred tax liabilities	17	**10,665**	10,414
Total non-current liabilities		**210,136**	200,232
Total liabilities		**248,522**	246,882
Commitments and contingencies	9,10,11,14,16,25		
EQUITY			
Shareholders' capital	13	**254,400**	249,470
Accumulated other comprehensive income		**(998)**	(600)
Contributed surplus	14	**11,133**	9,200
Equity component of debenture	11	**3,640**	–
Deficit		**(71,592)**	(34,265)
Total equity		**196,583**	223,805
Total equity and liabilities		**445,105**	470,687

See accompanying notes to the consolidated financial statements.

Dated on March 12, 2013 on behalf of the Board:

K.J. Harrison, Director

K.D. Kitagawa, Director

CONSOLIDATED STATEMENTS OF EARNINGS/(LOSS) AND COMPREHENSIVE INCOME/(LOSS)

For the years ended December 31 ($ thousands, except per share amounts)	Notes	**2012**	2011
Petroleum and natural gas sales		**157,945**	191,533
Royalties		**(30,137)**	(33,961)
PETROLEUM AND NATURAL GAS REVENUE, NET OF ROYALTIES		**127,808**	157,572
Gain on unrealized derivatives	15,16	**9,903**	8,449
Loss on realized derivatives	15,16	**(139)**	(11,833)
GAIN/(LOSS) ON DERIVATIVES		**9,764**	(3,384)
TOTAL INCOME		**137,572**	154,188
Operating		**47,283**	55,584
Transportation		**1,566**	1,696
General and administrative		**13,549**	15,810
Transaction costs		**37**	158
Exploration and evaluation	6	**6,539**	3,480
Gain on disposal of properties	5	**(20,823)**	(19,172)
Share-based compensation	14, 19	**2,134**	2,209
Unrealized foreign exchange (gain)/loss		**21**	(69)
Impairment loss	5,7	**37,321**	18,867
Depletion and depreciation	5	**48,198**	50,937
EXPENSES		**135,825**	129,500
EARNINGS BEFORE FINANCE EXPENSES AND INCOME TAXES		**1,747**	24,688
Interest and financing charges	10	**3,061**	5,231
Interest on convertible debentures	11	**2,306**	–
Accretion of convertible debentures	11	**801**	–
Accretion of asset retirement obligations	9	**2,771**	3,215
FINANCE EXPENSES		**8,939**	8,446
EARNINGS/(LOSS) BEFORE INCOME TAXES		**(7,192)**	16,242
Current tax expense	17	**567**	2,745
Deferred tax expense/(recovery)	17	**(2,382)**	3,117
INCOME TAXES		**(1,815)**	5,862
NET EARNINGS/(LOSS) FOR THE YEAR		**(5,377)**	10,380
Currency translation adjustment		**(398)**	608
OTHER COMPREHENSIVE INCOME/(LOSS) FOR THE YEAR		**(398)**	608
TOTAL COMPREHENSIVE INCOME/(LOSS) FOR THE YEAR		**(5,775)**	10,988
NET EARNINGS/(LOSS) PER SHARE			
Basic	19	**(0.18)**	0.36
Diluted	19	**(0.18)**	0.36

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

For the years ended December 31 ($ thousands)	Notes	Shareholders' Capital	Currency Translation Adjustment	Contributed Surplus	Equity Component of Convertible Debenture	Deficit	Total Equity
Balance at December 31, 2011		**249,470**	**(600)**	**9,200**	**–**	**(34,265)**	**223,805**
Net loss for the year		**–**	**–**	**–**	**–**	**(5,377)**	**(5,377)**
Dividends declared	8	**–**	**–**	**–**	**–**	**(31,950)**	**(31,950)**
Issue of common shares pursuant to the DRIP	8,13	**4,603**	**–**	**–**	**–**	**–**	**4,603**
Issuance of convertible debentures (equity component)	11	**–**	**–**	**–**	**3,640**	**–**	**3,640**
Share-based payments	14	**–**	**–**	**2,154**	**–**	**–**	**2,154**
Exercise of share options	13	**327**	**–**	**(221)**	**–**	**–**	**106**
Translation differences on foreign subsidiary		**–**	**(398)**	**–**	**–**	**–**	**(398)**
Balance at December 31, 2012		**254,400**	**(998)**	**11,133**	**3,640**	**(71,592)**	**196,583**
Balance at December 31, 2010		201,091	(1,208)	7,815	–	–	207,698
Net earnings for the year		–	–	–	–	10,380	10,380
Dividends declared	8	–	–	–	–	(44,645)	(44,645)
Issue of common shares pursuant to the DRIP	8,13	6,504	–	–	–	–	6,504
Issue of common shares pursuant to financing	13	38,985	–	–	–	–	38,985
Share issue costs, net of deferred tax effect of $524	13,17	(1,530)	–	–	–	–	(1,530)
Share-based payments	14	–	–	2,266	–	–	2,266
Exercise of share options	13	4,420	–	(881)	–	–	3,539
Translation differences on foreign subsidiary		–	608	–	–	–	608
Balance at December 31, 2011		249,470	(600)	9,200	–	(34,265)	223,805

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ thousands)	Notes	**2012**	2011
OPERATING ACTIVITIES			
Net earnings/(loss) for the year		**(5,377)**	10,380
Adjustments for non-cash items:			
Gain on sale of properties	5	**(20,823)**	(19,172)
Gain on unrealized derivatives	15,16	**(9,903)**	(8,449)
Depletion and depreciation	5	**48,198**	50,937
Accretion of asset retirement obligations	9	**2,771**	3,215
Accretion of convertible debentures	11	**801**	–
Share-based compensation	14	**2,134**	2,209
Unrealized foreign exchange (gain)/loss		**21**	(69)
Impairment loss	7	**37,321**	18,867
Deferred taxes/(recovery)	17	**(2,382)**	3,117
Exploration and evaluation	6	**6,539**	3,480
Asset retirement expenditures	9	**(2,639)**	(3,849)
Funds flow from operating activities		**56,661**	60,666
Changes in operating working capital	20	**2,210**	12,590
Net cash flows from operating activities		**58,871**	73,256
INVESTING ACTIVITIES			
Additions to property, plant and equipment	5	**(65,210)**	(79,190)
Additions to intangible exploration and evaluation assets	6	**(1,803)**	(1,893)
Proceeds from disposal of property, plant and equipment	5,6	**36,766**	32,435
Change in long term deposit		**149**	235
Changes in investing working capital	20	**1,622**	(3,333)
Net cash flows used in investing activities		**(28,476)**	(51,746)
FINANCING ACTIVITIES			
Repayments of bank debt	10	**(56,967)**	(22,582)
Cash dividends paid to shareholders	8	**(27,347)**	(38,141)
Proceeds from exercise of share rights	13	**106**	3,539
Issuance of shareholders' capital, net of issue costs	13	**–**	36,931
Issuance of convertible debentures, net of issue costs	11	**54,650**	–
Changes in financing working capital	20	**(837)**	(1,257)
Net cash flows used in financing activities		**(30,395)**	(21,510)
NET CHANGE IN CASH DURING THE YEAR AND CASH, END OF YEAR		**–**	–

See supplemental cash flow information contained in Note 21.

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2012 with comparative figures for 2011.
All amounts are stated in Canadian Dollars unless otherwise noted.

1. REPORTING ENTITY

Zargon Oil & Gas Ltd. ("the Company" or "Zargon") is a publicly traded corporation incorporated in Canada with its head office located at Suite 700, 333-5th Avenue SW, Calgary, Alberta. The consolidated financial statements of the Company as at and for the years ended December 31, 2012 and its 2011 comparative periods are comprised of the Company and its wholly owned subsidiaries. The Company is engaged in the exploration, development and production of oil and natural gas in Canada and the United States ("US") and conducts many of its activities jointly with others; these financial statements reflect only the Company's proportionate interest in such activities.

2. BASIS OF PRESENTATION AND ADOPTION OF IFRS

(a) Statement of compliance:

These consolidated financial statements represent the annual financial statements of the Company and its subsidiaries prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). These consolidated financial statements were approved and authorized for issue by the Board of Directors on March 12, 2013.

(b) Basis of measurement:

The consolidated financial statements have been prepared on the historical cost basis except for derivative financial instruments measured at fair value. The methods used to measure fair values of derivative financial instruments are discussed in Note 3(iv) and Note 4(i)(ii).

(c) Functional and presentation currency:

Items included in the financial statements of each consolidated entity are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). Zargon's US subsidiaries' functional currency is US dollars, while the Canadian subsidiaries have a functional currency of Canadian dollars. The consolidated financial statements are presented in Canadian dollars, which is the Company's functional and presentation currency.

3. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of the Company's consolidated financial statements requires management to make judgments, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the disclosure of contingent liabilities at the end of the reporting period. However, uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of the asset or liability affected in future periods.

Where applicable, further information about the significant accounting judgments, estimates and assumptions made in preparing the consolidated financial statements is disclosed in the notes specific to that item.

(i) Property, plant and equipment and intangible exploration and evaluation assets:

Property, plant and equipment and intangible exploration and evaluation assets, represents costs incurred in developing oil and natural gas reserves and maintaining or enhancing production from such reserves. The fair value of property, plant and equipment recognized in a business combination is based on market values. The market 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 recoverability of development and production asset carrying values are assessed at the cash-generating unit ("CGU") level. Determination of what constitutes a CGU is subject to management judgments. The asset composition of a CGU can directly impact the recoverability of the assets included therein. In assessing the recoverability of oil and gas properties, each CGU's carrying value is compared to its recoverable amount.

The amount recorded for depletion and depreciation of property and equipment and the assessment of these assets for impairment including intangible exploration and evaluation assets are based on estimates of proved and probable reserves, production rebates, oil and natural gas prices, future costs and other relevant assumptions. Exploration and evaluation assets are not depleted. All of Zargon's petroleum and natural gas reserves are evaluated and reported by independent engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

(ii) Asset retirement obligation:

Inherent in the calculation of asset retirement obligations are numerous assumptions and judgements including the ultimate settlement amounts, inflation factors, risk-free discount rates, timing of settlement and changes in the legal and regulatory environments. To the extent future revisions to these assumptions impact the measurement of the existing asset retirement obligation liability, a corresponding adjustment is made to the property, plant and equipment balance. The risk-free discount rate is based on the approximate government of Canada long term bond rate.

(iii) Share-based compensation:

The Company measures the cost of equity-settled transactions with employees and directors by reference to the fair value of the equity instruments at the date at which they are granted. The fair value of share awards is measured by reference to the quoted market price of the shares on the date of grant. The fair value of 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 behaviour), expected dividends and the risk-free interest rate (based on Government of Canada bonds).

(iv) Fair value of financial instruments:

Where the fair value of certain financial assets and financial liabilities recorded in the consolidated balance sheet cannot be derived from active markets, their fair value is determined using valuation techniques including the discounted cash flow model. The inputs to these models are taken from observable markets where possible, but where this is not feasible, a degree of judgment is required in establishing fair values. The judgments include considerations of inputs such as liquidity risk, credit risk and volatility. Changes in assumptions about these factors could affect the reported fair value of financial instruments.

Trade and other receivables are designated as "loans and receivables". Trade and other payables, cash dividends payable and long term bank debt are designated as "other liabilities". The fair value of long term bank debt approximates its carrying amount because it is subject to variable rates of interest. The fair values of trade and other receivables, trade and other payables and cash dividends payable approximate their carrying amounts due to their short terms to maturity.

The Company's convertible debentures are classified as debt with a portion of the proceeds allocated to equity representing the conversion feature. As the debentures are converted, a portion of debt and conversion feature components are transferred to share capital. The debt component associated with the convertible debentures are designated as "financial liability measured at amortized cost".

Derivative assets and liabilities are derivative financial instruments classified as "held-for-trading" and are carried at fair value.

All of the Company's risk management contracts are transacted in active markets. The Company classifies the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- Level I

Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and value to provide pricing information on an ongoing basis.

- Level II

Pricing inputs are other than quoted prices in active markets included in Level I. Prices in Level II are either directly or indirectly observable as of the reporting date. Level II valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the market place.

- Level III

Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The Company's risk management contracts have been assessed on the fair value hierarchy described above and are classified as Level II. Assessment of the significance of a particular input into the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level.

4. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements.

(a) Basis of consolidation:

(i) 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 are currently exercisable or convertible are taken into account. The financial statements of subsidiaries are included in the 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 fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the identifiable net assets of the subsidiary acquired, the difference is recognized immediately in the consolidated statement of earnings and comprehensive income as an impairment.

(ii) Jointly controlled operations and jointly controlled assets:

A joint venture is a contractual arrangement whereby two or more parties (venturers) undertake an economic activity that is subject to joint control. Joint control exists only when the strategic financial and operating decisions relating to the activity require the majority consent of the venturers. Many of the Company's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Company's share of these jointly controlled assets and its proportionate share of the relevant revenue and related costs.

(iii) Transactions eliminated on consolidation:

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

(b) Foreign currency:

(i) Transactions and balances:

Transactions in foreign currencies are translated to Canadian dollars at exchange rates at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Foreign currency differences arising on translation are recognized in earnings.

(ii) Group companies:

The assets and liabilities of foreign operations are translated at the rate of exchange prevailing at the reporting date and their statements of earnings are translated at exchange rates prevailing at the dates of the transactions. The exchange differences arising on the translation are recognized in equity. On disposal of a foreign operation, the component of other comprehensive income relating to that particular foreign operation is recognized in the consolidated statement of earnings/(loss) and comprehensive income/(loss).

(c) Property, plant and equipment and intangible exploration and evaluation assets:

(i) Recognition and measurement:

Exploration and evaluation costs:

The Company accounts for exploration and evaluation ("E&E") costs, having regard to the requirements of IFRS 6 "Exploration for and Evaluation of Mineral Resources." Undeveloped land is accounted for as exploration and evaluation assets on the consolidated balance sheet. Pre-license E&E costs and lease expiries are recognized in the consolidated statement of earnings/(loss) and comprehensive income/(loss) as incurred. Costs of exploring for and evaluating oil and natural gas properties are capitalized and the resulting intangible E&E assets are tested for impairment by grouping them with producing CGUs. The level at which E&E assets are grouped with producing CGUs must not be larger than the Company's operating segments.

E&E costs related to each license/prospect are initially capitalized within "intangible exploration and evaluation assets". Such E&E assets may include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administrative expenses, including remuneration of production personnel and supervisory management and the projected costs of retiring the assets (if any), but do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area, which are expensed directly to earnings as they are incurred.

E&E assets are not depleted and are carried forward until technical feasibility and commercial viability of extracting an oil or natural gas resource is considered to be determined. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved and/or probable reserves are determined to exist. A review of each exploration licence or field is carried out, at least annually, to ascertain whether proved and/or probable reserves have been discovered.

Upon determination of proved and probable reserves, E&E assets attributable to those reserves are first tested for impairment at the CGU level, and then reclassified from E&E assets to property, plant and equipment.

Development and production costs:

Items of property, plant and equipment, which include oil and natural gas development and production ("D&P") assets, are measured at cost less accumulated depletion and accumulated impairment losses. D&P assets are grouped into CGUs for impairment testing.

Expenditures on the construction, installation or completion of infrastructure facilities such as processing facilities, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, are capitalized within D&P assets, as long as the facts and circumstances indicate that it is technically feasible and economically viable to extract identified reserves.

The initial cost of an asset is comprised of the purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the asset retirement obligation, and for qualifying assets, borrowing costs. The purchase price or constructed cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

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.

Exchanges of assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measureable. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. The gain or loss on derecogniton of the asset given up is recognized in earnings.

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.

Other items of property, plant and equipment are carried at cost less accumulated depreciation and net accumulated impairment losses.

(ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability are included in the asset's carrying amount or recognized as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Company and the cost can be measured reliably. The carrying amount of a replaced asset is derecognized when replaced. Routine repairs and maintenance costs are charged to earnings during the period in which they are 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 year to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers on an annual basis. Major development projects are not depleted until production commences.

Proved and probable reserves are estimated using independent reserve engineer 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 viable. 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 productibility 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.

Routine turnarounds are depreciated and recognized in earnings over the period until the next turnaround is expected to be required. Turnarounds have an estimated life of two years and are depreciated over a two year life.

For other assets, depreciation is recognized in earnings on a declining balance basis at an annual rate of 20 percent over the estimated useful lives of each item of property, plant and equipment. 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:

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. All other leases are classified as operating leases, which are not recognized on the Company's consolidated balance sheet. Zargon has no finance leases at this time.

Payments made under operating leases are recognized in earnings 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.

(e) Business combinations and goodwill:

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at the acquisition date fair value and the amount of any non-controlling interest in the acquiree. For each business combination, Zargon measures the non-controlling interest in the acquiree either at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition costs incurred are expensed.

When Zargon acquires a business, it assesses the financial assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date.

If the business combination is achieved in stages, the acquisition date fair value of Zargon's previously held equity interest in the acquiree is re-measured to fair value at the acquisition date through earnings as an impairment.

Any contingent consideration to be transferred by the acquirer will be recognized at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration which is deemed to be an asset or liability will be recognized in accordance with IAS 39 Financial Instruments: Recognition and Measurement either in earnings or as a change to other comprehensive income. If the contingent consideration is classified as equity, it should not be re-measured until it is finally settled within equity.

Goodwill is initially measured at cost being the excess of the aggregate of the consideration transferred and the amount recognized for non-controlling interest over the net identifiable assets acquired and liabilities assumed. If this consideration is lower than the fair value of the net assets of the subsidiary acquired, the difference is recognized in earnings.

Subsequent to initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Company's CGUs that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill forms part of a CGU and part of the operation within that unit is disposed of, the goodwill associated with the operation disposed of is included in the carrying amount of the operation when determining the gain or loss on disposal of the operation. Goodwill disposed of in this circumstance is measured based on the relative values of the operation disposed of and the portion of the CGU retained.

(f) Impairment:

(i) 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 the amortized cost of the loan or receivable and the present value of the estimated future cash flows, discounted using the instrument’s original effective interest rate. The carrying amount of the asset is reduced by this amount either directly or indirectly through the use of an allowance account.

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 earnings.

An impairment loss on financial assets carried at amortized cost 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 earnings.

(ii) Non-financial assets:

The carrying amounts of the Company’s non-financial assets, other than E&E assets and 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. These indicators include, future prices, future cost and reserves value, this list is not exhaustive. For goodwill, an impairment test is completed at least annually. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, as D&P assets, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash flows that are largely independent of the cash flows of other assets or groups of assets (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.

Fair value is determined as the amount that would be obtained from the sale of the assets in an arm’s length transaction between knowledgeable and willing parties. Fair value for oil and gas assets is generally determined as the present value of estimated future cash flows arising from the continued use of assets, which includes estimates such as the cost of future expansion plans and eventual disposal, using assumptions that an independent market participant may take into account. Cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount. Impairment losses are recognized in earnings. Impairment losses recognized in respect of CGUs 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 (group of units) on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, 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.

(g) Provisions:

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. Where the Company expects some or all of the provision to be reimbursed, for example under an insurance contract, the reimbursement is recognized as a separate asset but only when the reimbursement is virtually certain. 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.

Asset retirement obligations:

The Company's activities give rise to dismantling, decommissioning and site restoration activities (often referred to as asset retirement obligations). A provision is made for the estimated cost of site restoration and capitalized in the relevant asset category. The capitalized amount is depleted on the unit of production method based on proved and probable reserves.

Asset retirement obligations are measured at the present value of management's best estimate of expenditures required to settle the present obligation at the balance sheet date. 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 or discount rate underlying the obligation. The increase in the provision due to the passage of time is recognized under finance costs as accretion whereas increases/decreases due to changes in the estimated future cash flows or the estimated discount rate are capitalized. Actual costs incurred upon settlement of the asset retirement obligations are charged against the provision to the extent the provision was established.

(h) Share-based payments:

Under the Company's share award and option plans (the "Plans"), options to purchase common shares were granted to directors, officers, employees and other service providers at market prices. Share awards and options grants of the Company are measured at fair value at the date of grant and recognized as share-based compensation expense with a corresponding increase in contributed surplus. The total amount to be expensed is determined by reference to the fair value of the awards/options granted, excluding the impact of any non-market service and performance vesting conditions. Non-market vesting conditions are included in assumptions about the number of awards/options that are expected to vest. When awards/options vest in instalments over the vesting period, each instalment is accounted for as a separate arrangement. A forfeiture rate is estimated on the grant date and, at each reporting date, the Company revises its estimates of the number of awards/options that are expected to vest.

(i) Financial instruments:

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Company has transferred substantially all risks and rewards of ownership.

Financial assets and liabilities are offset and the net amount reported in the consolidated balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

At initial recognition, the Company classifies its financial instruments in the following categories depending on the purpose for which the instruments were acquired:

(i) Non-derivative financial instruments:

Non-derivative financial instruments comprise trade and other receivables, cash and cash equivalents, bank overdrafts, loans and borrowings, and trade and other payables. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through earnings, any directly attributable transaction costs. Subsequent to initial recognition non-derivative financial instruments are measured as described below.

Cash and cash equivalents:

Cash and cash equivalents comprise cash on hand, term deposits held with banks and other short term highly liquid investments with original maturities of three months or less. Bank overdrafts that are repayable on demand and form an integral part of the Company's cash management, whereby management has the ability and intent to net bank overdrafts against cash, are included as a component of cash and cash equivalents for the purpose of the consolidated statement of cash flows.

Financial assets at fair value through earnings:

An instrument is classified at fair value through earnings if it is held for trading or is designated as such upon initial recognition. Financial instruments are designated at fair value through earnings if the Company manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Company's risk management or investment strategy. Upon initial recognition, attributable transaction costs are recognized in earnings when incurred. These financial instruments are measured at fair value and changes therein are recognized in the consolidated statement of earnings and comprehensive income. The Company's risk management contracts are derivatives classified as held for trading as discussed in part (ii) below. The Company has not designated any financial instruments at fair value through earnings.

Other:

Other non-derivative financial instruments, such as trade and other receivables, loans and borrowings and trade and other payables, are measured at amortized cost using the effective interest method, less any impairment losses.

(ii) Derivative financial instruments:

Derivative financial instruments are sometimes utilized to reduce commodity price risk associated with the Company's production of oil and natural gas. The base prices for the commodities are sometimes denominated in US dollars and the Company may also use such financial instruments to reduce the related foreign currency risk. Financial instruments may also be used from time to time to reduce interest rate risk on outstanding debt. The Company does not enter into financial instruments for trading or speculative purposes.

The Company follows a policy of using risk management instruments such as fixed price swaps, forward sales, puts and costless collars. The objective is to partially offset or mitigate the wide price swings commonly encountered in oil and natural gas commodities and in so doing protect a minimum level of cash flow.

Interest rate swaps are utilized to hedge interest on long term debt to manage the Company's exposure to rate fluctuations, which impact finance expenses.

Electricity price contracts are sometimes utilized to hedge anticipated purchases of electricity to manage the Company's exposure to price fluctuations, which impact operating expenses.

The Company considers these financial risk management contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and, accordingly, for outstanding contracts not designated as hedges, an unrealized gain or loss is recorded based on the change in fair value ("mark-to-market") of the contracts at each reporting period end. These instruments have been recorded as derivative financial instruments in the consolidated balance sheet.

In the case of forward sales, the instrument can sometimes be satisfied by physical delivery. In the case of physical delivery, the payment/receipt is recorded as part of the normal revenue stream.

Foreign currency collar and swap agreements are utilized to manage the risk inherent in producing commodities whose price is based directly or indirectly on US dollars, using notional principal amounts equal to the projected monthly revenue from their sale. Payments or charges are calculated and paid according to the terms of the agreement, typically with monthly settlement.

(j) Income tax:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in earnings 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 consolidated 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 and, at the time of the transaction, affects neither the accounting profit nor taxable profit. 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 the Company intends to settle current tax liabilities and assets on a net basis or the 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. Deferred tax assets and liabilities are presented as non-current.

(k) Revenue:

Revenue from the sale of crude oil, natural gas and natural gas liquids 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 an external party. This is generally at the plant gate, which is the pipeline delivery point for natural gas and at the contracted delivery point for crude oil. Revenue is measured net of discounts, customs duties and royalties. With respect to the latter, the entity is acting as a collection agent on behalf of others.

Tariffs and tolls charged to other entities for use of pipelines and facilities owned by the Company are recognized as revenue as they accrue in accordance with the terms of the service or tariff and tolling agreements.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements and is included in revenue.

(l) Finance expenses:

Finance expense comprises interest expense on borrowings and convertible debentures and accretion of the discount on asset retirement obligations and convertible debenture.

Borrowing costs, which consist of interest expense incurred for the construction of qualifying assets, are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in profit or loss using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

Interest income is recognized as it accrues in earnings using the effective interest method.

(m) Earnings per share:

Basic earnings per share is calculated by dividing net earnings for the period by the weighted average number of common shares outstanding during the period. Diluted earnings per share is calculated by dividing the net earnings by the weighted average number of common shares outstanding during the year plus the weighted average number of common shares that would be issued if all the dilutive potential common shares were converted into common shares. The dilutive potential common shares consist of share-based compensation awards for which dilution is determined by assuming that the proceeds received from "in-the-money" common share rights and unrecognized future share-based compensation expense are used to repurchase common shares at the average market rate during the period. The convertible debenture could potentially dilute basic earnings per share, if earnings are positive in the year.

(n) Cash dividends:

The Company declares monthly dividends of cash to shareholders of record on the last day of each calendar month. Pursuant to the Company's policy, it will pay dividends to its shareholders subject to satisfying its financing covenants and the requirements of the Business Corporation Act (Alberta). Such dividends are recorded as distributions of equity upon declaration of the dividend.

(o) Segment reporting:

Operating segments are reported in a manner consistent with the internal reporting provided to the Chief Operating Decision-Maker. The Chief Operating Decision-Maker, who is responsible for allocating resources and assessing performance of the operating segments, has been identified as the Chief Executive Officer.

An operating segment is a component of the Company that engages in business activities from which it may earn revenue and incur expenses, including revenue and expenses that relates to transactions with any of the Company's other components.

Segment results that are reported directly to the Chief Operating Decision-Maker include items directly attributable to a segment as well as results that have been allocated on a reasonable basis.

(p) Changes in accounting policy and disclosure

Standards, amendments and interpretations to existing standards that are not yet effective and may be relevant to the Company but have not been early adopted by the Company include:

- IFRS 9 "Financial Instruments: Classification and Measurement", as issued reflects the first phase of the IASB's work on the replacement of IAS 39 "Financial Instruments: Recognition and Measurement" and applies to classification and measurement of financial assets and financial liabilities as defined in IAS 39. The standard is effective for annual periods beginning on or after January 1, 2015. In subsequent phases, the IASB will address hedge accounting and impairment of financial assets. The Company does not expect changes to its financial statements on the adoption of this standard.

- IFRS 10 "Consolidated Financial Statements", IFRS 11 "Joint Arrangements" and IFRS 12 "Disclosure of Interests in Other Entities" were issued in May 2011.

  IFRS 10 provides a single consolidation model that identifies control as the basis for consolidation for all types of entities. IFRS 10 replaces IAS 27 "Consolidated and Separate Financial Statements" and SIC-12 "Consolidation – Special Purpose Entities".

  IFRS 11 establishes principles for the financial reporting by parties to a joint arrangement. IFRS 11 supersedes IAS 31 "Interests in Joint Ventures" and SIC-13 "Jointly Controlled Entities – Non-monetary Contributions by Venturers".

  IFRS 12 combines, enhances and replaces the disclosure requirements for subsidiaries, joint arrangements, associates and unconsolidated structured entities. As a consequence of these new IFRS, the IASB also issued amended and re-titled IAS 27 "Separate Financial Statements" and IAS 28 "Investments in Associates and Joint Ventures". The new requirements are effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The Company does not expect changes to its financial statements on the adoption of those standards.

- IFRS 13 "Fair Value Measurement" was issued in May 2011. IFRS 13 defines fair value, sets out in a single IFRS a framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 applies when other IFRS require or permit fair value measurements. It does not introduce any new requirements to measure an asset or a liability at fair value, change what is measured at fair value in IFRS or address how to present changes in fair value. The new requirements are effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The Company does not expect changes to its financial statements on the adoption of this standard.

5. PROPERTY, PLANT AND EQUIPMENT

($ thousands)	**2012**	2011
Cost, beginning of year	**510,787**	461,264
Accumulated depletion and depreciation, beginning of year	**(100,120)**	(49,145)
Net carrying amount, beginning of year	**410,667**	412,119
Additions	**86,148**	99,132
Disposals	**(36,546)**	(32,435)
Change in asset retirement obligation	**15,758**	790
Assets transferred from intangible exploration	**241**	182
Impairment loss	**(37,321)**	(18,867)
Exchange differences	**(778)**	683
Depletion and depreciation	**(48,198)**	(50,937)
Net carrying amount, end of year	**389,971**	410,667
Cost, end of year	**535,791**	510,787
Accumulated depletion and depreciation, end of year	**(145,820)**	(100,120)
Net carrying amount, end of year	**389,971**	410,667

(a) Depletion, Depreciation and Impairment charge:

The depletion, depreciation and impairment of property, plant and equipment, and any eventual reversal thereof, are recognized in depletion and depreciation and impairment loss in the consolidated statement of earnings/(loss) and comprehensive income/(loss) (see also Note 7).

Property, plant and equipment are not depleted and depreciated for major development projects until production commences. For the year ended December 31, 2012, $6.48 million of 2012 major development project property, plant and equipment was not depleted.

(b) Security:

At December 31, 2012 and 2011, a $300 million demand debenture on assets of the Company has been provided as security for the Company's syndicated committed credit facilities.

(c) Contingencies:

Although the Company believes that it has title to its oil and natural gas properties, it cannot control or completely protect itself against the risk of title disputes or challenges.

For the year ended December 31, 2012, $0.33 million (2011 – $0.53 million) of direct and incremental general and administrative expenses were capitalized to property, plant and equipment.

For the year ended December 31, 2012, the Company disposed of certain assets for gross cash proceeds of $36.77 million (2011 – $32.44 million), resulting in a gain of $20.82 million (2011 – $19.17 million).

6. INTANGIBLE EXPLORATION AND EVALUATION ASSETS AND GOODWILL

($ thousands)	Goodwill	E&E assets	Total
Cost:			
Balance at December 31, 2010	2,969	27,708	30,677
Additions	–	1,123	1,123
Transfers to property, plant and equipment	–	(182)	(182)
Exploration and evaluation expense	–	(3,480)	(3,480)
Exchange differences	–	15	15
Balance at December 31, 2011	**2,969**	**25,184**	**28,153**
Additions	–	**1,803**	**1,803**
Disposals	–	**(220)**	**(220)**
Transfers to property, plant and equipment	–	**(241)**	**(241)**
Exploration and evaluation expense	–	**(6,539)**	**(6,539)**
Exchange differences	–	**(19)**	**(19)**
Balance at December 31, 2012	**2,969**	**19,968**	**22,937**

Exploration and evaluation assets consist of the Company's undeveloped land which are pending the determination of proved or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the year.

(a) Impairment charge:

The impairment of intangible exploration assets and intangible assets, and any eventual reversals therefore, and goodwill, are recognized as impairment expense in the consolidated statement of earnings and comprehensive income. There was no impairment of exploration and evaluation assets or goodwill during the year. Goodwill is allocated to one CGU and its value is supported by the excess recoverable amount over the carrying amount of that CGU.

(b) Recoverability of exploration and evaluation assets:

The Company assesses the recoverability of intangible E&E assets, before and at the moment of reclassification to property, plant and equipment, at the CGU level. The CGU includes both E&E assets and D&P assets for the relevant area, but is not larger than an operating segment.

7. IMPAIRMENT LOSS

As at December 31, 2012, the Company tested its CGUs, as defined under IFRS, for impairment. Low crude oil and natural gas prices as well as the write off of certain natural gas reserves resulted in impairment of two Alberta and one Saskatchewan CGUs out of the eight Company CGUs. The E&E assets associated with these CGUs were not included in this impairment test and were tested separately.

The recoverable amount of the CGUs was estimated based on their fair value less costs to sell. The estimate of fair value less costs to sell was determined using an after-tax discount rate of 10 percent and forecasted cash flows. The forecasted cash flows are prepared over the estimated life of the reserves in the CGUs. The prices used to estimate the fair value less cost to sell are those used by McDaniel and Associates Consultants Ltd., our independent reserve engineers.

The following commodity price estimates were used to determine the recoverable amount:

Year	WTI Oil ($US/bbl) (1)	AECO Gas ($Cdn/mmbtu) (1)	$US/$Cdn Exchange Rates (1)
2013	92.50	3.35	1.000
2014	92.50	3.85	1.000
2015	93.60	4.35	1.000
2016	95.50	4.70	1.000
2017	97.40	5.10	1.000
2018	99.40	5.45	1.000
2019	101.40	5.55	1.000
2020	103.40	5.70	1.000
2021	105.40	5.80	1.000
2022	107.60	5.90	1.000
2023	109.70	6.00	1.000
2024	111.90	6.15	1.000
2025	114.10	6.25	1.000
2026	116.40	6.35	1.000
2027	118.80	6.50	1.000
Remainder (2)	2.0%	2.0%	1.000

(1) Source: McDaniel & Associates Consultants Ltd. price forecast effective January 1, 2013.

(2) Percentage change represents the change in each year after 2027 to the end of the reserve life.

Based on the assessment on December 31, 2012, the carrying amount of the three CGUs were determined to be $14.45 million lower than their recoverable amount, and an impairment loss was recognized. In addition to the December 31, 2012 impairment, the Company recognized impairment at June 30, 2012 of $22.87 million which totals to $37.32 million of impairment losses in 2012. In 2011, the Company determined there was $27.01 million in impairment and $8.14 in reversals of impairment. No impairment losses from prior years were reversed in 2012.

The above estimates are particularly sensitive in the following areas:

- A one percent increase in the discount rate used would have increased the impairment loss by $9.42 million.
- A 10 percent decrease in future planned cash flows would have increased the impairment loss by $16.99 million.

8. CASH DIVIDENDS

During the year, the Company declared dividends to the shareholders in the aggregate amount of $31.95 million (2011 – $44.64 million) in accordance with the following schedule:

2012 Dividends (1)	Record Date	Dividend Date	Per Common Share
January	January 31, 2012	February 15, 2012	$0.10
February	February 29, 2012	March 15, 2012	$0.10
March	March 31, 2012	April 16, 2012	$0.10
April	April 30, 2012	May 15, 2012	$0.10
May	May 31, 2012	June 15, 2012	$0.10
June	June 30, 2012	July 16, 2012	$0.10
July	July 31, 2012	August 15, 2012	$0.10
August	August 31, 2012	September 17, 2012	$0.10
September	September 30, 2012	October 15, 2012	$0.10
October	October 31, 2012	November 15, 2012	$0.06
November	November 30, 2012	December 17, 2012	$0.06
December	December 31, 2012	January 15, 2013	$0.06

(1) The 2012 cash dividends include a non-cash equity issuance amount of $4.60 million for the Dividend Reinvestment Plan.

During the 2012 third quarter, the Company announced, effective for October and the subsequent months, the monthly dividend had been set at $0.06 per share.

Subsequent to the end of the period and prior to the consolidated financial statements being authorized for issue on March 12, 2013, the Company declared dividends of $1.79 million or $0.06 per share for each of January and February of 2013.

2011 Dividends (1)	Record Date	Dividend Date	Per Common Share
January	January 31, 2011	February 15, 2011	$0.14
February	February 28, 2011	March 15, 2011	$0.14
March	March 31, 2011	April 15, 2011	$0.14
April	April 30, 2011	May 16, 2011	$0.14
May	May 31, 2011	June 15, 2011	$0.14
June	June 30, 2011	July 15, 2011	$0.14
July	July 31, 2011	August 15, 2011	$0.14
August	August 31, 2011	September 15, 2011	$0.14
September	September 30, 2011	October 17, 2011	$0.14
October	October 31, 2011	November 15, 2011	$0.10
November	November 30, 2011	December 15, 2011	$0.10
December	December 31, 2011	January 16, 2012	$0.10

(1) The 2011 cash dividends include a non-cash equity issuance amount of $6.50 million for the Dividend Reinvestment Plan.

During the 2011 third quarter, the Company announced, effective for October and the subsequent months, the monthly dividend had been set at $0.10 per share.

9. PROVISIONS

($ thousands)	Asset retirement obligations	Other	Total
Balance at December 31, 2011	**96,596**	**881**	**97,477**
Provisions made during the year	**3,763**	**–**	**3,763**
Foreign exchange and other	**(203)**	**–**	**(203)**
Provisions used during the year	**(2,639)**	**–**	**(2,639)**
Provisions related to dispositions	**(4,755)**	**–**	**(4,755)**
Revisions to estimated provisions	**16,750**	**–**	**16,750**
Accretion	**2,771**	**–**	**2,771**
Balance at December 31, 2012	**112,283**	**881**	**113,164**
Current	**–**	**881**	**881**
Non-current	**112,283**	**–**	**112,283**

($ thousands)	Asset retirement obligations	Other	Total
Balance at December 31, 2010	96,395	–	96,395
Provisions made during the year	12,027	1,270	13,297
Foreign exchange and other	45	–	45
Provisions used during the year	(3,849)	(389)	(4,238)
Provisions related to dispositions	(1,140)	–	(1,140)
Revisions to estimated provisions	(10,097)	–	(10,097)
Accretion	3,215	–	3,215
Balance at December 31, 2011	96,596	881	97,477
Current	–	881	881
Non-current	96,596	–	96,596

Asset retirement obligations:

The Company's asset retirement obligation results from net ownership interests in petroleum and natural gas assets, including well sites, gathering systems and processing facilities. Zargon estimates the undiscounted value of its total asset retirement obligations to be $135 million as at December 31, 2012. These obligations are expected to be incurred over the next 50 years. The asset retirement obligation is calculated using a discount factor being the risk-free rate related to the liability and is based on the Government of Canada long term bond rate. At the end of the second quarter of 2012, the discount factor of 3.0 percent was reduced to 2.5 percent based on the Government of Canada long term bond rate. Accordingly, Zargon recorded an adjustment to property, plant and equipment and the asset retirement obligation. An inflation rate of two percent per annum used in the calculation of the present value of the asset retirement obligation remains unchanged.

Other:

Zargon is subject to normal course income tax audits by Canadian and US taxation authorities. During the fourth quarter of 2010, the Canada Revenue Agency commenced a flow-through share audit of a predecessor company from a prior corporate acquisition. In the first quarter of 2011, Zargon recorded a $1.27 million provision which was comprised of a $0.92 million charge to current income tax expense and a $0.35 million charge to interest expense for the related Part XII.6 tax, with respect to this ongoing flow-through share audit. The interest expense related to the Part XII.6 tax has been paid to the Canada Revenue Agency and the remaining provision is currently $0.88 million.

10. LONG TERM BANK DEBT

On June 14, 2012, Zargon amended and renewed its syndicated committed credit facilities, the result of which was the reduction of the available facilities and borrowing base to $165 million. A $300 million demand debenture on the assets of the Company has been provided as security for these facilities. The facilities are fully revolving for a 377 day period with the provision for an annual extension at the option of the lenders and upon notice from Zargon's Management. The next renewal date is June 26, 2013, with a semi-annual review that took place in the fall of 2012. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 377 day period. Repayment would not be required until the end of the non-revolving term, and, as such, these facilities have been classified as long term debt.

Interest rates fluctuate under the syndicated facilities with Canadian prime, US prime and US base rates plus an applicable margin between 50 basis points and 200 basis points as well as with Canadian banker's acceptance and LIBOR rates plus an applicable margin between 200 basis points and 350 basis points. At December 31, 2012, $35.74 million (December 31, 2011 - $92.70 million) had been drawn on the syndicated committed credit facilities with any unused amounts subject to standby fees. In the normal course of operations Zargon enters into various letters of credit. At December 31, 2012, the approximate value of outstanding letters of credit totalled $0.71 million (December 31, 2011 - $0.60 million). The letters of credit reduce the amount of Zargon's available credit facilities to $128.55 million at December 31, 2012 (December 31, 2011 - $86.70 million).

Zargon reviews its compliance with its bank debt covenants on a quarterly basis and is in compliance as at December 31, 2012.

11. CONVERTIBLE DEBENTURES

On May 1, 2012, Zargon completed the issuance of convertible unsecured subordinated debentures for gross proceeds of $50.00 million (net proceeds of $47.45 million after transaction costs) at a price of $1,000 per debenture. On May 4, 2012, Zargon completed the issuance of the over-allotment of the convertible unsecured subordinated debentures for gross proceeds of $7.50 million (net proceeds of $7.20 million) at a price of $1,000 per debenture. The debentures bear interest at a rate of six percent per annum, which is payable semi-annually, in arrears, on June 30 and December 31 of each year commencing on December 31, 2012. The debentures mature on June 30, 2017 and can be converted into common shares of Zargon at the option of the holders at a conversion price of $18.80 per common share.

After June 30, 2015, Zargon may redeem the debentures in whole or in part provided the common shares' weighted average trading price during a specified period prior to redemption is not less than 125 percent of the conversion price.

The debentures have been classified as debt, net of issuance costs with the residual value allocated to shareholders' equity. The issuance costs will be amortized over the term of the debentures and the debt portion will accrete up to the principal balance at maturity. The accretion of the convertible debentures and the interest paid are expensed on the consolidated statements of earnings and comprehensive income.

($ thousands)	December 31, 2012
Principal, December 31, 2011	–
Issuance	57,500
Principal, December 31, 2012	57,500
Debt component, December 31, 2011	–
Issuance, net of transaction costs	50,460
Accretion of convertible debentures	801
Debt component, December 31, 2012	51,261
Equity component, December 31, 2011	–
Issuance, net of transaction costs and deferred tax	3,640
Equity component, December 31, 2012	3,640

12. CAPITAL DISCLOSURES

The Company's capital structure is comprised of shareholders' equity plus long term bank debt and convertible debentures. The Company's objectives when managing its capital structure are to:

a) Maintain financial flexibility so as to preserve Zargon's access to capital markets and its ability to meet its financial obligations; and

b) Finance internally generated growth as well as acquisitions.

The Company monitors its capital structure and short term financing requirements using a non-GAAP financial metric, which is the ratio of debt net of working capital ("net debt") to funds flow from operating activities. Net debt, as used by Zargon, is calculated as bank debt plus the full future face value of the convertible debenture of $57.50 million and any working capital deficit excluding the unrealized derivative assets/liabilities. Funds flow from operating activities represent net earnings/loss and asset retirement expenditures except for non-cash items. The metric is used to steward the Company's overall debt position as a measure of the Company's overall financial strength and is calculated as follows:

($ thousands, except ratio)	**December 31, 2012**	December 31, 2011
Net debt	**113,175**	109,498
Funds flow from operating activities	**56,661**	60,666
Net debt to funds flow from operating activities ratio	**2.00**	1.80

As at December 31, 2012, Zargon's net debt to funds flow from operating activities ratio was 2.00, an increase from 1.80 at December 31, 2011. Bank debt levels decreased during the year as a result of Zargon closing a convertible unsecured subordinated debenture and transactions to sell select properties in Manitoba and southeast Saskatchewan. On June 14, 2012, Zargon amended and renewed its syndicated committed credit facilities, the result of which was the reduction of the available facilities and borrowing base from $180 million to $165 million. The next renewal date is June 26, 2013. These facilities continue to be available for general corporate purposes and the potential acquisition of oil and natural gas properties.

To manage its capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, issue new shares, issue new debt or repay existing debt.

The Company's capital management objectives, evaluation measures, definitions and targets have remained unchanged over the periods presented. Zargon reviews its compliance with its bank debt covenants on a quarterly basis and is in compliance as at December 31, 2012.

13. SHARE CAPITAL

The Company is authorized to issue an unlimited number of voting common shares and 10,000,000 preferred shares.

Zargon has a Dividend Reinvestment Plan ("DRIP") in place in conjunction with the Company's transfer agent to provide the option for shareholders to reinvest cash dividends into common shares issued from treasury at a five percent discount to the prevailing market price.

Common Shares

	December 31, 2012	
(thousands)	**Number of Shares**	**Amount ($)**
Balance, as at December 31, 2011	**29,360**	**249,470**
Share options exercised for cash	**18**	**106**
Share-based compensation transferred from contributed surplus on exercise of share options	**–**	**221**
Issued pursuant to the Dividend Reinvestment Plan	**490**	**4,603**
Balance, as at December 31, 2012	**29,868**	**254,400**

Common Shares

(thousands)	December 31, 2011 Number of Shares	Amount ($)
Balance, as at December 31, 2010	27,046	201,091
Share options exercised for cash	202	3,539
Share-based compensation transferred from contributed surplus on exercise of share options	–	881
Issued pursuant to the Dividend Reinvestment Plan	387	6,504
Equity issuance	1,725	38,985
Issue costs, net of deferred tax effect of $524	–	(1,530)
Balance, as at December 31, 2011	29,360	249,470

14. SHARE-BASED PAYMENTS

Share Award Plan

On December 15, 2010, a new share-based compensation plan (the “Share Award Plan”) was approved and was effective January 1, 2011. Under the Share Award Plan, directors, officers, employees and other service providers (the “grantees”) are granted the right to receive a defined number of shares in the future, which increases commensurately with each dividend declared by the Company after the grant date. The grantees will receive equity compensation in relation to the value of a specified number of underlying Share Awards. The awards vest equally over four years and expire five years after grant date. Holders may choose to exercise upon vesting or at any time thereafter, with forfeiture of any shares not exercised by the expiry date. Upon vesting, the grantees are eligible to receive a share award based on the fair value of the underlying Share Award’s plus all notional dividends accrued since the grant date. Zargon uses a fair value methodology to value the share awards.

Due to the nature of the plan, Zargon is required to estimate the forfeiture rate upon initial calculation of fair values. The forfeiture rate is estimated at three percent while the interest rate and volatility is set at a historical rate as there is no exercise price.

The following table summarizes information about the Company’s share awards under the Share Award Plan:

	December 31, 2012 Number of Share Awards (thousands)	December 31, 2011 Number of Share Awards (thousands)
Outstanding at beginning of year	**158**	–
Share awards granted	**229**	184
Share awards exercised	**(9)**	(4)
Share awards forfeited	**(56)**	(22)
Outstanding at end of the year	**322**	158
Share awards exercisable at end of year	**31**	–

Common Share Rights Incentive Plans

In conjunction with the corporation conversion, Zargon’s two original Trust Unit Rights Incentive Plans were amended and restated as Common Share Rights Incentive Plans. Under these plans, directors, officers, employees and other service providers of the Company possess rights to acquire common shares at their option of either the original exercise price or a “modified price” as calculated per the provisions of the relevant plan. The Common Share Rights Incentive Plan (2007) (the “Old Plan”) provides for a modified price based on the increment of the amount by which monthly dividends exceed a monthly return of 0.833 percent of the Company’s recorded net book value of oil and natural gas properties (as defined in the Old Plan). Under the Common Share Rights Incentive Plan (2009) (the “New Plan”), if the monthly dividend exceeds the monthly return of 0.833 percent of the Company’s recorded net book value of oil and natural gas properties (as defined under the New Plan), the entire amount (not the increment) of the dividend is deducted from the original grant price. Options granted under either Plan generally vest equally over a three-year period and expire approximately five years from the grant date. Zargon uses a fair value methodology to value the option grants.

The following table summarizes information about the Company's share options under the Old Plan:

	December 31, 2012		December 31, 2011	
	Number of Share Options (thousands)	**Weighted Average Exercise Price Initial and Modified ($/share)**	Number of Share Options (thousands)	Weighted Average Exercise Price Initial and Modified ($/share)
Outstanding at beginning of year	**409**	**24.24 / 22.02**	738	25.61 / 23.10
Share options exercised	**(3)**	**13.42**	(114)	20.89
Share options expired	**(211)**	**25.36**	(145)	31.49
Share options forfeited	**(25)**	**22.73**	(70)	25.07
Outstanding at end of the year	**170**	**23.23 / 21.40**	409	24.24 / 22.02
Share rights exercisable at end of year	**170**	**23.23 / 21.40**	409	24.24 / 22.02

The following table summarizes information about the Company's share options under the New Plan:

	December 31, 2012		December 31, 2011	
	Number of Share Options (thousands)	**Weighted Average Exercise Price Initial and Modified ($/share)**	Number of Share Options (thousands)	Weighted Average Exercise Price Initial and Modified ($/share)
Outstanding at beginning of year	**537**	**18.12 / 14.51**	708	18.03 / 15.64
Share options granted	–	–	–	–
Share options exercised	**(6)**	**10.82**	(85)	13.65
Share options forfeited	**(73)**	**18.57**	(86)	18.62
Outstanding at end of the year	**458**	**18.08 / 14.44**	537	18.12 / 14.51
Share rights exercisable at end of year	**372**	**17.70 / 13.89**	245	17.51 / 13.64

The following tables summarize information about share rights outstanding at December 31, 2012:

For the Old Plan at the initial grant price:

	Share Options Outstanding			Share Options Exercisable	
Range of Exercise Prices ($/share option)	**Number Outstanding (thousands)**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price ($/share option)**	**Number Exercisable (thousands)**	**Weighted Average Exercise Price ($/share option)**
14.93 – 21.55	**63**	**0.1 years**	**21.55**	**63**	**21.55**
22.10	**49**	**0.1 years**	**22.10**	**49**	**22.10**
26.00 – 26.10	**58**	**0.1 years**	**26.00**	**58**	**26.00**
	170		**23.23**	**170**	**23.23**

For the Old Plan at the modified price:

	Share Options Outstanding			Share Options Exercisable	
Range of Exercise Prices ($/share option)	**Number Outstanding (thousands)**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price ($/share option)**	**Number Exercisable (thousands)**	**Weighted Average Exercise Price ($/share option)**
13.42 – 19.85	**63**	**0.1 years**	**19.85**	**63**	**19.85**
20.12	**49**	**0.1 years**	**20.12**	**49**	**20.12**
24.14 – 24.30	**58**	**0.1 years**	**24.14**	**58**	**24.14**
	170		**21.40**	**170**	**21.40**

For the New Plan at the initial grant price:

Range of Exercise Prices ($/share option)	Share Options Outstanding Number Outstanding (thousands)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price ($/share option)	Share Options Exercisable Number Exercisable (thousands)	Weighted Average Exercise Price ($/share option)
15.56	**160**	**1.1 years**	**15.56**	**160**	**15.56**
15.80	**8**	**1.1 years**	**15.80**	**8**	**15.80**
17.31	**13**	**1.1 years**	**17.31**	**13**	**17.31**
17.70 – 19.85	**277**	**2.1 years**	**19.63**	**191**	**19.59**
	458		**18.08**	**372**	**17.70**

For the New Plan at the modified price:

Range of Exercise Prices ($/share option)	Share Options Outstanding Number Outstanding (thousands)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price ($/share option)	Share Options Exercisable Number Exercisable thousands)	Weighted Average Exercise Price ($/share option)
10.82	**160**	**1.1 years**	**10.82**	**160**	**10.82**
11.33	**8**	**1.1 years**	**11.33**	**8**	**11.33**
13.21	**13**	**1.1 years**	**13.21**	**13**	**13.21**
14.09 – 17.95	**277**	**2.1 years**	**16.68**	**191**	**16.62**
	458		**14.44**	**372**	**13.89**

Share-Based Compensation

The share awards for the year ended December 31, 2012, together with the continued vesting of options granted in prior years, resulted in share-based compensation expense in 2012 of $2.13 million (2011 – $2.21 million).

Compensation expense associated with awards/options granted under each Plan is recognized in earnings over the vesting period of the Plan with a corresponding increase in contributed surplus. The exercise of awards/options is recorded as an increase in common shares with a corresponding reduction in contributed surplus.

15. FINANCIAL INSTRUMENTS

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgement.

The following table shows the comparison of the carrying and fair value of the company's financial instruments:

	December 31, 2012		December 31, 2011	
	Carrying Amount ($)	**Fair Value ($)**	Carrying Value ($)	Fair Value ($)
Loans and receivables:				
Trade and other receivables	**16,660**	**16,660**	22,373	22,373
Fair value through profit and loss:				
Derivative assets	**4,798**	**4,798**	977	977
Derivative liabilities	**263**	**263**	6,345	6,345
Other liabilities:				
Trade and other payables	**35,777**	**35,777**	37,450	37,450
Cash dividends	**1,656**	**1,656**	2,493	2,493
Long term bank debt	**35,736**	**35,736**	92,703	92,703
Convertible debentures	**51,261**	**57,500**	–	–

The Company is exposed to financial risks arising from its financial assets and liabilities. The financial risks include market risk (commodity prices, interest rates and foreign exchange rates), credit risk and liquidity risk.

- Market Risk

  Market risk is the risk that the fair value of future cash flows of financial assets or liabilities will fluctuate due to movements in market prices and is comprised of the following:

  - Commodity Price Risk

  Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result in changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, but also world economic events that dictate the levels of supply and demand. As a means of mitigating exposure to commodity price risk volatility, the Company has entered into various derivative agreements. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is to not use derivative financial instruments for speculative purposes.

  Natural Gas – To partially mitigate the natural gas commodity price risk, the Company may enter into swaps, which fix the Canadian dollar AECO prices.

  Crude Oil – The Company has partially mitigated its exposure to the WTI NYMEX price with fixed price swaps.

  - Interest Rate Risk

  Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. Borrowings under bank credit facilities are market rate based (variable interest rates); thus, carrying values approximating fair values.

  At the December 31, 2012 debt pricing levels, the increase or decrease in net earnings for the year for each one percent change in interest rates would amount to $0.55 million (2011 - $0.92 million) before swaps.

  - Foreign Exchange Risk

  Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. The underlying market prices in Canada for petroleum and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollar. As Zargon operates in North America, fluctuations in the exchange rate between the US/Canadian dollar can have a significant effect on the Company's reported results. A $0.01 change in the US to Canadian dollar exchange rate would have resulted in a $0.80 million (2011 - $0.92 million) increase or decrease in net earnings for the year ended December 31, 2012. In order to mitigate the Company's exposure to foreign exchange fluctuations, the Company may enter into foreign exchange derivative agreements.

- Credit Risk

  Credit risk is the risk that the counterparty to a financial asset will default, resulting in the Company incurring a financial loss. This credit exposure is mitigated with credit practices that limit transactions according to counterparties' credit quality. A substantial portion of the Company's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks.

  The maximum credit risk exposure associated with accounts receivable and derivative assets is the total carrying value. The Company monitors these balances monthly to limit the risk associated with collection. Of Zargon's accounts receivable at December 31, 2012, approximately 45 percent (December 31, 2011 – 49 percent) was owing from two companies and Zargon anticipates full collection.

  The Company's allowance for doubtful accounts at December 31, 2012 was $0.25 million (December 31, 2011 – $0.26 million).

When determining whether amounts that are past due are collectible, management assesses the credit worthiness and past payment history of the counterparty, as well as the nature of the past due amount. Zargon considers all material amounts greater than 90 days to be past due. As at December 31, 2012, $1.06 million of accounts receivable are past due, excluding amounts described above, all of which are considered to be collectable.

- Liquidity Risk

  Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company manages its liquidity risk through funds flow and debt management. See Note 12 for a more detailed discussion.

  As at December 31, 2012, Zargon had available unused committed bank credit facilities of approximately $128.55 million compared to $86.70 million at December 31, 2011. The Company believes it has sufficient funding through the use of these facilities to meet foreseeable borrowing requirements.

The timing of cash outflows relating to financial liabilities are outlined in the table below:

($ thousands)	1 year	2–5 years	Total
Accounts payable and accrued liabilities	**35,777**	**–**	**35,777**
Cash dividends payable	**1,656**	**–**	**1,656**
Derivative liabilities	**72**	**191**	**263**
Long term bank debt	**–**	**35,736**	**35,736**
Convertible debenture [1]	**–**	**57,500**	**57,500**

(1) Amount is the full face value of the convertible debenture at $57.50 million.

Commodity Price Sensitivities

The following summarizes the sensitivity of the fair value of the Company's risk management positions to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, the Company believes 10 percent volatility is a reasonable long term measure.

Fluctuations of 10 percent in commodity prices could have resulted in unrealized gains or losses of $7.67 million (2011 – $9.57 million) on risk management contracts impacting net earnings.

16. DERIVATIVES

The Company is a party to certain financial instruments that have fixed the price of a portion of its oil production and interest rates. The Company enters into these contracts for risk management purposes only in order to protect a portion of its future cash flows from the volatility of oil and natural gas commodity prices and interest rates. For financial risk management contracts, the Company considers these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and, accordingly, any unrealized gains or losses are recorded in earnings based on the fair value (mark-to-market) of the contracts at each reporting period. The unrealized gain on the statement of earnings and comprehensive income for 2012 was $9.90 million and the unrealized gain for 2011 was $8.45 million.

As at December 31, 2012, the Company had the following outstanding commodity and interest risk management contracts:

Commodity Financial Risk Management Contracts:

	Rate	Weighted Average Price	Range of Terms	Fair Market Value Asset ($ thousands)
Oil swaps	500 bbl/d	$103.12 US/bbl	Jan. 1/13 – Mar. 31/13	499
	600 bbl/d	$100.12 US/bbl	Jan. 1/13 – Jun. 30/13	817
	1,200 bbl/d	$99.31 US/bbl	Jan. 1/13 – Dec. 31/13	2,713
	200 bbl/d	$97.90 US/bbl	Jan. 1/13 – Jun. 30/14	533
	200 bbl/d	$93.80 US/bbl	Apr. 1/13 – Dec. 31/13	19
	200 bbl/d	$96.20 US/bbl	Jul. 1/13 – Jun. 30/14	217
Total Fair Market Value, Commodity Price Financial Contracts				**4,798**

Oil swaps are settled against the NYMEX WTI pricing index.

Interest Rate Risk Management Contracts:

	Notional Value	Interest Rate (1)	Range of Terms	Fair Market Value Liability ($ thousands)
Interest rate swaps	$20,000,000/month	1.640%	Jan. 1/13 – Jul. 26/16	(65)
	$20,000,000/month	1.731%	Jan. 1/13 – Aug. 26/16	(198)
Total Fair Market Value, Interest Rate Financial Contracts				**(263)**

(1) Excludes the current stamping fee of 2.5% for each swap.

Interest rate swaps are reset monthly and settled against the BA-CDOR interest rate index.

17. INCOME TAX EXPENSE

The provision for income taxes in the consolidated statements of earnings/(loss) and comprehensive income/(loss) reflect an effective tax rate which differs from the expected statutory tax rate. Differences were accounted for as follows:

($ thousands)	**2012**	2011
Earnings/(loss) before tax	**(7,192)**	16,242
Expected tax rate	**25.45%**	26.95%
Expected income taxes expense/(recovery)	**(1,830)**	4,377
Add (deduct) income tax effect of:		
Rate adjustments	**(587)**	(32)
Withholding taxes	–	303
Permanent differences and other	**602**	1,214
Total income tax expense/(recovery)	**(1,815)**	5,862

The decrease in the statutory rate from 2011 to 2012 was due to a reduction in the 2011 Canadian corporate tax rate as part of a series of corporate rate reductions previously enacted by the Canadian government in 2007.

As at December 31, Zargon's estimated tax pools are as follows:

($ thousands)	2012	2011
Canadian oil and natural gas property expenses	**8,862**	43,134
Canadian development expenses	**80,545**	65,919
Canadian exploration expenses	**67,210**	63,535
Capital cost allowance	**59,633**	63,613
Non-capital losses	**112,347**	129,452
US tax pools	**1,739**	1,270
Partnership deferral	**(22,854)**	(25,378)
Other	**5,822**	4,252
	313,304	345,797

The Company has capital losses of approximately $0.55 million (December 31, 2011 - $0.55 million) which may be applied against future capital gains for Canadian tax purposes. The allowable capital losses can be carried forward indefinitely. The benefit of these losses has not been recognized as they have not been deemed more likely than not to be recoverable.

The Company has tax allowances of approximately $1.70 million (December 31, 2011 - $1.70 million) which may be applied against future income for Canadian tax purposes. These allowances are not subject to expiry. The benefit of these allowances has not been recognized as they have not been deemed more likely than not to be recovered.

The Company has non-capital losses of approximately $9.70 million (December 31, 2011 - $9.70 million) which may be applied against future income for Canadian tax purpose. These non-capital losses are subject to expiry within 20 years. The benefit of these losses has not been recognized as they have not been deemed more likely than not to be recovered.

The movement in deferred tax balances during the years ended December 31, 2012 and 2011 are as follows:

2012	Balance December 31, 2011	Recognized in earnings	Recognized on Balance Sheet	Balance December 31, 2012
Property, plant and equipment and intangible assets	**(54,675)**	**2,572**	**–**	**(52,103)**
Convertible debentures	**–**	**204**	**(1,276)**	**(1,072)**
Unrealized portion of derivative assets	**(249)**	**316**	**–**	**67**
Deferred partnership earnings	**(7,657)**	**2,713**	**–**	**(4,944)**
Non-capital losses	**30,476**	**(4,358)**	**–**	**26,118**
Decommissioning obligations	**25,609**	**4,142**	**–**	**29,751**
Unrealized portion of derivative liabilities	**1,615**	**(2,836)**	**–**	**(1,221)**
Share issue costs	**610**	**(299)**	**725**	**1,036**
Foreign exchanges	**–**	**(230)**	**230**	**–**
Other liabilities	**300**	**158**	**–**	**458**
Net deferred tax asset/(liability)	**(3,971)**	**2,382**	**(321)**	**(1,910)**

2011	Balance December 31, 2010	Recognized in earnings (1)	Recognized on Balance Sheet	Balance December 31, 2011 (1)
Property, plant and equipment and intangible assets	(44,049)	(10,626)	–	(54,675)
Unrealized portion of derivative assets	–	(249)	–	(249)
Deferred partnership earnings	(9,399)	1,742	–	(7,657)
Non-capital losses	23,221	7,255	–	30,476
Decommissioning obligations	24,848	761	–	25,609
Unrealized portion of derivative liabilities	3,724	(2,109)	–	1,615
Share issue costs	355	(268)	523	610
Foreign exchanges	–	230	(230)	–
Other liabilities	153	147	–	300
Net deferred tax asset/(liability)	(1,147)	(3,117)	293	(3,971)

(1) Certain 2011 balances have been reclassified compared to the 2011 Annual Financial Report.

18. PERSONNEL EXPENSES

The Company provides salaries and benefits to its officers as well as director fees to its directors. Directors and officers also participate in the Company's share-based payment compensation programs. Key Management Personnel Compensation is comprised of the following:

Directors and Officers:

($ thousands)	**2012**	2011
Short term employee benefits	**3,050**	2,878
Share-based payments (1)	**1,160**	710
	4,210	3,588

(1) Represents the amortization of share-based payment compensation granted to directors and officers as recorded in the consolidated financial statements and discussed further in Note 14.

19. EARNINGS/(LOSS) PER SHARE

Basic and diluted net earnings/(loss) per share have been calculated as follows:

(thousands)	**2012**	2011
Net earnings for diluted net earnings/(loss) per share calculation	**(5,377)**	10,380
Weighted average number of common shares – basic	**29,606**	28,630
Dilutive impact of share right incentive plans and share award plan	**–**	139
Weighted average number of common shares – diluted	**29,606**	28,769

The average market value of the Company's shares for purposes of calculating the dilutive effect of share options was based on quoted market prices for the period that the options were outstanding. Basic per share amounts are calculated using the weighted average number of shares outstanding during the period. Diluted per share amounts are calculated using the treasury stock method to determine the dilutive effect of share-based compensation. Due to the fact that at the time of exercise, the shareholder has the option of exercising at the original grant price or a modified price as calculated under both the Old Plan and the New Plan, the prices used in the dilution calculation are the lower prices calculated under the Old Plan and New Plan.

The convertible debenture could potentially dilute basic earnings per share, but were not included in the calculation of diluted earnings per share because they are antidilutive for the period ended December 31, 2012.

20. CHANGE IN NON-CASH FLOW INFORMATION

The net change in working capital is comprised of:

($ thousands)	**2012**	2011
Source/(use) of cash:		
Trade and other receivables	**5,713**	510
Deposits and prepaid expenses	**(59)**	535
Trade and other payables	**(1,673)**	7,019
Cash dividends payable	**(837)**	(1,257)
Provisions	**–**	881
Foreign exchange and other	**(149)**	312
	2,995	8,000
Related to operating activities	**2,210**	12,590
Relating to investing activities	**1,622**	(3,333)
Related to financing activities	**(837)**	(1,257)
	2,995	8,000

21. SUPPLEMENTAL CASH FLOW INFORMATION

($ thousands)	**2012**	2011
Cash interest paid	**5,148**	5,522
Cash taxes paid	**361**	958

22. SIGNIFICANT SUBSIDIARIES

The Company has the following significant wholly owned, directly or indirectly, subsidiaries which are incorporated in Canada:

Subsidiary Name	The Company's effective interest (%)
Zargon Energy Ltd.	100
Zargon Oil & Gas Partnership	100
Zargon U.S. Holdings Ltd.	100
Ashton Oil & Gas Ltd.	100

Additionally, the Company has the following significant wholly owned, directly or indirectly, subsidiaries incorporated in the United States:

Subsidiary Name	The Company's effective interest (%)
Zargon Acquisition Inc.	100
Zargon Oil (ND) Inc.	100

23. RELATED PARTY TRANSACTIONS

Zargon paid $0.21 million (2011 – $0.25 million) for legal services to a law firm of which a Board member is a partner. These payments were in the normal course of operations, were made on commercial terms and, therefore, were recorded at their fair value. As at December 31, 2012, there was $0.12 million (2011 - $0.11 million) in payables to a law firm of which a Board member is a partner. There were no purchases, loans or accounts payable with key management personnel.

For Key Management Personnel Compensation, refer to Note 18.

24. SEGMENTED INFORMATION

Zargon's entire operating activities are related to exploration, development and production of oil and natural gas in the geographic regions of Canada and the US.

	2012		
($ thousands)	**Canada**	**United States**	**Combined**
Petroleum and natural gas sales	**144,785**	**13,160**	**157,945**
Segment profit/(loss)	**(2,301)**	**4,048**	**1,747**
Earnings/(losses) before income taxes	**(10,959)**	**3,767**	**(7,192)**
Impairment loss	**(37,321)**	**–**	**(37,321)**
Property and equipment, net	**353,866**	**36,105**	**389,971**
Intangible exploration and evaluation assets and goodwill	**21,593**	**1,344**	**22,937**
Total assets	**405,110**	**39,995**	**445,105**
Net capital expenditures	**26,069**	**4,178**	**30,247**

	2011		
($ thousands)	Canada	United States	Combined
Petroleum and natural gas sales	175,458	16,075	191,533
Segment profit	17,638	7,050	24,688
Earnings before income taxes	9,329	6,913	16,242
Impairment loss	(18,867)	–	(18,867)
Property and equipment, net	376,210	34,457	410,667
Intangible exploration and evaluation assets and goodwill	27,217	936	28,153
Total assets	433,767	36,920	470,687
Net capital expenditures	46,978	1,670	48,648

Zargon derives over 90 percent of its revenue from six significant oil and natural gas purchasers.

25. COMMITMENTS AND CONTINGENCIES

In the normal course of operations, Zargon executes agreements that provide for indemnification and guarantees to counterparties in transactions such as the sale of assets and operating leases.

These indemnifications and guarantees may require compensation to counterparties for costs and losses incurred as a result of various events, including breaches of representations and warranties, loss of or damages to property, environmental liabilities or as a result of litigation that may be suffered by counterparties.

Certain indemnifications can extend for an unlimited period and generally do not provide for any limit on the maximum potential amount. The nature of substantially all of the indemnifications prevents the Company from making a reasonable estimate of the maximum potential amount that might be required to pay counterparties as the agreements do not specify a maximum amount, and the amounts depend on the outcome of future contingent events, the nature and likelihood of which cannot be determined at this time.

The Company indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their services to the Company to the extent permitted by law. The Company has acquired and maintains liability insurance for its directors and officers. The Company is party to various legal claims associated with the ordinary conduct of business. The Company does not anticipate that these claims will have a material impact on its financial position.

The Company is committed to future minimum payments for natural gas transportation sales commitments, Alkaline Surfactant Polymer purchase commitments and operating leases for office space and office equipment. Payments required under these commitments are as follows:

(thousands)	December 31, 2012
Less than one year	**4,068**
Between one and five years	**2,885**
	6,953

Zargon is subject to normal course income tax audits by Canadian and US taxation authorities. During the fourth quarter of 2010, the Canada Revenue Agency commenced a flow-through share audit of a predecessor company from a prior corporate acquisition. During the first quarter of 2011, Zargon recorded a $1.27 million provision which was comprised of a $0.92 million charge to current income tax expense and $0.35 million charge to interest expense for the related Part XII.6 tax, with respect to this ongoing flow-through share audit. The interest expense related to the Part XII.6 tax has been paid to the Canada Revenue Agency and the remaining provision is currently $0.88 million (see Note 9).

CORPORATE INFORMATION

Board of Directors

Craig H. Hansen
Calgary, Alberta

K. James Harrison [2]
Chairman of the Board
Oakville, Ontario

Kyle D. Kitagawa [1]
Calgary, Alberta

Margaret A. McKenzie [1]
Calgary, Alberta

Geoffrey C. Merritt [1]
Calgary, Alberta

Jim Peplinski [2]
Calgary, Alberta

J. Graham Weir [1]
Calgary, Alberta

Grant A. Zawalsky [2]
Calgary, Alberta

Officers

Craig H. Hansen
President and Chief Executive Officer

Leslie E. Burden
Vice President, Land

Randolph J. Doetzel
Vice President, Operations

Jason B. Dranchuk
Vice President, Finance and
Chief Financial Officer

Tracy L. Howard
Corporate Secretary

Christopher M. Hustad
Vice President, Alberta Plains South

Pete H.S. Janjua
Vice President, Williston Basin

Brian G. Kergan
Vice President, Corporate Development

Kevin C.Y. Lee
Vice President, Alberta Plains North

Robert T. Moriyama
Vice President, Enhanced Recovery

(1) Audit and Reserves Committee
(2) Governance and Compensation Committee

Stock Exchange Listing

Toronto Stock Exchange

Zargon Oil & Gas Ltd.
Common Shares
Trading Symbol: ZAR

Zargon Oil & Gas Ltd.
Convertible Debentures
Trading Symbol: ZAR.DB

Transfer Agent

Valiant Trust Company
310, 606 – 4th Street S.W.
Calgary, Alberta T2P 1T1

Bankers

The Toronto Dominion Bank
910, 333 – 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Canadian Imperial Bank of Commerce
9th Floor, Bankers Hall East
855 – 2nd Street S.W.
Calgary, Alberta T2P 2P2

The Bank of Nova Scotia
2000, 700 – 2nd Street S.W.
Calgary, Alberta T2P 2N7

Legal Counsel

Burnet, Duckworth & Palmer LLP
2400, 525 – 8th Avenue S.W.
Calgary, Alberta T2P 1G1

Consulting Engineers

McDaniel & Associates Consultants Ltd.
2200, 255 – 5th Avenue S.W.
Calgary, Alberta T2P 3G6

Auditors

Ernst & Young LLP
1000, 440 – 2nd Avenue S.W.
Calgary, Alberta T2P 5E9

Head Office

700, 333 – 5th Avenue S.W.
Calgary, Alberta T2P 3B6
Telephone: 403-264-9992
Fax: 403-265-3026
Email: zargon@zargon.ca

Website

www.zargon.ca

ZARGON
OIL & GAS LTD.

700, 333 – 5th Avenue S.W.
Calgary, AB T2P 3B6
telephone: 403.264.9992

www.zargon.ca