



Third Quarter Interim Report for the Three and Nine Months Ended September 30, 2011

HIGHLIGHTS

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change	2011	2010	Change
<i>(000s, except per share amounts)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(%)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(%)</i>
Financial						
Petroleum and natural gas revenues	11,566	5,657	104	32,626	20,151	62
Funds flow from operations ⁽¹⁾	5,318	1,558	241	14,681	6,960	111
Per share – basic	0.13	0.05	160	0.39	0.26	50
– diluted	0.13	0.05	160	0.39	0.26	50
Net earnings (loss)	1,914	(1,357)		(747)	(2,288)	
Per share – basic	0.05	(0.04)		(0.02)	(0.08)	
– diluted	0.05	(0.04)		(0.02)	(0.08)	
Capital expenditures	11,084	5,135	116	30,172	19,936	51
Working capital deficiency	50,868	45,511	12	50,868	45,511	12
Shareholders' equity	101,285	85,759	18	101,285	85,759	18
<i>(000s)</i>	<i>(#)</i>	<i>(#)</i>	<i>(%)</i>	<i>(#)</i>	<i>(#)</i>	<i>(%)</i>
Share Data						
At period-end						
Basic	39,583	33,083	20	39,583	33,083	20
Options and warrants	3,455	3,461	--	3,455	3,461	--
Weighted average						
Basic	39,583	30,524	30	37,798	27,164	39
Diluted	39,889	30,524	31	37,798	27,164	39
			<i>(%)</i>			<i>(%)</i>
Operating						
Production						
Natural gas <i>(mcf/d)</i>	8,406	6,324	33	8,068	7,446	8
Crude oil <i>(bbls/d)</i>	1,022	505	102	914	518	76
NGLs <i>(bbls/d)</i>	75	44	70	74	54	37
Total <i>(boe/d)</i> ⁽²⁾	2,498	1,602	56	2,332	1,813	29
Average wellhead prices						
Natural gas <i>(\$/mcf)</i> ⁽³⁾	4.52	4.43	2	4.57	4.83	(5)
Crude oil <i>(\$/bbl)</i> ⁽³⁾	83.18	72.35	15	86.38	73.57	17
NGLs <i>(\$/bbl)</i>	72.02	61.80	17	73.43	62.12	18
Total <i>(\$/boe)</i> ⁽⁴⁾	51.98	41.99	23	52.38	42.76	22
Royalties <i>(\$/boe)</i>	(11.06)	(7.71)	43	(10.55)	(6.74)	57
Operating cost <i>(\$/boe)</i>	(11.06)	(12.85)	(14)	(11.33)	(12.78)	(11)
Transportation cost <i>(\$/boe)</i>	(1.70)	(1.74)	(2)	(1.75)	(1.73)	1
Operating netback <i>(\$/boe)</i> ⁽⁵⁾	28.16	19.69	43	28.75	21.50	34
Drilling activity – gross (net)						
Development (#)	1 (0.6)	2 (1.6)		3 (1.5)	3 (2.1)	
Exploration (#)	1 (0.6)	1 (0.6)		2 (1.6)	3 (2.6)	
Abandoned (#)	-- (--)	-- (--)		-- (--)	-- (--)	
Total (#)	2 (1.2)	3 (2.2)		5 (3.1)	6 (4.7)	
Average working interest (%)	60	73		62	78	
Success rate (%)	100	100		100	100	

(1) Funds flow from operations is calculated using cash flow from operating activities, as presented in the statement of cash flows, before changes in non-cash working capital and settlement of asset retirement costs. Funds flow from operations is used to analyze the Company's operating performance and leverage. Funds flow from operations does not have a standardized measure prescribed by International Financial Reporting Standards ("IFRS"), and therefore, may not be comparable with the calculations of similar measures for other companies.

(2) For a description of the boe conversion ratio, refer to the advisories contained herein.

(3) Product prices include realized gains/losses from financial derivative contracts.

(4) Oil equivalent price includes minor sulphur sales revenue.

(5) Operating netback equals revenue less royalties, transportation and operating costs calculated on a per boe basis. Operating netback does not have a standardized measure prescribed by IFRS, and therefore, may not be comparable with the calculations of similar measures for other companies.

MESSAGE TO SHAREHOLDERS

Artek Exploration Ltd. is pleased to report its financial and operating results for the three and nine months ended September 30, 2011.

Third Quarter Highlights

- Production averaged 2,498 boe/d, representing a 56% increase from the same three-month period a year ago and an 8% improvement over the second quarter of 2011.
- Crude oil and NGLs average production of 1,097 bbls/d rose to 44% of total corporate production, which is up 100% from the third quarter of 2010 and up 7% from the second quarter of 2011.
- Operating netbacks totaled \$28.16/boe, a 43% increase from the same period last year.
- Funds flow from operations grew to \$5.3 million, representing a 241% increase from the third quarter of 2010.
- Earnings increased to \$1.9 million from a loss of \$1.4 million for the same period last year.
- Exited the period with a working capital deficiency of \$50.9 million.
- Capital expenditures totaled \$11.1 million, which included the drilling of 2 gross (1.2 net) wells (100% success rate) in the Inga area of British Columbia, including a new oil discovery.
- The new oil discovery tested at a restricted rate of 1,650 boe/d (65% crude oil).

Operations Review – Liquids Focus

During the third quarter of 2011, production averaged 2,498 boe/d, up 56% from a year ago and 8% higher than the second quarter, despite approximately 300 boe/d being shut-in or restricted due primarily to ongoing third party facility and plant turnaround issues at Sinclair, Alberta. Crude oil and NGLs production averaged 1,097 bbls/d in the third quarter (93% crude oil), which represents 44% of total corporate production, up 100% from the same period last year. The increased liquids production is a result of our Company's continued focus on increasing liquids production through our capital program. Year-over-year operating costs were down 14% to \$11.06/boe from the same period last year and dropped slightly from the second quarter. Operating netbacks of \$28.16/boe were up 43% from the third quarter of 2010 as a result of cost reductions, higher liquids prices and the resulting higher netbacks associated with the increased liquids production. Operating netbacks were 11% lower than the second quarter due primarily to realized crude oil prices, which were also 11% lower.

In the Inga area of British Columbia, the Company horizontally drilled and completed a new discovery oil well (60% working interest) in the Doig formation. The well flowed inline at a restricted rate of 1,070 bbls/d of oil and 3.7 mmcf/d of natural gas or approximately 1,650 boe/d at a flowing pressure of 1,830 PSI. The well was drilled with only a 665-metre horizontal lateral and completed with a seven-stage hydrocarbon frac stimulation program. The well was brought on-stream during the quarter at a facility-restricted rate of approximately 660 boe/d.

Two additional horizontal wells (1.2 net) were spud during the third quarter from the same surface location testing independent spacing units. The wells were drilled with horizontal laterals of 1,129 to 1,270 metres and packer assemblies have been landed in both wells for 15-stage hydrocarbon frac programs scheduled for back-to-back completion commencing on or about November 11, 2011. The wells are expected to be flowing back by the end of November. Because of the success at Inga, the Company has expanded its facility from 7 mmcf/d capacity to 16 mmcf/d and is now ready for the new volumes expected from these latest two wells. Artek has accumulated 29 gross (21 net) sections of land and maps approximately 42 gross (25 net) locations on its lands, assuming only two to three horizontal wells per section. We anticipate the well density will increase given the high liquids ratio of the project. Long-term, we plan to access additional capacity at a third party deep cut facility, which will result in a further increase in liquids yield for relatively minimal additional pipeline capital costs.

Outlook

For the remainder of the year, our Company plans to drill a shallow horizontal well (100% working interest) in the Dunvegan area of Alberta targeting Triassic oil adjacent to a well that we drilled and tested in excess of 400 boe/d (approximately 50% oil). The well, which was drilled in the first quarter, is currently producing between 140 and 150 boe/d (30% crude oil). Water from the well is now being disposed of at the Company's operated water disposal facility and netbacks from the well are approximately \$30/boe (using a \$3.25/GJ natural gas price and a \$90/bbl wellhead oil price) and are expected to increase as the well is optimized. Artek has now compiled in excess of 30 sections of land in the Dunvegan area and approximately 55 sections of land on the shallow Triassic oil play in the Peace River Arch area.

For fiscal 2011, the Company still anticipates achieving its average production guidance of 2,400 to 2,550 boe/d as well as meeting or exceeding its year-end exit guidance of between 2,900 and 3,100 boe/d.

For the 2012 calendar year, Artek has hedged 300 bbls/d of crude oil at CDN\$92.00/bbl. The Company plans to release its 2012 capital spending budget and production expectations following analysis of the completion results on the two Inga horizontal wells discussed above. We will continue to pursue opportunities to divest non-core assets in order to expand investments in our core properties.

We are pleased with the execution of our ongoing strategy of focusing capital on oil and high liquids ratio projects, while managing our exposure to dry natural gas projects in this period of prolonged low natural gas prices. We have grown our oil and liquids production 100% from the same period last year and the liquids to total production ratio has increased 29%, while also improving total production 56%. We look forward to reporting our Company's year-end results as we anticipate a strong finish to a solid operational year.

Respectfully,



Darryl F. Metcalfe
President & Chief Executive Officer

November 9, 2011

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") for Artek Exploration Ltd. ("Artek" or the "Company") reports on the financial condition and the results of operations for the three and nine months ended September 30, 2011 and 2010 and should be read with the accompanying unaudited interim financial statements and related notes and the audited financial statements and related notes for the year ended December 31, 2010. All financial measures are expressed in Canadian dollars unless otherwise indicated. This commentary is based on the information available as at, and is dated November 9, 2011. Additional information relating to Artek, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com.

Basis of Presentation

The unaudited interim financial statements and comparative information for the three and nine months ended September 30, 2011 have been prepared in accordance with International Accounting Standard 34 – "Interim Financial Reporting". Previously, the Company prepared its financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). In accordance with International Financial Reporting Standards ("IFRS") 1, Artek's transition date to IFRS was January 1, 2010, and therefore, the comparative information for 2010 has been prepared in accordance with the Company's IFRS accounting policies. The 2009 financial information contained within this MD&A has been prepared following Canadian previous GAAP. Certain amounts in prior years have been reclassified to conform to the current year's IFRS presentation format.

Barrel of Oil Equivalency

Production information is commonly reported in units of barrel of oil equivalent ("boe"). For purposes of computing such units, natural gas is converted to equivalent barrels of crude oil using a conversion factor of six thousand cubic feet of gas to one barrel of oil. This conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Such disclosure of boes may be misleading, particularly if used in isolation.

Non-IFRS Measurements

This MD&A contains the terms "funds from operations", "funds flow netback", "operating netback" and "net earnings (loss) netback", which are not measures that have any standardized meaning prescribed by IFRS and are considered non-IFRS measures, and as a result, should not be considered an alternative to or more meaningful than net loss or cash flow from operating activities as determined in accordance with IFRS as an indicator of the Company's performance. Artek's determination of funds from operations, funds from operations per share, funds flow netback and net earnings (loss) netback may not be comparable to that reported by other companies. The Company considers corporate netbacks a key measure as it demonstrates its profitability relative to current commodity prices. Operating netbacks are calculated on a boe basis by deducting royalties, operating costs and transportation from petroleum and natural gas revenues; funds flow netback, in addition, deducts interest expenses and general and administrative expenses; and, net earnings (loss) netback further deducts depletion, depreciation and accretion, share-based compensation and deferred tax expense. Management uses funds from operations to analyze operating performance and leverage, and considers funds from operations to be a key measure as it demonstrates the Company's ability to generate cash necessary to fund future capital investments and to repay debt. Funds from operations is calculated using cash flow from operating activities as presented in the statement of cash flows before changes in non-cash working capital and settlement of decommissioning liabilities costs. Per share amounts are calculated using weighted average shares outstanding consistent with the calculation of loss per share. The following table reconciles funds from operations to cash flow from operating activities, which is the most directly comparable measure calculated in accordance with IFRS:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
Cash flow from operating activities	5,153	126	14,636	7,413
Changes in non-cash working capital	(165)	1,432	(45)	(453)
Funds from operations	5,318	1,558	14,681	6,960

Forward-Looking Statements

This document contains forward-looking statements. Statements used throughout this MD&A that are not historical facts may be considered to be "forward-looking statements". These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Company's objectives, goals or future plans, including management's assessment of future plans and operations, anticipated commodity prices and their impact, timing of expenditures, budgeted capital expenditures and the method of funding thereof and the nature of the expenditures, expected production rates including 2011 exit rates, expected cash flows for 2011, timing of phases of the IFRS conversion project, timing of drilling, completion and tie-in of wells, anticipated results from wells drilled, new incentives under the British Columbia royalty regime and the possible effect thereof on the Company and the economics of the wells to be drilled in that province, expected royalty rates, operating expenses, general and administrative expenses, and the expected levels of activities may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, volatility of commodity prices, imprecision of reserves estimates, environmental risks, competition from other producers, incorrect assessment of the value of acquisitions, ability to access sufficient capital from internal and external sources, and changes in the regulatory and taxation environment. Consequently, the Company's actual results may differ materially from those expressed in, or implied by, the forward-looking statements. Forward-looking statements or information is based on a number of factors and assumptions that have been used to develop such statements and information, but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions that may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Company operates; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects that the Company has an interest in to operate the field in a safe, efficient and effective manner; the Company's ability to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and cost of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and, the Company's ability to successfully market its oil and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included elsewhere herein and in reports on file with Canadian securities regulatory authorities and may be accessed

through the SEDAR website at www.sedar.com or at the Company's website at www.artekexploration.com. Furthermore, the forward-looking statements contained in this MD&A are made as at the date of this MD&A and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Overview

Artek was founded in February 2005 through the reorganization of 1143879 Alberta Ltd., which was incorporated on December 21, 2004 under the Business Corporations Act of Alberta. The Company's operational activities are concentrated primarily in the Peace River Arch and Deep Basin areas of northwestern Alberta and northeastern British Columbia where it is focused on organically generating conventional and resource natural gas and NGLs projects to achieve its reserves and production growth objectives. Artek also has a producing conventional crude oil project in the Leduc Woodbend area of central Alberta.

On January 14, 2010, Artek completed a reverse take-over of COSTA Energy Inc., a TSX Venture Exchange listed company. As a new public company, Artek's primary objective is to continue using its strong technical expertise in its core areas to achieve profitable per share growth in reserves, production and cash flow, complemented with opportunistic acquisitions that have drilling upside and where the Company has a competitive advantage.

Common shares of Artek trade on the Toronto Stock Exchange under the symbol RTK.

Financial and Operating Results

Production

The following is a summary of the Company's daily production for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Natural gas (mcf/d)	8,406	6,324	8,068	7,446
Crude oil (bbls/d)	1,022	505	914	518
NGLs (bbls/d)	75	44	74	54
Total (boe/d)	2,498	1,602	2,332	1,813

For the three months ended September 30, 2011, production averaged 2,498 boe/d (44% weighted to crude oil and NGLs), a 56% increase from the 1,602 boe/d (34% weighted to crude oil and NGLs) averaged during the same period of 2010. Volumes increased primarily due to additional oil and gas production brought on-stream from three wells drilled at Inga, British Columbia during the fourth quarter of 2010 and first nine months of 2011.

For the nine months ended September 30, 2011, Artek's production averaged 2,332 boe/d versus 1,813 boe/d a year ago. During the first nine months of 2011, production consisted of 8,068 mcf/d of natural gas and 988 bbls/d of crude oil and NGLs. Liquids production increased to 42% of total production compared to 32% for the same period of 2010 primarily as a result of the above-mentioned liquids-rich Inga wells coming on-stream.

Revenue and Pricing

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
Revenue				
Natural gas	3,049	2,043	8,813	8,805
Realized financial derivative gain	447	533	1,245	1,010
Total natural gas	3,496	2,576	10,058	9,815
Crude oil	7,892	3,361	22,068	10,395
Realized financial derivative loss	(68)	--	(523)	--
Total crude oil	7,824	3,361	21,545	10,395
NGLs	494	248	1,483	922
Sulphur	131	5	262	29
Total revenue before unrealized financial derivative gain (loss)	11,945	6,190	33,348	21,161
Unrealized derivative gain (loss)	1,039	(442)	741	--
Total revenue	12,984	5,748	34,089	21,161
Average Prices				
Natural gas (\$/mcf)	3.94	3.51	4.00	4.33
Realized derivative gain (\$/mcf)	0.58	0.92	0.57	0.50
Total natural gas sales price (\$/mcf)	4.52	4.43	4.57	4.83
Crude oil (\$/bbl)	83.91	72.35	88.48	73.57
Realized derivative loss (\$/bbl)	(0.73)	--	(2.10)	--
Total crude oil sales price (\$/bbl)	83.18	72.35	86.38	73.57
NGLs sales price (\$/bbl)	72.02	61.80	73.43	62.12
Total sales price (\$/boe) ⁽¹⁾	51.98	41.99	52.38	42.76

(1) Oil equivalent price includes minor sulphur sales revenue.

Artek's production is sold within Canada and is marketed to three significant North American purchasers. The Company's commodity prices are driven by Alberta spot prices applicable to its natural gas and the prevailing worldwide crude oil price, other than the derivative commodity contracts that are in place.

During the third quarter of 2011, revenue before unrealized derivative losses increased 93% to \$11,945,000 from \$6,190,000 recorded in the same period of 2010 due to a 23% increase in the Company's overall realized price to \$51.98/boe from \$41.99/boe recorded last year along with a 56% year-over-year increase in production. Liquids production as a percentage of total production increased to 44% compared to 34% a year ago. During the 2011 three-month period, Artek realized an average natural gas price of \$4.52/mcf (including a \$0.58/mcf realized gain from a financial derivative contract), \$83.18/bbl for crude oil (including a \$0.73/bbl realized loss from a financial derivative contract) and \$72.02/bbl for NGLs. For the corresponding period of 2010, the Company realized average natural gas, crude oil and NGLs prices of \$4.43/mcf (including a \$0.92/mcf realized gain from a physical derivative contract), \$72.35/bbl and \$61.80/bbl, respectively.

For the first nine months of 2011, revenue before unrealized derivative losses rose 58% to \$33,348,000 from \$21,161,000 in the same period last year partly because of a 29% increase in production. The Company's overall realized price increased 22% to \$52.38/boe from \$42.76/boe in the same period last year primarily as a result of improved commodity prices received during the 2011 period along with an increased liquids weighting to 42% of total production versus 32% for the same period last year.

The following table summarizes the natural gas and crude oil benchmark prices for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Average Benchmark Prices				
Natural gas – AECO Spot				
Daily index (\$/GJ)	3.47	3.36	3.57	3.91
Daily index (\$/mcf)	3.84	3.73	3.95	4.34
Crude oil – WTI (US\$/bbl)	89.76	76.20	95.48	77.65
Crude oil – Edmonton Par (CDN\$/bbl)	91.78	74.65	94.38	76.90
Exchange rate (US\$/CDN\$)	1.02	0.96	1.02	0.97

Artek utilizes risk management activities to mitigate the risk of volatile fluctuations in the commodity price environment and to guarantee a portion of the Company's cash flows. As at September 30, 2011, Artek had entered into the following financial derivative contracts, which are recorded at fair value. Artek locked in 3,000 GJ/d for the calendar year 2011 at a price of \$5.09/GJ. As part of the same swap transaction, the Company sold WTI calls on 300 bbls/d at US\$90.00/bbl for the 2011 calendar year and US\$95.00/bbl for the 2012 calendar year. The fair value of these contracts as at September 30, 2011 was a liability of \$88,000. Artek recorded an unrealized gain on derivative instruments of \$1,085,000 in the third quarter.

Term	Volume	Price	Settlement Index
Jan. 1, 2011 – Dec. 31, 2011	3,000 GJ/d	\$5.09/GJ	AECO Daily
Jan. 1, 2011 – Dec. 31, 2011	Call 300 bbls/d	US\$90.00/bbl	WTI
Jan. 1, 2012 – Dec. 31, 2012	Call 300 bbls/d	US\$95.00/bbl	WTI

On November 2, 2011, the Company entered into a crude oil swap for 300 bbls/d at CDN\$92.00/bbl for the 2012 calendar year.

Royalties

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
Oil and gas revenues before realized and unrealized gain on derivative instruments	11,566	5,657	32,626	20,151
Royalties				
Crown	891	222	2,465	930
Freehold/GORRs	1,652	915	4,254	2,406
Total royalties	2,543	1,137	6,719	3,336
Total royalties (\$/boe)	11.06	7.71	10.55	6.74
	(%)	(%)	(%)	(%)
% of Revenue				
Crown	8	4	8	5
Other	14	16	13	12
Total	22	20	21	17

For the quarter ended September 30, 2011, the Company recorded \$2,543,000 in total royalties or 22% of revenue versus \$1,137,000 or 20% of revenue a year ago. Approximately 8% of total revenue paid in the third quarter of 2011 consisted of Crown royalties and 14% of total revenue was paid to overriding and freehold royalty owners ("GORRs") compared to 4% and 16%, respectively, in the 2010 three-month period. The royalty rates increased as a result of increased liquids production, which bear higher royalty rates compared to natural gas production.

For the nine-month period ended September 30, 2011, total royalties were \$6,719,000 or 21% of revenue versus \$3,336,000 or 17% of revenue a year ago. The year-over-year increases were again due to the increase in the Company's liquids production. During the first nine months of 2011, the royalty rates on natural gas and liquids production were approximately 8% and 25%, respectively.

Production and Operating Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
Production and operating expenses	2,542	1,895	7,211	6,327
Production and operating expenses (\$/boe)	11.06	12.85	10.55	12.78

Production and operating expenses include all costs associated with the production of oil and natural gas. The major components of production and operating costs include charges for gathering and processing, compression as well as water hauling and water disposal. Artek processes all of its natural gas at third party facilities and rents most of its wellsite facilities.

Total production and operating costs were \$2,542,000 for the third quarter of 2011 compared to \$1,895,000 a year ago. Production and operating costs on a boe basis decreased 14% to \$11.06/boe from \$12.85/boe in 2010. The decrease was a result of additional Inga volumes being processed at the Company owned gas facility at Inga, British Columbia.

For the nine months ended September 30, 2011, total production and operating costs were \$7,211,000 or \$10.55/boe versus \$6,327,000 or \$12.78/boe in the same period of 2010. The decrease was again based on the additional Inga volumes.

Transportation Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
Transportation expenses	390	256	1,114	855
Transportation expenses (\$/boe)	1.70	1.74	1.75	1.73

Transportation costs consist of gas transportation and fuel charges on NOVA and Alliance pipelines, pipeline tariffs for oil and NGLs as well as trucking charges. These costs can vary depending on the type of production facilities, the method of transportation, the distances covered, the rates charged by the carriers, quantities shipped and the type of service on various pipelines (interruptible versus firm service).

For the three months ended September 30, 2011, transportation costs were \$390,000 or \$1.70/boe compared to \$256,000 or \$1.74/boe for the same period of 2010.

During the first nine months of 2011, transportation costs totaled \$1,114,000 or \$1.75/boe versus \$855,000 or \$1.73/boe for the same period a year ago.

Operating Netbacks

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenue				
Natural gas (\$/mcf)	4.52	4.43	4.57	4.83
Crude oil (\$/bbl)	83.18	72.35	86.38	73.57
NGLs (\$/bbl)	72.02	61.80	73.43	62.12
Production revenue (\$/boe) ⁽¹⁾	51.98	41.99	52.38	42.76
Expenses				
Royalties (\$/boe)	(11.06)	(7.71)	(10.55)	(6.74)
Operating (\$/boe)	(11.06)	(12.85)	(11.33)	(12.78)
Transportation (\$/boe)	(1.70)	(1.74)	(1.75)	(1.73)
Operating netback (\$/boe)	28.16	19.69	28.75	21.50

(1) Includes sulphur net revenue with no associated production as no conversion exists for tons to boes. On a per boe basis for the three and nine months ended September 30, 2011, production revenue includes \$0.57/boe and \$0.41/boe (2010 – \$0.04/boe and \$0.06/boe) from sulphur, respectively.

For the third quarter of 2011, the Company recorded an operating netback of \$28.16/boe compared to \$19.69/boe in the same quarter of 2010. The 43% year-over-year increase was a result of crude oil and NGLs production increasing to 44% of total production versus 34% recorded last year along with a reduction in per boe operating costs. During the 2011 three-month period, crude oil and NGLs pricing was much stronger than pricing for natural gas.

During the first nine months of 2011, Artek's operating netback was \$28.75/boe versus \$21.50/boe in the same period a year ago. Again, the primary reason for the increase was crude oil and NGLs production increasing to 42% of total production versus 32% recorded last year along with a reduction in per boe operating costs.

General and Administrative ("G&A") Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
G&A expenses (gross)	1,213	1,156	4,081	3,184
G&A capitalized (direct)	(327)	(318)	(1,185)	(921)
G&A recoveries via operations	(152)	(93)	(634)	(374)
G&A expenses (net)	734	745	2,262	1,889
G&A expenses (\$/boe)	3.20	5.05	3.55	3.82

For the three months ended September 30, 2011, net G&A expenses totaled \$734,000 or \$3.20/boe compared to \$745,000 or \$5.05/boe recorded in the same period a year ago. During the third quarter of 2011, the Company capitalized \$327,000 (2010 – \$318,000) relating to its exploration and development staff salaries and recovered \$152,000 (2010 – \$93,000) relating to operator overhead. Decreased G&A expenses on a boe basis were primarily due to the Company's production increasing 56%.

Net G&A expenses increased to \$2,262,000 in the first nine months of 2011 from \$1,889,000 in the same period of 2010. During the 2011 nine-month period, \$1,185,000 (2010 – \$921,000) of direct costs were capitalized, while \$634,000 (2010 – \$374,000) of operator overhead recoveries were capitalized. Gross G&A expenses increased because of increased employee costs and office rent expenses. On a per boe basis, the G&A costs decreased, again because corporate production increased 29%.

Share-Based Compensation Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
Gross share-based compensation expense	459	268	1,139	784
Capitalized share-based compensation expense	(226)	(105)	(552)	(307)
Share-based compensation expense	233	163	587	477
Share-based compensation expense (\$/boe)	1.01	1.11	0.86	0.96

For the three months ended September 30, 2011, Artek recorded non-cash share-based compensation expense of \$233,000 or \$1.01/boe (2010 – \$163,000 or \$1.11/boe) and capitalized \$226,000 (2010 – \$105,000) for total share-based compensation of \$459,000 (2010 – \$268,000).

The Company had non-cash share-based compensation expense of \$587,000 or \$0.86/boe for the first nine months of 2011 (2010 – \$477,000 or \$0.96/boe) and capitalized \$552,000 (2010 – \$307,000) for total share-based compensation of \$1,139,000 (2010 – \$784,000).

Other Costs

For the first quarter of 2010, the Company incurred transaction costs of \$301,000 relating to the reverse take-over of COSTA Energy Inc. that closed on January 14, 2010. The majority of the costs related to legal and audit expenses.

Finance Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
Interest expense	418	599	1,361	1,493
Accretion expense	66	72	184	209
Total finance expenses	484	671	1,545	1,702
Total finance expenses (\$/boe)	2.11	4.56	2.41	3.43

For the third quarter of 2011, the Company incurred interest expense of \$418,000 compared to \$599,000 in 2010. Artek paid an average interest rate of approximately 4.5% (2010 – 5.1%) on its bank debt during the 2011 three-month period. On a boe basis, the Company's interest costs amounted to \$1.82/boe compared to \$4.07/boe the previous year. The decrease was a function of increased production, decreased bank debt and lower interest rates during the quarter.

The Company's accretion expense for the three-month period ended September 30, 2011 was \$66,000 or \$0.29/boe versus \$72,000 or \$0.49/boe in the comparable period of 2010. The accretion expense relates to the increase in the decommissioning obligations due to the passage of time.

During the first nine months of 2011, Artek's interest expense totaled \$1,361,000 or \$2.14/boe compared to \$1,493,000 or \$3.01/boe in 2010, while the Company's accretion expense was \$184,000 or \$0.29/boe versus \$209,000 or \$0.42/boe in the comparable period of 2010. The decrease in per boe interest expense was again a function of increased production and decreased bank debt during the period.

Depletion and Depreciation ("D&D") Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
D&D expense	2,951	1,842	14,570	6,507
D&D expense (\$/boe)	12.84	12.50	22.88	13.15

The Company's D&D expense for the three-month period ended September 30, 2011 was \$2,951,000 or \$12.84/boe versus \$1,842,000 or \$12.50/boe in the comparable period of 2010.

For the nine months ended September 30, 2011, total D&D expense was \$14,570,000 or \$22.88/boe compared to \$6,507,000 or \$13.15/boe. The increase was a result of the Company recording a \$6,100,000 impairment charge in the first quarter of 2011 on one of its cash-generating units ("CGUs") due to reduced natural gas prices.

Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit-of-production basis over proved plus probable reserves. The depletion policy under Canadian GAAP was based on units of production over proved reserves. In addition, depletion was calculated on the Canadian cost centre under Canadian GAAP. IFRS requires D&D to be calculated based on individual components (i.e. fields or combinations thereof).

Deferred Income Taxes

For the three months ended September 30, 2011, Artek recorded a deferred income tax expense in the amount of \$851,000 (\$3.70/boe) compared to a deferred income tax reduction of \$438,000 (\$2.97/boe) a year ago. The increase was due to the year-over-year increase in earnings.

Deferred income tax expense totaled \$234,000 (\$0.37/boe) for the first nine months of 2011 versus \$779,000 (\$1.57/boe) in the comparable 2010 period. The difference was based on a year-over-year decrease in net loss. For the nine months ended September 30, 2011 and 2010, the deferred tax expense increased by \$315,000 and \$729,000, respectively, due to the flow-through shares issued in 2011 and 2010.

Artek follows the liability method of accounting for income taxes whereby deferred income taxes are calculated based on temporary differences arising from the variance between tax basis of an asset or liability and its property, plant and equipment, exploration and evaluation assets' carrying value and decommissioning liabilities, and fair value of derivative instruments.

Funds Flow from Operations and Net Earnings (Loss)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s, except per share amounts)	(\$)	(\$)	(\$)	(\$)
Funds flow from operations	5,318	1,558	14,681	6,960
Per share – basic	0.13	0.05	0.39	0.26
– diluted	0.13	0.05	0.39	0.26
Cash flow from operating activities	5,153	126	14,636	7,413
Net earnings (loss)	1,914	(1,357)	(747)	(2,288)
Per share – basic	0.05	(0.04)	(0.02)	(0.08)
– diluted	0.05	(0.04)	(0.02)	(0.08)

Funds flow from operations for the third quarter of 2011 totaled \$5,318,000 or \$0.13 per basic and diluted share compared to \$1,558,000 or \$0.05 per basic and diluted share in 2010. For the nine months ended September 30, 2011, funds flow from operations totaled \$14,681,000 or \$0.39 per basic and diluted share versus \$6,960,000 or \$0.26 per basic and diluted share recorded a year ago. The increase in funds flow from operations was due to the Company achieving a higher operational netback, which was primarily a result of increased crude oil and NGLs production as a percentage of total production. Stronger crude oil and NGLs pricing compared to pricing for natural gas contributed to higher funds flow from operations.

During the three months ended September 30, 2011, the Company recorded net earnings of \$1,914,000 or \$0.05 per basic and diluted share compared to a net loss of \$1,357,000 or \$(0.04) per basic and diluted share in the same quarter of 2010. The increase in net earnings was primarily a result of the unrealized gain on financial derivatives in the third quarter of 2011 that totaled \$1,039,000 along with an increase in liquids production, which increased the Company's operating netbacks. For the first nine months of 2011, the Company recorded a net loss of \$747,000 or \$(0.02) per basic and diluted share compared to \$2,288,000 or \$(0.08) per basic and diluted share in the same period of 2010. The year-over-year decrease in net loss was again a result of a higher operational netback as discussed above.

Netbacks

The following table provides detailed unit statistics on a boe basis for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(\$/boe)	(\$/boe)	(\$/boe)	(\$/boe)
Revenue				
Natural gas (\$/mcf)	4.52	4.43	4.57	4.83
Crude oil (\$/bbl)	83.18	72.35	86.38	73.57
NGLs (\$/bbl)	72.02	61.80	73.43	62.12
Production revenue (\$/boe) ⁽¹⁾	51.98	41.99	52.38	42.76
Expenses				
Royalties	(11.06)	(7.71)	(10.55)	(6.74)
Operating	(11.06)	(12.85)	(11.33)	(12.78)
Transportation	(1.70)	(1.74)	(1.75)	(1.73)
Operating netback	28.16	19.69	28.75	21.50
G&A (excludes non-cash items)	(3.20)	(5.05)	(3.55)	(3.82)
Interest expense	(1.82)	(4.06)	(2.14)	(3.02)
Transaction costs for COSTA Energy Inc. reverse take-over	--	--	--	(0.61)
Funds flow netback ⁽²⁾	23.14	10.57	23.06	14.06
D&D	(12.84)	(12.50)	(22.88)	(13.15)
Accretion of decommissioning liabilities	(0.29)	(0.49)	(0.29)	(0.42)
Exploration and evaluation	(1.49)	(2.90)	(0.93)	(0.86)
Loss on disposal of property, plant and equipment	--	(2.76)	--	(0.82)
Share-based compensation	(1.01)	(1.11)	(0.92)	(0.96)
Unrealized gain (loss) on derivative instruments	4.52	(3.00)	1.16	(0.89)
Deferred income taxes (reduction)	(3.70)	2.97	(0.37)	(1.57)
Net earnings (loss) netback	8.33	(9.21)	(1.17)	(4.62)

(1) Includes sulphur net revenue with no associated production as no conversion exists for tons to boes. On a boe basis for the three and nine months ended September 30, 2011, production revenue includes \$0.57/boe and \$0.41/boe (2010 – \$0.04/boe and \$0.06/boe) from sulphur, respectively.

(2) Non-IFRS measure: refer to disclosure on non-IFRS measure. Funds flow netback is calculated by dividing funds flow by the sales volume per boe for the periods then ended.

Capital Expenditures on Property, Plant and Equipment as well as Exploration and Evaluation Assets

During the three and nine months ended September 30, 2011, the Company invested \$11,084,000 and \$30,172,000, respectively, in total capital expenditures, which included capital expenditures on exploration and evaluation assets as well as property, plant and equipment, compared to \$5,135,000 and \$19,936,000 in the respective periods of 2010.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)(excluding decommissioning liabilities and capitalized share-based compensation)	(\$)	(\$)	(\$)	(\$)
Drilling and completions	5,377	3,880	18,842	15,629
Equipment and facilities	3,770	797	6,520	2,591
Property acquisition	--	--	--	365
Geological and geophysical	835	75	1,583	118
Land and lease retention	753	64	2,020	267
Capitalized G&A and other	349	319	1,207	966
Total capital additions	11,084	5,135	30,172	19,936

During the third quarter of 2011, the Company incurred \$5,377,000 (2010 – \$3,880,000) in drilling and completion expenditures that involved the participation in 2 gross (1.2 net) wells for a 100% success rate. Equipping and facilities expenditures for the three months ended September 30, 2011 and 2010 were \$3,770,000 and \$797,000, respectively. During the 2011 three-month period, the Company invested \$1,588,000 on land and seismic as well as \$349,000 on capitalized G&A and other corporate assets versus \$139,000 and \$319,000, respectively, in the same period of 2010.

Drilling and completion expenditures totaled \$18,842,000 for the nine months ended September 30, 2011 (2010 – \$15,629,000) that involved the participation in 5 gross (3.1 net) wells for a 100% success rate. During the comparative period of 2010, the Company drilled 6 gross (4.7 net) wells for a 100% success rate. The property acquisition totaling \$365,000 in the first nine months of 2010 relates to a property price adjustment on the Leduc Woodbend asset that was acquired in November 2009 as part of the Rising Sky Energy Ltd. ("Rising Sky") acquisition.

Drilling Activity

	Exploration		Development		Total	
	Gross (#)	Net (#)	Gross (#)	Net (#)	Gross (#)	Net (#)
Three Months Ended						
September 30, 2011						
Natural gas	--	--	1	0.6	1	0.6
Crude oil and NGLs	1	0.6	--	--	1	0.6
Abandoned	--	--	--	--	--	--
Total wells	1	0.6	1	0.6	2	1.2
Success rate (%)		100		100		100
Average working interest (%)		60		60		60
Three Months Ended						
September 30, 2010						
Natural gas	1	0.6	--	--	1	0.6
Crude oil and NGLs	--	--	2	1.6	2	1.6
Abandoned	--	--	--	--	--	--
Total wells	1	0.6	2	1.6	3	2.2
Success rate (%)		100		100		100
Average working interest (%)		60		80		73
Nine Months Ended						
September 30, 2011						
Natural gas	--	--	3	1.5	3	1.5
Crude oil and NGLs	2	1.6	--	--	2	1.6
Abandoned	--	--	--	--	--	--
Total wells	2	1.6	3	1.5	5	3.1
Success rate (%)		100		100		100
Average working interest (%)		60		50		62
Nine Months Ended						
September 30, 2010						
Natural gas	2	1.6	1	0.5	3	2.1
Crude oil and NGLs	1	1.0	2	1.6	3	2.6
Abandoned	--	--	--	--	--	--
Total wells	3	2.6	3	2.1	6	4.7
Success rate (%)		100		100		100
Average working interest (%)		87		70		78

Acquisition

On January 14, 2010, the Company closed the acquisition of COSTA Energy Inc. ("COSTA") through a Plan of Arrangement. COSTA was a shell company that was trading on the NEX Board of the TSX Venture Exchange ("TSX-V"). Artek commenced trading on the TSX-V (Tier 1 Status) on January 21, 2010 under the symbol RTK. Artek issued 233,200 common shares for the acquisition of COSTA. The transaction was recorded as a reverse take-over that does not constitute a business combination, and accordingly, has been accounted for as though Artek acquired COSTA using the purchase method of accounting. The fair values of the net assets acquired were as follows:

	Amount
(000s)	(\$)
Net assets acquired:	
Working capital deficiency	(122)
Future tax asset	1,008
	886
Consideration for the acquisition:	
Issuance of 233,200 common shares	886
	886

Share Capital

On March 17, 2011, the Company closed a bought deal equity financing where it raised gross proceeds of \$16,620,000, which resulted in the issuance of 4,800,000 common shares at a price of \$2.40 per share and 1,700,000 flow-through common shares at a price of \$3.00 per share.

In January 2010, prior to the common share split completed as part of the acquisition of COSTA, 112,000 (560,000 post stock split) warrants were exercised at a price of \$7.50 (\$1.50 post stock split) per warrant for total proceeds of \$840,000. In addition, 198,500 (992,500 post stock split) warrants were exercised based on a cashless exercise whereby 120,145 (600,725 post stock split) common shares were issued based on an imputed price of \$19.00 (\$3.80 post stock split) per share and 25,000 (125,000 post stock split) options were exercised based on a cashless exercise whereby 10,526 (52,630 post stock split) common shares were issued based on an imputed price of \$19.00 (\$3.80 post stock split) per share.

In March 2010, 100,000 warrants (post stock split) were exercised at a price of \$1.50 per warrant for total proceeds of \$150,000.

On August 11, 2010, Artek completed a non-brokered private placement of 7,594,940 common shares at \$1.15 per share for total gross proceeds of \$8,734,000.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(#)	(#)	(#)	(#)
Weighted average shares outstanding:				
Basic	39,583	30,524	37,798	27,164
Diluted	39,889	30,524	38,130	27,164
Outstanding securities:				
Common shares	39,583	33,083	39,583	33,083
Options	3,455	3,211	3,455	3,211
Warrants	--	250	--	250

On January 26, 2011, 1,855,000 options with an exercise price of \$1.90 per share were granted by Artek.

On July 25, 2011, 660,000 options with an exercise price of \$2.25 per share were granted by Artek.

On October 5, 2011, 30,000 options with an exercise price of \$1.50 per share were granted by Artek.

As at November 9, 2011, Artek had 39,583,000 common shares outstanding along with 3,485,000 stock options with an average exercise price of \$1.75 per share to acquire the same number of common shares of the Company.

Liquidity and Capital Resources

Working Capital

Accounts receivable consist of production revenue receivables from Artek's three major purchasers as well as joint venture receivables from the Company's partners with respect to operating and capital costs. Virtually all of Artek's accounts receivable are from companies in the oil and gas industry and are subject to normal industry credit risks. As at September 30, 2011, the Company's accounts receivable consisted of \$5,510,000 (2010 – \$4,705,000) from joint venture partners, \$3,923,000 (2010 – \$1,927,000) from petroleum and natural gas marketers, \$180,000 (2010 – \$352,000) from provincial governments and \$651,000 (2010 – \$132,000) from GST receivables. Prepaid costs primarily include unamortized insurance premiums, prepaid rent and Crown royalty deposits.

At September 30, 2011, of the accounts receivable balance of \$10,264,000, 91% was current and the balance was over 90 days due. Artek had no material accounts receivable deemed uncollectible. The amounts outstanding for more than 90 days are predominantly due from large, well-established joint venture partners or have offsetting accounts payable.

Accounts payable include capital, operating, royalty and G&A costs as well as accrued or estimated costs for these items. Included in accounts payable are amounts owing to the Company's joint venture partners with respect to cash calls and non-operated properties.

Liquidity risk relates to the risk the Company will encounter should it have difficulty in meeting obligations associated with the financial liabilities. The financial liabilities on the Company's balance sheet consist of accounts payable, risk management contracts and bank debt. Accounts payable consist of invoices payable to trade suppliers relating to the office and field operating activities and the Company's capital spending program. Artek processes invoices within a normal payment period. Artek anticipates it will continue to have adequate liquidity to fund its financial liabilities through its future funds from operations and available bank debt. The Company had no defaults or breaches on its bank debt or any of its financial liabilities.

The following table summarizes the change in working capital for the nine months ended September 30, 2011 and the year ended December 31, 2010:

	Nine Months Ended September 30, 2011	Year Ended December 31, 2010
(000s)	(\$)	(\$)
Working capital deficiency – beginning of period	(50,606)	(42,488)
Funds flow from operations	14,681	9,484
Issue of capital stock for cash, net of share issue expenses	15,563	9,611
Capital expenditures	(30,172)	(28,396)
Property dispositions	--	897
Change in fair value of derivative instruments	(334)	408
Working capital deficiency acquired from business combination	--	(122)
Working capital deficiency – end of period	(50,868)	(50,606)

Source of Funds

Artek entered 2011 with a working capital deficiency of \$50,606,000. During the first nine months, the Company generated funds flow from operations of \$14,681,000, issued share capital net of share issue expenses of \$15,563,000 and incurred \$30,172,000 in capital activities. As at September 30, 2011, the Company had a working capital deficiency of \$50,868,000. On February 3, 2011, the Company obtained a \$10,000,000 acquisition/development demand loan credit facility. The facility must be used for the acquisition of producing petroleum and natural gas reserves and/or the development of proved non-producing or undeveloped petroleum and natural gas reserves. Repayment of principal and interest shall commence the month following drawdown based on the half-life of the reserves being financed. No amounts were outstanding at September 30, 2011 on this facility. On July 7, 2011, the revolving credit facility was increased to \$60,000,000 from \$56,000,000, of which \$44,402,000 had been drawn against the credit facility as at September 30, 2011. The amount of the facility is subject to a borrowing base test performed on a periodic basis by the lenders based primarily on reserves and using commodity prices estimated by the lenders as well as other factors. A decrease in the borrowing base could result in a reduction to the credit facility, which may require a repayment to the lenders. The next bank credit review is scheduled for November 2011.

Off-Balance Sheet Transactions

There were no off-balance sheet transactions entered into during the period, nor were there any outstanding as of the date of this MD&A other than letters of credit totaling \$334,000 with the British Columbia Oil and Gas Commission.

Capital Resources and Credit Facility

Artek actively manages its capital structure, which includes shareholders' equity, bank debt and working capital. In order to maintain or adjust the capital structure, Artek considers the following: incremental investment and acquisition opportunities, the current level of credit available from the Company's lender, the level of credit that may be obtainable from the Company's lender as a result of growth in reserves values, the availability of other sources of debt with different characteristics than the existing bank debt, the sale of assets, limiting the size of the investment program, and new share issuances, if available on favourable terms. The Company's objective is to maintain a flexible structure that will allow it to execute its investment program, including exploration and development of its oil and gas properties and acquisition and disposition transactions, which all carry varying amounts of risk. Artek continually strives to balance the proportion of debt and equity in its capital structure to take into account the level of risk being incurred in its investment program. Artek may from time to time issue shares and adjust its capital spending to manage current and projected debt levels.

The methods used by the Company to monitor capital is based on the ratio of net debt to annualized cash flow and also the ratio of net debt to the Company's credit facility availability. The first net debt ratio is calculated as net debt, defined as outstanding revolving bank loan plus or minus working capital, divided by annualized cash flow from operations before changes in non-cash working capital and asset retirement obligations based on the most recent quarter. The second net debt ratio is calculated as net debt, defined as outstanding revolving bank loan plus or minus working capital, divided by the credit facility availability. Artek's current strategy is to maintain a ratio of net debt to annualized cash flow no more than 2.0:1, or if the ratio exceeds 2.0:1, to not draw more than 80% of the Company's current credit facility availability. The ratio may temporarily increase at certain times as a result of acquisitions. In order to facilitate the management of this ratio, the Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors, including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors. As at September 30, 2011, Artek's ratio of net debt to annualized cash flow was 2.4:1 and the Company's ratio of net debt to credit facility availability was 85%, which are both just outside the range established by the Company. In order to continually improve upon the above-mentioned ratios, Artek plans to review its options to either dispose of certain non-core assets as normal course of business or to raise additional equity capital in 2011 and to invest 75% of its capital budget towards crude oil and liquids-rich natural gas projects, which have higher netbacks.

Three Months Ended September 30, (000s)	2011 (\$)	2010 (\$)
Current assets	11,066	7,802
Current liabilities	61,934	53,313
Net debt	50,868	45,511
Net earnings (loss)	1,914	(1,394)
Add (deduct):		
D&D	2,951	1,842
Accretion of decommissioning liabilities	66	72
Exploration and evaluation	342	428
Loss on disposal of property, plant and equipment	--	406
Unrealized gain on financial derivatives	(1,039)	442
Share-based compensation	233	163
Deferred income tax expense	851	(451)
	5,318	1,558
Annualized cash flow	21,272	6,232
Net debt to annualized cash flow	2.4	7.3
Credit facility available	60,000	53,000
Net debt to credit facility available (%)	85	86

Artek has a financial covenant with its banker whereby its working capital ratio cannot fall below 1.0:1 where the undrawn availability under the credit facility is included with the current assets. As of September 30, 2011, the Company was in compliance with the required covenant.

Contractual Obligations

As at September 30, 2011, the Company had contractual obligations for its office lease totaling \$933,000 to the end of 2015.

As at September 30, 2011, the Company had contractual obligations for firm natural gas transportation charges totaling \$1,813,000 to the end of 2014.

As at September 30, 2011, the Company had contractual obligations for leasing of a drilling rig totaling \$5,940,000 to the end of 2012.

Related Party Transactions

During the period ended September 30, 2011, the Company received legal services from a firm in which the Corporate Secretary of the Company is a partner. The Company incurred costs totaling \$199,000 (2010 – \$116,000), which have been included in G&A expenses and share issuance costs, and \$nil (2010 – \$46,000) remained in accounts payable at September 30, 2011. These amounts are billed and recorded at rates consistent with those charged to third parties.

Subsequent Events

Effective October 19, 2011, the Company entered into an interest rate swap transaction whereby the interest rate applicable to borrowings by way of bankers' acceptances was fixed. Borrowings in the amount of \$20,000,000 were fixed at an annual interest rate of 1.14% (before bank stamping fees) until the contract matures on October 19, 2013.

On November 2, 2011, the Company entered into a crude oil swap for 300 bbls/d at CDN\$92.00/bbl for the 2012 calendar year.

Outlook

For fiscal 2011, the Company still anticipates achieving its average production guidance of 2,400 to 2,550 boe/d as well as meeting or exceeding its year-end exit guidance of between 2,900 and 3,100 boe/d.

For the 2012 calendar year, Artek has hedged 300 bbls/d of crude oil at CDN\$92.00/bbl. The Company plans to release its 2012 capital spending budget and production expectations following analysis of the completion results on the two Inga horizontal wells, which will be completed at the end of November. The Company will continue to pursue opportunities to divest non-core assets in order to expand investments in its core properties.

Disclosure Controls and Procedures and Internal Control Over Financial Reporting

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to Artek is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. No material changes in the Company's internal controls over financial reporting were identified during the quarter ended September 30, 2011 that would materially affect, or is reasonably likely to materially affect, the Company's internal controls over financial reporting.

While the Officers have designed the Company's disclosure controls and procedures and internal controls over financial reporting, they expect that these controls and procedures will not prevent all errors and fraud. A controls system, no matter how well conceived or operated, can only provide reasonable, not absolute, assurance that the objectives of the control system are met.

Selected Quarterly Information

Below is summarized quarterly information for the previous eight quarters.

Three Months Ended	Dec.31, 2009 ⁽¹⁾	Mar.31, 2010	Jun.30, 2010	Sep.30, 2010	Dec.31, 2010	Mar.31, 2011	Jun.30, 2011	Sep.30, 2011
<i>(000s, except per share amounts)(unaudited)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>
Petroleum and natural gas revenues	5,740	8,286	6,684	5,749	6,767	9,103	11,956	11,566
Cash provided by operations	1,545	3,646	3,642	126	4,077	3,985	5,519	5,153
Funds from operations	2,290	3,046	2,356	1,558	2,524	3,873	5,490	5,318
Per share – basic	0.11	0.12	0.09	0.05	0.08	0.11	0.14	0.13
– diluted	0.10	0.12	0.09	0.05	0.08	0.11	0.14	0.13
Net earnings (loss)	(777)	(428)	(503)	(1,357)	(572)	(4,836)	2,175	1,914
Per share – basic	(0.04)	(0.02)	(0.02)	(0.04)	(0.02)	(0.14)	0.05	0.05
– diluted	(0.04)	(0.02)	(0.02)	(0.04)	(0.02)	(0.14)	0.05	0.05
Capital expenditures	4,612	11,730	3,070	5,135	8,460	11,339	7,748	11,084
Working capital deficiency	(42,488)	(50,318)	(51,034)	(45,511)	(50,606)	(43,352)	(45,572)	(50,868)
Shareholders' equity	77,959	78,420	78,185	85,759	86,083	96,357	98,911	101,285
Production								
Natural gas (mcf/d)	8,074	8,807	7,233	6,324	7,034	8,056	7,740	8,406
Crude oil (bbls/d)	298	539	509	505	573	760	956	1,022
NGLs (bbls/d)	36	64	56	44	48	74	73	75
Total (boe/d)	1,680	2,071	1,770	1,602	1,793	2,177	2,319	2,498
Average wellhead prices								
Natural gas (\$/mcf)	4.81	5.29	4.63	4.43	4.38	4.52	4.66	4.52
Crude oil (\$/bbl)	71.03	76.81	71.39	72.35	76.33	81.29	93.85	83.18
NGLs (\$/bbl)	60.87	64.24	59.95	61.80	62.03	70.67	77.67	72.02
Total (\$/boe) ⁽²⁾	37.14	44.45	41.50	41.99	43.38	47.97	56.90	51.98
Operating cost (\$/boe)	10.86	12.29	13.30	12.85	12.14	11.76	11.21	11.06
Operating netback (\$/boe)	20.04	22.87	21.59	19.69	21.50	26.44	31.54	28.16

(1) The amounts for 2009 are non-adjusted Canadian GAAP calculations. The comparative amounts for 2010 have been adjusted to comply with IFRS.

(2) Product prices include gains/losses from physical fixed price contracts and include minor sulphur sales revenue.

Artek's oil and gas revenues, cash and funds from operations, and net earnings are all impacted by production levels and volatile commodity pricing. From 2009 to 2011, these performance measures have fluctuated as a result of volatile oil and natural gas prices due to the unstable global economy.

Significant factors and trends that have impacted the Company's results during the above periods include:

- Revenue is directly impacted by the Company's ability to replace existing declining production and add incremental production through its on-going capital expenditure program.
- Production in the second and third quarters of 2010 were negatively impacted by scheduled and unscheduled third party shutdowns and wet weather conditions experienced during the spring and summer.
- In November 2009, the Company acquired Rising Sky with approximately 550 boe/d (85% to 90% leveraged towards crude oil and NGLs) of production at closing. In the same quarter, Artek divested 165 boe/d of low interest natural gas production.
- In the fourth quarter of 2010, the Company recorded an impairment charge of \$600,000 on one of its CGUs because of a decrease in natural gas prices.
- In the first quarter of 2011, the Company recorded an impairment charge of \$6,100,000 on one of its CGUs relating to a further decrease in natural gas prices.
- Revenue and royalties are significantly impacted by underlying commodity prices. The Company uses financial derivative contracts to reduce the exposure to commodity price fluctuations on a portion of its production. These contracts can cause volatility in net earnings as a result of unrealized gains and losses on financial derivative contracts. Artek incurred unrealized losses of \$442,000 in the third quarter of 2010, \$387,000 in the fourth quarter of 2010, \$1,641,000 in the first quarter of 2011, an unrealized gain of \$1,344,000 in the second quarter of 2011 and an unrealized gain of \$1,039,000 in the third quarter of 2011 in regards to its risk management contracts.

Adoption of International Financial Reporting Standards ("IFRS")

Artek's unaudited interim financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34 – "Interim Financial Reporting". These interim financial statements are for part of the period covered by the first IFRS annual financial statements and IFRS 1 – "First-Time Adoption of International Financial Reporting Standards" has been applied. The interim financial statements do not include all of the information required for full annual financial statements.

An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Company is provided in note 19 of the unaudited interim financial statements. This note includes reconciliations of equity and total comprehensive income for comparative periods reported under Canadian GAAP to those reported for those periods and at the date of transition under IFRS along with details of the IFRS 1 exemptions taken. The adoption of IFRS does not impact the underlying economics of Artek's operations or cash flows.

New and Pending Accounting Standards

In May 2011, the International Accounting Standards Board ("IASB") issued four new standards and two amendments to existing standards. Five of these items relate to consolidation, while the remaining standard addresses fair value measurement. All of the new standards are effective for annual periods beginning on or after January 1, 2013. Early adoption is permitted.

IFRS 10 – "Consolidated Financial Statements" replaces IAS 27 – "Consolidated Separate Financial Statements". IFRS 10 introduces a new principle-based definition of control applicable to all investees to determine the scope of consolidation. The standard provides the framework for consolidated financial statements and their preparation based on the principle of control.

IFRS 11 – "Joint Arrangements" replaces IAS 31 – "Interests in Joint Ventures". IFRS 11 divides joint arrangements into two types, each having its own accounting model. A joint operation continues to be accounted for using proportionate consolidation where a joint venture must be accounted for using equity accounting. This differs from IAS 31 where there was a choice to use proportionate consolidation or equity accounting for joint ventures. A joint venture is defined as the joint operators having rights to the assets and obligations for the liabilities relating to the arrangement. In a joint venture, the joint operators have rights to the net assets of the arrangement, typically through their investment in a separate joint venture entity.

IFRS 12 – "Disclosure of Interests in Other Entities" is a new standard that combines all of the disclosure requirements for subsidiaries, associates and joint arrangements as well as unconsolidated structured entities.

IFRS 13 – "Fair Value Measurement" is a new standard meant to clarify the definition of fair value, provide guidance on measuring fair value and improve disclosure requirements related to fair value measurement.

IFRS 28 – "Investments in Associate and Joint Ventures" revised the existing standard and prescribes the accounting for investments as well as sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

The IASB also issued "Presentation of Items of Other Comprehensive Income", an amendment to IAS 1 – "Financial Statement Presentation". The amendment addresses the presentation of other comprehensive income and requires the grouping of items within other comprehensive income that might eventually be reclassified to the profit and loss section of the income statement. The change becomes effective for financial years after July 1, 2012 with earlier adoption permitted.

The Company has not completed its evaluation of the effect of adopting these standards on its financial statements.

Business Risks and Risk Management

General

The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Artek attempts to reduce risk in accomplishing these goals through the combination of hiring experienced and knowledgeable personnel and careful evaluation of drilling opportunities.

Certain of the wells the Company drills tend to be deep and are subject to higher drilling costs than those in more shallow areas. Furthermore, most wells require fracture treatment before they are capable of production, which also increases costs. Artek mitigates the additional economic pressure that this creates by carefully evaluating risk/reward scenarios for each location, by taking what management considers to be appropriate working interests after considering project risk, by practicing prudent operations so that drilling risk is decreased, by ranking and limiting the zones that the Company is willing to complete, and by drilling deep so that the multi-zone potential of the area can be accessed and potentially developed. In addition, Artek monitors capital spending on an ongoing and regular basis in order to maintain liquidity.

Commodity price fluctuations pose a risk to Artek, and as a result, the Company's management monitors these on an ongoing basis. External factors beyond the Company's control may affect the marketability of the natural gas, crude oil and NGLs produced.

Attracting and retaining qualified individuals is crucial to the Company's success. Artek understands the importance of maintaining competitive compensation levels given the competitive environment in which the Company operates. The inability to attract and retain key employees could have a material adverse effect on the Company.

Artek has selected the appropriate personnel to monitor operations and has automated field information where possible so that operational issues can be assessed and dealt with on a timely basis. The Company, however, is not always the operator, and therefore, not all operational issues are within its control. Management will address them nonetheless and attempt to implement solutions, which may be longer-term by their nature.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts and spills, each of which could result in damage to wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company insures against most of these risks (although not all such risks are insurable). Artek maintains liability insurance in an amount that it considers consistent with industry practice, although the nature of these risks is such that liabilities could potentially exceed policy limits. The Company also reduces risk by operating a large percentage of its operations. As such, Artek has control over the quality of work performed and the personnel involved.

The Company's ability to move heavy equipment in the field is dependent on weather conditions. Rain and snow can affect conditions and many secondary roads and future oil and gas production sites are incapable of supporting the weight of heavy equipment until the roads are thoroughly dry. The duration of difficult conditions can have an impact on the Company's activity levels and potentially delay operations.

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 and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the 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 costs.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition. Artek optimizes its operations with respect to compressor fuel usage and natural gas flaring so that a reduction in emissions is realized.

Royalties

Artek's production is generated from properties within the provinces of Alberta and British Columbia. As a result, a significant portion of the Company's production is subject to Crown royalties, which are affected directly by the Alberta and British Columbia government royalty programs. Crown royalty rates are subject to change and a change may have a significant impact on Artek's cash flow.

The Alberta Government revised its royalty program in 2009 and issued several amendments to the program subsequent thereto, which have been favourable to Artek; however, there is a risk that future amendments to the program could have an unfavourable impact on the Company.

Global Financial Situation

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to financial markets. These conditions continued throughout 2010 and the first six months of 2011, and are expected to continue for the remainder of the year. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions continue. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are still expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies.

Substantial Capital Requirements

Artek anticipates incurring substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Company's revenues may decline as a result of decreased commodity pricing, it may be required to reduce its capital spending. In addition, uncertain levels of near-term industry activity, coupled with the present global credit crisis, exposes the Company to additional risk. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of Artek to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

Third Party Credit Risk

The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production, and other parties. The financial capability of the Company's partners can pose increased risks to Artek, particularly during periods when access to capital is limited and prices are depressed. The Company mitigates the risk of collection by attempting to obtain the partners' share of capital expenditures in advance of a project and by monitoring receivables regularly. Artek also attempts to mitigate risks by cultivating multiple business relationships and obtaining new partners when needed and where possible.

In the event that joint venture partners fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on Artek's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until Artek finds a suitable alternative partner.

Inherent Industry Risks – Risk of Failing to Discover Economic Reserves Additions

The Company's strategies include focusing on selected oil and gas prone areas in Western Canada, utilizing a team of highly qualified professionals with expertise and experience in these areas, expanding operations in core areas, continuously assessing new exploration opportunities to complement existing activities and striving for a balance between higher risk exploratory drilling and lower risk development drilling.

Beyond exploration risk, there is the potential that the Company's oil and natural gas reserves may not be economically produced at prevailing prices. Artek minimizes this risk by generating exploration prospects internally, targeting high quality projects and attempting to operate its projects along with access to the sales market through Company owned or mid-stream operators.

Financial, Commodity Price, Capital Expenditures, Liquidity and Environmental Risks

Commodity prices are driven by supply, demand and market conditions outside the Company's influence and control. Artek manages this risk by constantly monitoring the forecasted price given by aggregators. In addition, from time to time the Company employs a commodity hedging program that has a primary goal of minimizing significant downward movements in commodity prices.

Artek utilizes risk management activities to mitigate the risk of volatile fluctuations in the commodity price environment and guarantee a portion of the Company's cash flows.

Artek manages capital expenditures by two separate tracking systems: a historical accounting system that records the actual costs and a perpetual forecasting model that is constantly updated based on real-time information. Artek's capital investment process is based on risk analysis to ensure capital expenditures balance the objectives of immediate cash flow growth in development activities and future cash flow from the discovery of reserves through exploration.

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

The Company manages operational risks by employing skilled professionals utilizing leading-edge technology and conducting regular maintenance and training programs. Artek has established an Environmental, Health and Safety Management Program and continually updates its operational emergency response plan and operational safety manual to address these operational issues. In addition, a comprehensive insurance program is maintained to mitigate risks and protect against significant losses where possible. Artek operates in accordance with all applicable environmental legislation and strives to maintain compliance with such regulations.

Additional Information

Additional information relating to Artek Exploration Ltd. can be accessed on the Company's website at www.artekexploration.com or under the Company's public filings found at www.sedar.com.

STATEMENTS OF FINANCIAL POSITION

As at	September 30, 2011	December 31, 2010
<i>(000s)(unaudited)</i>	<i>(\$)</i>	<i>(\$)</i>
Assets		
Current assets		
Trade and other receivables	10,264	6,190
Deposits and prepaid expenses	728	863
Fair value of derivative instruments <i>(note 14)</i>	74	408
	11,066	7,461
Non-current assets		
Property, plant and equipment <i>(note 5)</i>	145,716	132,078
Exploration and evaluation assets <i>(note 6)</i>	12,557	10,535
	158,273	142,613
Total assets	169,339	150,074
Liabilities		
Current liabilities		
Trade and other payables	17,532	16,879
Bank debt <i>(note 7)</i>	44,402	41,188
	61,934	58,067
Non-current liabilities		
Fair value of derivative instruments <i>(note 14)</i>	162	1,237
Decommissioning liabilities <i>(note 8)</i>	3,967	3,683
Deferred tax liabilities	1,991	1,005
	6,120	5,925
Total liabilities	68,054	63,992
Equity		
Share capital <i>(note 9)</i>	99,709	84,899
Contributed surplus	5,186	4,046
Deficit	(3,610)	(2,863)
Total equity	101,285	86,082
Total liabilities and equity	169,339	150,074

Subsequent events *(note 14)*Commitments *(note 17)**The notes are an integral part of these financial statements.*

STATEMENTS OF EARNINGS (LOSS) AND COMPREHENSIVE EARNINGS (LOSS)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
<i>(000s, except per share amounts)(unaudited)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>
Revenue				
Petroleum and natural gas revenues	11,566	5,657	32,626	20,151
Royalties	(2,543)	(1,137)	(6,719)	(3,336)
	9,023	4,520	25,907	16,815
Realized gain on financial derivatives	379	533	722	1,010
Unrealized gain (loss) on financial derivatives	1,039	(442)	741	(442)
	10,441	4,611	27,370	17,383
Expenses				
Production and operating	2,542	1,895	7,211	6,327
Transportation	390	256	1,114	855
Depletion and depreciation	2,951	1,842	14,570	6,507
Exploration and evaluation	342	428	594	428
Loss on disposal of property, plant and equipment	--	406	--	406
General and administrative	734	745	2,262	1,889
Share-based compensation	233	163	587	477
Other <i>(note 11)</i>	--	--	--	301
	7,192	5,735	26,338	17,190
	3,249	(1,124)	1,032	193
Finance expenses <i>(note 10)</i>	484	671	1,545	1,702
Earnings (loss) before income taxes	2,765	(1,795)	(513)	(1,509)
Income tax expense (reduction)	851	(438)	234	779
Earnings (loss) and comprehensive earnings (loss) for the period	1,914	(1,357)	(747)	(2,288)
Earnings (loss) per share				
Basic and diluted <i>(note 15)</i>	0.05	(0.04)	(0.02)	(0.08)

The notes are an integral part of these financial statements.

STATEMENTS OF CHANGES IN EQUITY

	Number of Common Shares	Share Capital	Contributed Surplus	Deficit	Total Equity
<i>(000s)(unaudited)</i>	<i>(#)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>
Balance – January 1, 2010	23,942	73,281	3,458	(3)	76,736
Shares issued to COSTA shareholders <i>(note 4)</i>	233	886	--	--	886
Issue of common shares <i>(note 9)</i>	7,595	8,734	--	--	8,734
Share issue costs, net of tax of \$29	--	(83)	--	--	(83)
Share-based payments <i>(note 16)</i>	--	--	784	--	784
Options and warrants exercised <i>(note 9)</i>	1,313	2,081	(1,091)	--	990
Loss for the period	--	--	--	(2,288)	(2,288)
Balance – September 30, 2010	33,083	84,899	3,151	(2,291)	85,759
Share-based payments <i>(note 16)</i>	--	--	895	--	895
Loss for the period	--	--	--	(572)	(572)
Balance – December 31, 2010	33,083	84,899	4,046	(2,863)	86,082
Issue of common shares <i>(note 9)</i>	6,500	15,600	--	--	15,600
Share issue costs, net of tax of \$268 <i>(note 9)</i>	--	(790)	--	--	(790)
Share-based payments <i>(note 16)</i>	--	--	1,140	--	1,140
Loss for the period	--	--	--	(747)	(747)
Balance – September 30, 2011	39,583	99,709	5,186	(3,610)	101,285

The notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
<i>(000s)(unaudited)</i>	(\$)	(\$)	(\$)	(\$)
Cash flows from operating activities				
Earnings (loss) for the period	1,914	(1,357)	(747)	(2,288)
Adjustments for:				
Depletion and depreciation <i>(note 5)</i>	2,951	1,842	14,570	6,507
Exploration and evaluation <i>(note 6)</i>	342	428	594	428
Loss on disposal of property, plant and equipment	--	406	--	406
Unrealized loss (gain) on financial derivatives <i>(note 14)</i>	(1,039)	442	(741)	442
Deferred income taxes (reduction)	851	(438)	234	779
Accretion of decommissioning liabilities <i>(note 8)</i>	66	72	184	209
Share-based compensation <i>(note 16)</i>	233	163	587	477
	5,318	1,558	14,681	6,960
Change in non-cash working capital <i>(note 12)</i>	(165)	(1,432)	(45)	453
Net cash from operating activities	5,153	126	14,636	7,413
Cash flows from investing activities				
Property, plant and equipment				
Additions	(9,531)	(4,643)	(26,868)	(19,334)
Disposals	--	905	--	905
Additions to exploration and evaluation assets	(1,553)	(492)	(3,304)	(602)
Change in non-cash working capital <i>(note 12)</i>	3,776	624	(3,241)	(330)
Net cash used in investing activities	(7,308)	(3,606)	(33,413)	(19,361)
Cash flows from financing activities				
Proceeds from issue of share capital <i>(note 9)</i>	--	8,734	16,620	9,724
Proceeds from (repayments of) loans and borrowings	2,155	(5,157)	3,214	2,336
Share issuance costs <i>(note 9)</i>	--	(97)	(1,057)	(112)
Net cash from financing activities	2,155	3,480	18,777	11,948
Change in cash and cash equivalents	--	--	--	--
Cash and cash equivalents – beginning of period	--	--	--	--
Cash and cash equivalents – end of period	--	--	--	--

The notes are an integral part of these financial statements.

CONDENSED NOTES TO FINANCIAL STATEMENTS

Three and Nine Months Ended September 30, 2011

(unaudited)

Tabular amounts are stated in thousands of dollars, except share and per share amounts)

1. Reporting Entity

Artek Exploration Ltd. ("Artek" or the "Company") was founded in February 2005 through the reorganization of 1143879 Alberta Ltd., which was incorporated on December 21, 2004 under the Business Corporations Act of Alberta. The Company is engaged in the exploration for and development and production of natural gas, crude oil and NGLs in Western Canada 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 Preparation

(a) Statement of Compliance

The unaudited interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), specifically IFRS 1 – "First-Time Adoption of International Financial Reporting Standards", and with International Accounting Standard 34 – "Interim Financial Reporting". These interim financial statements are for part of the period covered by the first IFRS annual financial statements of the Company and IFRS 1 – "First-Time Adoption of International Financial Reporting Standards" has been applied. The interim financial statements do not include all of the information required for full annual financial statements.

An explanation of how the transition to IFRS has affected the reported financial position and financial performance of the Company is provided in note 19. This note includes reconciliations of equity and total comprehensive income for comparative periods reported under previous Canadian generally accepted accounting principles ("GAAP") to those reported periods and at the date of transition under IFRS.

These financial statements were authorized for issuance by the Board of Directors on November 9, 2011.

(b) Basis of Measurement

The financial statements have been prepared on the historical cost basis, except for derivative financial instruments that are measured at fair value.

The methods used to measure fair values are discussed in note 13.

(c) Functional and Presentation of Currency

These financial statements are presented in Canadian dollars, which is the Company's functional currency.

(d) Use of Estimates and Judgements

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

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

Information about significant areas of estimation uncertainty and critical judgements in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements is included in the following notes:

- Note 5 – valuation of property, plant and equipment
- Note 6 – valuation of exploration and evaluation assets
- Note 8 – decommissioning obligations
- Note 14 – valuation of financial instruments
- Note 16 – measurement of share-based payments

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

3. Significant Accounting Policies

The interim financial statements have been prepared following the same accounting policies and methods of computation as the interim financial statements as at March 31, 2011 and June 30, 2011. The significant accounting policies are described in note 2 of the March 31, 2011 interim financial statements.

4. Acquisitions

On November 26, 2009, Artek and COSTA Energy Inc. ("COSTA") entered into a Plan of Arrangement (the "Arrangement") to effect a reverse take-over transaction. Under the Arrangement, Artek and COSTA were to be amalgamated to form a new corporation that would carry on Artek's current business and operations under the name "Artek Exploration Ltd.". This transaction was successfully executed on January 14, 2010 with the shares of the new corporation listed on the TSX-V. As a result of the transaction mechanics, the shareholders of Artek held 25,155,260 shares of the new corporation as of the closing date (99.08%) and the shareholders of COSTA held 233,200 shares (0.92%). The transaction was recorded as a reverse take-over transaction that does not constitute a business combination, and accordingly, has been accounted for as though Artek acquired COSTA using the purchase method of accounting. The consideration consisted of 233,200 common shares of the Company valued at \$3.80 per common share, being the most recent equity price of the Company's shares.

The purchase price allocation is as follows:

	Amount
<i>(000s)</i>	<i>(\$)</i>
Identifiable assets acquired and acquired assumed:	
Working capital deficiency	(122)
Future tax asset	1,008
	886
Consideration paid:	
Common shares	886

5. Property, Plant and Equipment

	Oil and Natural Gas Properties
<i>(000s)</i>	<i>(\$)</i>
Cost or deemed cost:	
Balance – January 1, 2010	113,488
Additions	28,078
Transfers from exploration and evaluation assets	340
Capitalized share-based compensation	632
Change in decommissioning obligations	119
Divestitures	(1,302)
Balance – December 31, 2010	141,355
Additions	26,868
Transfer from exploration and evaluation assets	688
Capitalized share-based compensation	552
Change in decommissioning obligations	100
Balance – September 30, 2011	169,563
Depletion and depreciation:	
Balance – January 1, 2010	--
Depletion and depreciation for the year	8,677
Impairment loss	600
Balance – December 31, 2010	9,277
Depletion and depreciation for the period	8,470
Impairment loss	6,100
Balance – September 30, 2011	23,847
Carrying amounts:	
January 1, 2010	113,488
December 31, 2010	132,078
September 30, 2011	145,716

The calculation of 2011 depletion and depreciation expense included an estimated \$137,785,000 (2010 – \$103,598,000) for future development costs associated with proved plus probable undeveloped reserves and excluded \$4,708,000 (2010 – \$4,596,000) for the estimated salvage value of production equipment and facilities.

(a) Amortization and Impairment Charge

The depletion, depreciation and impairment of property, plant and equipment, and any eventual reversal thereof, are recognized in depletion and depreciation in earnings. At December 31, 2010, as a result of decreasing natural gas prices, Artek recognized a \$600,000 impairment relating to one of the Company's cash-generating units ("CGUs"). An impairment charge was taken at December 31, 2010 and was recorded as additional depletion and depreciation expense. The impairment was based on the difference between the period-end book value of the assets and the recoverable amount. The recoverable amount was determined using discounted cash flows of proved plus probable reserves using forecast prices and a discount rate of 10%. At March 31, 2011, Artek also recognized a \$6,100,000 impairment relating to one of the Company's CGUs as a result of further decreasing natural gas prices.

(b) Security

At September 30, 2011 and 2010, all of the Company's properties were pledged as security for the bank loan.

(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.

6. Exploration and Evaluation Assets

<i>(000s)</i>	<i>(\$)</i>
Cost:	
Balance – January 1, 2010	11,123
Additions	318
Transfers to property, plant and equipment	(340)
Impairments	(566)
Balance – December 31, 2010	10,535
Additions	3,304
Transfers to property, plant and equipment	(688)
Impairments	(594)
Balance – September 30, 2011	12,557

Exploration and evaluation assets consist of the Company's exploration projects that are pending the determination of proved or probable reserves. Additions represent the Company's share of costs incurred on exploration and evaluation assets during the period.

7. Bank Debt

At September 30, 2011, the Company had a revolving demand term credit facility with a bank with a borrowing base of \$60,000,000 (2010 – \$53,000,000), of which \$44,402,000 (2010 – \$41,257,000) had been drawn against the credit facility. The amount of the facility is subject to a borrowing base test performed on a periodic basis by the lenders based primarily on reserves and using commodity prices estimated by the lenders as well as other factors. A decrease in the borrowing base could result in a reduction to the credit facility, which may require a repayment to the lenders. The next bank credit review date is scheduled for November 2011.

The current credit facility provides that advances may be made by way of direct advances or guaranteed notes. Direct advances bear interest at the bank's prime rate plus 0.75% (unless the net debt to trailing cash flow exceeds 1.5:1, in which case the interest rate is the bank's prime rate plus 1.25%). The interest rate rises incrementally with increases in the net debt to trailing cash flow ratio to a maximum of the bank's prime rate plus 2.5% at 3.0:1. Under the terms of the facility, a financial covenant must be maintained. The Company must not permit the working capital ratio to fall below 1.0:1. The working capital ratio is defined as the ratio of current assets plus any undrawn availability under the credit facilities to current liabilities less any amount drawn under the credit facilities. As of September 30, 2011, the Company was in compliance with the financial covenant. A general security agreement over all present and after acquired personal property and a floating charge on all lands has been provided as security.

The Company also has available a \$10,000,000 acquisition/development demand loan credit facility, which is in addition to the revolving demand term credit facility. The facility must be used for the acquisition of producing petroleum and natural gas reserves and/or the development of proved non-producing or undeveloped petroleum and natural gas reserves. Repayment of principal and interest shall commence the month following drawdown based on the half-life of the reserves being financed. Direct advances bear interest at the bank's prime rate plus 1.25% (unless the net debt to trailing cash flow exceeds 1.5:1, in which case the interest rate is the bank's prime rate plus 1.75%). The interest rate rises incrementally with increases in the net debt to trailing cash flow ratio to a maximum of the bank's prime rate plus 3.0% at 3.0:1. At September 30, 2011, no amount was drawn on this facility.

At September 30, 2011, letters of credit totaling \$334,000 were outstanding that reduce the amount that can be borrowed under the credit facilities.

8. Decommissioning Liabilities

	Nine Months Ended September 30, 2011	Year Ended December 31, 2010
<i>(000s)</i>	<i>(\$)</i>	<i>(\$)</i>
Balance – beginning of period	3,683	3,281
Liabilities incurred	100	199
Liabilities disposed through property disposition	--	(79)
Accretion of decommissioning liability	184	282
Balance – end of period	3,967	3,683

8. Decommissioning Liabilities (continued)

The Company's decommissioning liabilities result from its ownership interest in oil and natural gas assets, including wellsites and gathering systems. The total decommissioning liability is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning liabilities to be \$3,967,000 as at September 30, 2011 (2010 – \$3,683,000) based on an undiscounted total future liability of \$8,978,000 (2010 – \$8,303,000). These payments are expected to be made over the next 40 years with the majority of costs to be incurred before 2025. The discount factor, being the credit adjusted risk-free rate related to the liability, is 8% (2010 – 8%).

9. Share Capital

(a) Authorized

An unlimited number of voting common shares. The holders of common shares are entitled to receive dividends as declared by the Company and are entitled to one vote per share.

(b) Share Capital Issued

	Nine Months Ended September 30, 2011		Year Ended December 31, 2010	
	Shares	Amount	Shares	Amount
(000s)	(#)	(\$)	(#)	(\$)
Common Shares				
Balance – beginning of period	33,083	84,899	23,942	73,281
Public offering – flow-through	1,700	5,100	--	--
Flow-through share premium	--	(1,020)	--	--
Public offering – common	4,800	11,520	--	--
Exercise of warrants	--	--	1,160	1,820
Exercise of options (cashless)	--	--	53	111
Shares cancelled pursuant to reverse take-over	--	--	(25,155)	--
Shares issued to Artek shareholders pursuant to reverse take-over (note 4)	--	--	25,155	--
Shares issued to COSTA shareholders pursuant to reverse take-over (note 4)	--	--	233	886
Private placement – common	--	--	7,595	8,734
Exercise of warrants	--	--	100	150
Share issue cost	--	(1,058)	--	(112)
Tax benefit of share issue cost	--	268	--	29
Balance – end of period	39,583	99,709	33,083	84,899

All the common share amounts, including the comparative period, reflects the 5:1 common share split that occurred as part of the Arrangement with COSTA (note 4).

On March 17, 2011, the Company closed a bought deal equity financing where it raised gross proceeds of \$16,620,000, which resulted in the issuance of 4,800,000 common shares at a price of \$2.40 per share and 1,700,000 flow-through common shares at a price of \$3.00 per share. The flow-through obligations were all incurred by September 30, 2011.

10. Finance Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
Interest on loans and borrowings	418	599	1,361	1,493
Accretion of provisions	66	72	184	209
Finance expenses recognized in profit or loss	484	671	1,545	1,702

11. Other Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
Transaction costs (note 4)	--	--	--	301
Total other expenses	--	--	--	301

12. Supplemented Cash Flow Information

Changes in non-cash working capital is comprised of:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(\$)	(\$)	(\$)	(\$)
Trade and other receivables	(2,711)	(1,322)	(4,074)	(1,422)
Deposit and prepaid expenses	320	70	135	1,079
Trade and other payables	6,002	444	653	466
	3,611	(808)	(3,286)	123
Related to operating activities	(165)	(1,432)	(45)	453
Related to investing activities	3,776	624	(3,241)	(330)
	3,611	(808)	(3,286)	123

13. Determination of Fair Values

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

(a) Cash and Cash Equivalents, Trade and Other Receivables, Bank Debt, and Trade and Other Payables

The fair value of cash and cash equivalents, trade and other receivables, bank debt, and trade and other payables is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At September 30, 2011 and December 31, 2010, the fair value of these balances approximated their carrying value due to their short-term to maturity.

(b) Derivatives

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates.

(c) Stock Options

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

14. Financial Risk Management

(a) Overview

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

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital.

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

(b) Credit Risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers. The maximum exposure to credit risk at period-end was the outstanding trade and other receivables balance of \$10,264,000.

The maximum exposure to credit risk for loans and receivables at the reporting date by type of customer was:

As at September 30, 2011	Carrying Amount
<i>(000s)</i>	<i>(\$)</i>
Oil and natural gas marketing companies	3,923
Joint venture partners	5,510
Other	831
Total trade and other receivables	10,264

The Company's most significant customer, a Canadian oil and natural gas marketer, accounted for \$2,362,000 of the trade receivables at September 30, 2011 (2010 – \$1,927,000).

The Company's trade and other receivables are aged as follows:

As at September 30, 2011	Carrying Amount
<i>(000s)</i>	<i>(\$)</i>
Current (less than 90 days)	9,387
Past due (more than 90 days)	877
Total	10,264

The Company does not anticipate any default as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. As such, a provision for doubtful accounts has not been recorded at September 30, 2011.

14. Financial Risk Management (continued)**(c) Liquidity Risk**

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company's reputation.

Typically, the Company ensures that it has sufficient cash on demand to meet expected operational expenses for a period of 90 days, including the servicing of financial obligations; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters. To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month. In addition, the Company maintains a \$60,000,000 revolving demand credit facility to provide capital when needed, of which \$15,264,000 was available at the end of the period.

The financial liabilities on the statement of financial position include bank debt, trade and other payables, and fair value of derivative instruments.

The following are the contractual maturities of financial liabilities, including estimated interest payments and excluding the impact of netting agreements at September 30, 2011:

As at September 30, 2011	Carrying Amount	Contractual Cash Flows	Less than 1 Year	1 – 2 Years	2 – 5 Years	More Than 5 Years
(000s)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
Non-derivative financial liabilities:						
Trade and other payables	17,532	17,532	17,532	--	--	--
Bank debt (i)	44,402	44,402	44,402	--	--	--
Derivative financial liabilities:						
Financial commodity contracts	162	162	--	162	--	--
	62,096	62,096	61,934	162	--	--

(i) Assumes the credit facilities are not renewed in November 2011 (see note 7).

(d) Market Risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates, will affect the Company's earnings or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Currency 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 Company does not sell or transact in any foreign currency; however, the United States dollar influences the price of petroleum and natural gas sold in Canada. The Company's financial assets and liabilities are not affected by a change in currency rates. The Company had no foreign exchange contracts in place at September 30, 2011.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank loan fluctuates with the interest rates posted by the lenders. The Company is exposed to interest rate risk and had not entered into any mitigating interest rate swaps as at September 30, 2011. Had the borrowing rate been 100 basis points higher (or lower) throughout the period ended September 30, 2011, earnings would have been affected by \$197,000 (2010 – \$219,000) based on the average debt balance outstanding during the period. Effective October 19, 2011, the Company entered into an interest rate swap transaction whereby the interest rate applicable to borrowings by way of bankers' acceptances was fixed. Borrowings in the amount of \$20,000,000 were fixed at an annual interest rate of 1.14% (before bank stamping fees) until the contract matures on October 19, 2013.

14. Financial Risk Management (continued)**(d) Market Risk (continued)***Commodity Price Risk*

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil 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.

It is the Company's policy to enter into various financial derivative forward sales contracts and physical sales contracts to protect its cash flow from operating activities. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near-term contracts with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long-term, fixed price marketing contracts. The Company does not enter into commodity contracts other than to meet the Company's expected sales requirements.

At September 30, 2011, the following derivative contracts were outstanding and recorded at estimated fair value:

Term	Volume	Price	Settlement Index
Jan. 1, 2011 – Dec. 31, 2011	3,000 GJ/d	\$5.09/GJ	AECO Daily
Jan. 1, 2011 – Dec. 31, 2011	Call 300 bbls/d	US\$90.00/bbl	WTI
Jan. 1, 2012 – Dec. 31, 2012	Call 300 bbls/d	US\$95.00/bbl	WTI

The estimated fair value of the financial oil and natural gas contracts has been determined on the amounts the Company would receive or pay to terminate the oil and natural gas contracts at period-end. At September 30, 2011, the amount the Company would pay to terminate the contracts would be \$88,000. On November 2, 2011, the Company entered into a crude oil swap for 300 bbls/d at CDN\$92.00/bbl for the 2012 calendar year.

The fair value of the financial commodity risk management contracts have been allocated to current and non-current assets and liabilities on a contract-by-contract basis as follows:

Nine Months Ended September 30,	2011	2010
(000s)	(\$)	(\$)
Assets (Liabilities):		
Current	74	--
Long-term	(162)	--
Net position	(88)	--

The fair value of derivative contracts at September 30, 2011 would have been impacted as follows had the forward price curves used to estimate the fair value changed by:

As at September 30, 2011	Effect of an Increase in Price on After-Tax Earnings	Effect of a Decrease in Price on After-Tax Earnings
(000s)	(\$)	(\$)
CDN\$1.00/bbl change in the oil price	(101)	101
CDN\$0.50/mcf change in the gas price	(101)	101

14. Financial Risk Management (continued)

(e) Fair Value of Financial Instruments

The following table provides fair value measurement information for financial assets and liabilities as at September 30, 2011 and December 31, 2010. The carrying value of trade and other receivables, bank debt, and trade and other payables included in the statement of financial position approximate fair value due to the short-term nature of those instruments. These assets and liabilities are not included in the following table.

	Carrying Amount	Fair Value	Fair Value Measures Using		
			Quoted Prices in Active Markets (Level 1)	Significant Other Unobservable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(000s)	(\$)	(\$)	(\$)	(\$)	(\$)
September 30, 2011					
Financial assets					
Fair value of derivative instruments	74	74	--	74	--
Financial liabilities					
Fair value of derivative instruments	162	162	--	162	--
December 31, 2010					
Financial assets					
Fair value of derivative instruments	408	408	--	408	--
Financial liabilities					
Fair value of derivative instruments	1,237	1,237	--	1,237	--

The Company classifies the fair value of these transactions according to the following hierarchy:

Level 1 Fair Value Measurements – are based on unadjusted quoted market prices.

Level 2 Fair Value Measurements – are based on valuation models and techniques where the significant inputs are derived from quoted indices.

Level 3 Fair Value Measurements – are based on unobservable information.

(f) Capital Management

Artek actively manages its capital structure, which includes shareholders' equity, bank debt and working capital. In order to maintain or adjust the capital structure, Artek considers the following: incremental investment and acquisition opportunities; the current level of credit available from the Company's lender; the level of credit that may be obtainable from the Company's lender as a result of growth in reserves values; the availability of other sources of debt with different characteristics than the existing bank debt; the sale of assets; limiting the size of the investment program; and, new share issuances, if available on favourable terms. The Company's objective is to maintain a flexible structure that will allow it to execute its investment program, including exploration and development of its oil and gas properties and acquisition and disposition transactions, which all carry varying amounts of risk. Artek continually strives to balance the proportion of debt and equity in its capital structure to take into account the level of risk being incurred in its investment program. Artek may from time to time issue shares and adjust its capital spending to manage current and projected debt levels.

14. Financial Risk Management (continued)**(f) Capital Management (continued)**

The methods used by the Company to monitor capital is based on the ratio of net debt to annualized cash flow and also the ratio of net debt to the Company's credit facility availability. The first net debt ratio is calculated as net debt, defined as outstanding revolving bank loan plus or minus working capital, divided by annualized cash flow from operations before changes in non-cash working capital and decommissioning liabilities based on the most recent quarter. The second net debt ratio is calculated as net debt, defined as outstanding revolving bank loan plus or minus working capital, divided by the credit facility availability. Artek's current strategy is to maintain a ratio of net debt to annualized cash flow no more than 2.0:1, or if the ratio exceeds 2.0:1, to not draw more than 80% of the Company's current credit facility availability. The ratio may temporarily increase at certain times as a result of acquisitions. In order to facilitate the management of this ratio, the Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors, including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors. As at September 30, 2011, Artek's ratio of net debt to annualized cash flow was 2.4:1 and the Company's ratio of net debt to credit facility availability was 85%, which are both just outside the range established by the Company. In order to continually improve upon the above-mentioned ratios, Artek plans to review its options to dispose of certain non-core assets as normal course of business or to raise additional equity capital in 2011 and to invest approximately 75% of its capital budget towards crude oil and liquids-rich natural gas projects, which have higher netbacks. The Company's strategy for managing its capital structure since the prior year is unchanged.

Three Months Ended September 30, (000s)	2011 (\$)	2010 (\$)
Current assets	11,066	7,802
Current liabilities	61,934	53,313
Net debt	50,868	45,511
Net earnings (loss)	1,914	(1,357)
Add (deduct):		
Depletion and depreciation	2,951	1,842
Accretion of decommissioning liabilities	66	72
Exploration and evaluation	342	428
Loss on disposal of property, plant and equipment	--	406
Unrealized gain on financial derivatives	(1,039)	442
Share-based compensation	233	163
Deferred income tax expense	851	(438)
	5,318	1,558
Annualized cash flow	21,272	6,232
Net debt to annualized cash flow	2.4	7.3
Credit facility available	60,000	53,000
Net debt to credit facility available (%)	85	86

The Company is not subject to externally imposed capital requirements. The credit facilities are subject to a semi-annual review of the borrowing base, which is directly impacted by the value of the oil and natural gas reserves.

15. Earnings (Loss) Per Share

Basic loss per share was calculated as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(#)	(#)	(#)	(#)
Weighted average number of common shares (basic)				
Issued common shares – beginning of period	39,583	25,488	33,083	23,942
Share options and warrants exercised	--	--	--	1,313
Effects of shares issued	--	5,036	4,715	1,909
Weighted average number of common shares – basic	39,583	30,524	37,798	27,164

Diluted earnings per share was calculated as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(000s)	(#)	(#)	(#)	(#)
Weighted average number of common shares – basic	39,583	30,524	37,798	27,164
Effects of options in-the-money	306	--	332	--
Weighted average number of common shares – basic	39,889	30,524	38,130	27,164

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. A total of 2,515,000 (2010 – 3,210,500) options were not included in the diluted earnings per share calculation because the options were out of the money or, as in 2010, all the options were dilutive because of the net loss.

16. Share-Based Payments

The Company has an option program that entitles officers, directors, employees and certain consultants to purchase shares in the Company. Options are granted at the market price of the shares at the date of grant, have a five-year term and vest over three years.

The number and weighted average exercise prices of share options are as follows:

	2011		2010	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
	(#000s)	(\$)	(#000s)	(\$)
Outstanding – January 1	940	1.11	2,214	3.24
Exercised	--	--	(125)	(2.20)
Forfeited	--	--	(98)	(2.81)
Granted	2,515	1.99	1,219	1.36
Outstanding – September 30	3,455	1.75	3,210	2.58
Exercisable – September 30	313	1.11	1,240	3.05

16. Share-Based Payments (continued)

The range of exercise prices of the outstanding options is as follows:

Exercise Price (\$)	Options (#000s)	Weighted Average Exercise Price (\$)	Weighted Average Contractual Life (years)
1.10 – 1.20	940	1.11	4.0
1.90	1,855	1.90	4.3
2.25	660	2.25	2.8
1.10 – 2.25	3,455	1.75	3.9

The fair value of the options was estimated using the Black-Scholes option pricing model with the following weighted average inputs:

As at	September 30, 2011 (\$)	December 31, 2010 (\$)
Share price	1.99	2.87
Exercise price	1.99	2.87
Volatility (%)	72	65
Option life (years)	4.5	5.0
Dividends	--	--
Risk-free interest rate (%)	2.4	2.6
Weighted average fair value of options granted during period	1.13	1.61

A forfeiture rate of 5% (2010 – 5%) was used when calculating the fair value. This estimate is adjusted to the actual forfeiture rate. Share-based compensation cost of \$587,000 (2010 – \$477,000) was expensed during 2011. In addition, share-based compensation expense of \$552,000 (2010 – \$307,000) was capitalized to property, plant and equipment during 2011.

17. Commitments

The Company has the following fixed-term commitments related to its ongoing business:

	2011 (\$)	2012 (\$)	2013 (\$)	2014 (\$)	2015 (\$)	Total (\$)
(000s)						
Leased office space	82	234	242	250	125	933
Transportation agreements	301	1,345	96	71	--	1,813
Drilling rig	1,342	4,598	--	--	--	5,940

18. Related Party Transactions

During the period ended September 30, 2011, the Company received legal services from a firm in which the Corporate Secretary of the Company is a partner. The Company incurred costs totaling \$199,000 (2010 – \$116,000), which have been included in general and administrative expenses and share issuance costs, and \$nil (2010 – \$46,000) remained in accounts payable at September 30, 2011. These amounts are billed and recorded at rates consistent with those charged to third parties.

19. Transition to IFRS

Artek's accounting policies under IFRS differ from those followed under previous GAAP. These accounting policies have been applied for the three and nine months ended September 30, 2011 as well as to the opening statement of financial position on the transition date, January 1, 2010, the comparative information for the three and nine months ended September 30, 2010 and the comparative information for the year ended December 31, 2010.

The adjustments arising from the application of IFRS to amounts on the statement of financial position on the transition date and on transactions prior to the date of transition were recognized as an adjustment to the Company's opening deficit category on the statement of financial position when appropriate.

On transition to IFRS on January 1, 2010, Artek used certain exemptions allowed under IFRS 1. The exemptions used were:

Full Cost Accounting – IFRS 1 allows an entity that used full cost accounting under its previous GAAP to elect, at the time of adoption to IFRS, to measure oil and gas assets in the development and production phase by allocating the amount determined under the entity's previous GAAP for those assets to the underlying assets pro rata using reserves volumes or reserves values as of that date. Artek has used reserves values as at January 1, 2010 to allocate the cost of development and production assets to CGUs.

Share-Based Compensation – IFRS 1 allows an entity an exemption on IFRS 2 – "Share-Based Payments" to equity instruments, which vested before Artek's transition date to IFRS.

Business Combinations – IFRS 1 allows an entity to use the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations.

Decommissioning Obligation – As the Company elected to use the oil and gas exemption, the decommissioning liability was measured at transition using a consistent credit adjusted risk-free rate with a corresponding adjustment to retained earnings.

19. Transition to IFRS (continued)*Reconciliation of the Statement of Financial Position*

At the End of the Last Reporting Year Under Canadian GAAP – September 30, 2010

	Canadian GAAP	Effect of Transition to IFRS	IFRS
(000s)	(\$)	(\$)	(\$)
Assets			
Current assets			
Trade and other receivables	7,116	--	7,116
Deposits and prepaid expenses	686	--	686
	7,802	--	7,802
Non-current assets			
Property, plant and equipment (notes a,c)	134,753	(8,505)	126,248
Exploration and evaluation assets (note a)	--	10,465	10,465
	134,753	1,960	136,713
Total assets	142,555	1,960	144,515
Liabilities and Equity			
Current liabilities			
Bank debt	41,257	--	41,257
Trade and other payables	11,614	--	11,614
Fair value of derivative instruments	442	--	442
	53,313	--	53,313
Non-current liabilities			
Decommissioning liabilities	3,596	--	3,596
Deferred tax liabilities (notes a,e)	1,414	433	1,847
	5,010	433	5,443
Total liabilities	58,323	433	58,756
Equity			
Share capital (note d)	81,852	3,047	84,899
Contributed surplus (note b)	3,110	41	3,151
Retained earnings (deficit)	(730)	(1,561)	(2,291)
Total equity	84,232	1,527	85,759
Total liabilities and equity	142,555	1,960	144,515

19. Transition to IFRS (continued)*Reconciliation of the Statements of Loss and Comprehensive Loss*

For the Three Months Ended September 30, 2010

	Canadian GAAP	Effect of Transition to IFRS	IFRS
<i>(000s, except per share amounts)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>
Revenues			
Petroleum and natural gas revenues	5,657	--	5,657
Royalties	(1,137)	--	(1,137)
	4,520	--	4,520
Realized gain on financial derivatives	533	--	533
Unrealized loss on financial derivatives	(442)	--	(442)
	4,611	--	4,611
Expenses			
Production and operating	1,895	--	1,895
Transportation	256	--	256
Depletion and depreciation <i>(note c)</i>	2,796	(954)	1,842
Exploration and evaluation <i>(note a)</i>	--	428	428
Loss on disposal of property, plant and equipment <i>(note a)</i>	--	406	406
General and administrative	745	--	745
Share-based compensation <i>(note b)</i>	165	(2)	163
Interest <i>(note f)</i>	599	(599)	--
	6,456	(721)	5,735
	(1,845)	(721)	(1,124)
Finance expenses <i>(note f)</i>	--	671	671
Loss before income taxes	(1,845)	(50)	(1,795)
Income tax expense (reduction) <i>(note e)</i>	(451)	13	(438)
Loss and comprehensive loss for the period	(1,394)	(37)	(1,357)
Loss per share			
Basic and diluted	(0.05)	0.01	(0.04)

19. Transition to IFRS (continued)*Reconciliation of the Statements of Loss and Comprehensive Loss*

For the Nine Months Ended September 30, 2010

	Canadian GAAP	Effect of Transition to IFRS	IFRS
<i>(000s, except per share amounts)</i>	<i>(\$)</i>	<i>(\$)</i>	<i>(\$)</i>
Revenues			
Petroleum and natural gas revenues	20,151	--	20,151
Royalties	(3,336)	--	(3,336)
	16,815	--	16,815
Realized gain on financial derivatives	1,010	--	1,010
Unrealized loss on financial derivatives	(442)	--	(442)
	17,383	--	17,383
Expenses			
Production and operating	6,327	--	6,327
Transportation	855	--	855
Depletion and depreciation <i>(note c)</i>	9,944	(3,437)	6,507
Exploration and evaluation	--	428	428
Loss on disposal of property, plant and equipment <i>(note a)</i>	--	406	406
General and administrative	1,889	--	1,889
Share-based compensation <i>(note b)</i>	449	28	477
Interest <i>(note f)</i>	1,493	(1,493)	--
Other	301	--	301
	21,258	(4,068)	17,190
	(3,875)	(4,068)	193
Finance expenses <i>(note f)</i>	--	1,702	1,702
Loss before income taxes	(3,875)	(2,366)	(1,509)
Income tax expense (reduction) <i>(note e)</i>	(577)	1,356	779
Loss and comprehensive loss for the period	(3,298)	1,010	(2,288)
Loss per share			
Basic and diluted	(0.12)	(0.04)	(0.08)

Notes to Reconciliations

(a) IFRS 1 Election for Full Cost Oil and Gas Entities

The Company elected an IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS as follows:

- (i) exploration and evaluation assets were reclassified from the full cost pool to intangible exploration and evaluation assets at the amount that was recorded under Canadian GAAP; and
- (ii) the remaining full cost pool was allocated to the producing/development assets and components pro rata using reserves values.

Exploration and evaluation assets at January 1, 2010 were deemed to be \$11,123,000, representing the unproved properties balance under previous GAAP. This resulted in a reclassification of \$11,123,000 from property, plant and equipment to exploration and evaluation assets with a corresponding decrease in property, plant and equipment at January 1, 2010. In addition, pre-exploration and evaluation costs of \$156,000 were written off on transition with a corresponding change to retained earnings.

19. Transition to IFRS (continued)*Notes to Reconciliations (continued)*

During the three and nine months ended September 30, 2010, Artek transferred \$65,000 and \$230,400, respectively, of capitalized exploration and evaluation assets to property, plant and equipment. Capitalized share-based compensation decreased \$29,500 and \$124,900 for the three and nine months ended September 30, 2010, respectively, which reduced property, plant and equipment. The deferred tax effect of capitalized share-based compensation was removed from property, plant and equipment, and correspondingly, deferred tax liabilities was reduced by \$153,000 at September 30, 2010. A loss of \$406,500 on disposal of an asset was recorded for the three and nine months ended September 30, 2011. Exploration and evaluation costs of \$427,600 were written off for the three and nine months ended September 30, 2011.

(b) Share-Based Payments

Under Canadian GAAP, the Company recognized an expense related to share-based payments on a straight-line basis through the date of full vesting and did not incorporate a forfeiture multiple on the grant date. Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate. Accordingly, upon transition to IFRS, the Company recorded a fair value adjustment of \$138,000 as at January 1, 2010 to increase contributed surplus with a corresponding charge to retained earnings. For the nine-month period ended September 30, 2011, share-based compensation was reduced \$97,200 with a corresponding decrease to contributed surplus. Capitalized share-based compensation also decreased \$124,900 for the nine-month period. For the three and nine months ended September 30, 2010, share-based compensation expense decreased by \$2,000 and increased by \$28,000, respectively, as compared to previous GAAP to reflect changes under IFRS.

(c) Depletion Policy

Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit-of-production basis over proved plus probable reserves. The depletion policy under Canadian GAAP was based on units of production over proved reserves. In addition, depletion was done at the Canadian cost centre under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on individual components (i.e. fields or combinations thereof).

There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the IFRS 1 election as discussed above.

For the three months ended September 30, 2010, depleting the oil and gas interests over proved plus probable reserves resulted in a decrease to depletion and depreciation of \$882,000 (\$651,000 net of tax) with a corresponding change to property, plant and equipment. Depletion and depreciation was also reduced for \$72,000 of accretion expenses, which are reclassified to finance expenses under IFRS. For the nine months ended September 30, 2010, component accounting resulted in a decrease to depletion and depreciation of \$3,228,000 (\$2,383,000 net of tax) with a corresponding change to property, plant and equipment. Again, depletion and depreciation is reduced for \$209,000 of accretion expenses, which are reclassified to finance expenses under IFRS.

(d) Flow-Through Shares

Under previous GAAP, share capital was reduced and the future tax liability was increased by the tax effected amount of the renounced tax deductions at the time of renouncement. Under IFRS, share capital is reduced by the flow-through share premium. At the time that expenditures are incurred, the deferred tax liability is increased by the tax effected amount of the tax deductions. The difference between the flow-through share premium and the increase in the deferred tax liability is booked to deferred income tax expense. Accordingly, upon transition to IFRS, the Company recorded a flow-through share premium adjustment of \$1,108,000 as at January 1, 2010 along with an increase to share capital of \$1,210,000 with a corresponding charge to retained earnings of \$2,318,000.

As the flow-through expenditures were completed by March 31, 2011, the flow-through premium of \$1,108,000 was reversed during that period.

(e) Deferred Income Tax

Deferred income taxes have been adjusted to reflect the tax effect arising from the differences between IFRS and GAAP. The adjustment to deferred income taxes on transition relates to the opening adjustment to pre-exploration and evaluation costs. The deferred income tax impact of the opening adjustment was a reduction in deferred tax liability of \$41,000 with a corresponding change recorded in deficit. Because of the flow-through shares issued in 2010, the deferred tax expense increased by \$729,000 for the nine months ended September 30, 2010. For the three and nine months ended September 30, 2010, the application of the IFRS adjustments as discussed in (a) through (d) above resulted in a \$13,000 reduction and a \$1,356,000 increase to expense, respectively, to the Company's deferred income tax expense and liability, and a corresponding change to Artek's previous GAAP net loss.

19. Transition to IFRS (continued)

Notes to Reconciliations (continued)

(f) Finance Expenses

Under IFRS, a separate line item is required in the statement of earnings and comprehensive income for finance expenses. The items under the previous GAAP that were reclassified to finance expenses were interest and accretion on decommissioning obligations. For the three and nine months ended September 30, 2010, \$72,000 and \$209,000, respectively, were reclassified from depletion and depreciation to net finance expenses.

CORPORATE INFORMATION

Board of Directors

M. Bruce Chernoff – Chairman ⁽¹⁾⁽²⁾
President
Caribou Capital Corp.

Gary F. Aitken ⁽³⁾
President
Whitemountain Resource Properties Ltd.

Darryl F. Metcalfe
President & Chief Executive Officer
Artek Exploration Ltd.

Rafi G. Tahmazian ⁽¹⁾⁽²⁾⁽³⁾
Principal
Canoe Financial LP

David J. Wilson ⁽¹⁾⁽²⁾⁽³⁾
President & Chief Executive Officer
Celtic Exploration Ltd.

(1) Member of the Audit Committee

(2) Member of the Reserves & Environment Committee

(3) Member of the Compensation Committee

Executive Officers and Management

Darryl Metcalfe
President & Chief Executive Officer

Darcy Anderson
Vice-President, Finance & Chief Financial Officer

Peter Andrews
Vice-President, Drilling & Operations

Greg Frolek
Vice-President, Business Development

Bruce Nociar
Vice-President, Production

Anthony Sacheli
Vice-President & Chief Geologist

Jennifer Swertz
Vice-President, Land

Michael Sandrelli
Corporate Secretary

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Auditors

KPMG LLP
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Banker

National Bank of Canada
Calgary, Alberta

Evaluation Engineers

Sproule Associates Limited
Calgary, Alberta

Legal Counsel

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

Registrar and Transfer Agent

Valiant Trust Company
Calgary, Alberta

Stock Trading

Toronto Stock Exchange
Trading Symbol: RTK

Abbreviations

bbls	barrels
boe	barrels of oil equivalent
GJ	gigajoules
mcf	thousand cubic feet
mmcf	million cubic feet
NGLs	natural gas liquids
/d	per day
PSI	pounds per square inch

Conversion of Units

1.0 acre	=	0.40 hectares
2.5 acres	=	1.0 hectare
1.0 bbl	=	0.159 cubic metres
6.29 bbls	=	1.0 cubic metre
1.0 foot	=	0.3048 metres
3.281 feet	=	1.0 metre
1.0 mcf	=	28.2 cubic metres
0.035 mcf	=	1.0 cubic metre
1.0 mile	=	1.61 kilometres
0.62 miles	=	1.0 kilometre

Natural gas is equated to oil on the basis of 6 mcf : 1 bbl



Artek Exploration Ltd.