ZARGON
O I L & G A S L T D.

2013 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
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 2013 financial results and should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2013 and 2012. The 2013 and 2012 consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), 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 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 11, 2014, 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 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 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 2014 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 11, 2014.

ABOUT ZARGON OIL & GAS LTD.

Zargon Oil & Gas Ltd. (“the Company” or “Zargon”) is a publicly traded dividend-paying corporation incorporated in Canada with its head office located in Calgary, Alberta. The Company is engaged in the exploration, development and production of oil and natural gas in Canada and the United States (“US”).

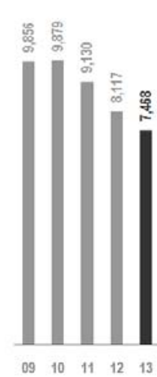
2013 HIGHLIGHTS

- For calendar 2013, funds flow from operating activities of $58.48 million ($1.95 per basic share) was three percent higher than the $56.66 million ($1.91 per basic share) recorded in the prior year.
- Oil and liquids production averaged 4,870 barrels of oil and liquids per day in 2013, a seven percent decrease from the preceding year as production additions from the 2013 drilling and exploitation activities were offset by property dispositions. Natural gas production averaged 15.59 million cubic feet per day in 2013, a nine percent decrease from 2012 reflecting natural occurring production declines and the continued curtailment of natural gas capital programs. Total 2013 production averaged 7,468 barrels of oil equivalent per day, an eight percent decrease from the prior year, a level that reflected significant property sales, a modest focused oil exploitation capital program, an ASP facility construction project that provides for significant future production growth and the beneficial effect of our low decline property base.
- Zargon declared cash dividends totalling $0.72 per common share during 2013 for a total of $21.61 million ($20.35 million net of the Dividend Reinvestment Plan (“DRIP”)). These cash dividends (net of the DRIP) were equivalent to a payout ratio of 35 percent of funds flow from operating activities. As previously reported, Zargon has suspended the DRIP until further notice starting with the September 2013 dividend.
- Net capital expenditures for the year totalled $41.74 million; consisting of $76.16 million of exploitation, development and facility programs and $0.03 million of administrative assets which was offset by $34.45 million of net property dispositions. The $76.16 million of exploitation, development and facility programs include $35.33 million of Alkaline Surfactant Polymer (“ASP”) project costs, which will provide significant oil production gains in 2015 and beyond. During the year, Zargon drilled 16.6 net wells yielding 13.6 net oil wells and 3.0 net ASP related service wells. Excluding the ASP project, Zargon’s 2014 net capital expenditures were a modest $6.41 million.
- Zargon’s December 31, 2013 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 $116.24 million, was approximately 1.99 times 2013 funds flow from operating activities, and was up three percent from the 2012 year end net debt of $113.18 million. At December 31, 2013, Zargon had approximately $125 million of unutilized credit facilities available.

Oil and Liquids Production
(bbl/d)

Natural Gas Production
(mmcf/d)

Production
(boe/d)



Financial Highlights

($ millions, except for per share amounts)	**2013**	2012	2011
Petroleum and natural gas sales	**158.65**	157.95	191.53
Funds flow from operating activities	**58.48**	56.66	60.67
Per share – basic	**1.95**	1.91	2.11
Cash flows from operating activities	**57.00**	58.87	73.26
Per share – basic	**1.90**	1.99	2.55
Net earnings/(loss)	**(5.90)**	(5.38)	10.38
Per share – diluted	**(0.20)**	(0.18)	0.36
Total assets	**452.98**	445.11	470.69
Net capital expenditures (1)	**41.74**	30.25	48.65
Long term bank debt	**39.97**	35.74	92.70
Convertible debentures (2)	**57.50**	57.50	–
Cash dividends (3)	**20.35**	27.35	38.14

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

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

(3) *Cash dividends represent the cash portion only and do not include equity issued through the DRIP which was suspended September 2013.*

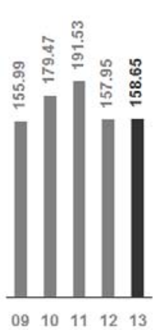
Production Highlights

	2013	2012	2011
Oil and liquids production (bbl/d)	**4,870**	5,255	5,468
Natural gas production (mmcf/d)	**15.59**	17.17	21.97
Production (boe/d)	**7,468**	8,117	9,130
Oil weighting (%)	**65**	65	60

DETAILED FINANCIAL ANALYSIS

Petroleum and Natural Gas Sales

Petroleum and Natural Gas Sales
($ millions)



($ millions)	**2013**	2012	Percent Change
Petroleum sales	**141.97**	144.38	(2)
Natural gas sales	**16.68**	13.57	23
Petroleum and natural gas sales	**158.65**	157.95	–

Petroleum and natural gas sales, exclusive of the impact of financial risk management contracts, were $158.65 million in 2013 compared to $157.95 million in 2012. Higher commodity prices in 2013 were offset by lower production. For 2013, the relative weighting of production revenue from oil and liquids decreased to 89 percent (91 percent in 2012) with 11 percent coming from the sale of natural gas (nine percent in 2012). Average production volumes in 2013 decreased to 7,468 barrels of oil equivalent per day compared to the prior year's 8,117 barrels of oil equivalent per day. Of the 7,468 barrels of oil equivalent per day of production volumes in 2013, oil and liquids were 65 percent (35 percent natural gas), unchanged from 2012.

Natural gas production in 2013 decreased nine percent, and oil and liquids production decreased seven percent from 2012 levels. Oil and liquids production declines were due to the 2013 property dispositions and naturally occurring production declines that were partially offset by ongoing oil exploitation programs. 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 increased to $79.88 per barrel in 2013, up six percent from $75.07 per barrel in 2012. The average Zargon realized field price of natural gas was $2.93 per thousand cubic feet in 2013, a 36 percent increase from $2.16 per thousand cubic feet realized in 2012.

Production by Core Area

	2013			2012		
	Oil and Liquids (bbl/d)	**Natural Gas (mmcf/d)**	**Equivalents (boe/d)**	Oil and Liquids (bbl/d)	Natural Gas (mmcf/d)	Equivalents (boe/d)
Alberta Plains North	**1,288**	**12.48**	**3,368**	1,355	13.87	3,667
Alberta Plains South	**1,661**	**2.75**	**2,119**	1,717	2.86	2,193
Williston Basin	**1,921**	**0.36**	**1,981**	2,183	0.44	2,257
	4,870	**15.59**	**7,468**	5,255	17.17	8,117

Pricing

Average for the period	**2013**	2012	2011
Natural Gas:			
NYMEX average daily spot price ($US/mmbtu)	**3.72**	2.75	4.00
AECO average daily spot price ($Cdn/mmbtu)	**3.17**	2.39	3.63
Zargon realized field price before the impact of financial risk management contracts ($Cdn/mcf) (1)	**2.93**	2.16	3.45
Zargon realized field price before the impact of physical and financial risk management contracts ($Cdn/mcf) (1)	**2.93**	2.16	3.45
Zargon realized field price after the impact of physical and financial risk management contracts ($Cdn/mcf) (1)	**2.94**	2.18	3.45
Zargon realized natural gas field price differential (1) (2)	**0.24**	0.23	0.18
Zargon realized natural gas field price differential before the impact of physical and financial risk management contracts	**0.24**	0.23	0.18
Crude Oil:			
WTI ($US/bbl)	**97.97**	94.21	95.10
Edmonton par price ($Cdn/bbl)	**92.96**	86.15	95.06
Zargon realized field price before the impact of financial risk management contracts ($Cdn/bbl)	**79.88**	75.07	82.09
Zargon realized field price after the impact of financial risk management contracts ($Cdn/bbl)	**79.71**	75.02	76.19
Zargon realized oil field price differential (3)	**13.08**	11.08	12.97

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

(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 2011.

(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. In 2013, Zargon's average oil and liquids field price, exclusive of the impact of financial risk management contracts, increased six percent to $79.88 per barrel from $75.07 per barrel in 2012 and was three percent lower than the $82.09 per barrel received in 2011. The field price differential for

Oil and Liquid Prices
($/bbl)

Zargon's average blended 27 degree API crude stream was $13.08 per barrel less than the 2013 Edmonton reference crude price, which compares to the 2012 differential of $11.08 per barrel and the 2011 differential of $12.97 per barrel.

Natural Gas Pricing

Natural Gas Prices
($/mcf)

The average field natural gas price for 2013 increased to $2.93 per thousand cubic feet, which is 36 percent higher than the 2012 average of $2.16 per thousand cubic feet (before the impact of financial risk management contracts) and 15 percent lower than the 2011 average of $3.45 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 2013 field price differential for Zargon's natural gas was a discount of $0.24 per thousand cubic feet, compared to discounts of $0.23 and $0.18 per thousand cubic feet (exclusive of the impact of physical and financial risk management contracts) in 2012 and 2011, respectively.

Royalties

($ millions)	**2013**	2012	Percent Change
Royalties	**29.33**	30.14	(3)
Percentage of revenue	**18.5%**	19.1%	

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 2013, total royalties were $29.33 million, a decrease of three percent from $30.14 million in 2012. The variations in royalty rates generally track changes in production volumes and prices. As a percentage of gross sales, royalties were 18.5 percent in 2013 compared to 19.1 percent in 2012 and 17.7 percent in 2011. On a commodity basis, natural gas royalties averaged 11.3 percent in 2013, a decrease from the previous year's average of 15.3 percent which was affected by adjustments to the Gas Cost Allowance. Oil royalties averaged 19.3 percent, down slightly from the prior year rate of 19.4 percent.

During 2013, 59 percent (2012 – 58 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 $1.01 million in 2013, a slight increase from $1.00 million in the prior year and a decrease from $1.19 million in 2011. North Dakota state oil production/extraction taxes decreased to $0.92 million in 2013 from $0.93 million in the prior year primarily due to 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 certain percentage of its estimated before royalty production volumes for each commodity up to a 30 month period. Zargon's policy permits for the sale of up to a 70 percent maximum of estimated before royalty production volumes for oil for the first 12 months, a 60 percent maximum on the following 12 months and a 50 percent maximum on the final six months. Zargon's policy permits for the sale of up to a 60 percent maximum of estimated before royalty production volumes for natural gas for the first 24 months and a 50 percent maximum on the final six months. The commodity price risk management policy is maintained for 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 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 2.00 percent) and two physical electricity hedges.

For 2013, the total realized derivative loss was $0.46 million; compared to a loss of $0.14 million in 2012 and a loss of $11.83 million in 2011. For 2013, there was a $0.30 million loss (equivalent to a decrease of $0.11 per barrel of oil equivalent) from oil financial risk management transactions, a $0.03 million gain (equivalent to an increase of $0.01 per barrel of oil equivalent) from natural gas financial risk management transactions and a $0.19 million loss (equivalent to a decrease of $0.06 per barrel of oil equivalent) from interest rate swaps. Oil swaps are settled against the NYMEX WTI pricing index, natural gas swaps and basis hedges 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 2013 net unrealized derivative loss totalled $9.72 million, which compares to a $9.90 million net unrealized derivative gain in 2012 (2011 – $8.45 million gain). Specifically, the 2013 net unrealized derivative gain resulted from financial oil contract losses ($9.60 million), financial gas contract losses ($0.22 million) and financial interest rate swap gains ($0.10 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/(loss) and their fair value is reflected in "derivative assets" or "derivative liabilities" on the consolidated balance sheet.

The electricity rate hedges are physical contracts and, therefore, do not have a mark-to-market and are included as part of operating costs. As a result of the contracts being physical contracts, there are no realized and unrealized gains or losses on the contracts.

As at December 31, 2013, the Company had the following outstanding commodity, basis, interest and electricity rate risk management contracts:

Commodity Financial Risk Management Contracts:

	Rate	Weighted Average Price	Range of Terms
Oil swaps	400 bbl/d	$96.33 US/bbl	Jan. 1/14 – Mar. 31/14
	1,200 bbl/d	$95.59 US/bbl	Jan. 1/14 – Jun. 30/14
	1,400 bbl/d	$90.30 US/bbl	Jan. 1/14 – Dec. 31/14
	400 bbl/d	$91.73 US/bbl	Apr. 1/14 – Mar. 31/15
	400 bbl/d	$90.00 US/bbl	Jul. 1/14 – Dec. 31/14
	400 bbl/d	$99.60 Cdn/bbl	Jul. 1/14 – Dec. 31/14
Natural gas swaps	6,000 gj/d	$3.33 Cdn/gj	Jan. 1/14 – Mar. 31/14
	3,000 gj/d	$3.59 Cdn/gj	Apr. 1/14 – Oct. 31/14

AECO Basis Natural Gas Risk Management Contract:

	Rate	Weighted Average Price	Range of Terms
NYMEX-AECO basis	6,000 MMBtu/d	$(0.485) US/MMBtu	Apr. 1/14 – Oct. 31/14

Interest Rate Financial Risk Management Contracts:

	Notional Value	Interest Rate (1)	Range of Terms
Interest rate swaps	$20,000,000/month	1.640%	Jan. 1/14 – Jul. 26/16
	$20,000,000/month	1.731%	Jan. 1/14 – Aug. 26/16

(1) *Excludes the current stamping fee of 2.00 percent for each swap.*

Electricity Physical Risk Management Contracts:

	Rate	Price	Range of Terms
Electricity forwards	1.5 MW/d	$54.81/MWh	Jan. 1/14 – Dec. 31/15
	2.0 MW/d	$52.55/MWh	Jan. 1/14 – Dec. 31/15

Operating Expenses and Transportation Expenses

($ millions)	2013	2012	Percent Change
Operating expenses	**46.22**	47.28	(2)
Transportation expenses	**1.79**	1.57	14
Total	**48.01**	48.85	(2)
Total ($/boe)	**17.61**	16.44	7

Zargon's operating expenses decreased two percent to $46.22 million in 2013 from $47.28 million in 2012 due to fewer (post disposition) properties and was partially offset by higher Alberta electricity costs and repairs and maintenance expenditures. Transportation expenses increased 14 percent to $1.79 million from $1.57 million in 2012. On a per unit of production basis, operating and transportation expenses increased seven percent to $17.61 per barrel of oil equivalent from $16.44 in 2012 due to the combined effect of relatively stable costs and lower production volumes. For 2014, Zargon forecasts that the summation of operating and transportation expenses (inclusive of the Little Bow ASP project) will average approximately $18.00 per barrel of oil equivalent.

Natural gas operating expenses in 2013 increased eight percent to $2.14 per thousand cubic feet from $1.99 per thousand cubic feet in 2012 due mainly to the decrease in production volumes and limited capital expenditures on natural gas wells.

Oil operating and transportation expenses increased in 2013 to $20.16 per barrel, an increase of seven percent from $18.90 per barrel in 2012. The primary reason for the increase is a reduction of oil production volumes from properties with fixed cost operations as well as higher electricity costs.

Operating Netbacks

	2013		2012	
	Oil and Liquids ($/bbl)	**Natural Gas ($/mcf)**	Oil and Liquids ($/bbl)	Natural Gas ($/mcf)
Sales	**79.88**	**2.93**	75.07	2.16
Royalties	**(15.44)**	**(0.33)**	(14.60)	(0.33)
Realized gain/(loss) on derivatives	**(0.17)**	**0.01**	(0.05)	0.02
Operating expenses	**(19.16)**	**(2.14)**	(18.09)	(1.99)
Transportation expenses	**(1.00)**	–	(0.81)	–
Operating netbacks	**44.11**	**0.47**	41.52	(0.14)

The average oil and liquids price received, after realized derivative gains/losses, in 2013 of $79.71 per barrel was six percent higher than the $75.02 per barrel received in 2012. The average natural gas price received, after realized derivative gains/losses, in 2013 of $2.94 per thousand cubic feet was 35 percent higher than the $2.18 per thousand cubic feet received in 2012. Oil and liquids netbacks at $44.11 per barrel were up slightly from $41.52 per barrel in 2012 due to higher prices offset partially by lower production volumes. Natural gas netbacks increased to $0.47 per thousand cubic feet from a $0.14 loss per thousand cubic feet in 2012 due to an increase in natural gas prices. On a barrel of oil equivalent basis, overall 2013 operating netbacks increased to $29.67 from $26.53 in 2012.

General and Administrative Expenses

($ millions, except as noted)	**2013**	2012	2011
Gross general and administrative expenses	**14.77**	16.76	19.92
Overhead recoveries	**(3.27)**	(3.21)	(4.11)
Net general and administrative expenses	**11.50**	13.55	15.81
Net expense after recoveries ($/boe)	**4.22**	4.56	4.74
Number of office employees at year end	**42**	45	64

Gross general and administrative expenses ("G&A") decreased 12 percent in 2013 to $14.77 million from $16.76 million in 2012. On a per unit of production basis, net G&A expenses decreased seven percent to $4.22 per barrel of oil equivalent compared to $4.56 per barrel of oil equivalent in 2012 and $4.74 in 2011. G&A expenses decreased in 2013 due to reductions in salaries and wages from prior year staff reorganization and administrative reductions. G&A expenses also include one-time employment related costs of $0.42 million or $0.15 per barrel of oil equivalent. For 2014, Zargon forecasts that G&A expenses, exclusive of transaction costs or other one-time adjustments will average approximately $4.50 per barrel of oil equivalent.

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, 2013, transaction costs were $0.48 million, or $0.18 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, 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.

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 $2.34 million or $0.86 per barrel of oil equivalent compared to $3.06 million or $1.03 per barrel of oil equivalent in 2012 and $5.23 million in 2011. The decrease in interest and financing charges is a result of a convertible debenture financing in May 2012 which reduced the average outstanding bank debt, proceeds from the 2013 property dispositions and lower interest rates due to lower debt pricing levels. Zargon's effective interest and financing charge rate was 4.9 percent on an average outstanding bank debt of $47.45 million in 2013, compared to 5.1 percent on an average bank debt of $59.98 million in 2012, and 5.5 percent on an average bank debt of $94.68 million in 2011. The decrease in the 2013 average bank debt levels was the result of the property divestiture program and the full year effect of the 2012 convertible debenture financing in 2013 which reduced the average outstanding debt. At year end 2013, Zargon's bank debt, net of working capital (excluding unrealized derivative assets/liabilities) and including the full $57.50 million convertible debentures, totalled $116.24 million, up three percent from $113.18 million at December 31, 2012. The increase in net debt at the end of 2013 is due to an active fourth quarter drilling program and ASP capital expenditures. 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 and mature on June 30, 2017. Interest is payable semi-annually at a rate of six percent, calculated on the gross proceeds of $57.50 million. The interest charges for 2013 were $3.45 million or $1.27 per barrel of oil equivalent. For more information on Zargon's convertible debentures, see the "Convertible Debentures" section of this report.

Funds Flow Netbacks
($/boe)

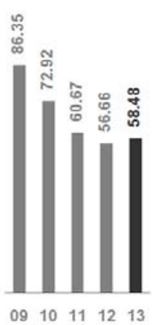
Current Taxes

Current income taxes for 2013 were $0.81 million compared to $0.57 million in 2012. When compared to the prior period, current income taxes increased $0.24 million primarily as a result of decreased United States ("US") field drilling expenditures in North Dakota.

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 $0.40 million at December 21, 2013.

Tax pools as at December 31, 2013 were approximately $310 million, down from the $313 million of tax pools available to Zargon at the end of 2012. This one percent decrease is due primarily from 2013 property dispositions. The Company is a taxable entity under the *Income Tax Act* (Canada); however, based on the current forward commodity strip, the Company is currently exempt from paying cash taxes in Canada.

Funds Flow from Operating Activities
($ millions)

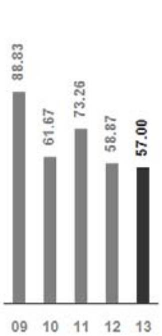


For Canadian income tax purposes, all 2013 cash dividends paid or to be paid on Zargon's common shares are designated as "eligible dividends".

Corporate Netbacks

($/boe)	**2013**	2012	2011
Petroleum and natural gas sales	**58.20**	53.16	57.47
Royalties	**(10.76)**	(10.14)	(10.19)
Realized derivative gain/(loss)	**(0.16)**	(0.05)	(3.55)
Operating expenses	**(16.96)**	(15.92)	(16.68)
Transportation expenses	**(0.65)**	(0.52)	(0.51)
Operating netbacks	**29.67**	26.53	26.54
General and administrative expenses	**(4.22)**	(4.56)	(4.74)
Transaction costs	**(0.18)**	(0.01)	(0.05)
Interest and financing charges	**(0.86)**	(1.03)	(1.57)
Interest on convertible debentures	**(1.27)**	(0.78)	–
Asset retirement expenditures	**(1.39)**	(0.89)	(1.16)
Current income taxes	**(0.30)**	(0.19)	(0.82)
Funds flow netbacks	**21.45**	19.07	18.20

Cash Flows from Operating Activities
($ millions)



Operating netbacks in 2013 increased compared to 2012. On a barrel of oil equivalent basis, revenue of $58.20 in 2013 was nine percent higher than 2012, while operating netbacks increased to $29.67 and funds flow netbacks increased 12 percent to $21.45 per barrel of oil equivalent.

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

In 2013, increased revenue as well as lower royalties, operating and general and administrative expenses were partially offset by an increase in interest costs related to the convertible debenture, an increased loss of realized derivative contracts and higher asset retirement expenditures which resulted in a three percent increase in funds flow from operating activities to $58.48 million, compared to $56.66 million in 2012 and $60.67 million in 2011. The corresponding funds flow per basic share was $1.95 in 2013, a two percent increase from $1.91 in 2012 and an eight percent decrease from $2.11 in 2011. The basic per share statistics reflect a one percent increase in the weighted average outstanding shares to 30.02

million in 2013 from 29.61 million in 2012. The 2012 weighted average outstanding shares were also three percent higher than the 2011 amount of 28.63 million.

Depletion and Depreciation

In 2013, Zargon's depletion and depreciation expense decreased six percent to $45.36 million, compared to $48.20 million in 2012. The lower charges reflect a three percent increase in the charge on a per barrel of oil equivalent basis due to lower volumes, property dispositions in 2013 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 2013 depletion calculation includes $37.95 million of future capital expenditures (excluding future ASP capital expenditures) to develop the Company's reserves, but excludes $13.33 million of unproven properties relating to E&E assets.

Property, plant and equipment are not depleted and depreciated for major development projects until production commences. For the year ended December 31, 2013, $42.45 million (2012 – $6.48 million) of major development project property was not depleted or depreciated.

Zargon's depletion and depreciation, on a barrel of oil equivalent basis, increased three percent in 2013 to $16.64 from $16.22 in 2012 and increased nine percent from the 2011 rate of $15.29.

Accretion of Asset Retirement Obligations and Convertible Debentures

For the year ended December 31, 2013, the non-cash accretion expense for asset retirement obligations was $2.80 million compared to $2.77 million in 2012 and $3.22 million in 2011. The year-over-year increase is due to changes in the estimated future liability for asset retirement obligations. The significant assumptions used in this calculation are a risk-free rate of 2.50 percent, an inflation rate of two percent and payments to settle the retirement obligations occurring over the next 55 years, with the majority of the costs being incurred after 2022. At the end of the fourth quarter of 2013, the discount factor of 2.50 percent was increased to 3.25 percent based on the Government of Canada long term bond rate. The estimated net present value of the total asset retirement obligation was $135 million as at December 31, 2013, based on a total future liability of $196 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 2013 is $1.22 million.

Share-Based Compensation

Share-based compensation was $1.72 million in 2013, $0.41 million lower than the $2.13 million expense in 2012 due to the lower value of new grants in 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.

Under the Common Share Rights Incentive 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”) expired in the first quarter of 2013. 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 in the New Plan), the entire amount (not the increment) of the dividend 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.

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. Zargon uses a fair value methodology to value these share awards. The Company is authorized to issue up to an aggregate of 2.50 million share awards; 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, 2013, Zargon had 0.56 million of share awards outstanding.

Unrealized Foreign Exchange

An unrealized foreign exchange gain of $0.15 million in 2013 compared to a loss of $0.02 million in 2012. 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).

Losses on Disposal of Assets

As a result of the 2013 property dispositions, the Company had losses of $1.73 million (2012 - $20.82 million gain) on disposals of capital assets in its consolidated statement of earnings/(loss) and comprehensive income/(loss).

Exploration and Evaluation Expenses

Exploration and evaluation expenses for 2013 were $4.01 million, and were $2.53 million lower than the $6.54 million incurred in 2012. Exploration and evaluation expenses were the result of land expiries and mostly related to expiries in west central and northern Alberta.

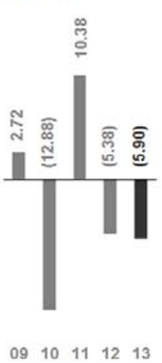
Impairment Loss

As at December 31, 2013, 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. 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, 2013, the carrying amount of the two CGUs were determined to be $4.39 million higher than their recoverable amount, and an impairment loss was recognized. In 2012, the Company determined there was $37.32 million in impairment. No impairment losses from prior years were reversed in 2013.

Net Earnings/ (Loss)
($ millions)



Deferred Taxes

The provision for the deferred tax recovery for 2013 was $2.64 million when compared to a deferred tax recovery of $2.38 million in 2012 and an expense of $3.12 million in 2011. The 2013 deferred tax recovery, when compared to the 2012 prior year recovery, is impacted by a further net loss in 2013 compared to 2012, which resulted from the decrease in petroleum and natural gas production and losses on unrealized derivatives.

Net Loss

Zargon's 2013 net loss was $5.90 million, a 10 percent increase from the net loss of $5.38 million in 2012. The 2011 net earnings were $10.38 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 2013 were primarily related to depletion and depreciation, unrealized derivative losses, losses on disposal on properties, impairment losses and exploration and evaluation expense. On a per diluted share basis, the 2013 net loss was $0.20 compared to a net loss of $0.18 in 2012 and net earnings of $0.36 in 2011.

The 2013 net loss was a negative 10 percent of funds flow from operating activities, an increase over 2012 when the net loss represented a negative nine percent of funds flow from operating activities. The net earnings were a positive 17 percent of funds flow from operating activities in 2011.

Capital Expenditures

Total net capital expenditures (including net property dispositions) in 2013 of $41.74 million increased 38 percent from $30.25 million in 2012, while Zargon's field capital expenditure program increased 18 percent in 2013 to $76.16 million from $64.69 million in 2012. Field capital expenditures include ASP project expenditures of $35.33 million in 2013 compared to $6.48 million in 2012. In 2013, Zargon drilled 19 gross (16.6 net) wells compared to 34 gross (27.8 net) wells in 2012. Drilling and completion expenditures decreased by 50 percent to $17.43 million due to fewer wells drilled in 2013. The 2013 drilling program yielded 13.6 net oil wells for a success ratio of 100 percent. The remaining 3.0 net wells were service wells related to the ASP project. Of the total 2013 field capital expenditures (excluding net property dispositions), $13.32 million were expended on Alberta Plains North, $44.47 million on Alberta Plains South (including ASP project expenditures) and $18.37 million on Williston Basin properties. Additionally, $0.03 million was incurred corporately on leasehold improvements and administrative assets. These expenditures were partially offset by $34.45 million of net property dispositions.

Zargon sanctioned the construction of the ASP oil exploitation project facility at the Little Bow oil property in Alberta during Q1 2013. The ASP project entails the injection of large volumes of dilutive chemical solution into a partially depleted oil reservoir to recover incremental oil reserves.

Capital Expenditures

($ millions)	**2013**	2012	2011
Undeveloped land	**4.36**	5.45	6.24
Geological and geophysical (seismic)	**1.27**	2.63	4.15
Drilling and completion of wells	**17.43**	35.11	43.10
Well equipment and facilities	**17.77**	15.02	17.53
ASP project	**35.33**	6.48	0.64
Exploration and development	**76.16**	64.69	71.66
Property acquisitions	**0.49**	2.27	9.07
Property dispositions	**(34.94)**	(36.77)	(32.44)
Net property dispositions	**(34.45)**	(34.50)	(23.37)
Total net capital expenditures excluding administrative assets	**41.71**	30.19	48.29
Administrative assets	**0.03**	0.06	0.36
Total net capital expenditures	**41.74**	30.25	48.65

PROPERTY ACQUISITIONS/DISPOSITIONS

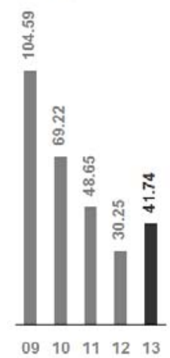
During 2013, Zargon completed property acquisitions and dispositions totalling net dispositions of $34.45 million, which consisted of $0.49 million of acquisitions and $34.94 million of dispositions. Property dispositions were primarily related to the disposal of certain assets in northern and southern Alberta as well as southeast Saskatchewan. There were no significant acquisitions during 2013.

LIQUIDITY AND CAPITAL RESOURCES

In 2013, the summation of the funds inflows coming from the funds flow from operating activities ($58.48 million) and the increase in bank debt of $4.23 million exceeded the summation of the funds outflows

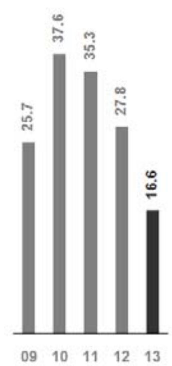
Net Capital Expenditures

($ millions)



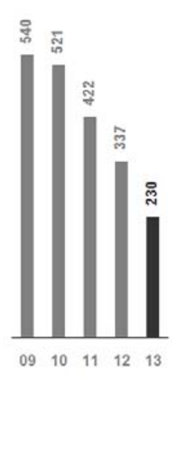
Drilling Activity

(net wells)



Undeveloped Land

(thousand net acres)



pertaining to the net capital expenditure program ($41.74 million) and the cash dividends to shareholders ($20.35 million) by $0.62 million compared to a negative $3.26 million in 2012.

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 to shareholders;
- Debt may be utilized for acquisitions or to expand capital programs when it is deemed appropriate. As at December 31, 2013, the Company had $165 million in syndicated committed credit facilities of which approximately $125 million or 76 percent was unutilized; and
- New equity, if available on favourable terms, can be utilized for acquisitions or to expand capital programs.

Cash Dividends Analysis

($ millions)	**2013**	2012	2011
Cash flows from operating activities	**57.00**	58.87	73.26
Net earnings/(loss)	**(5.90)**	(5.38)	10.38
Cash dividends relating to the period (1)	**(20.35)**	(27.35)	(38.14)
Excess of cash flows from operating activities over cash dividends	**36.65**	31.52	35.12
Excess (shortfall) of net earnings over cash dividends	**(26.25)**	(32.73)	(27.76)

(1) Cash dividends represent the cash portion only and do not include equity issued through the DRIP which was suspended September 2013.

Zargon has maintained a monthly dividend of $0.06 per common share since October 2012. 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.

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, 2013, cash flows from operating activities (after changes in non-cash working capital) of $57.00 million exceeded cash dividends of $20.35 million. In 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.

For the year ended December 31, 2013, cash dividends of $20.35 million exceeded a net loss of $5.90 million. The net loss included significant non-cash charges, particularly unrealized risk management losses, losses 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, 2012, cash dividends of $27.35 million exceeded a net loss of $5.38 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, 2013, cash dividends and net capital expenditures totalled $62.09 million, which was $5.09 million higher than cash flows from operating activities (after changes in non-cash working capital) of $57.00 million. 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. 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.

Prior to suspension, pursuant to the DRIP, Canadian shareholders were entitled to reinvest monthly cash dividends in additional shares of the Company. At the discretion of the Company, these additional shares were issued from Treasury at 95 percent of the "weighted average closing price". For the purposes of the shares issued, the "weighted average closing price" was calculated as the weighted average trading price of shares for the five days prior to the dividend payment date. For 2013, the DRIP participation rate was six percent compared to a 2012 rate of 14 percent. The DRIP was suspended starting with the September 2013 dividend paid on October 15, 2013.

Capital Sources and Uses

($ millions)	**2013**	2012	2011
Funds flow from operating activities	**58.48**	56.66	60.67
Change in long term bank debt	**4.23**	(56.97)	(22.58)
Issuance of convertible debentures, net of transaction costs	**–**	54.65	–
Issuance of common shares	**–**	0.11	40.47
Cash dividends to shareholders [1]	**(20.35)**	(27.35)	(38.14)
Changes in working capital and other	**(0.62)**	3.15	8.23
Total capital sources	**41.74**	30.25	48.65

(1) Cash distributions represent the cash portion only and do not include equity issued through the DRIP which was suspended September 2013.

Funds Flow from Operating Activities

It is anticipated that Zargon's 2014 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 2014 estimated sensitivity to moderate fluctuations in these key business parameters (excluding derivative contracts) is shown in the accompanying table.

Funds Flow Sensitivity Summary

	Change in 2014 Funds Flow ($ millions)	($/share)
Change of $1.00 US/bbl in the price of WTI oil	1.31	0.04
Change in oil production of 100 bbl/d	1.45	0.05
Change of $0.10 US/mcf in the price of NYMEX natural gas	0.44	0.01
Change in natural gas production of one mmcf/d	0.29	0.01
Change of $0.01 in the $US/$Cdn exchange rate	1.10	0.04

Long Term Bank Debt

On June 10, 2013, Zargon amended and renewed its syndicated committed credit facilities, the result of which was the maintaining of the available facilities and borrowing base of $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 364 day period with the provision for an annual extension at the option of the lenders and upon notice from Zargon's Management. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 364 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. These facilities continue to be available for general corporate purposes and the potential acquisition of additional oil and natural gas properties.

For the 2014 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 (2012 – 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 (2012 – 200 and 350 basis points, respectively).

At December 31, 2013, $39.97 million (December 31, 2012 - $35.74 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, 2013.

In the normal course of operations, Zargon enters into various letters of credit. At December 31, 2013, the approximate value of outstanding letters of credit totalled $0.87 million (December 31, 2012 - $0.71 million).

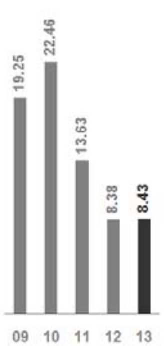
Zargon's debt, net of working capital (excluding unrealized derivative assets/liabilities) of $116.24 million at December 31, 2013 was equivalent to 1.99 times 2013 funds flow from operating activities of $58.48 million. At December 31, 2012, the debt net of working capital (excluding unrealized derivative assets/liabilities) was $113.18 million, equivalent to 2.00 times 2012 funds flow from operating activities of $56.66 million.

Convertible Debentures

In addition to its long term bank debt, Zargon has borrowings through its convertible debentures, which were issued in May 2012 and mature on June 30, 2017. Interest is payable semi-annually at a rate of six percent, calculated on the gross proceeds of $57.50 million.

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 11, 2014, Zargon Oil & Gas Ltd. had 30.095 million common shares outstanding. Pursuant to the common share rights incentive plans and the share award plan, there are currently an additional 0.944 million common share incentive rights issued and outstanding.

During 2013, 16.48 million Zargon common shares traded on the Toronto Stock Exchange with a high trading price of $9.40 per share, a low of $6.00 per share and a closing price of $8.43 per share. The 2013 trading statistics show a 10 percent year-over-year increase in trading volume and a one percent increase in the closing share price. Zargon's market capitalization at year end 2013 was approximately $254 million, compared to approximately $250 million at the end of 2012.

Segmented Geographic Information

During 2013, approximately 92 percent (2012 – 92 percent) of Zargon's combined petroleum and natural gas revenue came from Western Canadian (Alberta and Saskatchewan) properties, with the remaining eight percent (2012 – eight percent) of revenue generated in the United States (North Dakota). For 2012, petroleum and natural gas revenue included Manitoba 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 $0.87 million as at December 31, 2013.

RELATED PARTY TRANSACTIONS

During the year, the Company paid $0.05 million (2012 – $0.21 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	2014	2015 to 2016	2017 to 2018	Thereafter
Head office lease and other	2.92	1.83	1.07	0.02	–
ASP related contracts	1.52	1.10	0.21	0.20	0.01
Natural gas transportation sales contracts	0.36	0.29	0.07	–	–
Total	4.80	3.22	1.35	0.22	0.01

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 $35 million for field capital and $16 million for ASP capital in 2014. 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 in the audited consolidated financial statements for the year ended December 31, 2013.

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 2013 and as a consequence North American natural gas inventories are at record highs. Oil production in North Dakota continued to increase in 2013 which put a strain on pipeline capacity. Delays in pipeline construction have also negatively affected pipeline capacity. Natural gas prices have increased in 2013 from 2012 but long term pricing is uncertain. Low 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 2013 and affected Zargon's revenues. 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 rights 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's changes in accounting policies are discussed in Note 4 to the Financial Statements.

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, 2013.
- 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, 2013.
- Zargon reports that no changes were made to ICFR during 2013 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 2013.

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. Zargon uses the 1992 Committee of Sponsoring Organizations of the Treadway Commission ("COSO") Framework as the Company has not yet adopted the 2013 COSO Framework.

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 2014 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

	2013			
	Q1	Q2	Q3	**Q4**
Petroleum and natural gas sales ($ millions)	37.08	40.59	45.14	**35.84**
Net earnings/(loss) ($ millions)	0.23	1.13	(2.35)	**(4.91)**
Net earnings/(loss) per diluted share ($)	0.01	0.04	(0.08)	**(0.16)**
Funds flow from operating activities ($ millions)	13.90	15.99	16.45	**12.15**
Funds flow from operating activities per diluted share ($)	0.46	0.53	0.55	**0.40**
Cash flows from operating activities ($ millions)	12.46	14.68	16.30	**13.56**
Cash flows from operating activities per diluted share ($)	0.42	0.49	0.54	**0.45**
Cash dividends ($ millions) (1)	4.75	5.01	5.17	**5.42**
Cash dividends declared per common share ($)	0.18	0.18	0.18	**0.18**
Net capital expenditures ($ millions)	16.19	2.42	17.54	**5.59**
Total assets ($ millions)	450.34	437.88	441.87	**452.98**
Long term bank debt ($ millions)	44.02	42.06	43.65	**39.97**
Convertible debentures ($ millions) (2)	57.50	57.50	57.50	**57.50**
Net debt	120.10	111.33	117.61	**116.24**
Average daily oil and liquids production (bbl)	5,113	4,930	4,816	**4,625**
Average daily natural gas production (mmcf)	15.21	14.77	16.46	**15.90**
Average daily production (boe)	7,648	7,392	7,560	**7,276**
Average oil production weighting (%)	67	67	64	**64**
Average realized commodity field price before the impact of financial risk management contracts ($/boe)	53.87	60.34	64.90	**53.55**
Funds flow netback ($/boe)	20.20	23.77	23.64	**18.14**

(1) Cash dividends represent the cash portion only and do not include common shares issued through Zargon's Dividend Reinvestment Plan which was suspended September 2013.

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

	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.

FOURTH QUARTER 2013

During the fourth quarter of 2013, Zargon's petroleum and natural gas sales of $35.84 million were 21 percent lower than the previous quarter's sales. Production for the 2013 fourth quarter of 7,276 barrels of oil equivalent per day was four percent lower than the 2013 third quarter's production of 7,560 barrels of oil equivalent per day. Compared to the previous quarter, oil production was four percent lower at 4,625 barrels per day due to property dispositions. Fourth quarter natural gas production decreased three percent from the previous quarter to 15.90 million cubic feet per day due to natural production declines. Average field prices received during the fourth quarter, before the impact of financial risk management contracts, were $73.40 per barrel for oil and liquids, a 22 percent decrease compared to the 2013 third quarter and $3.15 per thousand cubic feet for natural gas, a 39 percent increase from the prior quarter. Zargon's field price differential for its crude oil stream decreased to a $12.92 per barrel discount to the Edmonton reference crude oil price, a three percent improvement from Zargon's average differential of $13.26 per barrel for the first nine months of 2013. Despite stabilized field price differentials from Edmonton Par price, Zargon's fourth quarter oil field price realizations were unfavourably reduced due to Edmonton Par to WTI oil price differentials.

Funds flow from operating activities was $12.15 million in the fourth quarter, a decrease of 26 percent or $4.30 million from the prior quarter. A comparative analysis of the primary factors that caused this quarter-over-quarter increase is as follows:

- Fourth quarter 2013 petroleum and natural gas sales of $35.84 million were 21 percent lower than the 2013 third quarter sales of $45.14 million. This sales decrease was a result of the four percent decrease in production and 22 percent decrease in oil and liquids pricing over the third quarter.

- Royalties for the fourth quarter were $6.79 million, a decrease of $2.01 million from the prior quarter as the average royalty rate for the quarter decreased to 18.9 percent from the 2013 third quarter rate of 19.5 percent.
- Realized derivative losses were $0.15 million in the fourth quarter of 2013, a $2.41 million decrease from the prior quarter's $2.56 million loss due to the weakening of oil prices. The fourth quarter derivative losses were comprised of losses on realized financial oil risk management contracts ($0.13 million), gains on financial natural gas risk management contracts ($0.03 million) and losses on financial interest rate swaps ($0.05 million).
- Operating expenses were $10.67 million for the quarter, seven percent lower than the third quarter of 2013. Transportation expenses were $0.38 million, a 23 percent decrease over the prior quarter. On a per barrel of oil equivalent basis, operating expenses decreased four percent to $15.93 in the fourth quarter of 2013 compared to $16.53 in the prior quarter and transportation expenses decreased 21 percent to $0.57 from $0.72 in the prior quarter. The quarterly decrease in operating expenses was due to lower electricity and repairs and maintenance costs in the fourth quarter.
- General and administrative expenses were $2.70 million for the quarter, five percent lower than the third quarter of 2013 due to increased capital overhead recoveries from the fourth quarter drilling program. General and administrative expenses on a per barrel of oil equivalent basis were $4.04 compared to $4.10 in the prior quarter.
- Transaction costs incurred in the fourth quarter were $0.39 million compared to nil in the prior quarter. The transaction costs mainly related to property dispositions in the quarter.
- Interest and financing charges on long term bank debt were $0.50 million, a decrease of 24 percent or $0.15 million from the prior quarter. Due to cash from property dispositions used for debt repayments in the fourth quarter, the average bank debt level decreased 12 percent to $43.27 million compared to $49.00 million in the third quarter of 2013, resulting in lower debt servicing charges. Interest on convertible debentures was $0.87 million.
- Asset retirement expenditures reflect the actual amounts incurred to abandon and reclaim wells. These asset retirement expenditures totalled $1.14 million in the 2013 fourth quarter and increased 81 percent from the prior quarter amount of $0.63 million.
- Current income taxes of $0.12 million were $0.23 million lower than in the 2013 third quarter. The decrease was primarily due to the decrease in oil prices received in the 2013 fourth quarter.

The net loss for the quarter was $4.91 million, an increase in loss of $2.56 million compared to the prior quarter net loss of $2.35 million, mainly as a result of an impairment loss recognized in the fourth quarter that was partially offset by unrealized derivatives gains. 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 2013:

- Depletion and depreciation expense increased by $0.03 million to $11.45 million in the 2013 fourth quarter. The increased expense was due to a year end depletion and depreciation rate of $17.10 per barrel of oil equivalent, compared to the prior quarter's $16.42 per barrel of oil equivalent charge.
- Fourth quarter 2013 unrealized derivative gains of $0.95 million compared with third quarter unrealized derivative losses of $7.99 million. These unrealized gains result from the mark-to-market of financial risk management contracts at each period end. These non-cash unrealized derivative gains are generated by the change over the reporting period in the mark-to-market valuation of Zargon's risk management contracts. In particular, lower year end futures resulted in unrealized risk management contract oil gains of $1.33 million, unrealized risk management contract natural gas losses of $0.23 million and interest rate swap losses of $0.15 million.
- Accretion of convertible debentures remained unchanged at $0.29 million compared to the prior quarter amount.

- The provision for accretion of asset retirement obligations for the 2013 fourth quarter was $0.65 million, down nine percent from the prior quarter expense. The quarter-over-quarter decrease is due to changes in the estimated future liability for asset retirement obligations as a result of wells removed through property dispositions 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 $0.13 million during the fourth quarter of 2013 to $0.57 million, a 29 percent increase from the third quarter due to fewer forfeitures in the fourth quarter.
- Unrealized foreign exchange losses of nil in the 2013 fourth quarter compared to losses of $0.04 million for the prior quarter.
- Exploration and evaluation expenses in the fourth quarter were $1.02 million and were 52 percent higher than the third quarter's $0.67 million. Exploration and evaluation expenses were the result of land expiries.
- During the fourth quarter of 2013, Zargon closed several dispositions in northern and southern Alberta for gross proceeds of $18.64 million. Zargon reported a net loss of $2.00 million on the disposal of the assets.
- At the end of the fourth quarter, due to low commodity prices and the write off of certain natural gas reserves, two of the Company's CGUs were found to be impaired. The impairment was calculated to be a loss of $4.39 million. The E&E assets associated with these CGUs were not included in this impairment test.
- The deferred tax recovery was $1.22 million during the quarter compared to a deferred tax recovery of $0.95 million from the third quarter of 2013. The increase was due to the increase in losses before taxes of $6.01 million compared to the third quarter losses before taxes of $2.94 million.

Net capital expenditures were $5.59 million during the fourth quarter of 2013, compared to a prior quarter spend amount of $17.54 million which was a result of property dispositions. Fourth quarter conventional expenditures were $12.61 million while ASP expenditures were $11.65 million. These expenditures were offset by net dispositions of $18.68 in the quarter. Zargon also had $0.01 million of administrative asset expenditures. During the fourth quarter, Zargon drilled 8.5 net wells, which resulted in 5.5 net oil wells and 3.0 net ASP related service wells.

Fourth quarter cash dividends to shareholders of $0.06 per share per month totalled $5.42 million and compared to the prior quarter's $0.06 per share per month dividend that totalled $5.17 million (net of the DRIP). The DRIP was suspended starting with the September 2013 dividend that was paid in October 2013.

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.

Jason Dranchuk

C.H. Hansen
President and Chief Executive Officer

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

Calgary, Canada
March 11, 2014

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, 2013 and 2012, 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, 2013 and 2012 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 11, 2014

CONSOLIDATED BALANCE SHEETS

($ thousands)	Notes	**December 31, 2013**	December 31, 2012
ASSETS			
Trade and other receivables		**14,087**	16,660
Deposits and prepaid expenses		**997**	1,715
Investment in marketable securities	15	**800**	–
Derivatives	15,16	**22**	4,514
Total current assets		**15,906**	22,889
Long term deposits		**128**	269
Derivatives	15,16	**–**	284
Property, plant and equipment, net	5,7	**408,719**	389,971
Intangible exploration and evaluation assets	6	**13,331**	19,968
Goodwill	6	**2,969**	2,969
Deferred tax assets	17	**11,924**	8,755
Total assets		**452,977**	445,105
LIABILITIES			
Trade and other payables		**32,450**	35,777
Cash dividends payable	8	**1,805**	1,656
Provisions	9	**399**	881
Derivatives	15,16	**5,000**	72
Total current liabilities		**39,654**	38,386
Long term bank debt	10	**39,968**	35,736
Convertible debentures	11	**52,478**	51,261
Derivatives	15,16	**210**	191
Provisions	9	**135,177**	112,283
Deferred tax liabilities	17	**11,945**	10,665
Total liabilities		**279,432**	248,522
Commitments and contingencies	9,10,11,14,16,25		
EQUITY			
Shareholders’ capital	13	**256,092**	254,400
Accumulated other comprehensive income/(loss)		**493**	(998)
Contributed surplus	14	**12,423**	11,133
Equity component of debentures	11	**3,640**	3,640
Deficit		**(99,103)**	(71,592)
Total equity		**173,545**	196,583
Total equity and liabilities		**452,977**	445,105

See accompanying notes to the consolidated financial statements.

Dated on March 11, 2014 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	**2013**	2012
Petroleum and natural gas sales		**158,648**	157,945
Royalties		**(29,325)**	(30,137)
PETROLEUM AND NATURAL GAS REVENUE, NET OF ROYALTIES		**129,323**	127,808
Gain/(loss) on unrealized derivatives	15,16	**(9,724)**	9,903
Loss on realized derivatives	15,16	**(463)**	(139)
GAIN/(LOSS) ON DERIVATIVES		**(10,187)**	9,764
TOTAL INCOME		**119,136**	137,572
Operating		**46,224**	47,283
Transportation		**1,783**	1,566
General and administrative		**11,502**	13,549
Transaction costs		**484**	37
Exploration and evaluation	6	**4,013**	6,539
(Gain)/loss on disposal of properties	5	**1,733**	(20,823)
Share-based compensation	14, 18	**1,722**	2,134
Unrealized foreign exchange (gain)/loss		**(149)**	21
Impairment loss	5,7	**4,393**	37,321
Depletion and depreciation	5	**45,357**	48,198
EXPENSES		**117,062**	135,825
EARNINGS BEFORE FINANCE EXPENSES AND INCOME TAXES		**2,074**	1,747
Interest and financing charges	10	**2,336**	3,061
Interest on convertible debentures	11	**3,450**	2,306
Accretion of convertible debentures	11	**1,217**	801
Accretion of asset retirement obligations	9	**2,802**	2,771
FINANCE EXPENSES		**9,805**	8,939
LOSS BEFORE INCOME TAXES		**(7,731)**	(7,192)
Current tax expense	17	**812**	567
Deferred tax recovery	17	**(2,643)**	(2,382)
INCOME TAXES		**(1,831)**	(1,815)
NET LOSS FOR THE YEAR		**(5,900)**	(5,377)
Currency translation adjustment that may be reclassified subsequent to net earnings		**1,491**	(398)
OTHER COMPREHENSIVE INCOME/(LOSS) FOR THE YEAR		**1,491**	(398)
TOTAL COMPREHENSIVE LOSS FOR THE YEAR		**(4,409)**	(5,775)
NET LOSS PER SHARE			
Basic	19	**(0.20)**	(0.18)
Diluted	19	**(0.20)**	(0.18)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

($ thousands)	Notes	Shareholders' Capital	Accumulated Other Comprehensive Income	Contributed Surplus	Equity Component of Convertible Debentures	Deficit	Total Equity
Balance at December 31, 2012		**254,400**	**(998)**	**11,133**	**3,640**	**(71,592)**	**196,583**
Net loss for the year		**–**	**–**	**–**	**–**	**(5,900)**	**(5,900)**
Dividends declared	8	**–**	**–**	**–**	**–**	**(21,611)**	**(21,611)**
Issue of common shares pursuant to the DRIP	8,13	**1,260**	**–**	**–**	**–**	**–**	**1,260**
Share-based compensation	14	**–**	**–**	**1,722**	**–**	**–**	**1,722**
Exercise of share options	13	**432**	**–**	**(432)**	**–**	**–**	**–**
Translation differences on foreign subsidiary		**–**	**1,491**	**–**	**–**	**–**	**1,491**
Balance at December 31, 2013		**256,092**	**493**	**12,423**	**3,640**	**(99,103)**	**173,545**
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 compensation	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

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ thousands)	Notes	**2013**	2012
OPERATING ACTIVITIES			
Net loss for the year		**(5,900)**	(5,377)
Adjustments for non-cash items:			
(Gain)/loss on sale of properties	5	**1,733**	(20,823)
(Gain)/loss on unrealized derivatives	15,16	**9,724**	(9,903)
Depletion and depreciation	5	**45,357**	48,198
Accretion of asset retirement obligations	9	**2,802**	2,771
Accretion of convertible debentures	11	**1,217**	801
Share-based compensation	14	**1,722**	2,134
Unrealized foreign exchange (gain)/loss		**(149)**	21
Impairment loss	7	**4,393**	37,321
Deferred tax recovery	17	**(2,643)**	(2,382)
Exploration and evaluation	6	**4,013**	6,539
Asset retirement expenditures	9	**(3,788)**	(2,639)
Funds flow from operating activities		**58,481**	56,661
Changes in operating working capital	20	**(1,482)**	2,210
Net cash flows from operating activities		**56,999**	58,871
INVESTING ACTIVITIES			
Additions to property, plant and equipment	5	**(76,333)**	(65,210)
Additions to intangible exploration and evaluation assets	6	**(349)**	(1,803)
Proceeds from disposal of property, plant and equipment	5	**31,907**	36,766
Proceeds from disposal of exploration and evaluation assets	6	**3,033**	–
Change in long term deposits		**141**	149
Changes in investing working capital	20	**572**	1,622
Net cash flows used in investing activities		**(41,029)**	(28,476)
FINANCING ACTIVITIES			
Advances/(repayments) of bank debt	10	**4,232**	(56,967)
Cash dividends paid to shareholders	8	**(20,351)**	(27,347)
Proceeds from exercise of share rights	13	**–**	106
Issuance of convertible debentures, net of issue costs	11	**–**	54,650
Changes in financing working capital	20	**149**	(837)
Net cash flows used in financing activities		**(15,970)**	(30,395)
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, 2013 with comparative figures for 2012.
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, 2013 and its 2012 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 11, 2014.

(b) Basis of measurement:

The consolidated financial statements have been prepared on a going concern basis under 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), Note 4(i)(ii) and Note 15.

(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 represent 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. Reserve 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". In addition, the fair value of the convertible debenture is disclosed in Note 15, which was determined using Level I inputs.

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.

The investment in marketable securities is classified as "available-for-sale" and is carried at fair value. This investment is available on the active market and the Company classifies the fair value of this investment 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.

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/(loss) and comprehensive income/(loss) 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.

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. Transaction costs associated with a business combination are expensed as incurred.

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.

For available-for-sale financial investments, the impairment loss is calculated as the difference between the acquisition cost and the current fair value, less any impairment loss on that investment previously recognized in the statement of profit or loss is removed from other comprehensive income and recognized in the statement of profit or loss. Impairment losses on equity investments classified as available-for-sale are not reversed through profit or loss, any increases in their fair value after impairment is recognized in other comprehensive income.

(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, but 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 common share rights 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 that define 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/(loss) and comprehensive income/(loss). 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.

Available-for-sale financial assets:

Equity investments classified as available-for-sale are those that are neither classified as held for trading nor designated at fair value through profit or loss. After initial measurement, available-for-sale financial investments are subsequently measured at fair value with unrealized gains or losses recognized in other comprehensive income and credited in the available-for-sale reserve until the investment is derecognized, at which time the cumulative gain or loss is recognized in other operating income, or the investment is determined to be impaired, when the cumulative loss is reclassified from the available-for-sale reserve to the statement of earnings/(losses) in financing expense.

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 expenses comprise interest expense on borrowings and convertible debentures and accretion of the discount on asset retirement obligations and convertible debentures.

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 debentures could also potentially dilute basic earnings per share.

(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

(i) New and amended standards adopted by the Company for the year ended December 31, 2013:

- In May 2011 the IASB issued IFRS 10 "Consolidated Financial Statements", IFRS 11 "Joint Arrangements" and IFRS 12 "Disclosure of Interests in Other Entities" and two revised standards, IAS 27 "Separate Financial Statements" and IAS 28 "Investments in Associates and Joint Ventures".
- 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 this new IFRS, the IASB also issued amended and re-titled IAS 27 "Separate Financial Statements" and IAS 28 "Investments in Associates and Joint Ventures".
- IAS 27 "Separate Financial Statements" establishes the accounting and disclosure requirements for investments in subsidiaries, joint ventures and associates when an entity prepares separate financial statements and replaces the current IAS 27 "Consolidated and Separate Financial Statements" as the consolidation guidance is included in IFRS 10 "Consolidated Financial Statements".
- IAS 28 "Investments in Associates and Joint Ventures" establishes the accounting for investments in associates and defines how the equity method is applied when accounting for associates and joint ventures.

The adoption of the above standards effective January 1, 2013 did not have an impact on the Company's consolidated financial statements.

- IAS 1 "Presentation of Items of Other Comprehensive Income" – Amendments to IAS 1. The amendments to IAS 1 improve the quality of the presentation of Other Comprehensive Income ("OCI"). The amendments require companies preparing financial statements in accordance with IFRS to group together items within OCI that may be reclassified to the profit or loss section of the income statement. The amendments also reaffirm existing requirements that items in OCI and profit or loss should be presented as either a single statement or two consecutive statements. The amendment affected presentation only and had no impact on the Company's financial position or performance as at January 1, 2013.
- IAS 19 "Employee Benefits" was amended in June 2011 with revisions to certain aspects of the accounting for pension plans and other benefits, including amendments to the recognition, disaggregation, presentation and disclosure of all employee benefits. The adoption of this standard effective January 1, 2013 did not have an impact on the Company's consolidated financial statements.
- IFRS 7 "Financial Instruments: Disclosures" – Offsetting Financial Assets and Financial Liabilities – Amendments to IFRS 7 introduce new disclosure requirements about the effects of offsetting financial assets and financial liabilities and related arrangements on an entity's financial position. The disclosures will provide users with information that

may be useful in evaluating the effect of any netting arrangements in an entity's financial position. As the Company is not netting any significant amounts related to financial instruments in accordance with IAS 32 and does not have significant offsetting arrangements, the amendment effective January 1, 2013 does not have an impact on the Company.

- IFRS 13 “Fair Value Measurement” provides a single, comprehensive framework for fair value measurement and disclosure requirements for use across all IFRS standards. IFRS 13 clarifies that the fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. Under IFRS 13, the fair value of a liability must reflect the non-performance risk, which includes an entity’s own credit risk. The Company adopted IFRS 13 on January 1, 2013 on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Company to measure fair value and did not result in any measurement adjustments as at January 1, 2013.

(ii) Standards, amendments and interpretations to existing standards that are not yet effective and have not been early adopted by the Company:

- IAS 36 “Impairment of Assets”, has been amended to require additional disclosures in the event of recognizing an impairment of assets. The retrospective application of this standard is required to be adopted for periods on or after January 1, 2014. The Company is currently assessing the impact of this amendment on its consolidated financial statements.

- IFRIC 21 “Levies”, clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. The interpretation also clarifies that no liability should be recognized before the specified minimum threshold to trigger that levy is reached. IFRIC 21 is required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. IFRIC 21 will be applied by the Company on January 1, 2014 and the adoption may have an impact on the company’s accounting for production and similar taxes, which do not meet the definition of an income tax in IAS 12 "Income Taxes." The Company is currently assessing the impact of this interpretation on its consolidated financial statements.

- The IASB has undertaken a three-phase project to replace IAS 39 "Financial Instruments: Recognition and Measurement" with IFRS 9 "Financial Instruments." In November 2009, the IASB issued the first phase of IFRS 9, which details the classification and measurement requirements for financial assets. Requirements for financial liabilities were added to the standard in October 2010. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

  In November 2013, the IASB issued the third phase of IFRS 9 which details the new general hedge accounting model. Hedge accounting remains optional and the new model is intended to allow reporters to better reflect risk management activities in the financial statements and provide more opportunities to apply hedge accounting. The Company does not employ hedge accounting for its risk management contracts currently in place. In July 2013, the IASB deferred the mandatory effective date of IFRS 9 and has left this date open pending the finalization of the impairment and classification and measurement requirements. IFRS 9 is still available for early adoption. The full impact of the standard on the Company’s financial statements will not be known until the project is complete.

5. PROPERTY, PLANT AND EQUIPMENT

($ thousands)	**2013**	2012
Cost, beginning of year	**535,791**	510,787
Accumulated depletion and depreciation, beginning of year	**(145,820)**	(100,120)
Net carrying amount, beginning of year	**389,971**	410,667
Additions	**74,600**	86,148
Disposals	**(31,871)**	(36,546)
Change in asset retirement obligation	**23,285**	15,758
Assets transferred from intangible exploration and evaluation assets	**25**	241
Impairment loss	**(4,393)**	(37,321)
Exchange differences	**2,459**	(778)
Depletion and depreciation	**(45,357)**	(48,198)
Net carrying amount, end of year	**408,719**	389,971
Cost, end of year	**580,267**	535,791
Accumulated depletion and depreciation, end of year	**(171,548)**	(145,820)
Net carrying amount, end of year	**408,719**	389,971

(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, 2013, $42.45 million (2012 – $6.48 million) of major development project property was not depleted or depreciated.

(b) Security:

At December 31, 2013 and 2012, 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, 2013, $0.34 million (2012 – $0.33 million) of direct and incremental general and administrative expenses were capitalized to property, plant and equipment.

For the year ended December 31, 2013, the Company disposed of certain assets for gross cash proceeds of $31.91 million (2012 – $36.77 million), resulting in a loss of $1.73 million (2012 – $20.82 million gain).

6. INTANGIBLE EXPLORATION AND EVALUATION ASSETS AND GOODWILL

($ thousands)	Goodwill	E&E assets	Total
Cost:			
Balance at December 31, 2011	2,969	25,184	28,153
Additions	–	1,803	1,803
Disposal	–	(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**
Additions	**–**	**349**	**349**
Disposals	**–**	**(3,033)**	**(3,033)**
Transfers to property, plant and equipment	**–**	**(25)**	**(25)**
Exploration and evaluation expense	**–**	**(4,013)**	**(4,013)**
Exchange differences	**–**	**85**	**85**
Balance at December 31, 2013	**2,969**	**13,331**	**16,300**

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/(loss) and comprehensive income/(loss). There was no impairment of exploration and evaluation assets or goodwill during the year. Goodwill is allocated to one 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, 2013, 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 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]
2014	95.00	4.00	0.950
2015	95.00	4.25	0.950
2016	95.00	4.55	0.950
2017	95.00	4.75	0.950
2018	95.30	5.00	0.950
2019	96.60	5.25	0.950
2020	98.50	5.35	0.950
2021	100.50	5.45	0.950
2022	102.50	5.55	0.950
2023	104.60	5.65	0.950
2024	106.70	5.75	0.950
2025	108.80	5.90	0.950
2026	111.00	6.00	0.950
2027	113.20	6.15	0.950
2028	115.50	6.25	0.950
Remainder [2]	2.0%	2.0%	0.950

(1) Source: McDaniel & Associates Consultants Ltd. price forecast effective January 1, 2014.

(2) Percentage change represents the change in each year after 2028 to the end of the reserve life.

Based on the assessment on December 31, 2013, the carrying amount of the two CGUs were determined to be $4.39 million higher than their recoverable amount, and an impairment loss was recognized. The carrying amounts before impairment were $82.40 million and $26.20 million for the Alberta Plains North and West Central Alberta CGUs, respectively. In 2012, the Company determined there was $37.32 million in impairment. No impairment losses from prior years were reversed in 2013.

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 $13.92 million.
- A five percent decrease in future planned cash flows would have increased the impairment loss by $15.53 million.

8. CASH DIVIDENDS

During the year, the Company declared dividends to the shareholders in the aggregate amount of $21.61 million (2012 – $31.95 million) in accordance with the following schedule:

2013 Dividends (1)	Record Date	Dividend Date	Per Common Share
January	January 31, 2013	February 15, 2013	$0.06
February	February 28, 2013	March 15, 2013	$0.06
March	March 31, 2013	April 15, 2013	$0.06
April	April 30, 2013	May 15, 2013	$0.06
May	May 31, 2013	June 17, 2013	$0.06
June	June 30, 2013	July 15, 2013	$0.06
July	July 31, 2013	August 15, 2013	$0.06
August	August 31, 2013	September 16, 2013	$0.06
September	September 30, 2013	October 15, 2013	$0.06
October	October 31, 2013	November 15, 2013	$0.06
November	November 30, 2013	December 16, 2013	$0.06
December	December 31, 2013	January 15, 2014	$0.06

(1) The 2013 cash dividends include a non-cash equity issuance amount of $1.26 million for the Dividend Reinvestment Plan which was suspended September 2013.

Subsequent to the end of the period and prior to the consolidated financial statements being authorized for issue on March 11, 2014, the Company declared dividends of $1.81 million or $0.06 per share for each of January and February of 2014.

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.

9. PROVISIONS

($ thousands)	Asset retirement obligations	Other	Total
Balance at December 31, 2012	**112,283**	**881**	**113,164**
Provisions made during the year	**1,248**	**–**	**1,248**
Foreign exchange and other	**595**	**–**	**595**
Provisions used during the year	**(3,788)**	**(482)**	**(4,270)**
Provisions related to dispositions	**(12,814)**	**–**	**(12,814)**
Revisions to estimated provisions	**34,851**	**–**	**34,851**
Accretion	**2,802**	**–**	**2,802**
Balance at December 31, 2013	**135,177**	**399**	**135,576**
Current	**–**	**399**	**399**
Non-current	**135,177**	**–**	**135,177**

($ 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

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 $196 million as at December 31, 2013. These obligations are expected to be incurred over the next 55 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 fourth quarter of 2013, the discount factor of 2.50 percent was increased to 3.25 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 $0.40 million.

10. LONG TERM BANK DEBT

On June 10, 2013, Zargon amended and renewed its syndicated committed credit facilities, the result of which was the maintaining of the available facilities and borrowing base of $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 364 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 25, 2014, with a semi-annual review that took place in the fall of 2013. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 364 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, 2013, $39.97 million (December 31, 2012 - $35.74 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, 2013, the approximate value of outstanding letters of credit totalled $0.87 million (December 31, 2012 - $0.71 million). The letters of credit reduce the amount of Zargon's available credit facilities to $124.16 million at December 31, 2013 (December 31, 2012 - $128.55 million).

Zargon reviews its compliance with its bank debt covenants on a quarterly basis and is in compliance as at December 31, 2013.

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 which commenced 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/(loss) and comprehensive income/(loss).

($ thousands)	**December 31, 2013**	December 31, 2012
Principal, beginning of year	**57,500**	–
Issuance	**–**	57,500
Principal, end of year	**57,500**	57,500
Debt component, beginning of year	**51,261**	–
Issuance, net of transaction costs	**–**	50,460
Accretion of convertible debentures	**1,217**	801
Debt component, end of year	**52,478**	51,261
Equity component, beginning of year	**3,640**	–
Issuance, net of transaction costs and deferred tax	**–**	3,640
Equity component, end of year	**3,640**	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, 2013**	December 31, 2012
Net debt	**116,238**	113,175
Funds flow from operating activities	**58,481**	56,661
Net debt to funds flow from operating activities ratio	**1.99**	2.00

As at December 31, 2013, Zargon's net debt to funds flow from operating activities ratio was 1.99, a decrease from 2.00 at December 31, 2012. Bank debt levels increased during the year as a result of an active fourth quarter drilling program and ASP capital expenditures, which were partially offset by property dispositions in the year. On June 10, 2013, Zargon amended and renewed its syndicated committed credit facilities, the result of which was the maintaining of the available facilities and borrowing base of $165 million. The next renewal date is June 25, 2014. 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, 2013.

13. SHARE CAPITAL

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

Zargon had 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. The DRIP was suspended starting with the September 2013 dividend paid on October 15, 2013.

Common Shares

	December 31, 2013	
(thousands)	**Number of Shares**	**Amount ($)**
Balance, as at December 31, 2012	**29,868**	**254,400**
Share options exercised for cash	**28**	**–**
Share-based compensation transferred from contributed surplus on exercise of share options	**–**	**432**
Issued pursuant to the Dividend Reinvestment Plan	**191**	**1,260**
Balance, as at December 31, 2013	**30,087**	**256,092**

Common Shares

(thousands)	December 31, 2012 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

14. SHARE-BASED PAYMENTS

Share Award Plan

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 awards 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 12 percent while the interest rate and volatility is set at a historical rate as there is no exercise price. The fair value of the share award is determined on the grant date at the prior day closing price of the Company's common shares on the Toronto Stock Exchange.

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

	December 31, 2013 **Number of Share Awards (thousands)**	December 31, 2012 Number of Share Awards (thousands)
Outstanding at beginning of year	**322**	158
Share awards granted	**318**	229
Share awards exercised	**(28)**	(9)
Share awards forfeited	**(49)**	(56)
Outstanding at end of the year	**563**	322
Share awards exercisable at end of year	**88**	31

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") expired in the first quarter of 2013. 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 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 rights under the Old Plan:

	December 31, 2013		December 31, 2012	
	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	**170**	**23.23 / 21.40**	409	24.24 / 22.02
Share options exercised	–	–	(3)	13.42
Share options expired	**(170)**	**23.23**	(211)	25.36
Share options forfeited	–	–	(25)	22.73
Outstanding at end of the year	–	–	170	23.23 / 21.40
Share rights exercisable at end of year	–	–	170	23.23 / 21.40

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

	December 31, 2013		December 31, 2012	
	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	**458**	**18.08 / 14.44**	537	18.12 / 14.51
Share options exercised	–	–	(6)	10.82
Share options forfeited	**(67)**	**18.14**	(73)	18.57
Outstanding at end of the year	**391**	**18.06 / 14.39**	458	18.08 / 14.44
Share rights exercisable at end of year	**391**	**18.06 / 14.39**	372	17.70 / 13.89

The following tables summarize information about share rights outstanding at December 31, 2013:

For the New 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)
15.56	**138**	**0.1 years**	**15.56**	**138**	**15.56**
15.80	**8**	**0.1 years**	**15.80**	**8**	**15.80**
17.31	**13**	**0.1 years**	**17.31**	**13**	**17.31**
17.70 – 19.85	**232**	**1.1 years**	**19.68**	**232**	**19.68**
	391		**18.06**	**391**	**18.06**

For the New 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)
10.82	**138**	**0.1 years**	**10.82**	**138**	**10.82**
11.33	**8**	**0.1 years**	**11.33**	**8**	**11.33**
13.21	**13**	**0.1 years**	**13.21**	**13**	**13.21**
14.09 – 17.95	**232**	**1.1 years**	**16.69**	**232**	**16.69**
	391		**14.39**	**391**	**14.39**

Share-Based Compensation

The share awards for the year ended December 31, 2013, together with the continued vesting of options granted in prior years, resulted in share-based compensation expense in 2013 of $1.72 million (2012 – $2.13 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, 2013		December 31, 2012	
(thousands)	**Carrying Amount ($)**	**Fair Value ($)**	Carrying Value ($)	Fair Value ($)
Loans and receivables:				
Trade and other receivables	**14,087**	**14,087**	16,660	16,660
Fair value through profit and loss:				
Derivative assets	**22**	**22**	4,798	4,798
Derivative liabilities	**5,210**	**5,210**	263	263
Fair value through other comprehensive income:				
Investment in marketable securities	**800**	**800**	–	–
Other liabilities:				
Trade and other payables	**32,450**	**32,450**	35,777	35,777
Cash dividends	**1,805**	**1,805**	1,656	1,656
Long term bank debt	**39,968**	**39,968**	35,736	35,736
Convertible debentures	**52,478**	**56,638**	51,261	57,500

Determination of Fair Value

The Company's investment in marketable securities and risk management contracts have been assessed on the fair value hierarchy described in Note 3(iv) and are classified as Level I and Level II, respectively. 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. The Company's policy is to recognize transfers into and out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer. The company does not have any fair value measurements classified as Level III.

At each reporting date, the Company determines whether transfers have occurred between levels in the hierarchy by reassessing the level of classification for each financial asset and financial liability measured or disclosed at fair value in the financial statements. Assessment of the significance of a particular input to the fair value measurement requires judgement and may affect the placement within the fair value hierarchy. During the year ended December 31, 2013, there were no transfers between levels I, II, or III.

The carrying value of receivables and other liabilities approximate their fair value due to their short maturities, except for the convertible debentures which is determined using Level I inputs.

Financial Risk Management

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 has entered into swaps, which fix the Canadian dollar AECO prices and a natural gas basis hedge.

  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, 2013 debt pricing levels, the increase or decrease in net earnings for the year for each one percent change in interest rates would amount to $0.42 million (2012 - $0.55 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 $0.81 million (2012 - $0.80 million) increase or decrease in net earnings for the year ended December 31, 2013. 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, 2013, approximately 58 percent (December 31, 2012 – 45 percent) was owing from two companies and Zargon anticipates full collection.

  The Company's allowance for doubtful accounts at December 31, 2013 was $0.26 million (December 31, 2012 – $0.25 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, 2013, $0.51 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, 2013, Zargon had available unused committed bank credit facilities of approximately $124.16 million compared to $128.55 million at December 31, 2012. 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	2–4 years	Total
Trade and other payables	**32,450**	**–**	**32,450**
Cash dividends payable	**1,805**	**–**	**1,805**
Derivative liabilities	**5,000**	**210**	**5,210**
Long term bank debt	**–**	**39,968**	**39,968**
Interest on convertible debentures	**3,450**	**8,625**	**12,075**
Convertible debentures (1)	**–**	**57,500**	**57,500**

(1) Amount is the full face value of the convertible debentures 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 $10.83 million (2012 – $7.67 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 loss on the statement of earnings and comprehensive income for 2013 was $9.72 million and the unrealized gain for 2012 was $9.90 million. The realized loss on the statement of earnings/(loss) and comprehensive income/(loss) for 2013 was $0.46 million and the realized loss for 2012 was $0.14 million.

As at December 31, 2013, 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	400 bbl/d	$96.33 US/bbl	Jan. 1/14 – Mar. 31/14	(82)
	1,200 bbl/d	$95.59 US/bbl	Jan. 1/14 – Jun. 30/14	(598)
	1,400 bbl/d	$90.30 US/bbl	Jan. 1/14 – Dec. 31/14	(3,269)
	400 bbl/d	$91.73 US/bbl	Apr. 1/14 – Mar. 31/15	(436)
	400 bbl/d	$90.00 US/bbl	Jul. 1/14 – Dec. 31/14	(351)
	400 bbl/d	$99.60 Cdn/bbl	Jul. 1/14 – Dec. 31/14	(66)
Natural gas swaps	6,000 gj/d	$3.33 Cdn/gj	Jan. 1/14 – Mar. 31/14	(187)
	3,000 gj/d	$3.59 Cdn/gj	Apr. 1/14 – Oct. 31/14	(55)
Total Fair Market Value, Commodity Price Financial Contracts				**(5,044)**

Oil swaps are settled against the NYMEX WTI pricing index, whereas natural gas swaps are settled against the AECO pricing index.

Subsequent to the end of the period and prior to the consolidated financial statements being authorized for issue on March 11, 2014, the Company entered into the following natural gas hedges, 3,000 gj/d at $3.74 Cdn/gj from April 1, 2014 to October 31, 2014, 3,000 gj/d at $3.73 Cdn/gj from April 1, 2014 to October 31, 2014, 3,000 gj/d at $4.175 Cdn/gj from November 1, 2014 to March 31, 2015 and 3,000 gj/d at $4.32 Cdn/gj from November 1, 2014 to March 31, 2015.

AECO Basis Gas Rate Risk Management Contract:

	Rate	Average Price	Range of Terms	Fair Market Value Liability ($ thousands)
NYMEX-ACEO basis	6,000 MMBtu/d	$(0.485) US/MMBtu	Apr. 1/14 – Oct. 31/14	22
Total Fair Market Value, Interest Rate Financial Contracts				**22**

AECO basis natural gas swaps are settled against the AECO pricing index.

Subsequent to the end of the period and prior to the consolidated financial statements being authorized for issue on March 11, 2014, the Company entered into a natural gas basis swap for 3,000 MMBtu per day of natural gas at $0.5075 US/MMBtu AECO to NYMEX from April 1, 2014 to October 31, 2014.

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. 1/14 – Jul. 26/16	(46)
	$20,000,000/month	1.731%	Jan. 1/14 – Aug. 26/16	(120)
Total Fair Market Value, Interest Rate Financial Contracts				**(166)**

(1) Excludes the current stamping fee of 2.0% 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)	2013	2012
Loss before tax	**(7,731)**	(7,192)
Expected tax rate	**25.45%**	25.45%
Expected income taxes expense/(recovery)	**(1,967)**	(1,830)
Add (deduct) income tax effect of:		
Rate adjustments	**(808)**	(587)
Permanent differences and other	**944**	602
Total income tax recovery	**(1,831)**	(1,815)

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

($ thousands)	2013	2012
Canadian oil and natural gas property expenses	**–**	8,862
Canadian development expenses	**56,765**	80,545
Canadian exploration expenses	**69,046**	67,210
Capital cost allowance	**79,956**	59,633
Non-capital losses	**126,791**	112,347
US tax pools	**1,306**	1,739
Partnership deferral	**(28,415)**	(22,854)
Other	**4,819**	5,822
	310,268	313,304

The Company has tax allowances of approximately $1.70 million (December 31, 2012 - $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, 2012 - $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, 2013 and 2012 are as follows:

($ thousands)	**Balance December 31, 2012**	**Recognized in earnings**	**Recognized on Balance Sheet**	**Balance December 31, 2013**
Property, plant and equipment and intangible assets	**(52,103)**	**(7,257)**	**–**	**(59,360)**
Convertible debentures	**(1,072)**	**309**	**–**	**(763)**
Unrealized portion of derivative assets	**67**	**1,259**	**–**	**1,326**
Deferred partnership earnings	**(4,944)**	**(2,383)**	**–**	**(7,327)**
Non-capital losses	**26,118**	**3,676**	**–**	**29,794**
Asset retirement obligations	**29,751**	**5,639**	**–**	**35,390**
Unrealized portion of derivative liabilities	**(1,221)**	**1,216**	**–**	**(5)**
Share issue costs	**1,036**	**(331)**	**–**	**705**
Foreign exchanges	**–**	**754**	**(754)**	**–**
Other liabilities	**458**	**(239)**	**–**	**219**
Net deferred tax asset/(liability)	**(1,910)**	**2,643**	**(754)**	**(21)**

($ thousands)	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
Asset retirement 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)

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)	**2013**	2012
Short term employee benefits	**4,018**	3,050
Share-based payments [(1)]	**1,114**	1,160
	5,132	4,210

(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.

The change in short term employee benefits from 2012 to 2013 is due to the reorganization of the Company's senior officers.

19. EARNINGS/(LOSS) PER SHARE

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

(thousands)	**2013**	2012
Net loss for diluted net loss per share calculation	**$(5,900)**	$(5,377)
Weighted average number of common shares – basic	**30,015**	29,606
Dilutive impact of share right incentive plans and share award plan	**–**	–
Weighted average number of common shares – diluted	**30,015**	29,606

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 the New Plan, the prices used in the dilution calculation are the lower prices calculated under the New Plan.

The convertible debentures 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 periods ended December 31, 2013 and 2012.

20. CHANGE IN NON-CASH FLOW INFORMATION

The net change in working capital is comprised of:

($ thousands)	**2013**	2012
Source/(use) of cash:		
Trade and other receivables	**2,573**	5,713
Deposits and prepaid expenses	**718**	(59)
Trade and other payables	**(3,327)**	(1,673)
Cash dividends payable	**149**	(837)
Provisions	**(482)**	–
Foreign exchange and other	**(392)**	(149)
	(761)	2,995
Related to operating activities	**(1,482)**	2,210
Relating to investing activities	**572**	1,622
Related to financing activities	**149**	(837)
	(761)	2,995

21. SUPPLEMENTAL CASH FLOW INFORMATION

($ thousands)	**2013**	2012
Cash interest paid	**5,818**	5,148
Cash taxes paid	**668**	361

22. SIGNIFICANT SUBSIDIARIES

The Company has the following significant wholly owned, directly or indirectly, subsidiaries which are incorporated in Canada as at December 31, 2013:

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

Subsequent to the end of the period, the Company amalgamated Ashton Oil & Gas Ltd. with Zargon Oil & Gas Ltd. This amalgamation did not have an impact on the Company's consolidated financial statements.

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 $0.05 million (2012 – $0.21 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, 2013, there was $0.11 million (2012 - $0.12 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.

		2013	
($ thousands)	**Canada**	**United States**	**Combined**
Petroleum and natural gas sales	**145,427**	**13,221**	**158,648**
Segment profit/(loss)	**(2,376)**	**4,450**	**2,074**
Earnings/(loss) before income taxes	**(11,914)**	**4,183**	**(7,731)**
Impairment loss	**(4,393)**	**–**	**(4,393)**
Property and equipment, net	**371,069**	**37,650**	**408,719**
Intangible exploration and evaluation assets and goodwill	**15,030**	**1,270**	**16,300**
Total assets	**408,682**	**44,295**	**452,977**
Net capital expenditures	**38,294**	**3,448**	**41,742**

		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/(loss) 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

Zargon derives over 92 percent of its revenue from five 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, 2013**
Less than one year	**3,217**
Between one and five years	**1,581**
	4,798

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 $0.40 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

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

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

Common Shares
Trading Symbol: ZAR

Convertible Debentures
Trading Symbol: ZAR.DB

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