Crocotta Energy Announces Year End 2013 Financial and Operating Results

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CALGARY, ALBERTA -- (Marketwired - Mar 25, 2014) - Crocotta Energy Inc. (TSX:CTA) is pleased to announce its financial and operating results for the year ended December 31, 2013, including consolidated financial statements, notes to the consolidated financial statements, and Management's Discussion and Analysis. All dollar figures are Canadian dollars unless otherwise noted.

HIGHLIGHTS

- Increased average production 26% to 8,724 boepd in 2013 from 6,911 boepd in 2012
- Increased netbacks to $27.49 per boe in Q4 2013 versus $21.50 per boe average in 2012
- Reduced operating costs to $4.72 per boe in Q4 2013 (excluding 2012 adjustments relating to third party processing facilities) versus $5.83 per boe average in 2012
- Reduced operating costs at its core Edson AB property to approximately $4.00 per boe in Q4 2013 (excluding 2012 adjustments relating to third party processing facilities) versus $5.11 per boe average in 2012
- Increased proved plus probable reserves 22% to 46.3 Mmboe in 2013 from 38.1 Mmboe in 2012
- Increased funds from operations 33% to $67.2 million in 2013 from $50.6 million in 2012
- Drilled 14.5 net Cardium and Bluesky wells at Edson, AB at a 100% success rate
- Drilled 3.0 net Montney wells in Northeast BC at a 100% success rate
- Entered into a $150 million syndicated credit facility

FINANCIAL RESULTS

($000s, except per share amounts)	Three Months Ended December 31			Year Ended December 31		
	2013	2012	% Change	2013	2012	% Change
Oil and natural gas sales	31,090	24,938	25	111,459	80,518	38
Funds from operations [(1)]	19,691	14,478	36	67,197	50,615	33
Per share - basic	0.20	0.16	25	0.72	0.57	26
Per share - diluted	0.20	0.16	25	0.71	0.56	27
Net earnings (loss)	4,387	(2,082)	311	11,570	(5,254)	320
Per share - basic	0.05	(0.02)	350	0.12	(0.06)	300
Per share - diluted	0.04	(0.02)	300	0.12	(0.06)	300
Capital expenditures	32,659	36,320	(10)	127,270	98,548	29
Property acquisitions	-	5,406	(100)	-	5,406	(100)
Net debt [(2)]				117,840	80,112	47
Common shares outstanding (000s)						
Weighted average - basic	96,306	88,980	8	93,051	88,319	5
Weighted average - diluted	98,197	91,522	7	94,973	90,705	5
End of period - basic				96,712	89,261	8
End of period - diluted				105,561	100,183	5

(1) Funds from operations and funds from operations per share do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the Non-GAAP Measures section in the MD&A for more details and the Funds from Operations section in the MD&A for a reconciliation from cash flow from operating activities.

(2) Net debt includes current liabilities (excluding risk management contracts) and the credit facility less current assets. Net debt does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the Non-GAAP Measures section in the MD&A for more details.

OPERATING RESULTS	Three Months Ended December 31			Year Ended December 31		
	2013	2012	% Change	2013	2012	% Change
Daily production						
Oil and NGLs (bbls/d)	2,605	2,476	5	2,488	2,227	12
Natural gas (mcf/d)	39,767	29,160	36	37,416	28,099	33
Oil equivalent (boe/d)	9,233	7,336	26	8,724	6,911	26
Revenue						
Oil and NGLs ($/bbl)	74.62	67.55	10	71.67	64.81	11
Natural gas ($/mcf)	3.61	3.56	1	3.40	2.69	26
Oil equivalent ($/boe)	36.60	36.95	(1)	35.00	31.83	10
Royalties						
Oil and NGLs ($/bbl)	7.38	7.14	3	7.98	9.17	(13)
Natural gas ($/mcf)	0.06	0.17	(65)	0.09	0.14	(36)
Oil equivalent ($/boe)	2.34	3.07	(24)	2.64	3.52	(25)
Production expenses						
Oil and NGLs ($/bbl)	6.26	5.96	5	6.01	5.31	13
Natural gas ($/mcf)	0.93	1.11	(16)	1.08	1.01	7
Oil equivalent ($/boe)	5.78	6.41	(10)	6.33	5.83	9
Transportation expenses						
Oil and NGLs ($/bbl)	1.15	0.95	21	1.30	0.87	49
Natural gas ($/mcf)	0.15	0.15	-	0.13	0.17	(24)
Oil equivalent ($/boe)	0.99	0.90	10	0.95	0.98	(3)
Operating netback (1)						
Oil and NGLs ($/bbl)	59.83	53.50	12	56.38	49.46	14
Natural gas ($/mcf)	2.47	2.13	16	2.10	1.37	53
Oil equivalent ($/boe)	27.49	26.57	3	25.08	21.50	17
Depletion and depreciation ($/boe)	(14.64)	(13.49)	9	(14.01)	(14.50)	(3)
Asset impairment ($/boe)	(0.30)	(11.47)	(97)	(0.25)	(5.31)	(95)
General and administrative expenses ($/boe)	(2.06)	(3.87)	(47)	(1.89)	(2.17)	(13)
Share based compensation ($/boe)	(0.80)	(1.01)	(21)	(0.65)	(1.39)	(53)
Finance expenses ($/boe)	(1.42)	(0.85)	67	(1.40)	(0.75)	87
Deferred tax reduction (expense) ($/boe)	(2.83)	0.44	743	(2.76)	(0.07)	3,843
Realized gain (loss) on risk management contracts ($/boe)	(1.02)	(0.59)	73	(0.88)	1.25	(170)
Unrealized gain (loss) on risk management contracts ($/boe)	0.75	1.18	(36)	0.38	(0.63)	160
Net earnings (loss) ($/boe)	5.17	(3.09)	(267)	3.62	(2.07)	(275)

(1) Operating netback does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the Non-GAAP Measures section in the MD&A for more details.

PRESIDENT'S MESSAGE

Crocotta's goals for 2013 were to continue to expand core areas, add new core areas, and improve netbacks by increasing efficiencies.

The focus on efficiencies resulted in increasing netbacks on our Edson property by over $5 per boe and increasing netbacks on our Dawson Montney property by over $6 per boe. At Edson, Crocotta moved substantially all of its liquids-rich production to the Alliance system and signed an agreement with Aux Sable for its liquids production. This resulted in higher liquids pricing and reduced operating costs that contributed to the $5 per boe increase in netbacks. By comparison, Edson's netbacks improved by 22% from $25.37 per boe in Q1-Q3 2013 to $30.88 per boe in Q4 2013. At Dawson, Crocotta commissioned its sweet gas plant in late Q3 2013 and started to see the benefits in Q4 2013 through reduced operating costs and increased liquids yields. Operating costs were reduced from $10.50 per boe in Q1-Q3 2013 to $6.30 per boe in Q4 2013 and overall netback improved by 71% from $13.85 per boe in Q1-Q3 2013 to $23.65 per boe in Q4 2013.

Core properties received a high portion of the capital allocation with Edson seeing 45% of total capital spent to expand the Cardium drilling inventory and to augment the infrastructure. Crocotta drilled 14 gross (12.3 net) Cardium wells while increasing drilling inventory to 67.5 net wells despite drilling 12.3 net wells of the opening 2013 Cardium inventory. 3 gross (3.0 net) wells were drilled at Dawson-Sunrise in the Montney to further prove up lands for future development and infrastructure was put in place to enhance netbacks. For 2014, Edson will continue to see a substantial portion of the capital budget, however, this will shift more to the Montney for Q4 2014 and beyond.

Capital of $13.2 million was spent on new initiatives including a light oil play at Stoddart in Northeast British Columbia. Crocotta has drilled one horizontal well with encouraging results and plans to put this well on production in Q3 2014 to test commerciality of the play. Crocotta has accumulated approximately 45 prospective sections on this regional oil play.

For 2014, Crocotta will take the same approach as in 2013 to expand core areas, develop new core areas, and focus on improving netbacks.

During Q1 2014, average production is estimated at approximately 9,000 boepd which was slightly lower than forecasted. A number of factors affected the production including delays in bringing on new Montney wells, operational difficulties with the new Montney facility, and pipeline construction delays.

Rob Zakresky, President & Chief Executive Officer

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

March 20, 2014

The MD&A should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2013 and 2012. The audited consolidated financial statements and financial data contained in the MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") in Canadian currency (except where noted as being in another currency).

DESCRIPTION OF BUSINESS

Crocotta Energy Inc. ("Crocotta" or the "Company") is an oil and natural gas company, actively engaged in the acquisition, development, exploration, and production of oil and natural gas reserves in Western Canada. The Company trades on the Toronto Stock Exchange under the symbol "CTA".

FREQUENTLY RECURRING TERMS

The Company uses the following frequently recurring industry terms in the MD&A: "bbls" refers to barrels, "mcf" refers to thousand cubic feet, and "boe" refers to barrel of oil equivalent. Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. A boe conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent has been used for the calculation of boe amounts in the MD&A. This boe conversion rate is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NON-GAAP MEASURES

This MD&A refers to certain financial measures that are not determined in accordance with IFRS (or "GAAP"). This MD&A contains the terms "funds from operations", "funds from operations per share", "net debt", and "operating netback" which do not have any standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures used by other companies. The Company uses these measures to help evaluate its performance.

Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations is a non-GAAP measure and has been defined by the Company as net earnings (loss) plus non-cash items (depletion and depreciation, asset impairments, share based compensation, non-cash finance expenses, unrealized gains and losses on risk management contracts, and deferred income taxes) and excludes the change in non-cash working capital related to operating activities and expenditures on decommissioning obligations. The Company also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding, consistent with the calculation of earnings per share. Funds from operations is reconciled from cash flow from operating activities under the heading "Funds from Operations".

Management uses net debt as a measure to assess the Company's financial position. Net debt includes current liabilities (excluding risk management contracts) and the credit facility less current assets.

Management considers operating netback an important measure as it demonstrates its profitability relative to current commodity prices. Operating netback, which is calculated as average unit sales price less royalties, production expenses, and transportation expenses, represents the cash margin for every barrel of oil equivalent sold. Operating netback per boe is reconciled to net earnings (loss) per boe under the heading "Operating Netback".

2013 HIGHLIGHTS

- Increased average production 26% to 8,724 boepd in 2013 from 6,911 boepd in 2012
- Increased netbacks to $27.49 per boe in Q4 2013 versus $21.50 per boe average in 2012
- Reduced operating costs to $4.72 per boe in Q4 2013 (excluding 2012 adjustments relating to third party processing facilities) versus $5.83 per boe average in 2012
- Reduced operating costs at its core Edson AB property to approximately $4.00 per boe in Q4 2013 (excluding 2012 adjustments relating to third party processing facilities) versus $5.11 per boe average in 2012
- Increased proved plus probable reserves 22% to 46.3 Mmboe in 2013 from 38.1 Mmboe in 2012
- Increased funds from operations 33% to $67.2 million in 2013 from $50.6 million in 2012
- Drilled 14.5 net Cardium and Bluesky wells at Edson, AB at a 100% success rate
- Drilled 3.0 net Montney wells in Northeast BC at a 100% success rate
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SUMMARY OF FINANCIAL RESULTS

($000s, except per share amounts)	Three Months Ended December 31			Year Ended December 31		
	2013	2012	2011	2013	2012	2011
Oil and natural gas sales	31,090	24,938	20,391	111,459	80,518	54,974
Funds from operations	19,691	14,478	12,115	67,197	50,615	30,608
Per share - basic	0.20	0.16	0.15	0.72	0.57	0.39
Per share - diluted	0.20	0.16	0.14	0.71	0.56	0.38
Net earnings (loss)	4,387	(2,082)	(7,052)	11,570	(5,254)	(5,592)
Per share - basic	0.05	(0.02)	(0.09)	0.12	(0.06)	(0.07)
Per share - diluted	0.04	(0.02)	(0.09)	0.12	(0.06)	(0.07)
Total assets				373,301	300,980	239,554
Total long-term liabilities				158,610	21,852	20,063

Net debt					117,840	80,112	27,736

The Company has experienced significant growth in oil and natural gas sales, funds from operations, and net earnings over the past three years. Successful capital activity during the previous three years at Edson, AB and Northeast BC led to a significant increase in production which resulted in increased revenue, funds from operations, and net earnings. The Company had a net loss in 2011 and 2012 mainly due to asset impairments recorded on non-core properties in each year due to declines in commodity prices and limited capital activity in these non-core areas to maintain reserves. Net debt increased significantly in 2013 due to capital expenditures of $127.3 million during the year, offset by an equity financing that raised gross proceeds of $22.0 million and funds from operations of $67.2 million. Net debt in 2012 was higher than 2011 due to capital expenditures of $104.0 million, offset by funds from operations of $50.6 million.

PRODUCTION	Three Months Ended December 31			Year Ended December 31		
	2013	2012	% Change	2013	2012	% Change
Average Daily Production						
Oil and NGLs (bbls/d)	2,605	2,476	5	2,488	2,227	12
Natural gas (mcf/d)	39,767	29,160	36	37,416	28,099	33
Combined (boe/d)	9,233	7,336	26	8,724	6,911	26

Daily production for the three months ended December 31, 2013 increased 26% to 9,233 boe/d compared to 7,336 boe/d for the comparative period in 2012. For the year, daily production increased 26% to 8,724 boe/d in 2013 from 6,911 boe/d in 2012. The significant increase in production was due to successful drilling activity at Edson, AB and Northeast BC during the past year. Compared to the previous quarter, daily production increased 7% in Q4 2013 from 8,596 boe/d in Q3 2013.

Crocotta's production profile for 2013 was comprised of 71% natural gas and 29% oil and NGLs compared with the production profile for 2012 which was comprised of 68% natural gas and 32% oil and NGLs. The increase in gas weighting is due to a higher percentage of total production coming from Northeast BC in 2013 compared to 2012.

REVENUE	Three Months Ended December 31			Year Ended December 31		
($000s)	2013	2012	% Change	2013	2012	% Change
Oil and NGLs	17,882	15,389	16	65,070	52,839	23
Natural gas	13,208	9,549	38	46,389	27,679	68
Total	31,090	24,938	25	111,459	80,518	38
Average Sales Price						
Oil and NGLs ($/bbl)	74.62	67.55	10	71.67	64.81	11
Natural gas ($/mcf)	3.61	3.56	1	3.40	2.69	26
Combined ($/boe)	36.60	36.95	(1)	35.00	31.83	10

Revenue totaled $31.1 million for the fourth quarter of 2013, up 25% from $24.9 million in the comparative period. For the year, revenue increased 38% to $111.5 million in 2013 from $80.5 million in 2012. The increase in revenue was mainly due to significant increases in production, combined with increases in oil, NGLs, and natural gas commodity prices.

The following table outlines the Company's realized wellhead prices and industry benchmarks:

Commodity Pricing	Three Months Ended December 31			Year Ended December 31		
	2013	2012	% Change	2013	2012	% Change
Oil and NGLs						
Corporate price ($CDN/bbl)	74.62	67.55	10	71.67	64.81	11
Edmonton par ($CDN/bbl)	86.38	84.43	2	93.27	86.57	8
West Texas Intermediate ($US/bbl)	97.46	88.30	10	97.98	94.19	4
Natural gas						
Corporate price ($CDN/mcf)	3.61	3.56	1	3.40	2.69	26
AECO price ($CDN/mcf)	3.52	3.22	9	3.13	2.39	31
Exchange rate						
CDN/US dollar average exchange rate	0.9528	1.0093	(6)	0.9712	1.0009	(3)

Differences between corporate and benchmark prices can be the result of quality differences (higher or lower

API oil and higher or lower heat content natural gas), sour content, NGLs included in reporting, and various other factors. Crocotta's differences are mainly the result of lower priced NGLs included in oil price reporting and higher heat content natural gas production that is priced higher than AECO reference prices. The Company's corporate average oil and NGLs prices were 86.4% and 76.8% of Edmonton Par price for the three months and year ended December 31, 2013, respectively, up from 80.0% and 74.9% for the respective comparative periods in 2012. The Company experienced an increase in realized NGLs prices for a significant portion of its NGLs volumes at Edson, AB and Northeast BC as they were transitioned to new marketing arrangements in June 2013 and September 2013, respectively, which allowed the Company to access higher propane and butane prices in the United States. Corporate average natural gas prices were 102.6% and 108.6% of AECO prices for the three months and year ended December 31, 2013, respectively, down from 110.6% and 112.6% in the respective comparative periods. The decreases in realized natural gas prices were also due to gas volumes at Edson, AB and Northeast BC being transitioned to the new marketing arrangements in 2013, which decreased the premium received on the Company's natural gas production.

Future prices received from the sale of the products may fluctuate as a result of market factors. In addition, the Company may enter into commodity price contracts to manage future cash flows. For the year ended December 31, 2013, the realized loss on the Company's oil contracts was $1.2 million and the realized loss on the gas contracts was $1.6 million. For the year ended December 31, 2013, the unrealized loss on the oil contracts was $0.2 million and the unrealized gain on the gas contracts was $1.4 million.

At December 31, 2013, the Company had the following commodity price contracts outstanding:

Commodity	Period	Type of Contract	Quantity Contracted	Contract Price
Oil	January 1, 2014 - December 31, 2014	Financial - Swap	500 bbls/d	WTI CDN $100.80/bbl
Oil	January 1, 2014 - March 31, 2014	Financial - Swap	500 bbls/d	WTI CDN $106.55/bbl
Natural Gas	April 1, 2014 - October 31, 2014	Financial - Swap	5,000 GJ/d	AECO CDN $3.505/GJ
Natural Gas	April 1, 2014 - October 31, 2014	Financial - Swap	5,000 GJ/d	AECO CDN $3.650/GJ

Subsequent to December 31, 2013, the Company entered into the following commodity price contracts:

Commodity	Period	Type of Contract	Quantity Contracted	Contract Price
Oil	April 1, 2014 - June 30, 2014	Financial - Swap	500 bbls/d	WTI CDN $108.00/bbl
Oil	July 1, 2014 - September 30, 2014	Financial - Swap	500 bbls/d	WTI CDN $110.00/bbl
Natural Gas	April 1, 2014 - October 31, 2014	Financial - Swap	10,000 GJ/d	AECO CDN $3.745/GJ

ROYALTIES	Three Months Ended December 31			Year Ended December 31		
($000s)	2013	2012	% Change	2013	2012	% Change
Oil and NGLs	1,768	1,627	9	7,241	7,476	(3)
Natural gas	224	444	(50)	1,163	1,435	(19)
Total	1,992	2,071	(4)	8,404	8,911	(6)
Average Royalty Rate (% of sales)						
Oil and NGLs	9.9	10.6	(7)	11.1	14.1	(21)
Natural gas	1.7	4.6	(63)	2.5	5.2	(52)
Combined	6.4	8.3	(23)	7.5	11.1	(32)

The Company pays royalties to provincial governments (Crown), freeholders, which may be individuals or companies, and other oil and gas companies that own surface or mineral rights. Crown royalties are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to commodity price fluctuations and changes in production volumes on a well-by-well basis, subject to a minimum and maximum rate restriction ascribed by the Crown. The provincial government has also enacted various royalty incentive programs that are available for wells that meet certain criteria, such as natural gas deep drilling, which can result in fluctuations in royalty rates.

For the three months ended December 31, 2013, oil, NGLs, and natural gas royalties decreased 4% to $2.0 million from $2.1 million in the comparative period. For the year ended December 31, 2013, oil, NGLs, and natural gas royalties decreased to $8.4 million from $8.9 million in 2012. The overall effective royalty rate was 6.4% for the three months ended December 31, 2013 compared to 8.3% for the three months ended December 31, 2012. For the year, the overall effective royalty rate was 7.5% in 2013 compared to 11.1% in 2012. These decreases were the result of royalty incentives received on new wells brought on production during the year combined with an increase in the monthly capital cost and processing fee deductions in 2013 compared to 2012.

PRODUCTION EXPENSES	Three Months Ended December 31			Year Ended December 31		
	2013	2012	% Change	2013	2012	% Change
Oil and NGLs ($/bbl)	6.26	5.96	5	6.01	5.31	13
Natural gas ($/mcf)	0.93	1.11	(16)	1.08	1.01	7
Combined ($/boe)	5.78	6.41	(10)	6.33	5.83	9

Per unit production expenses for the three months ended December 31, 2013 were $5.78/boe, down 10% from $6.41/boe for the comparative period ended December 31, 2012. For the year ended December 31, 2013, per unit production expenses increased 9% to $6.33/boe from $5.83/boe for the year ended December 31, 2012. The increase in year-over-year production expenses is mainly due to higher costs associated with wells brought on production in Northeast BC during 2012 and the first part of 2013. Production expenses in this area were approximately $10.00/boe due mainly to third party processing and throughput charges. During the latter part of the third quarter of 2013, the Company completed the expansion of its infrastructure in this area and as a result, production expenses in Northeast BC decreased to approximately $6.00/boe. This decrease led to production expenses per boe being lower in Q4 2013 compared to Q4 2012. Year-to-date, production expenses in Edson, AB continued to be very competitive at approximately $5.50/boe, declining in the latter half of the year as a result of the transition to a new marketing arrangement. The Company continues to focus on opportunities to maintain operational efficiencies to enhance operating netbacks.

TRANSPORTATION EXPENSES	Three Months Ended December 31			Year Ended December 31		
	2013	2012	% Change	2013	2012	% Change
Oil and NGLs ($/bbl)	1.15	0.95	21	1.30	0.87	49
Natural gas ($/mcf)	0.15	0.15	-	0.13	0.17	(24)
Combined ($/boe)	0.99	0.90	10	0.95	0.98	(3)

Transportation expenses are mainly third-party pipeline tariffs incurred to deliver production to the purchasers at main hubs. For the quarter ended December 31, 2013 compared to the quarter ended December 31, 2012, transportation expenses increased 10% to $0.99/boe from $0.90/boe. For the year, transportation expenses decreased to $0.95/boe in 2013 from $0.98/boe in 2012. Oil and NGLs transportation expenses were higher in 2013 compared to 2012 as a result of the Company's production in Northeast BC being diverted to a different processing facility from the second quarter through the third quarter of 2013 to obtain credit for NGLs volumes that were not being extracted previously. During September 2013, the Company transitioned production in Northeast BC to a new marketing arrangement, which resulted in a decrease in oil and NGLs transportation expenses from $1.93/boe in Q3 2013 to $1.15/boe in Q4 2013. The decrease in natural gas transportation expenses per boe is due to obtaining a lower contracted transportation fee in the fourth quarter of 2012 on the majority of the Company's natural gas production. The Company shifted this natural gas production to a new marketing arrangement during the second half of 2013 under which lower natural gas transportation expenses continued to be realized.

OPERATING NETBACK	Three Months Ended December 31			Year Ended December 31		
	2013	2012	% Change	2013	2012	% Change
Oil and NGLs ($/bbl)						
Revenue	74.62	67.55	10	71.67	64.81	11
Royalties	(7.38)	(7.14)	3	(7.98)	(9.17)	(13)
Production expenses	(6.26)	(5.96)	5	(6.01)	(5.31)	13
Transportation expenses	(1.15)	(0.95)	21	(1.30)	(0.87)	49
Operating netback	59.83	53.50	12	56.38	49.46	14
Natural gas ($/mcf)						
Revenue	3.61	3.56	1	3.40	2.69	26
Royalties	(0.06)	(0.17)	(65)	(0.09)	(0.14)	(36)
Production expenses	(0.93)	(1.11)	(16)	(1.08)	(1.01)	7
Transportation expenses	(0.15)	(0.15)	-	(0.13)	(0.17)	(24)
Operating netback	2.47	2.13	16	2.10	1.37	53
Combined ($/boe)						
Revenue	36.60	36.95	(1)	35.00	31.83	10
Royalties	(2.34)	(3.07)	(24)	(2.64)	(3.52)	(25)
Production expenses	(5.78)	(6.41)	(10)	(6.33)	(5.83)	9
Transportation expenses	(0.99)	(0.90)	10	(0.95)	(0.98)	(3)
Operating netback	27.49	26.57	3	25.08	21.50	17

During the fourth quarter of 2013, Crocotta generated an operating netback of $27.49/boe, an increase of

3% from $26.57/boe for the fourth quarter of 2012. For the year ended December 31, 2013, Crocotta generated an operating netback of $25.08/boe compared to $21.50/boe in the comparative period. The increases were due to higher oil, natural gas, and NGLs commodity prices and decreases in royalties. Operating netbacks in Q4 2013 increased from operating netbacks of $24.08/boe in Q3 2013 due to increases in natural gas commodity prices and a reduction in production expenses and transportation expenses.

The following is a reconciliation of operating netback per boe to net earnings (loss) per boe for the periods noted:

	Three Months Ended December 31			Year Ended December 31		
($/boe)	2013	2012	% Change	2013	2012	% Change
Operating netback	27.49	26.57	3	25.08	21.50	17
Depletion and depreciation	(14.64)	(13.49)	9	(14.01)	(14.50)	(3)
Asset impairment	(0.30)	(11.47)	(97)	(0.25)	(5.31)	(95)
General and administrative expenses	(2.06)	(3.87)	(47)	(1.89)	(2.17)	(13)
Share based compensation	(0.80)	(1.01)	(21)	(0.65)	(1.39)	(53)
Finance expenses	(1.42)	(0.85)	67	(1.40)	(0.75)	87
Deferred tax reduction (expense)	(2.83)	0.44	743	(2.76)	(0.07)	3,843
Realized gain (loss) on risk management contracts	(1.02)	(0.59)	73	(0.88)	1.25	(170)
Unrealized gain (loss) on risk management contracts	0.75	1.18	(36)	0.38	(0.63)	160
Net earnings (loss)	5.17	(3.09)	(267)	3.62	(2.07)	(275)

DEPLETION AND DEPRECIATION	Three Months Ended December 31			Year Ended December 31		
	2013	2012	% Change	2013	2012	% Change
Depletion and depreciation ($000s)	12,434	9,107	37	44,596	36,685	22
Depletion and depreciation ($/boe)	14.64	13.49	9	14.01	14.50	(3)

The Company calculates depletion on property, plant, and equipment based on proved plus probable reserves. Plant turnarounds and major overhauls are depreciated over three or four years, depending on each facility. Depletion and depreciation for the three months ended December 31, 2013 was $14.64/boe compared to $13.49/boe in the comparative period. The increase was due to a significant increase in estimated future capital costs associated with proved plus probable reserves at Edson AB in Q4 2013 compared to Q4 2012. For the year, depletion and depreciation was $14.01/boe in 2013, consistent with depletion and depreciation of $14.50/boe in 2012.

ASSET IMPAIRMENT	Three Months Ended December 31			Year Ended December 31		
	2013	2012	% Change	2013	2012	% Change
Asset impairment ($000s)	256	7,743	(97)	802	13,439	(94)
Asset impairment ($/boe)	0.30	11.47	(97)	0.25	5.31	(95)

Exploration and evaluation assets and property, plant, and equipment are grouped into cash-generating units ("CGU") for purposes of impairment testing. Exploration and evaluation assets are assessed for impairment when they are transferred to property, plant, and equipment or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For property, plant, and equipment, an impairment is recognized if the carrying value of a CGU exceeds the greater of its fair value less costs to sell or value in use.

For the year ended December 31, 2013, total exploration and evaluation asset impairments of $0.6 million were recognized relating to the expiry of undeveloped land rights (CGUs - Miscellaneous AB, and Saskatchewan). For the year ended December 31, 2012, total exploration and evaluation asset impairments of $4.7 million were recognized, including asset impairments of $2.4 million relating to the determination of certain exploration and evaluation activities to be uneconomical (CGU - Miscellaneous AB) and $2.3 million relating to the expiry of undeveloped land rights (CGUs - Lookout Butte AB, Miscellaneous AB, and Saskatchewan).

At December 31, 2013, with the exception of Lookout Butte AB, there were no indicators of impairment of property, plant, and equipment. Due to higher than expected production declines and no capital expenditures during 2013 at Lookout Butte AB to maintain reserve values, the Company recorded property, plant, and equipment impairments of $0.2 million during the fourth quarter. For the year ended December 31, 2012, the Company recorded property, plant, and equipment impairments of $8.7 million relating to Smoky AB, Lookout Butte AB, Miscellaneous AB, and Saskatchewan CGUs mainly as a result of weakening natural gas prices and limited capital expenditures in these CGUs to maintain their reserve values.

GENERAL AND ADMINISTRATIVE	Three Months Ended December 31			Year Ended December 31		
($000s)	2013	2012	% Change	2013	2012	% Change
G&A expenses (gross)	2,132	3,076	(31)	7,711	7,020	10
G&A capitalized	(117)	(195)	(40)	(539)	(435)	24
G&A recoveries	(264)	(272)	(3)	(1,142)	(1,098)	4
G&A expenses (net)	1,751	2,609	(33)	6,030	5,487	10
G&A expenses ($/boe)	2.06	3.87	(47)	1.89	2.17	(13)

General and administrative expenses ("G&A") decreased 47% to $2.06/boe for the fourth quarter of 2013 compared to $3.87/boe for the fourth quarter of 2012. For the year, G&A expenses decreased 13% to $1.89/boe in 2013 from $2.17/boe in 2012.The decreases in G&A expenses per boe were the result of significant increases in production.

SHARE BASED COMPENSATION	Three Months Ended December 31			Year Ended December 31		
	2013	2012	% Change	2013	2012	% Change
Share based compensation ($000s)	681	684	-	2,084	3,512	(41)
Share based compensation ($/boe)	0.80	1.01	(21)	0.65	1.39	(53)

The Company grants stock options to officers, directors, employees and consultants and calculates the related share based compensation using the Black-Scholes-Merton option pricing model. The Company recognizes the expense over the individual vesting periods for the graded vesting awards and estimates a forfeiture rate at the date of grant and updates it throughout the vesting period. Share based compensation expense decreased to $0.80/boe and $0.65/boe, respectively, for the three months and year ended December 31, 2013 from $1.01/boe and $1.39/boe in the comparative periods, respectively. During 2013, the Company granted 1.7 million options (2012 - 0.7 million). The decrease in share based compensation per boe is a result of a significant increase in production.

FINANCE EXPENSES	Three Months Ended December 31			Year Ended December 31		
($000s)	2013	2012	% Change	2013	2012	% Change
Interest expense	1,043	452	131	3,851	1,449	166
Accretion of decommissioning obligations	167	120	39	590	453	30
Finance expenses	1,210	572	112	4,441	1,902	133
Finance expenses ($/boe)	1.42	0.85	67	1.40	0.75	87

Interest expense relates mainly to interest incurred on amounts drawn from the Company's credit facility. The increase in interest expense is a result of higher amounts being drawn on the Company's credit facility in 2013 compared to 2012. At December 31, 2013, $116.3 million (2012 - $68.5 million) had been drawn on the Company's credit facility.

DEFERRED INCOME TAX EXPENSE

Deferred income tax expense on the earnings before taxes was $8.8 million in 2013 (2012 - $0.2 million). This was larger than expected by applying the statutory tax rate to the loss before taxes due mainly to flow-through shares and share based compensation.

Estimated tax pools at December 31, 2013 total approximately $341.1 million (2012 - $299.6 million).

FUNDS FROM OPERATIONS

Funds from operations for the three months and year ended December 31, 2013 were $19.7 million ($0.20 per diluted share) and $67.2 million ($0.71 per diluted share), respectively, compared to $14.5 million ($0.16 per diluted share) and $50.6 million ($0.56 per diluted share) for the three months and year ended December 31, 2012, respectively. The increase was mainly due to a significant increase in revenue in 2013 as a result of a significant increase in production and oil, natural gas, and NGLs commodity prices.

The following is a reconciliation of cash flow from operating activities to funds from operations for the periods noted:

($000s)	Three Months Ended December 31 2013	2012	% Change	Year Ended December 31 2013	2012	% Change
Cash flow from operating activities (GAAP)	19,796	12,096	64	65,513	47,449	38
Add back:						
Decommissioning expenditures	421	113	273	691	734	(6)
Change in non-cash working capital	(526)	2,269	(123)	993	2,432	(59)
Funds from operations (non-GAAP)	19,691	14,478	36	67,197	50,615	33

NET EARNINGS (LOSS)

The Company had net earnings of $4.4 million ($0.04 per diluted share) for the three months ended December 31, 2013 compared to a net loss of $2.1 million ($0.02 per diluted share) for the three months ended December 31, 2012. For the year, the Company had net earnings of $11.6 million ($0.12 per diluted share) in 2013 compared to a net loss of $5.3 million ($0.06 per diluted share) in 2012. Net earnings in 2013 arose mainly due to a significant increase in revenue as a result of a significant increase in production and oil, natural gas, and NGLs commodity prices The net loss in 2012 arose mainly due to asset impairments recorded on non-core properties due to declines in commodity prices, limited capital activity in the associated non-core areas to maintain reserve values, and exploration and evaluation activities determined to be uneconomical.

CAPITAL EXPENDITURES ($000s)	Three Months Ended December 31 2013	2012	% Change	Year Ended December 31 2013	2012	% Change
Land	5,661	2,701	110	8,856	7,107	25
Drilling, completions, and workovers	23,630	27,504	(14)	92,913	74,663	24
Equipment	2,802	5,781	(52)	23,745	15,949	49
Geological and geophysical	566	334	69	1,756	829	112
Property acquisitions	-	5,406	(100)	-	5,406	(100)
Exploration and development	32,659	41,726	(22)	127,270	103,954	22

For the three months ended December 31, 2013, the Company had capital expenditures of $32.7 million compared to capital expenditures of $41.7 million for the three months ended December 31, 2012. For the year ended December 31, 2013, the Company had capital expenditures of $127.3 million compared to capital expenditures of $104.0 million for the comparative period in 2012. The increase in exploration and development expenditures in 2013 was due mainly to an increase in capital activity in the Company's core areas of Edson, AB and Northeast BC. During 2013, Crocotta drilled a total of 21 (18.5 net) wells, which resulted in 15 (13.3 net) oil wells and 6 (5.2 net) liquids-rich natural gas wells. During 2012, Crocotta drilled a total of 21 (16.0 net) wells, which resulted in 12 (7.8 net) oil wells, 8 (7.2 net) liquids-rich natural gas wells, and 1 (1.0 net) exploratory well in a non-core area that was uneconomic.

LIQUIDITY AND CAPITAL RESOURCES

The Company had net debt of $117.8 million at December 31, 2013 compared to net debt of $80.1 million at December 31, 2012. The increase of $37.7 million was due to $127.3 million used for the purchase and development of oil and natural gas properties and equipment and $0.7 million for decommissioning expenditures, offset by funds from operations of $67.2 million and share issuances of $23.0 million (net of $1.0 million in share issue costs).

In June 2013, the Company issued approximately 6.0 million common shares on a flow-through basis for gross proceeds of approximately $22.0 million. Approximately 4.2 million shares were issued at a price of $3.70 per share in respect of Canadian exploration expenses ("CEE") and approximately 1.8 million shares were issued at a price of $3.50 per share in respect of Canadian development expenses ("CDE"). The proceeds were used by the Company to fund eligible CEE and CDE projects.

During the third quarter of 2013, the Company entered into a syndicated credit facility with three Canadian chartered banks. The syndicated credit facility replaced the Company's previous $140 million revolving operating demand loan credit facility. The syndicated facility has a borrowing base of $150 million, consisting of a $140 million revolving line of credit and a $10 million operating line of credit. The syndicated facility revolves for a 364 day period and will be subject to its next 364 day extension by July 11, 2014. If not extended, the syndicated facility will cease to revolve, the margins thereunder will increase by 0.50%, and all outstanding advances will become repayable in one year from the extension date.

Advances under the syndicated facility are available by way of prime rate loans, with interest rates between 1.00% and 2.50% over the Canadian prime lending rate, and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 2.00% to 3.50% depending upon the debt to cash flow ratio of the Company. Standby fees are charged on the undrawn syndicated facility at rates ranging from 0.50% to 0.875%. The credit facility is secured by a $300 million fixed and floating charge debenture on the assets of the Company. At December 31, 2013, $116.3 million (December 31, 2012 - $68.5 million) had been drawn on the credit facility. In addition, at December 31, 2013, 2013, the Company had outstanding letters of guarantee of approximately $2.5 million (December 31, 2012 - $1.5 million) which reduce the amount that can be borrowed under the credit facility. The next scheduled borrowing base review of the syndicated facility is scheduled on or before June 30, 2014.

The ongoing global economic conditions have continued to impact the liquidity in financial and capital markets, restrict access to financing, and cause significant volatility in commodity prices. Despite the economic downturn and financial market volatility, the Company continued to have access to both debt and equity markets recently. The Company raised gross proceeds of approximately $22.0 million from the issuance of common shares during the second quarter of 2013 and during the year, the Company entered into a $150 million syndicated credit facility which replaced the previous $140 million revolving operating demand loan credit facility. The Company has also maintained a very successful drilling program which has resulted in significant increases in production and funds flow from operations in recent quarters. Management anticipates that the Company will continue to have adequate liquidity to fund budgeted capital investments through a combination of cash flow, equity, and debt. Crocotta's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

CONTRACTUAL OBLIGATIONS

The following is a summary of the Company's contractual obligations and commitments at December 31, 2013:

($000s)	Total	Less than One Year	One to Three Years	After Three Years
Accounts payable and accrued liabilities	19,480	19,480	-	-
Credit facility	116,324	-	116,324	-
Risk management contracts	368	368	-	-
Decommissioning obligations	22,438	50	965	21,423
Office leases	395	395	-	-
Field equipment leases	559	559	-	-
Firm transportation agreements	22	8	14	-
Total contractual obligations	159,586	20,860	117,303	21,423

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares, Class A preferred shares, issuable in series, and Class B preferred shares, issuable in series. The voting common shares of the Company commenced trading on the TSX on October 17, 2007 under the symbol "CTA". The following table summarizes the common shares outstanding and the number of shares exercisable into common shares from options, warrants, and other instruments:

(000s)	December 31, 2013	March 20, 2014
Voting common shares	96,712	96,720
Stock options	8,849	8,940
Total	105,561	105,660

SUMMARY OF QUARTERLY RESULTS

	Q4 2013	Q3 2013	Q2 2013	Q1 2013	Q4 2012	Q3 2012	Q2 2012	Q1 2012

Average Daily Production								
Oil and NGLs (bbls/d)	2,605	2,497	2,158	2,691	2,476	2,103	2,053	2,277
Natural gas (mcf/d)	39,767	36,593	36,412	36,869	29,160	29,053	27,309	26,852
Combined (boe/d)	9,233	8,596	8,227	8,836	7,336	6,945	6,604	6,752
($000s, except per share amounts)								
Oil and natural gas sales	31,090	26,950	25,152	28,267	24,938	17,922	17,518	20,140
Funds from operations	19,691	16,102	14,280	17,124	14,478	10,888	12,275	12,974
Per share - basic	0.20	0.17	0.16	0.19	0.16	0.12	0.14	0.15
Per share - diluted	0.20	0.16	0.15	0.19	0.16	0.12	0.14	0.14
Net earnings (loss)	4,387	975	3,604	2,604	(2,082)	(3,944)	1,065	(293)
Per share - basic	0.05	0.01	0.04	0.03	(0.02)	(0.04)	0.01	-
Per share - diluted	0.04	0.01	0.04	0.03	(0.02)	(0.04)	0.01	-

The Company has experienced significant increases in production over the previous two years stemming from successful drilling activities during that period. These production increases resulted in substantial increases in revenue, funds from operations, and net earnings over the previous two years. The Company had a net loss in three of the four quarters in 2012 mainly as a result of asset impairments recognized in each quarter on non-core properties.

2014 OUTLOOK

The information below represents Crocotta's guidance for 2014 based on management's best estimates and the assumptions noted below.

Estimated Average Daily Production	Guidance 2014
Oil and NGLs (bbls/d)	2,700
Natural gas (mcf/d)	43,800
Total (boe/d)	10,000
Exit production (boe/d)	11,000 - 11,500

Estimated Financial Results	Guidance 2014
Oil and natural gas sales ($000s)	137,000
Funds from operations ($000s)	90,000
$ per share - basic (1)	0.93
$ per share - diluted (2)	0.85
Capital expenditures ($000s)	110,000
West Texas Intermediate ($US/bbl)	97.50
AECO Daily Spot Price ($CDN/mcf)	4.05
US/CDN Dollar Average Exchange Rate	0.95

(1) Based on 96.7 million common shares outstanding

(2) Based on 96.7 million common shares and 8.9 million options outstanding

Sensitivity Analysis

The outlook is based on estimates of key external market factors. Crocotta's actual results will be affected by fluctuations in commodity prices as well as the U.S./Canadian dollar exchange rate. The following table provides a summary of estimates for 2014 of the sensitivity of Crocotta's funds from operations to changes in commodity prices and the U.S./Canadian dollar exchange rate.

	Guidance 2014	Variance in Factor	Funds from Operations
West Texas Intermediate ($US/bbl)	97.50	1.00	750,000
AECO Daily Spot Price ($CDN/mcf)	4.05	0.10	1,590,000
US/CDN Dollar Average Exchange Rate	0.95	0.01	760,000

2013 OUTLOOK

The information below represents Crocotta's guidance for 2012 and a comparison to actual results for 2013:

Estimated Average Daily Production	Guidance 2013	Actual 2013	% Change

Oil and NGLs (bbls/d)	3,100	2,488	(20)
Natural gas (mcf/d)	37,300	37,416	-
Total (boe/d)	9,300	8,724	(6)
Exit production (boe/d)	10,500	10,500	-
Estimated Financial Results	Guidance 2013	Actual 2013	% Change
Oil and natural gas sales ($000s)	120,000	111,459	(7)
Funds from operations ($000s)	70,500	67,197	(5)
$ per share - basic [1]	0.79	0.72	(9)
$ per share - diluted [2]	0.70	0.71	1
Capital expenditures ($000s)	100,000	127,270	27
West Texas Intermediate ($US/bbl)	90.00	97.98	9
AECO Daily Spot Price ($CDN/mcf)	3.38	3.13	(7)
US/CDN Dollar Average Exchange Rate	1.00	0.97	(3)

(1) Based on 89.3 million common shares outstanding

(2) Based on 89.3 million common shares, 8.6 million options, and 2.3 million warrants outstanding

During 2013, actual production was lower than budget due to a longer than expected spring break-up and wet season. As a result, capital was shifted into the second half of the year still allowing the exit production guidance of 10,500 boe/d to be successfully achieved. Oil and natural gas sales and funds from operations were lower than budget as a result of lower than budgeted production and natural gas commodity prices. Capital expenditures exceeded budget by $27.3 million as a result of drilling more farm-in locations, spending more on facilities and infrastructure, and acquiring more land.

CRITICAL ACCOUNTING ESTIMATES

Management is required to make estimates, judgments, and assumptions in the application of IFRS that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended. Certain of these estimates may change from period to period resulting in a material impact on the Company's results from operations, financial position, and change in financial position. The following summarizes the Company's significant critical accounting estimates.

Oil and natural gas reserves

The Company engages a qualified, independent oil and gas reserves evaluator to perform an estimation of the amount of the Company's oil and natural gas reserves at least annually. Reserves form the basis for the calculation of depletion and assessment of impairment of oil and natural gas assets. Reserves are estimated using the definitions of reserves prescribed by National Instrument 51-101 and the Canadian Oil and Gas Evaluation Handbook.

Proved plus probable reserves are defined as the estimated quantities of crude oil, natural gas liquids including condensate, and natural gas that geological and engineering data demonstrate a 50 percent probability of being recovered at the reported level. Due to the inherent uncertainties and the necessarily limited nature of reservoir data, estimates of reserves are inherently imprecise, require the application of judgment, and are subject to change as additional information becomes available. The estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance, or changes in the Company's plans.

Impairment testing

Exploration and evaluation assets

Exploration and evaluation assets are assessed for impairment (i) if sufficient data exists to determine technical feasibility and commercial viability, (ii) if facts and circumstances suggest that the carrying amount exceeds the recoverable amount, and (iii) upon transfer to property, plant, and equipment. For purposes of impairment testing, exploration and evaluation assets are allocated to CGUs. Impairment tests by their nature involve estimates and judgment, which for exploration and evaluation assets include estimates of proved and probable reserves found, the market value of undeveloped land, and future development plans. Crocotta allocated its exploration and evaluation assets to specific CGUs for the purpose of impairment testing.

Property, plant, and equipment

For the purpose of impairment testing, items of property, plant, and equipment, which includes oil and natural gas development and production assets, are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (CGU). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell. The Company uses fair value less costs to sell for its impairment tests which is determined as the net present value of the estimated future cash flows expected to arise from the continued use of the CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU. The significant estimates and judgments include proved plus probable reserves, the estimated value of those reserves, including future commodity prices, the discount rate used to present value the estimated future cash flows, and other assumptions that an independent market participant may take into account, including acquisition metrics of recent transactions for similar assets.

Decommissioning obligations

Decommissioning obligations are estimated based on existing laws, contracts, or other policies. Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation as at the reporting date. Subsequent to the initial measurement, the obligation is adjusted at the end of each reporting period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation, and changes in the risk-free rate. The increase in the provision due to the passage of time is recognized as accretion whereas increases or decreases due to changes in the estimated future cash flows or changes in the discount rate are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Share based compensation

Measurement of compensation cost attributable to the Company's share based compensation plan is subject to the estimation of fair value using the Black-Scholes-Merton option pricing model. The valuation is based on significant assumptions including the estimated forfeiture rate, the expected volatility (based on the weighted average historic volatility adjusted for changes expected due to publicly available information), the weighted average expected life of the instrument (based on historical experience and general information), the expected dividends, and the risk free interest rate (based on government bonds).

Deferred income taxes

The determination of the Company's income taxes requires interpretation of complex laws and regulations. Tax interpretations, regulations, and legislation in the various jurisdictions in which the Company operates are subject to change. Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

CHANGES IN ACCOUNTING POLICIES

On January 1, 2013, the Company adopted new standards with respect to consolidations (IFRS 10), joint arrangements (IFRS 11), disclosure of interests in other entities (IFRS 12), fair value measurements (IFRS 13), and amendments to financial statement disclosures (IFRS 7). The adoption of these standards had no impact on the amounts recorded in the consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING POLICIES

In May 2013, the IASB issued amendments to IAS 36, *Impairment of Assets*, which reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The amendments are required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. These amendments will be applied by the Company on January 1, 2014 and the adoption will only impact disclosures in the notes to the financial statements in periods when an impairment loss or impairment reversal is recognized.

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

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

RISK ASSESSMENT

The acquisition, exploration, and development of oil and natural gas properties involves many risks common to all participants in the oil and natural gas industry. Crocotta's exploration and development activities are subject to various business risks such as unstable commodity prices, interest rate and foreign exchange fluctuations, the uncertainty of replacing production and reserves on an economic basis, government regulations, taxes, and safety and environmental concerns. While management realizes these risks cannot be eliminated, they are committed to monitoring and mitigating these risks.

Reserves and reserve replacement

The recovery and reserve estimates on Crocotta's properties are estimates only and the actual reserves may be materially different from that estimated. The estimates of reserve values are based on a number of variables including price forecasts, projected production volumes and future production and capital costs. All of these factors may cause estimates to vary from actual results.

Crocotta's future oil and natural gas reserves, production, and funds from operations to be derived therefrom are highly dependent on the Company successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Crocotta's reserves will depend on its abilities to acquire suitable prospects or properties and discover new reserves.

To mitigate this risk, Crocotta has assembled a team of experienced technical professionals who have expertise operating and exploring in areas the Company has identified as being the most prospective for increasing reserves on an economic basis. To further mitigate reserve replacement risk, Crocotta has targeted a majority of its prospects in areas which have multi-zone potential, year-round access, and lower drilling costs and employs advanced geological and geophysical techniques to increase the likelihood of finding additional reserves.

Operational risks

Crocotta's operations are subject to the risks normally incidental to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells. Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property.

Financial instruments

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

- Level 1 - observable inputs, such as quoted market prices in active markets
- Level 2 - inputs, other that the quoted market prices in active markets, which are observable, either directly or indirectly
- Level 3 - unobservable inputs for the asset or liability in which little or no market data exists, therefore requiring an entity to develop its own assumptions

The fair value of derivative contracts used for risk management as shown in the statement of financial position as at December 31, 2013 is measured using level 2. During the year ended December 31, 2013, there were no transfers between level 1, level 2, and level 3 classified assets and liabilities.

Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk, and other price risk, such as commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns. The Company may use financial derivatives or 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.

Foreign exchange risk

The prices received by the Company for the production of crude oil, natural gas, and NGLs are primarily determined in reference to US dollars, but are settled with the Company in Canadian dollars. The Company's cash flow from commodity sales will therefore be impacted by fluctuations in foreign exchange rates. The Company currently does not have any foreign exchange contracts in place.

Interest rate risk

The Company is exposed to interest rate risk as it borrows funds at floating interest rates. In addition, the Company may at times issue shares on a flow-through basis. This results in the Company being exposed to interest rate risk to the Canada Revenue Agency for interest on unexpended funds on the Company's flow-through share obligations. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations.

Commodity price risk

Oil and natural gas prices are impacted by not only the relationship between the Canadian and US dollar but also by world economic events that dictate the levels of supply and demand. The Company's oil, natural gas, and NGLs production is marketed and sold on the spot market to area aggregators based on daily spot prices that are adjusted for product quality and transportation costs. The Company's cash flow from product sales will therefore be impacted by fluctuations in commodity prices. In addition, the Company may enter into commodity price contracts to manage future cash flows. For the year ended December 31, 2013, the realized loss on the Company's oil contracts was $1.2 million and the realized loss on the gas contracts was $1.6 million. For the year ended December 31, 2013, the unrealized loss on the oil contracts was $0.2 million and the unrealized gain on the gas contracts was $1.4 million.

At December 31, 2013, the Company had the following commodity price contracts outstanding:

Commodity	Period	Type of Contract	Quantity Contracted	Contract Price
Oil	January 1, 2014 - December 31, 2014	Financial - Swap	500 bbls/d	WTI CDN $100.80/bbl
Oil	January 1, 2014 - March 31, 2014	Financial - Swap	500 bbls/d	WTI CDN $106.55/bbl
Natural Gas	April 1, 2014 - October 31, 2014	Financial - Swap	5,000 GJ/d	AECO CDN $3.505/GJ
Natural Gas	April 1, 2014 - October 31, 2014	Financial - Swap	5,000 GJ/d	AECO CDN $3.650/GJ

Subsequent to December 31, 2013, the Company entered into the following commodity price contracts:

Commodity	Period	Type of Contract	Quantity Contracted	Contract Price
Oil	April 1, 2014 - June 30, 2014	Financial - Swap	500 bbls/d	WTI CDN $108.00/bbl
Oil	July 1, 2014 - September 30, 2014	Financial - Swap	500 bbls/d	WTI CDN $110.00/bbl
Natural Gas	April 1, 2014 - October 31, 2014	Financial - Swap	10,000 GJ/d	AECO CDN $3.745/GJ

Credit risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial asset fail to meet or discharge their obligation to the Company. A substantial portion of the Company's accounts receivable and deposits are with customers and joint venture partners in the oil and natural gas industry and are subject to normal industry credit risks. The Company generally grants unsecured credit but routinely assesses the financial strength of its customers and joint venture partners.

The Company sells the majority of its production to three petroleum and natural gas marketers and therefore is subject to concentration risk. Historically, the Company has not experienced any collection issues with its oil and natural gas marketers. Joint venture receivables are typically collected within one to three months of the joint venture invoice being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval for significant capital expenditures prior to the expenditure being incurred. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners; however, in certain circumstances, the Company may cash call a partner in advance of expenditures being incurred.

The maximum exposure to credit risk is represented by the carrying amount of accounts receivable on the statement of financial position. At December 31, 2013, $15.4 million or 95.2% of the Company's outstanding accounts receivable were current while $0.8 million or 4.8% were outstanding over 90 days but not impaired. During the year ended December 31, 2013, the Company did not deem any outstanding accounts receivable to be uncollectable.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual, quarterly, and monthly capital expenditure budgets, which are monitored and updated as required, and requires authorizations for expenditures on projects to assist with the management of capital. In managing liquidity risk, the Company ensures that it has access to additional financing, including potential equity issuances and additional debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to insurable losses.

Safety and Environmental Risks

The oil and natural gas business is subject to extensive regulation pursuant to various municipal, provincial, national, and international conventions and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, or emissions of various substances produced in association with oil and natural gas operations. Crocotta is committed to meeting and exceeding its environmental and safety responsibilities. Crocotta has implemented an environmental and safety policy that is designed, at a minimum, to comply with current governmental regulations set for the oil and natural gas industry. Changes to governmental regulations are monitored to ensure compliance. Environmental reviews are completed as part of the due diligence process when evaluating acquisitions. Environmental and safety updates are presented and discussed at each Board of Directors meeting. Crocotta maintains adequate insurance commensurate with industry standards to cover reasonable risks and potential liabilities associated with its activities as well as insurance coverage for officers and directors executing their corporate duties. To the knowledge of management, there are no legal proceedings to which Crocotta is a party or of which any of its property is the subject matter, nor are any such proceedings known to Crocotta to be contemplated.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company's President and Chief Executive Officer ("CEO") and Vice President Finance and Chief Financial Officer ("CFO") are responsible for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting as defined in Multilateral Instrument 52-109 of the Canadian Securities Administrators.

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Company is accumulated and communicated to management as appropriate to allow timely decisions regarding required disclosure. The Company evaluated its disclosure controls and procedures for the year ended December 31, 2013. The Company's CEO and CFO have concluded that, based on their evaluation, the Company's disclosure controls and procedures are effective to provide reasonable assurance that all material or potentially material information related to the Company is made known to them and is disclosed in a timely manner if required.

Internal controls over financial reporting have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's internal controls over financial reporting include those policies and procedures that: pertain to the maintenance of records that in reasonable detail accurately and fairly reflect transactions and disposition of the assets; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures are being made only in accordance with authorizations of management and directors; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the annual financial statements or interim financial statements.

The Company evaluated the effectiveness of its internal controls over financial reporting as of December 31, 2013. In making this evaluation, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework issued in 1992. Based on their evaluation, the Company's CEO and CFO have identified weaknesses over segregation of duties. Specifically, due to the limited number of finance and accounting personnel at the Company, it is not feasible to achieve complete segregation of duties with regards to certain complex and non-routine accounting transactions that may arise. This weakness is considered to be a common deficiency for many smaller listed companies in Canada. Notwithstanding the weaknesses identified with regards to segregation of duties, the Company concluded that all other of its internal controls over financial reporting were effective as of December 31, 2013. No material changes in the Company's internal controls over financial reporting were identified during the most recent reporting period that have materially affected, or are likely to material affect, the Company's internal controls over financial reporting.

Because of their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, errors, or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control systems are met. As a result of the weaknesses identified in the Company's internal controls over financial reporting, there is a greater likelihood that a material misstatement would not be prevented or detected. To mitigate the risk of such material misstatement in financial reporting, the CEO and CFO oversee all material and complex transactions of the Company and the financial statements are reviewed and approved by the Board of Directors each quarter. In addition, the Company will seek the advice of external parties, such as the Company's external auditors, in regards to the appropriate accounting treatment for any complex and non-routine transactions that may arise.

FORWARD-LOOKING INFORMATION

This document contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "believe", "intends", "forecast", "plans", "guidance" and similar expressions are intended to identify forward-looking statements or information.

More particularly and without limitation, this MD&A contains forward looking statements and information relating to the Company's risk management program, oil, NGLs, and natural gas production, capital programs, oil, NGLs, and natural gas commodity prices, and debt levels. The forward-looking statements and information are based on certain key expectations and assumptions made by the Company, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities, and the availability and cost of labour and services.

Although the Company believes that the expectations reflected in such forward-looking statements and information are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs, and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty, and environmental legislation. The forward-looking statements and information contained in this document are made as of the date hereof for the purpose of providing the readers with the Company's expectations for the coming year. The forward-looking statements and information may not be appropriate for other purposes. The Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

ADDITIONAL INFORMATION

Additional information related to the Company, including the Company's Annual Information Form (AIF), may be found on the SEDAR website at www.sedar.com.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The Management of Crocotta Energy Inc. is responsible for the preparation of the consolidated financial statements. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards and include certain estimates that reflect Management's best estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly in all material respects.

Management is responsible for the integrity of the consolidated financial statements. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's shareholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with International Financial Reporting Standards.

The Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our oil and natural gas reserves. The Audit Committee meets regularly with Management and the Auditors to ensure that Management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of KPMG LLP and reviews their fees. The Auditors have access to the Audit Committee without the presence of Management.

Rob Zakresky, President, Chief Executive Officer and Director

Nolan Chicoine, Vice President, Finance and Chief Financial Officer

Calgary, Canada

March 20, 2014

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Crocotta Energy Inc.

We have audited the accompanying consolidated financial statements of Crocotta Energy Inc., which comprise the consolidated statements of financial position as at December 31, 2013 and December 31, 2012, the consolidated statements of earnings (loss) and comprehensive earnings (loss), shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Crocotta Energy Inc. as at December 31, 2013 and December 31, 2012, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

signed "KPMG LLP"

Chartered Accountants

March 20, 2014

Calgary, Canada

Crocotta Energy Inc.
Consolidated Statements of Financial Position

($000s)	Note	December 31 2013	December 31 2012
Assets			
Current assets			
Accounts receivable		16,166	15,983
Prepaid expenses and deposits		1,798	1,550
		17,964	17,533
Property, plant, and equipment	(6)	313,142	241,703
Exploration and evaluation assets	(5)	39,629	28,302
Deferred income taxes	(14)	2,566	13,442
		355,337	283,447
		373,301	300,980
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		19,480	29,165
Risk management contracts	(16)	368	1,592
Revolving credit facility	(7)	-	68,480
		19,848	99,237
Credit facility	(7)	116,324	-
Decommissioning obligations	(8)	22,438	21,852
		158,610	121,089
Shareholders' Equity			
Shareholders' capital	(9)	250,563	228,277
Contributed surplus		12,970	12,026
Deficit		(48,842)	(60,412)
		214,691	179,891
Subsequent events	(16)		
		373,301	300,980

The accompanying notes are an integral part of these consolidated financial statements.

Approved on behalf of the Board of Directors

Director, "signed" Rob Zakresky

Director, "signed" Larry Moeller

Crocotta Energy Inc.
Consolidated Statements of Earnings (Loss) and Comprehensive Earnings (Loss)

($000s, except per share amounts)	Note	Year Ended December 31 2013	2012
Revenue			
Oil and natual gas sales		111,459	80,518
Royalties		(8,404)	(8,911)
		103,055	71,607
Realized gain (loss) on risk management contracts	(16)	(2,809)	3,166
Unrealized gain (loss) on risk management contracts	(16)	1,224	(1,592)

		101,470	73,181
Expenses			
Production		20,154	14,743
Transportation		3,014	2,479
Depletion and depreciation	(6)	44,596	36,685
Asset impairment	(5,6)	802	13,439
General and administrative		6,030	5,487
Share based compensation	(10)	2,084	3,512
		76,680	76,345
Operating earnings (loss)		24,790	(3,164)
Other Expenses			
Finance expense	(13)	4,441	1,902
Earnings (loss) before taxes		20,349	(5,066)
Taxes			
Deferred income tax expense	(14)	8,779	188
Net earnings (loss) and comprehensive earnings (loss)		11,570	(5,254)
Net earnings (loss) per share			
Basic and diluted	(11)	0.12	(0.06)

The accompanying notes are an integral part of these consolidated financial statements.

Crocotta Energy Inc.
Consolidated Statements of Shareholders' Equity

		Year Ended December 31	
($000s)	Note	2013	2012
Shareholders' Capital			
Balance, beginning of year		228,277	225,848
Issue of shares (net of share issue costs and flow-through share premium)	(9)	18,887	-
Issued on exercise of stock options	(9)	2,052	17
Issued on exercise of warrants	(9)	-	1,680
Share based compensation - exercised	(9)	1,347	732
Balance, end of year		250,563	228,277
Contributed Surplus			
Balance, beginning of year		12,026	8,927
Share based compensation - expensed	(10)	2,084	3,512
Share based compensation - capitalized	(10)	207	319
Share based compensation - exercised	(9)	(1,347)	(732)
Balance, end of year		12,970	12,026
Deficit			
Balance, beginning of year		(60,412)	(55,158)
Net earnings (loss)		11,570	(5,254)
Balance, end of year		(48,842)	(60,412)
Total Shareholders' Equity		214,691	179,891

The accompanying notes are an integral part of these consolidated financial statements.

Crocotta Energy Inc.
Consolidated Statements of Cash Flows

		Year Ended December 31	
($000s)	Note	2013	2012
Operating Activities			
Net earnings (loss)		11,570	(5,254)
Depletion and depreciation	(6)	44,596	36,685
Asset impairment	(5,6)	802	13,439
Share based compensation	(10)	2,084	3,512
Finance expense	(13)	4,441	1,902
Interest paid		(3,851)	(1,449)
Deferred income tax expense	(14)	8,779	188
Unrealized loss (gain) on risk management contracts	(16)	(1,224)	1,592
Decommissioning expenditures	(8)	(691)	(734)
Change in non-cash working capital	(19)	(993)	(2,432)

		65,513	47,449
Financing Activities			
Issuance of shares	(9)	24,035	1,697
Share issue costs	(9)	(999)	-
Revolving credit facility	(7)	(68,480)	63,298
Credit facility	(7)	116,324	-
		70,880	64,995
Investing Activities			
Capital expenditures - property, plant, and equipment	(6)	(66,694)	(54,756)
Capital expenditures - exploration and evaluation assets	(5)	(60,576)	(49,198)
Change in non-cash working capital	(19)	(9,123)	(8,490)
		(136,393)	(112,444)
Change in cash and cash equivalents		-	-
Cash and cash equivalents, beginning of year		-	-
Cash and cash equivalents, end of year		-	-

The accompanying notes are an integral part of these consolidated financial statements.

Crocotta Energy Inc.

Notes to the Consolidated Financial Statements

Year Ended December 31, 2013

(Tabular amounts in 000s, unless otherwise stated)

1. REPORTING ENTITY

Crocotta Energy Inc. ("Crocotta" or the "Company") is an oil and natural gas company, actively engaged in the acquisition, development, exploration, and production of oil and natural gas reserves in Western Canada. The Company conducts many of its activities jointly with others and these consolidated financial statements reflect only the Company's proportionate interest in such activities. The Company currently has one wholly-owned subsidiary.

The Company's place of business is located at 700, 639 - 5th Avenue SW, Calgary, Alberta, Canada, T2P 0M9.

2. BASIS OF PRESENTATION

(a) Statement of compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

These consolidated financial statements were authorized for issuance by the Board of Directors on March 20, 2014.

(b) Basis of measurement

These consolidated financial statements have been prepared on the historical cost basis except for risk management contracts, which are measured at fair value. The methods used to measure fair value are discussed in note 4.

(c) Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the functional currency of the Company and its subsidiary.

(d) Use of estimates and judgments

The preparation of the consolidated financial statements in conformity with IFRS requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the year. These judgments, estimates, and assumptions are based on current trends and all relevant information available to the Company at the time of preparation of the consolidated financial statements. As the effect of future events cannot be determined with certainty, the actual results may differ from the estimated amounts.

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

Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below.

Critical accounting judgments

The following are critical judgments that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in the consolidated financial statements.

Cash-generating units ("CGU")

The Company's assets are aggregated into CGUs for the purposes of calculating depletion and depreciation and impairment. CGUs are determined based on the smallest group of assets that generate cash flows independent of other assets or groups of assets. Determination of the CGUs is subject to the Company's judgment and is based on geographical proximity, shared infrastructure, similar exposure to market risk, and materiality.

Impairment

Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land, and other relevant assumptions.

Exploration and evaluation assets

The application of the Company's accounting policy for exploration and evaluation assets requires the Company to make certain judgments as to future events and circumstances as to whether economic quantities of reserves will be found so as to assess if technical feasibility and commercial viability has been achieved.

Deferred taxes

Judgments are made by the Company to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings.

Significant estimates

The following are key estimates and assumptions made by the Company affecting the measurement of balances and transactions in the consolidated financial statements.

Recoverability of asset carrying values

The recoverability of development and production asset carrying values is assessed at a CGU level. The key estimates used in the determination of cash flows from oil and natural gas reserves include the following:

1. Reserves - Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs, or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.
2. Oil and natural gas prices - Forward price estimates are used in the cash flow model. Commodity prices can fluctuate for a variety of reasons including supply and demand fundamentals, inventory levels, exchange rates, weather, and economic and geopolitical factors.
3. Discount rate - The discount rate used to calculate the net present value of cash flows is based on estimates of an approximate industry peer group weighted average cost of capital. Changes in the general economic environment could result in significant changes to this estimate.

The key assumptions used in the impairment tests are described in note 6.

Depletion and depreciation

Amounts recorded for depletion and depreciation are based on estimates of total proved and probable oil and natural gas reserves and future development capital. By their nature, the estimates of reserves, including the estimates of future prices, costs, and future cash flows, are subject to measurement uncertainty. Accordingly, the impact to the consolidated financial statements in future periods could be material.

Decommissioning obligations

Amounts recorded for decommissioning obligations and the related accretion expense requires the use of estimates with respect to the amount and timing of decommissioning expenditures. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology. Other provisions are recognized in the period when it becomes probable that there will be a future cash outflow.

Share based compensation

Compensation costs recognized for share based compensation plans are subject to the estimation of what the ultimate value will be using pricing models such as the Black-Scholes-Merton model, which is based on significant assumptions such as volatility, expected term, and forfeiture rate.

Derivatives

The Company's estimate of the fair value of derivative financial instruments is dependent on estimated forward prices and volatility in those prices.

Deferred taxes

Deferred taxes are based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates, and the likelihood of assets being realized. Tax interpretations, regulations, and legislation in the various jurisdictions in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty.

3. SIGNIFICANT ACCOUNTING POLICIES

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

(a) Basis of consolidation

Subsidiaries

Subsidiaries are entities controlled by the Company. Control exists when the Company is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

Jointly controlled operations

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

Transactions eliminated on consolidation

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

(b) Financial instruments

Non-derivative financial instruments

Non-derivative financial instruments comprise cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and credit facility. Non-derivative financial instruments are recognized initially at fair value net of any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

Cash and cash equivalents

Cash and cash equivalents comprise cash on hand, term deposits held with banks, and other short-term highly liquid investments with original maturities of three months or less, measured at amortized cost.

Other

Other non-derivative financial instruments, such as accounts receivable, accounts payable and accrued liabilities, and credit facility, are measured at amortized cost using the effective interest method, less any impairment losses.

Derivative financial instruments

From time to time, the Company may enter into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company does not designate financial derivative contracts as effective accounting hedges, and thus does not apply hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are measured at fair value, with changes therein recognized in profit or loss. Transaction costs are recognized in profit or loss when incurred.

Share capital

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

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

Recognition and measurement

Exploration and evaluation expenditures

Pre-license costs are recognized in profit or loss as incurred.

Exploration and evaluation costs, including the costs of acquiring undeveloped land and drilling costs, are initially capitalized until the drilling of the well is complete and the results have been evaluated. The costs are accumulated in cost centers by well, field, or exploration area pending determination of technical feasibility and commercial viability. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. If proved or probable reserves are found, the accumulated costs and associated undeveloped land are transferred to property, plant, and equipment. The exploration and evaluation costs are reviewed for impairment prior to any such transfer.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to CGUs.

Development and production costs

Items of property, plant, and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The cost of development and production assets includes: transfers from exploration and evaluation assets, which generally include the cost to drill the well and the cost of the associated land upon determination of technical feasibility and commercial viability; the cost to complete and tie-in the well; facility costs; the cost of recognizing provisions for future restoration and decommissioning obligations; geological and geophysical costs; and directly attributable overhead.

Development and production assets are grouped into CGUs for impairment testing. The Company has grouped its development and production assets into the following six CGUs: (i) Edson AB (ii) Smoky AB (iii) Northeast BC (iv) Lookout Butte AB (v) Miscellaneous AB, and (vi) Saskatchewan.

When significant parts of an item of property, plant, and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components). The Company capitalizes the cost of major plant turnarounds and overhauls and depreciates these costs over their estimated useful life of three or four years, depending on each plant.

Gains and losses on disposal of an item of property, plant, and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant, and equipment and are recognized in profit or loss. The carrying amount of any replaced or disposed item of property, plant, and equipment is derecognized.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant, and equipment are recognized as property, plant, and equipment only when they increase the future economic benefits embodied in the specific asset to which they relate. Capitalized property, plant, and equipment generally represent costs incurred in developing proved or probable reserves and bringing in or enhancing production from such reserves and are accumulated on a field or geotechnical area basis. The costs of the day-to-day servicing of property, plant, and equipment are recognized in operating expenses as incurred.

Non-monetary asset swaps

Exchanges or swaps of property, plant, and equipment are measured at fair value unless the exchange transaction lacks commercial substance or neither the fair value of the assets given up nor the assets received can be reliably estimated. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. Any gain or loss on derecognition of the asset given up is included in profit or loss.

Exchanges or parts of exchanges that involve principally exploration and evaluation assets are measured at the carrying amount of the asset exchanged, reduced by the amount of any cash consideration received. No gain or loss is recognized unless the cash consideration received exceeds the carrying value of the asset held.

Depletion and depreciation

The net carrying value of development and production assets is depleted using the unit of production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account the estimated future development costs necessary to bring those reserves into production and the estimated salvage value of the assets at the end of their useful lives. Future development costs are estimated taking into account the level of development required to produce the reserves.

Proved plus probable reserves are estimated at least annually by independent qualified reserve evaluators and represent the estimated quantities of oil, natural gas, and natural gas liquids which geological, geophysical, and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible.

The Company has determined the estimated useful lives for gas processing plants, pipeline facilities, and compression facilities to be consistent with the reserve lives of the areas for which they serve. As such, the Company includes the cost of these assets within their associated CGU for the purpose of depletion using the unit of production method. For plant turnarounds and overhauls, the Company has estimated an average useful life of three or four years, depending on each plant, before further work must be performed and depreciates these costs using the straight-line method over the corresponding useful life.

The cost of office and other equipment is depreciated using the straight-line method over the estimated useful life of three years.

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

Leased assets

Leases wherein the Company assumes substantially all the risks and rewards of ownership are classified as finance leases, when applicable. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset. Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability. Other leases are classified as operating leases, which are not recognized on the Company's statement of financial position. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease. The Company's presently outstanding leases have been determined to be operating leases.

(d) Impairment

Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in profit or loss.

Non-financial assets

The carrying amounts of the Company's non-financial assets, other than exploration and evaluation assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Exploration and evaluation assets are assessed for impairment when they are transferred to property, plant, and equipment or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (CGU). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

Fair value less costs to sell is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The fair value less costs to sell of oil and natural gas assets is generally determined as the net present value of the estimated future cash flows expected to arise from the continued use of the CGU, including any expansion projects and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted using an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU. Consideration is given to acquisition metrics of recent transactions completed on similar assets to those contained within the relevant CGU.

Value in use is determined as the net present value of the estimated future cash flows expected to arise from the continued use of the asset in its present form and its eventual disposal. Value in use is determined by applying assumptions specific to the Company's continued use and can only take into account approved future development costs. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices and expected production volumes. The latter takes into account assessments of field reservoir performance and includes expectations about proved and unproved volumes, which are risk-weighted using geological, production, recovery, and economic projections.

An impairment loss is recognized if the carrying amount of a CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated to the assets in the CGUs on a pro rata basis. Impairment losses recognized in prior periods are assessed each reporting date if facts or circumstances indicate that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

(e) Share based compensation

The Company has a share based compensation plan, which is described in note 10. The Company uses the fair value method for valuing share based compensation. Under this method, the compensation cost attributed to stock options is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Upon the settlement of the stock options, the previously recognized value in contributed surplus is recorded as an increase to share capital.

(f) Provisions

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

Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning, and site disturbance remediation activities. A provision is made for the estimated cost of abandonment and site restoration and capitalized in the relevant asset category. The capitalized amount is depreciated on a unit of production basis over the life of the associated proved plus probable reserves. Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the reporting date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation, and changes in the risk-free rate. The increase in the provision due to the passage of time is recognized as accretion (within finance expenses) whereas increases or decreases due to changes in the estimated future cash flows or changes in the discount rate are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(g) Revenue

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product are transferred to the buyer which is usually when legal title passes to the external party.

(h) Finance income and expenses

Finance income and expenses comprises interest expense, including interest on credit facility, accretion on decommissioning obligations, and interest income.

(i) Income tax

Income tax expense is comprised of current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis, or their tax assets and liabilities will be realized simultaneously.

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

(j) Flow-through shares

The Company, from time to time, issues flow-through shares to finance a portion of its exploration capital expenditure program. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the exploration expenditures are renounced to the subscribers. On issuance of flow-through shares, the premium received on such shares, being the difference between the fair value ascribed to flow-through shares issued and the fair value that would have been received for common shares at the date of issuance of the flow-through shares, is recognized as a liability on the statement of financial position. When the exploration expenditures are incurred, the liability is drawn down, a deferred tax liability is recorded equal to the estimated amount of deferred income tax payable by the Company as a result of the foregone tax benefits, and the difference is recognized in profit or loss.

(k) Earnings per share

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

(l) Changes in accounting policies

On January 1, 2013, the Company adopted new standards with respect to consolidations (IFRS 10), joint arrangements (IFRS 11), disclosure of interests in other entities (IFRS 12), fair value measurements (IFRS 13), and amendments to financial statement disclosures (IFRS 7). The adoption of these standards had no impact on the amounts recorded in the consolidated financial statements.

(m) New standards and interpretations not yet adopted

In May 2013, the IASB issued amendments to IAS 36, *Impairment of Assets*, which reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The amendments are required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. These amendments will be applied by the Company on January 1, 2014 and the adoption will only impact disclosures in the notes to the financial statements in periods when an impairment loss or impairment reversal is recognized.

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

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

4. 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 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.

Property, plant, and equipment and exploration and evaluation assets

The fair value of property, plant, and equipment and exploration and evaluation assets recognized in a business combination, is based on market values. The market value of property, plant, and equipment and exploration and evaluation assets is the estimated amount for which the assets could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently, and without compulsion. The market value of property, plant, and equipment is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate used to discount the expected cash flows is specific to the asset with reference to general market conditions.

The market value of other items of property, plant, and equipment is based on the quoted market prices for similar items.

Stock options

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

Derivatives

The fair value of risk management contracts is determined by discounting the difference between the contracted price and published forward curves as at the statement of financial position date using the remaining contracted volumes and a risk-free interest rate (based on published government rates).

5. EXPLORATION AND EVALUATION ASSETS

	Total
Balance, December 31, 2011	20,641
Additions	49,198
Transfer to property, plant, and equipment	(36,838)
Impairment	(4,699)
Balance, December 31, 2012	28,302
Additions	60,576
Transfer to property, plant, and equipment	(48,610)

Impairment	(639)
Balance, December 31, 2013	39,629

Exploration and evaluation assets consist of the Company's exploration projects which 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 year, consisting primarily of undeveloped land and drilling costs until the drilling of the well is complete and the results have been evaluated. Included in the $60.6 million in additions during the year ended December 31, 2013 were additions of $43.4 million related to the Edson AB CGU, $9.6 million related to the Miscellaneous AB CGU, and $7.3 million related to the Northeast BC CGU. Transfers to property, plant, and equipment during the year ended December 31, 2013 included $39.2 million from the Edson AB CGU and $9.4 million from the Northeast BC CGU as a result of successful capital activity in the Company's core areas.

Included in the $49.2 million in additions during the year ended December 31, 2012 were additions of $33.1 million related to the Edson AB CGU, $9.4 million related to the Miscellaneous AB CGU, and $6.4 million related to the Northeast BC CGU. Transfers to property, plant, and equipment during the year ended December 31, 2012 included $31.9 million from the Edson AB CGU and $4.9 million from the Northeast BC CGU as a result of successful capital activity in the Company's core areas.

Impairments

Exploration and evaluation assets are assessed for impairment when they are transferred to property, plant, and equipment or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For the year ended December 31, 2013, total exploration and evaluation asset impairments of $0.6 million were recognized relating to the expiry of undeveloped land rights (CGUs - Miscellaneous AB, and Saskatchewan).

For the year ended December 31, 2012, total exploration and evaluation asset impairments of $4.7 million were recognized. Asset impairments of $2.4 million were recognized relating to the determination of certain exploration and evaluation activities to be uneconomical (CGU - Miscellaneous AB). Additional exploration and evaluation impairments of $2.3 million were recognized in 2012 relating to the expiry of undeveloped land rights (CGUs - Lookout Butte AB, Miscellaneous AB, and Saskatchewan).

6. PROPERTY, PLANT, AND EQUIPMENT

Cost	Total
Balance, December 31, 2011	236,846
Additions	54,756
Transfer from exploration and evaluation assets	36,838
Change in decommissioning obligation estimates	2,883
Capitalized share based compensation	319
Balance, December 31, 2012	331,642
Additions	66,694
Transfer from exploration and evaluation assets	48,610
Change in decommissioning obligation estimates	687
Capitalized share based compensation	207
Balance, December 31, 2013	447,840

Accumulated Depletion, Depreciation, and Impairment	Total
Balance, December 31, 2011	44,514
Depletion and depreciation	36,685
Impairment	8,740
Balance, December 31, 2012	89,939
Depletion and depreciation	44,596
Impairment	163
Balance, December 31, 2013	134,698

Net Book Value	Total
December 31, 2011	192,332
December 31, 2012	241,703
December 31, 2013	313,142

During the year ended December 31, 2013, approximately $0.5 million (2012 - $0.4 million) of directly attributable general and administrative costs were capitalized as expenditures on property, plant, and equipment.

Depletion and depreciation

The calculation of depletion and depreciation expense for the year ended December 31, 2013 included an estimated $335.8 million (2012 - $231.8 million) for future development costs associated with proved plus probable undeveloped reserves and excluded approximately $12.6 million (2012 - $11.4 million) for the estimated salvage value of production equipment and facilities.

Impairments

At December 31, 2013, with the exception of Lookout Butte AB, there were no indicators of impairment of property, plant, and equipment. Due to higher than expected production declines and no capital expenditures during 2013 at Lookout Butte AB to maintain reserve values, the Company recorded property, plant, and equipment impairments of $0.2 million during the fourth quarter. The impairment test at December 31, 2013 for Lookout Butte AB was primarily based on the net present value of cash flows from oil and natural gas reserves at a pre-tax discount rate of 15 percent. The impairment test was carried out using the following commodity price estimates of the Company's independent reserve evaluators:

Year	West Texas Intermediate Oil ($US/bbl)	Foreign Exchange Rate (USD/CDN)	Edmonton Oil Par Price ($CDN/bbl)	AECO Gas Price ($CDN/mmbtu)
2014	97.50	0.950	92.76	4.03
2015	97.50	0.950	97.37	4.26
2016	97.50	0.950	100.00	4.50
2017	97.50	0.950	100.00	4.74
2018	97.50	0.950	100.00	4.97
2019	97.50	0.950	100.00	5.21
2020	98.54	0.950	100.77	5.33
2021	100.51	0.950	102.78	5.44
2022	102.52	0.950	104.83	5.55
2023	104.57	0.950	106.93	5.66
Escalate Thereafter	2.0% per year		2.0% per year	2.0% per year

For the year ended December 31, 2012, the Company recorded property, plant, and equipment impairments of $8.7 million relating to Smoky AB, Lookout Butte AB, Miscellaneous AB, and Saskatchewan CGUs mainly as a result of weakening natural gas prices and limited capital expenditures in these CGUs to maintain their reserve values.

7. CREDIT FACILITY

During the third quarter of 2013, the Company entered into a syndicated credit facility with three Canadian chartered banks. The syndicated credit facility replaced the Company's previous $140 million revolving operating demand loan credit facility. The syndicated facility has a borrowing base of $150 million, consisting of a $140 million revolving line of credit and a $10 million operating line of credit. The syndicated facility revolves for a 364 day period and will be subject to its next 364 day extension by July 11, 2014. If not extended, the syndicated facility will cease to revolve, the margins thereunder will increase by 0.50%, and all outstanding advances will become repayable in one year from the extension date.

Advances under the syndicated facility are available by way of prime rate loans, with interest rates between 1.00% and 2.50% over the Canadian prime lending rate, and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 2.00% to 3.50% depending upon the debt to cash flow ratio of the Company. Standby fees are charged on the undrawn syndicated facility at rates ranging from 0.50% to 0.875%. The credit facility is secured by a $300 million fixed and floating charge debenture on the assets of the Company. At December 31, 2013, $116.3 million (December 31, 2012 - $68.5 million) had been drawn on the credit facility. In addition, at December 31, 2013, 2013, the Company had outstanding letters of guarantee of approximately $2.5 million (December 31, 2012 - $1.5 million) which reduce the amount that can be borrowed under the credit facility. The next scheduled borrowing base review of the syndicated facility is scheduled on or before June 30, 2014.

8. PROVISIONS - DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and gathering systems. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and facilities, and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows (adjusted for inflation at 2% per year) required to settle the decommissioning obligations is approximately $33.4 million which is estimated to be incurred over the next 27 years. At December 31, 2013, a risk-free rate of 3.1% (December 31, 2012 - 2.3%) was used to calculate the net present value of the decommissioning obligations.

	Year Ended December 31, 2013	Year Ended December 31, 2012
Balance, beginning of year	21,852	19,250
Provisions incurred	2,253	2,208
Provisions disposed	(80)	-
Provisions settled	(691)	(734)
Revisions	(1,486)	675
Accretion	590	453
Balance, end of year	22,438	21,852

9. SHAREHOLDERS' CAPITAL

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares, Class A preferred shares, issuable in series, and Class B preferred shares, issuable in series. No non-voting common shares or preferred shares have been issued.

Voting Common Shares	Number	Amount
Balance, December 31, 2011	88,095	225,848
Exercise of stock options	13	29
Exercise of warrants	1,200	2,400
Expiry of sunset clauses	(47)	-
Balance, December 31, 2012	89,261	228,277
Exercise of stock options	1,409	3,399
Share issuances	6,042	21,983
Share issue costs, net of future tax effect of $0.2 million		(749)
Flow-through share premium		(2,347)
Balance, December 31, 2013	96,712	250,563

In June 2013, the Company issued approximately 6.0 million common shares on a flow-through basis for gross proceeds of approximately $22.0 million. Approximately 4.2 million shares were issued at a price of $3.70 per share in respect of Canadian exploration expenses ("CEE") and approximately 1.8 million shares were issued at a price of $3.50 per share in respect of Canadian development expenses ("CDE"). Upon issuance, the premium received on the flow-through shares, being the difference between the fair value of the flow-through shares issued and the fair value that would have been received for common shares at the date of the announcement of the financing, was recognized as a liability. Under the terms of the flow-through share agreements, the Company is committed to spend approximately $22.0 million on qualifying exploration and development expenditures prior to December 31, 2014. As at December 31, 2013, the Company had satisfied this flow-through share commitment.

Proceeds from the share issuance were used to fund the Company's Edson Bluesky and Dawson Montney developments, other capital projects, and general corporate purposes.

10. SHARE BASED COMPENSATION PLANS

Stock options

The Company has authorized and reserved for issuance 9.7 million common shares under a stock option plan enabling certain officers, directors, employees, and consultants to purchase common shares. The Company will not issue options exceeding 10% of the shares outstanding at the time of the option grants. Under the plan, the exercise price of each option equals the market price of the Company's shares on the date of the grant. The options vest over a period of three years and an option's maximum term is 5 years. At December 31, 2013, 8.8 million options are outstanding at exercise prices ranging from $1.10 to $3.46 per share.

The number and weighted average exercise price of stock options are as follows:

	Number of Options	Weighted Average Exercise Price ($)
Balance, December 31, 2011	7,942	1.97
Granted	713	3.43
Exercised	(13)	1.30
Forfeited	(41)	2.51
Balance, December 31, 2012	8,601	2.09
Granted	1,717	2.77
Exercised	(1,409)	1.46
Forfeited	(60)	2.83
Balance, December 31, 2013	8,849	2.32

For the stock options exercised during 2013, the weighted average share price of the Company's common shares at the date of exercise was $2.95 per share (2012 - $2.40 per share).

The following table summarizes the stock options outstanding and exercisable at December 31, 2013:

	Options Outstanding			Options Exercisable	
Exercise Price	Number	Weighted Average Remaining Life	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$1.10 to $2.00	2,514	1.1	1.23	2,514	1.23
$2.01 to $3.00	5,593	2.9	2.65	2,766	2.62
$3.01 to $3.46	742	3.0	3.44	264	3.46
	8,849	2.4	2.32	5,544	2.03

Warrants

The Company had an arrangement that allowed warrants to be issued to directors, officers, and employees. During the year ended December 31, 2007, the Company issued 2.4 million warrants under this arrangement. The warrants expired unexercised in December 2013.

On October 29, 2009, the Company issued an additional 1.2 million warrants at an exercise price of $1.40 per share in conjunction with a private placement share issuance. The warrants vested immediately and had an expiry date of October 29, 2012. The warrants were exercised during 2012.

The number and weighted average exercise price of warrants are as follows:

	Number of Warrants	Weighted Average Exercise Price
Balance, December 31, 2011	3,521	3.64
Exercised	(1,200)	1.40
Balance, December 31, 2012	2,321	4.80
Expired	(2,321)	4.80
Balance, December 31, 2013	-	-

Share based compensation

The Company accounts for its share based compensation plans using the fair value method. Under this method, compensation cost is charged to earnings over the vesting period for stock options and warrants granted to officers, directors, employees, and consultants with a corresponding increase to contributed surplus.

The fair value of the stock options granted was estimated on the date of grant using the Black-Scholes-Merton option pricing model with the following weighted average assumptions:

	December 31, 2013	December 31, 2012
Risk-free interest rate (%)	1.6	1.3
Expected life (years)	4.0	4.0
Expected volatility (%)	51.6	77.2
Expected dividend yield (%)	-	-
Forfeiture rate (%)	5.9	7.4
Weighted average fair value of options granted ($ per option)	1.15	1.96

11. PER SHARE AMOUNTS

The following table summarizes the weighted average number of shares used in the basic and diluted net earnings per share calculations:

	December 31, 2013	December 31, 2012
Weighted average number of shares - basic	93,051	88,319
Dilutive effect of share based compensation plans	1,922	-
Weighted average number of shares - diluted	94,973	88,319

For the year ended December 31, 2013, 3.9 million stock options (2012 - 8.6 million) and nil warrants (2012 - 2.3 million) were anti-dilutive and were not included in the diluted earnings per share calculation.

12. KEY MANAGEMENT PERSONNEL

The Company considers its directors and executives to be key management personnel. The key management personnel compensation is comprised of the following:

	December 31, 2013	December 31, 2012
Short-term wages and benefits	2,996	2,511
Share based compensation (1)	1,700	2,645
Total (2) (3)	4,696	5,156

(1) Represents the amortization of share based compensation expense associated with the Company's share based compensation plans granted to key management personnel.

(2) Balances outstanding and payable at December 31, 2013 were $0.5 million (2012 - $0.5 million).

(3) At December 31, 2013, key management personnel included 15 individuals (2012 - 16 individuals).

13. FINANCE EXPENSES

Finance expenses include the following:

	December 31, 2013	December 31, 2012
Interest expense *(note 7)*	3,851	1,449
Accretion of decommissioning obligations *(note 8)*	590	453
Finance expenses	4,441	1,902

14. INCOME TAXES

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

	December 31, 2013	December 31, 2012
Earnings (loss) before taxes	20,349	(5,066)
Statutory income tax rate	25.0 %	25.0 %
Expected income tax expense (reduction)	5,087	(1,267)
Increase in income taxes resulting from:		
Share based compensation and other non-deductible amounts	524	878

Flow-through shares	5,496	1,250
Other	19	19
Recognition of previously unrecognized tax assets	-	121
	11,126	1,001
Flow-through share premium	(2,347)	(813)
	8,779	188

The Company has recognized a net deferred tax asset based on the independently evaluated reserve report as cash flows are expected to be sufficient to realize the deferred tax asset.

(b) Recognized deferred tax balances for the years ended December 31, 2013 and 2012 are as follows:

2013	Balance January 1, 2013	Recognized in Earnings or Loss	Recognized in Equity	Balance December 31, 2013
Deferred income tax assets (liabilities):				
Oil and natural gas properties and equipment	(719)	(10,758)	-	(11,477)
Decommissioning obligations	5,463	147	-	5,610
Risk management contracts	398	(306)	-	92
Share issue costs	534	(230)	250	554
Non-capital losses	7,766	21	-	7,787
Net deferred income tax asset	13,442	(11,126)	250	2,566

2012	Balance January 1, 2012	Recognized in Earnings or Loss	Recognized in Equity	Balance December 31, 2012
Deferred income tax assets (liabilities):				
Oil and natural gas properties and equipment	1,120	(1,839)	-	(719)
Decommissioning obligations	4,812	651	-	5,463
Risk management contracts	-	398	-	398
Share issue costs	745	(211)	-	534
Non-capital losses	7,766	-	-	7,766
Net deferred income tax asset	14,443	(1,001)	-	13,442

At December 31, 2013, the Company has estimated federal tax pools of $341.1 million (2012 - $299.6 million) available for deduction against future taxable income.

The Company has accumulated non-capital losses for income tax purposes of approximately $31.1 million (2012 - $31.1 million), which can be used to offset income in future periods. These losses are as follows:

Year of expiry	Amount
2032	83
2031	-
2030	-
2029	248
2028	903
2027	8,121
2026	6,744
2025	8,066
2024	2,209
2023	4,772
	31,146

(c) Deferred tax assets have not been recognized in respect of the following items:

	2013	2012
Deductible temporary differences	8,100	8,100
Capital losses	1,797	1,797
	9,897	9,897

The capital losses and the deductible temporary differences do not expire under current tax legislation. Deferred tax assets have not been recognized in respect of these items because it is not probable that future taxable profits will be available against which the Company can utilize the benefits.

In 2012, $0.1 million of previously recognized tax losses were derecognized as a result of changes in estimates of future results from operating activities.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS

Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, credit facility

The fair value of cash and cash equivalents, accounts receivable, and accounts payable and accrued liabilities at December 31, 2013 approximated their carrying value due to their short term to maturity.

The fair value of the credit facility approximates its carrying value as it bears interest at floating rates and the premium charged is indicative of the Company's current credit spreads.

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

- Level 1 - observable inputs, such as quoted market prices in active markets
- Level 2 - inputs, other that the quoted market prices in active markets, which are observable, either directly or indirectly
- Level 3 - unobservable inputs for the asset or liability in which little or no market data exists, therefore requiring an entity to develop its own assumptions

The fair value of derivative contracts used for risk management as shown in the statement of financial position as at December 31, 2013 is measured using level 2. During the year ended December 31, 2013, there were no transfers between level 1, level 2, and level 3 classified assets and liabilities.

16. FINANCIAL RISK MANAGEMENT

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. The Company employs risk management strategies and policies to ensure that any exposure to risk is in compliance with the Company's business objectives and risk tolerance levels. Risk management is ultimately established by the Board of Directors and is implemented by management.

Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk, and other price risk, such as commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns. The Company may use financial derivatives or 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.

Foreign exchange risk

The prices received by the Company for the production of oil, natural gas, and NGLs are primarily determined in reference to US dollars, but are settled with the Company in Canadian dollars. The Company's cash flow from commodity sales will therefore be impacted by fluctuations in foreign exchange rates. Assuming that all other variables remain constant, a $0.01 increase or decrease in the Canadian/US dollar exchange rate would have impacted net earnings and comprehensive earnings by approximately $0.8 million for the year ended December 31, 2013 (2012 - $0.5 million).

Interest rate risk

The Company is exposed to interest rate risk as it borrows funds at floating interest rates (note 7). In addition, the Company may at times issue shares on a flow-through basis (note 9). This results in the Company being exposed to interest rate risk to the Canada Revenue Agency for interest on unexpended funds on the Company's flow-through share obligations. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. A 100 basis point increase or decrease in interest rates would have impacted net earnings and comprehensive earnings by approximately $0.6 million for the year ended December 31, 2013 (2012 - $0.4 million).

Commodity price risk

Oil and natural gas prices are impacted by not only the relationship between the Canadian and US dollar but also by world economic events that dictate the levels of supply and demand. The Company's oil, natural gas, and NGLs production is marketed and sold on the spot market to area aggregators based on daily spot prices that are adjusted for product quality and transportation costs. The Company's cash flow from product sales will therefore be impacted by fluctuations in commodity prices. A $1.00/boe increase or decrease in commodity prices would have impacted net earnings and comprehensive earnings by approximately $2.2 million for the year ended December 31, 2013 (2012 - $1.7 million).

In addition, the Company may enter into commodity price contracts to manage future cash flows. For the year ended December 31, 2013, the realized loss on the Company's oil contracts was $1.2 million and the realized loss on the gas contracts was $1.6 million. For the year ended December 31, 2013, the unrealized loss on the oil contracts was $0.2 million and the unrealized gain on the gas contracts was $1.4 million.

At December 31, 2013, the Company had the following commodity price contracts outstanding:

Commodity	Period	Type of Contract	Quantity Contracted	Contract Price
Oil	January 1, 2014 - December 31, 2014	Financial - Swap	500 bbls/d	WTI CDN $100.80/bbl
Oil	January 1, 2014 - March 31, 2014	Financial - Swap	500 bbls/d	WTI CDN $106.55/bbl
Natural Gas	April 1, 2014 - October 31, 2014	Financial - Swap	5,000 GJ/d	AECO CDN $3.505/GJ
Natural Gas	April 1, 2014 - October 31, 2014	Financial - Swap	5,000 GJ/d	AECO CDN $3.650/GJ

Financial assets and liabilities are only offset if the Company has the legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. The following table summarizes the gross asset and liability positions of the Company's risk management contracts that are offset on the statement of financial position:

	December 31, 2013	December 31, 2012
Gross liability	(447)	(1,592)
Gross asset	79	-
Net liability	(368)	(1,592)

Subsequent to December 31, 2013, the Company entered into the following commodity price contracts:

Commodity	Period	Type of Contract	Quantity Contracted	Contract Price
Oil	April 1, 2014 - June 30, 2014	Financial - Swap	500 bbls/d	WTI CDN $108.00/bbl
Oil	July 1, 2014 - September 30, 2014	Financial - Swap	500 bbls/d	WTI CDN $110.00/bbl
Natural Gas	April 1, 2014 - October 31, 2014	Financial - Swap	10,000 GJ/d	AECO CDN $3.745/GJ

Credit risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial asset fail to meet or discharge their obligation to the Company. A substantial portion of the Company's accounts receivable and deposits are with customers and joint venture partners in the oil and natural gas industry and are subject to normal industry credit risks. The Company generally grants unsecured credit but routinely assesses the financial strength of its customers and joint venture partners.

The Company sells the majority of its production to three petroleum and natural gas marketers and therefore is subject to concentration risk. Historically, the Company has not experienced any collection issues with its oil and natural gas marketers. Joint venture receivables are typically collected within one to three months of the joint venture invoice being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval for significant capital expenditures prior to the expenditure being incurred. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners; however, in certain circumstances, the Company may cash call a partner in advance of expenditures being incurred.

The maximum exposure to credit risk is represented by the carrying amount of accounts receivable on the statement of financial position. At December 31, 2013, $15.4 million or 95.2% of the Company's outstanding accounts receivable were current while $0.8 million or 4.8% were outstanding over 90 days but not impaired. During the year ended December 31, 2013, the Company did not deem any outstanding accounts receivable to be uncollectable.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual, quarterly, and monthly capital expenditure budgets, which are monitored and updated as required, and requires authorizations for expenditures on projects to assist with the management of capital. In managing liquidity risk, the Company ensures that it has access to additional financing, including potential equity issuances and additional debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to insurable losses.

The following are the contractual maturities of financial liabilities at December 31, 2013:

	Carrying Amount	Contractual Cash Flows	Less than One Year	One to Two Years	More than Two Years
Non-derivative financial liabilities					
Accounts payable and accrued liabilities	19,480	19,480	19,480	-	-
Credit facility	116,324	116,324	-	116,324	-
Derivative financial liabilities					
Risk management contracts	368	368	368	-	-
	136,172	136,172	19,848	116,324	-

17. CAPITAL MANAGEMENT

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at an acceptable risk, and to maintain investor, creditor, and market confidence to sustain future development of the business.

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets. The Company considers its capital structure to include shareholders' equity and net debt (current liabilities, including the credit facility and excluding risk management contracts, less current assets). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt, or adjust its capital spending to manage its current and projected debt levels.

	December 31, 2013	December 31, 2012
Shareholders' equity	214,691	179,891
Net debt	117,840	80,112

In addition, management prepares annual, quarterly, and monthly budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment.

The Company's share capital is not subject to external restrictions; however, the Company's credit facility includes a covenant requiring the Company to maintain a working capital ratio of not less than one-to-one. The working capital ratio, as defined by its creditor, is calculated as current assets plus any undrawn amounts available on its credit facility less current liabilities excluding any current portion drawn on the credit facility and risk management contracts. The Company was fully compliant with this covenant at December 31, 2013.

There were no changes in the Company's approach to capital management from the previous year.

18. SUPPLEMENTAL DISCLOSURES

Presentation of expenses

The Company's consolidated statements of earnings (loss) and comprehensive earnings (loss) is prepared primarily by nature of expense, with the exception of employee compensation costs which are included in both production and general and administrative expenses. Included in production expenses and general and administrative expenses for the year ended December 31, 2013 are $0.1 million and $5.2 million of wages and benefits, respectively (2012 - $0.1 million and $4.3 million, respectively).

19. SUPPLEMENTAL CASH FLOW INFORMATION

	December 31, 2013	December 31, 2012
Accounts receivable	(183)	(4,685)
Prepaid expenses and deposits	(248)	(710)
Accounts payable and accrued liabilities	(9,685)	(5,527)
Change in non-cash working capital	(10,116)	(10,922)
Relating to:		
Investing	(9,123)	(8,490)
Operating	(993)	(2,432)
Change in non-cash working capital	(10,116)	(10,922)

20. COMMITMENTS

The following is a summary of the Company's contractual obligations and commitments at December 31, 2013:

	2014	2015	2016	2017	2018	Thereafter	Total
Office leases	395	-	-	-	-	-	395
Field equipment leases	559	-	-	-	-	-	559
Firm transportation agreements	8	8	6	-	-	-	22
	962	8	6	-	-	-	976

CORPORATE INFORMATION

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