



## FINANCIAL REPORT FOR THE THREE MONTHS AND YEAR ENDED DECEMBER 31, 2010

### FINANCIAL AND OPERATING HIGHLIGHTS

#### Consolidated Highlights

(in thousands except per share amounts)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Revenue <sup>(1)</sup>	\$ 13,791	\$ 9,254	\$ 47,972	\$ 28,203
Funds from operations	9,293	6,243	30,522	15,341
Per basic share	0.15	0.14	0.50	0.50
Per diluted share	0.15	0.14	0.50	0.50
Net earnings (loss)	(515)	(517)	(3,529)	(6,137)
Per basic and diluted share	(0.01)	(0.01)	(0.06)	(0.20)
Net debt	49,820	37,571	49,820	37,571
Capital expenditures, net	\$ (357)	\$ 65,950	\$ 42,268	\$ 85,778
Weighted average shares outstanding – basic and diluted	60,936	44,132	60,935	30,980

<sup>(1)</sup> Includes the realized gain or loss on commodity contracts.

#### Exploration & Production Highlights

	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Production				
Natural gas (mcf per day)	20,467	15,814	20,606	13,293
Oil and NGL (bbls per day)	386	282	349	241
Total (@ 6:1) (boe per day)	3,797	2,918	3,783	2,457
Realized average sales prices				
Natural gas (\$ per mcf) <sup>(2)</sup>	4.24	5.29	4.58	4.88
Oil and NGL (\$ per bbl)	64.93	60.09	65.52	51.41
Combined average (\$ per boe)	29.43	34.47	30.99	31.45
Royalties (\$ per boe)	(1.71)	(1.55)	(2.78)	(3.08)
Operating costs (\$ per boe)	(4.48)	(5.26)	(4.73)	(5.58)
Transportation costs (\$ per boe)	(0.97)	(0.75)	(0.90)	(0.96)
Operating netback (\$ per boe)	22.27	26.91	22.58	21.83
G&A costs (\$ per boe)	(2.40)	(1.92)	(2.26)	(3.09)
Net interest expense (\$ per boe)	(1.45)	(1.75)	(1.38)	(1.34)
Corporate netback (\$ per boe)	18.42	23.24	18.94	17.40

## Poseidon Concepts Highlights

(in thousands except percentages)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Fracturing fluid handling tank rental revenue	3,657	–	5,320	–
Operating costs	(485)	–	(586)	–
G&A costs	(172)	–	(225)	–
Operating earnings (EBITDA)	3,000	–	4,509	–
Operating margin	82%	–	85%	–

### HIGHLIGHTS

In the year ended December 31, 2010, Open Range:

- Grew average production to 3,783 boe per day, an increase of 54 percent over 2009 average volumes and net of non-core dispositions;
- Drilled 11 (7 net) wells, including four (3.6 net) gross horizontal wells targeting the Wilrich, Notikewin and Bluesky formations at the Company's core Ansell/Sundance Deep Basin property, as part of its \$42 million net capital investment program;
- Grew annual funds from operations to \$30.5 million (\$0.50 per share), an increase of 99 percent over 2009, and fourth quarter funds from operations to \$9.3 million (\$0.15 per share), a period-over-period increase of 49 percent;
- In the fourth quarter generated proceeds of \$12.6 million through disposition of non-core properties, reducing higher-cost production by just over 300 boe per day and abandonment liabilities by \$2.2 million;
- Generated revenues of \$5.3 million and EBITDA of \$4.5 million in the first seven months of operations of its Poseidon Concepts business unit;
- Exited the year with \$49.8 million in net debt, reducing its year-end debt to annualized fourth quarter 2010 funds from operations ratio to 1.3:1;
- Increased proved plus probable reserves to 20.4 million boe and total proved reserves to 12.7 million boe at year-end, representing year-over-year increases of 21 percent and 27 percent, respectively;
- Achieved finding, development and acquisition (FD&A) costs, excluding the change in future development capital (FDC), of \$8.67 per boe of reserves added in 2010, and including the change in FDC, of \$17.27 per boe of reserves added in 2010. This represents recycle ratios of 2.6 times and 1.3 times for proved plus probable reserves added, respectively; and
- Replaced 2010 production by 3.5 times and increased the Company's reserve-life-index to 15.3 years.

Subsequent to the year ended December 31, 2010, Open Range:

- Initiated and to date conducted the majority of its first-half 2011 capital program, focused at Ansell/Sundance and consisting of four (3.6 net) horizontal wells targeting the Wilrich Formation. All four gross wells have been drilled to date, the first coming on-stream in mid-February and having produced at an initial production (IP) rate over its first 30 days of 3.9 mmcf per day plus approximately 13 bbls of NGL per mmcf, with two others currently on fracturing fluid cleanup and about to come on-stream and one awaiting completion operations;
- Issued 7.0 million common shares at \$2.85 per common share in a bought-deal financing that raised gross proceeds of \$20 million and closed March 21;
- Announced revised first-half 2011 EBITDA guidance of \$9.5 million for the Poseidon Concepts business unit; and
- Remained on-track to meet guidance for first-half 2011 average daily production of 4,200 boe per day, which will generate estimated consolidated funds from operations of \$22 million (\$0.34 per share) in the six-month period ended June 30, 2011.

## **2010 IN REVIEW**

The past year has been the most successful and important for Open Range since the Company's founding in late 2005. We are larger, financially stronger and more diversified than at any time in our history. Over the past year we were focused on de-risking our Deep Basin horizontal play at Ansell/Sundance, maintaining and reducing our operating costs per boe and launching our Poseidon Concepts business unit. Success in all three areas has improved Open Range's competitive position as a natural gas producer.

The Company's performance accelerated further in the fourth quarter, with excellent initial results in the Wilrich horizontal program and the emergence of the Poseidon business, generating combined funds from operations of \$9.3 million for the quarter. Open Range is on a path to becoming an intermediate-sized producer by the end of 2012 through our:

- Base of low-cost Deep Basin production of approximately 4,000 boe per day;
- Repeatable success in our Wilrich horizontal play at Ansell/Sundance with an expanding inventory of horizontal locations;
- Focused operations in one of the highest-quality liquids-rich natural gas areas of the Western Canadian Sedimentary Basin; and
- Exposure to the strong operating environment for well fracturing services and related equipment from the Poseidon Concepts business unit.

The past year's results reflect the Company's technical focus on continuing to test, assess and prove up its horizontal opportunities. The rapid evolution of horizontal drilling with multi-stage fracturing was changing the exploration and production model in western Canada, offering a step-change in initial productivity, reserve recoveries and well economics. Initial horizontal drilling at Ansell/Sundance in the first half of 2010 added substantial volumes of liquids-rich production.

Strong competitor successes offsetting our lands pointed to the Wilrich as offering the best risk-reward profile. Proving to have highly repeatable per-well productivity, the new Wilrich horizontal play was driving volume growth and delivering great economics, with competitors reporting 90 percent internal rates of return. Open Range had already mapped an extensive Wilrich sand fairway utilizing well control from many of our nearly 50 producing multi-zone vertical wells at Ansell/Sundance.

The Company's first Wilrich horizontal well spud in August and was drilled to a total measured depth of 4,040 metres, including a 1,060-metre horizontal leg. It was completed using a packer system with 10, 80-120-tonne fractures and came on-stream in mid-October. This exciting result solidified an accelerated Wilrich program for winter 2010-2011.

### **WINTER 2010-2011 OPERATIONS UPDATE**

Encouraged by our initial Wilrich success and continued strong results by competitors offsetting Ansell/Sundance, our current winter program centres on four (3.6 net) Wilrich wells, the first of which spud in December. It was drilled to a total measured depth of 4,200 metres, including a 1,300-metre horizontal leg, and was completed with a packer system over 13, 80-tonne fractures. It replicated the initial well's results, coming on-stream in mid-February at 7.0 mmcf per day plus approximately 90 bbls per day of NGL. Its 30-day average IP was 3.9 mmcf per day plus NGL, and to date it has produced a cumulative 120 mmcf plus 1,550 bbls of NGL.

The second and third wells of the current program have been drilled and completed and fracturing fluid flowback operations are ongoing on both at this time. Initial flow test and production results for both wells are expected shortly. Fracturing of the fourth well is planned for April, and the well could be on-stream before spring breakup.

All four wells were drilled from existing pads with multi-zone vertical producing wells, facilitating quick tie-in of new volumes. Production from three of the wells will be processed at the Company-operated Ansell/Sundance gas plant, with the remaining well to be tied into a Company compressor and processed at a third-party facility. Plans to expand the Company's gas handling capacity at Ansell/Sundance to meet anticipated production growth from an accelerated Wilrich horizontal program are currently underway.

We are pleased with the Wilrich play's results to date and are confident that the Company has a low-risk resource play that can steadily grow volumes for the next two to three years on the recently expanded inventory of 37 net horizontal locations. This inventory is based on well-spacing of no more than two wells per section. The Wilrich may provide down-spacing opportunities to achieve full reservoir drainage where warranted, but we will be disciplined in not over-capitalizing this play.

### **FINANCIAL REVIEW**

The Company's track record of reducing cash costs per unit of production, its production growth – meeting the annual target for the fifth year in a row – and its prudent hedging program drove improved financial results in 2010. The \$30.5 million or \$0.50 per share in annual funds from operations was nearly double the amount generated in 2009.

Open Range maintained netbacks above \$22.00 per boe in 2010 thanks to the low and declining costs of its liquids-rich production at Ansell/Sundance. Operating costs (not including transportation) declined from \$5.58 per boe in 2009 to \$4.73 per boe in 2010, transportation costs also declined slightly, while overall cash costs declined from \$10.97 per boe to \$9.27 per boe year-over-year.

Operating netback performance is enhanced by our core property's liquids-rich production. The Ansell/Sundance gas plant enables us to take full advantage, extracting the range of liquids including condensate for separate marketing, and 60 percent of our produced liquids are the premium-priced condensate. In 2010 the Company's NGL represented approximately 10 percent of annual and fourth quarter production but delivered approximately 20 percent of oil and natural gas revenue. In addition, our low royalty structure, averaging 9 percent of revenue in 2010, contributed to our financial performance.

The Poseidon Concepts business unit, discussed below, became material in the second half of 2010, with fracturing fluid system rentals generating revenue of \$5.3 million and EBITDA of \$4.5 million.

Open Range today is a much stronger company financially. Traction in the Wilrich program has added volumes at high capital efficiency and strong rates of return. Our cost structure continues to improve. Property dispositions in December generated \$12.6 million and removed \$2.2 million in abandonment liabilities and dozens of low-productivity, higher-cost wellbores. The proceeds reduced long-term debt, freeing up credit capacity sufficient for at least two additional Wilrich wells.

We exited the year with total net debt of \$49.8 million on bank lines of \$80 million, with no borrowing capacity recognized for Poseidon, and a ratio of net debt to annualized quarterly funds from operations of 1.3:1. We are confident in our current bank line, which is supported by reserve additions offsetting the impact of the lower price deck, and with the possibility of an increase due to Poseidon's growing EBITDA.

## **POSEIDON CONCEPTS**

We have reported on the background and progress of our Poseidon Concepts business unit in several press releases and our third-quarter 2010 report. This unique, Open Range-designed fluid handling system stems from the Company's continual focus on technological and process innovations that can improve capital or operating efficiencies.

The Poseidon system was conceived and designed in-house initially for use in our multi-stage fracturing operations at Ansell/Sundance. The proprietary Poseidon system is a modular, easily transportable and insulated single tank with a very high capacity of 18,000 bbls or 2,900 m3 specifically designed for the larger fracturing jobs common at today's unconventional oil and liquids-rich natural gas plays across North America.

After proprietary testing, the first revenue-generating rental came in June 2010, and the industry's acceptance has been dramatic. By year-end tank rentals had generated \$5.3 million in revenue and approximately 25 systems had been manufactured in southern Alberta and deployed in western Canada.

By the end of February 2011 that figure had climbed to 65 systems in western Canada and the United States, where we have a third-party manufacturing facility building systems for that market. We recently introduced an enlarged model, the "Atlantis", with 41,000 bbls (6,500 m3) of fluid storage capacity, more than double the Poseidon model's capacity.

Poseidon Concepts has been structured in a tax-effective manner and is wholly owned by Open Range. EBITDA guidance for the first half of 2011, as recently reported, is \$9.5 million. Our December 31, 2010 net asset value does not reflect any value attributable to the Poseidon business, and none of the Company's current borrowing capacity of \$80 million is based on value imputed to this business line.

We believe Poseidon has a bright future in the competitive North American service and supply sector. Our plan for 2011 is to continue to execute in Canada, exploiting first-mover advantages, maintaining a high-quality product and service and expanding our market share, while expanding in the United States. We are already active in three states and are aggressively chasing new opportunities. Our immediate goal for the U.S. business is to deploy our product in every major unconventional basin.

## RESERVES EVALUATION RESULTS

The Company's proved plus probable reserves growth was solid at 21 percent year-over-year to 20.4 million boe at December 31, 2010, according to the independent reserve evaluation by GLJ Petroleum Consultants Ltd. (GLJ). Our year-end net asset value of \$226.3 million or \$3.62 per fully diluted share (proved plus probable, 10 percent discount, before tax), illustrates the quality of Open Range's reserves and the compelling value of the Ansell/Sundance asset.

FD&A costs were only \$8.67 per proved plus probable boe added in 2010, not including the change in FDC, and \$17.27 per proved plus probable boe including the change in FDC. These competitive FD&A costs, along with strong operating netbacks, generated recycle ratios of 2.6 times and 1.3 times with and without FDC, respectively. Open Range extended its record of replacing annual production by several times over, and our reserve-life-index of 15.3 years reflects our long-life, low-decline production.

## SUMMARY OF RESERVES (FORECAST PRICES AND COSTS)

December 31, Reserve category	2010		2009		
	(mboe)	% of Total	Year-over-year % change	(mboe)	% of Total
<b>Proved</b>					
Developed producing	6,055	30%	5%	5,753	34%
Developed non-producing	232	1%	67%	139	1%
Proved undeveloped	6,377	31%	57%	4,062	24%
<b>Total proved</b>	<b>12,664</b>	<b>62%</b>	<b>27%</b>	<b>9,954</b>	<b>59%</b>
<b>Probable</b>	<b>7,675</b>	<b>38%</b>	<b>12%</b>	<b>6,866</b>	<b>41%</b>
<b>Total Company gross working interest reserves – proved plus probable reserves<sup>(1)</sup></b>	<b>20,338</b>	<b>100%</b>	<b>21%</b>	<b>16,820</b>	<b>100%</b>
<b>Proved plus probable Company interests in royalties</b>	<b>15</b>		<b>(58)%</b>	<b>36</b>	
<b>Total Company interest reserves – proved plus probable reserves<sup>(2)</sup></b>	<b>20,353</b>		<b>21%</b>	<b>16,856</b>	

NOTE: Table may not add due to rounding.

<sup>(1)</sup> "Working interest" reserves equate to those reserves that are referred to as "company gross" reserves by the Canadian Securities Administrators in National Instruments 51-101.

<sup>(2)</sup> "Company interest" reserves and values refer to the sum of royalty interest and working interest reserves before deduction of royalty burdens payable.

**SUMMARY OF OIL, NATURAL GAS AND NATURAL GAS LIQUIDS (NGL) RESERVES  
(FORECAST PRICES AND COSTS)**

At December 31, 2010	Light & medium oil		Natural gas		NGL		Total	
	Gross (mmbbls)	Net (mmbbls)	Gross (mmcf)	Net (mmcf)	Gross (mmbbls)	Net (mmbbls)	Gross (mboe)	Net (mboe)
Proved								
Developed producing	–	–	32,872	29,779	576	374	6,055	5,337
Developed non-producing	–	–	1,287	1,159	18	11	232	205
Proved undeveloped	–	–	35,149	32,511	519	395	6,377	5,813
Total proved	–	–	69,309	63,449	1,112	780	12,664	11,355
Probable	–	–	42,316	38,536	622	425	7,675	6,848
Total proved plus probable	–	–	111,625	101,985	1,734	1,205	20,338	18,203

**NET PRESENT VALUE OF FUTURE NET REVENUE (FORECAST PRICES AND COSTS)**

(\$ millions)

Net Present Value (NPV) of Future Net Revenue (FNR)

At December 31, 2010	Before Income Taxes – Discounted at (%/yr)					After Income Taxes – Discounted at (%/yr)				
	0	5	10	15	20	0	5	10	15	20
Reserves category										
Proved										
Developed producing	173.6	130.5	105.2	88.6	77.0	172.4	130.0	105.0	88.5	76.9
Developed non-producing	5.5	3.4	2.3	1.6	1.2	4.1	2.7	1.9	1.4	1.1
Proved undeveloped	107.7	60.4	33.5	17.4	7.3	80.9	44.0	23.1	10.4	2.5
Total proved	286.8	194.3	141.0	107.7	85.4	257.4	176.8	130.0	100.4	80.5
Probable	266.1	131.6	78.4	52.5	37.9	200.0	98.7	58.7	39.3	28.4
Total proved plus probable	552.9	325.9	219.4	160.2	123.4	457.4	275.5	188.7	139.7	108.9

NOTE: Table may not add due to rounding.

**PRICING AND INFLATION RATE ASSUMPTIONS (FORECAST PRICES AND COSTS)**

Year	Oil		Natural gas		NGL		Inflation	
	WTI Cushing, Oklahoma (US\$/bbl)	Edmonton Par Price 40° API (Cdn\$/bbl)	AECO Price (Cdn\$/mmbtu)	Edmonton Pentanes Plus FOB Field Gate (Cdn\$/bbl)	Edmonton Butanes FOB Field Gate (Cdn\$/bbl)	Edmonton Propane FOB Field Gate (Cdn\$/bbl)	Inflation Rate (%/Yr)	Exchange Rate (US\$/Cdn\$)
2011	88.00	86.22	4.16	90.54	67.26	54.32	2.0	0.980
2012	89.00	89.29	4.74	91.96	68.75	56.25	2.0	0.980
2013	90.00	90.92	5.31	92.74	70.01	57.28	2.0	0.980
2014	92.00	92.96	5.77	94.82	71.58	58.56	2.0	0.980
2015	95.17	96.19	6.22	98.12	74.07	60.60	2.0	0.980
2016	97.55	98.62	6.53	100.59	75.94	62.13	2.0	0.980
2017	100.26	101.39	6.76	103.42	78.07	63.87	2.0	0.980
2018	102.74	103.92	6.90	106.00	80.02	65.47	2.0	0.980
2019	105.45	106.68	7.06	108.82	82.15	67.21	2.0	0.980
2020	107.56	108.84	7.21	111.01	83.80	68.57	2.0	0.980
2021+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.980

## RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE (FORECAST PRICES AND COSTS)

Factors	Light & medium oil			Associated and non-associated natural gas			NGL			Total		
	Proved (mmbbls)	Probable (mmbbls)	Proved Plus Probable (mmbbls)	Proved (mmcf)	Probable (mmcf)	Proved Plus Probable (mmcf)	Proved (mmbbls)	Probable (mmbbls)	Proved Plus Probable (mmbbls)	Proved (mboe)	Probable (mboe)	Proved Plus Probable (mboe)
Dec. 31, 2009	11	5	16	53,748	37,296	91,043	985	646	1,630	9,954	6,866	16,820
Extensions	100	25	124	22,987	6,536	29,523	404	115	518	4,335	1,228	5,563
Technical Revisions	-	-	-	1,846	(475)	1,371	(99)	(110)	(209)	209	(189)	20
Acquisitions	-	-	-	505	148	653	7	2	9	91	27	118
Dispositions	(103)	(29)	(132)	(2,025)	(891)	(2,916)	(58)	(26)	(85)	(499)	(204)	(703)
Economic Factors	-	-	-	(302)	(298)	(600)	(7)	(4)	(11)	(57)	(54)	(111)
Production	(9)	-	(9)	(7,450)	-	(7,450)	(119)	-	(119)	(1,369)	-	(1,369)
Dec. 31, 2010	-	-	-	69,309	42,316	111,625	1,112	622	1,734	12,664	7,675	20,338

NOTE: Table may not add due to rounding.

## RESERVE-LIFE-INDEX

Production (December 2010 average)	3,643 boe/d
Proved reserves (mboe)	12,675
Proved reserve-life-index (years)	9.5
Proved plus probable reserves (mboe)	20,353
Proved plus probable reserve-life-index (years)	15.3

## FINDING, DEVELOPMENT AND ACQUISITION (FD&A) COSTS

(thousands except per boe amounts)	Capital costs	Change in future development costs	Total capital costs	Reserve additions	FD&A costs (per boe)
Excluding future development costs					
Proved	\$ 42,268	-	\$ 42,268	4,075	\$ 10.37
Proved plus probable	\$ 42,268	-	\$ 42,268	4,878	\$ 8.67
Including future development costs <sup>(1)</sup>					
Proved	\$ 42,268	\$ 37,044	\$ 79,312	4,075	\$ 19.46
Proved plus probable	\$ 42,268	\$ 41,953	\$ 84,221	4,878	\$ 17.27

<sup>(1)</sup> Net of drilling credits.

## RESERVES REPLACEMENT

	Proved	Proved plus Probable
Reserves replacement of 2010 production (1,381 mboe)	3.0 times	3.5 times

## NET ASSET VALUE PER SHARE

As at December 31, 2010 (thousands except per share amounts)	Discounted at 10%	Discounted at 15%
Present value of reserves (P+P)	\$ 219,419	\$ 160,192
Stock option proceeds, in-the-money amount	2,684	2,684
Undeveloped acreage <sup>(1)</sup>	54,100	54,100
Working capital deficiency	(49,820)	(49,820)
Estimated value	\$ 226,383	\$ 167,156
Fully diluted shares outstanding <sup>(2)</sup>	62,467	62,467
Estimated NAV per diluted share	\$ 3.62	\$ 2.68

<sup>(1)</sup> Based on independent land evaluation as of December 31, 2010.

<sup>(2)</sup> Options to purchase 1.5 million common shares were included in the computation of fully diluted shares outstanding as they were dilutive at December 31, 2010.

## OUTLOOK

The Company's first-half 2011 capital program is substantially complete with the drilling of the four (3.6 net) Wilrich horizontal wells. The program also included participation in a Hoadley Glauconitic Deep Basin horizontal well. We remain on-track to average 4,200 boe per day in the first half of 2011, and we have hedged approximately one-third of our 2011 natural gas volumes at a minimum floor price of \$3.80 per mcf.

This month we conducted our first equity issue in nearly 18 months. The bought-deal financing closed yesterday and raised gross proceeds of \$20 million (\$19 million net). This complements our expanded cash flow base and available credit to provide the resources for a strong second-half drilling program.

With greater funds from operations, including EBITDA from the Poseidon business unit, available debt capacity and the recent equity proceeds, Open Range has the financial resources for accelerated second-half activity. It will continue to be tightly focused on the Wilrich, which continues to unfold around Ansell/Sundance as an exciting and profitable liquids-rich play. The Wilrich play is continuing to show low variance in initial productivity, predictable initial decline curves and fast payout thanks to the strong potential to recover 1 bcf or more in the first year.

Over the years we have had a good track record of efficient and timely drilling and completions operations, thanks to our experienced technical team and relationships with key suppliers. We continue working to sustain our access to high-quality and timely services and equipment as we expand our Wilrich horizontal activities.

Our medium-term goal continues to be to grow Open Range organically to 10,000 boe per day within two years. The Company expects to announce details of its second-half capital program plus full-year guidance prior to its 2011 annual general meeting. The meeting will be held at 9 a.m. MDT, June 2, 2011, in the Strand/Tivoli Room of The Metropolitan Centre, 333-4 Avenue S.W., Calgary, Alberta.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

The following management's discussion and analysis (MD&A) is a review of operations, current financial position and outlook for Open Range Energy Corp. ("Open Range" or the "Corporation") for the three months and year ended December 31, 2010 compared to the three months and year ended December 31, 2009. This MD&A should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2010 and comparative information for the year ended December 31, 2009, along with the MD&A for the quarters ended March 31, 2010, June 30, 2010 and September 30, 2010. This MD&A is dated March 22, 2011.

## **Boe Presentation**

The use of barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and is not intended to represent a value equivalency at the wellhead.

## **Non-GAAP Measurements**

The terms "funds from operations", "funds from operations per share", "operating netback", "operating earnings" and "operating margin" in this discussion are not recognized measures under Canadian generally accepted accounting principles (GAAP). Open Range management believes that in addition to net earnings and cash flow from operations as per GAAP, funds from operations, operating netback, operating earnings and operating margin are useful supplemental measurements. Open Range utilizes funds from operations to evaluate operating performance and assess leverage. The Corporation considers funds from operations to be an important measure of the results generated by its principal business activities before the consideration of how those activities are financed or how the results are taxed and before abandonment expenditures. Operating netback is a benchmark used in the oil and natural gas industry to assess operating profitability by measuring the contribution of oil and natural gas sales following the deduction of royalties, operating expenses and transportation costs. Operating earnings are net earnings before interest and income taxes. Operating earnings and operating margin provide an indication of the results generated by the Corporation's fracturing fluid tank rental activities prior to consideration of how those activities are financed or how the results are taxed. Users are cautioned, however, that these measures should not be construed as an alternative to net earnings determined in accordance with GAAP as an indication of Open Range's performance.

## **Reconciliation of Cash Flow per GAAP to Funds from Operations**

Open Range's method of calculating funds from operations may differ from that of other corporations and, accordingly, may not be comparable to measures used by other corporations. Open Range calculates funds from operations by taking cash flow from operating activities as determined under GAAP before the change in non-cash working capital related to operating activities and asset retirement expenditures incurred.

The Corporation uses this method as it believes the uncertainty surrounding the timing of collection, payment or incurrence of these items makes them less useful in evaluating Open Range's operating performance. A summary of this reconciliation is as follows:

(thousands)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Cash flow from operating activities (per GAAP)	\$ 5,381	\$ 781	\$ 26,793	\$ 13,365
Change in non-cash working capital	3,775	5,161	3,214	1,501
Asset retirement expenditures	137	301	515	475
Funds from operations	\$ 9,293	\$ 6,243	\$ 30,522	\$ 15,341

### Forward-Looking Statements

This MD&A contains certain forward-looking statements, which relate to future events or the Corporation's future performance, that include terms such as "will", "intend", "anticipate", "could", "should", "may", "might", "expect", "estimate", "forecast", "plan", "potential", "project", "assume", "contemplate", "believe", "shall" and similar terms. These statements involve known and unknown risks, uncertainties and other factors that are beyond the Corporation's control, which may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Open Range believes the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A.

This MD&A contains forward-looking statements pertaining to the following: (a) future production volumes; (b) expected royalty rates, operating expenses and G&A costs; (c) future capital expenditures and the method of financing thereof; (d) amount of asset retirement obligations; (e) future liquidity and the ability to raise capital to continually add to reserves through exploration, development and/or acquisition; (f) the future tax horizon of the Corporation; (g) the timing and impact of the adoption of International Financial Reporting Standards and other accounting policies and standards; (h) the performance characteristics of the Corporation's oil and natural gas properties; (i) estimates of future cash flows from operations; (j) drilling plans and timing of drilling, completion and tie-in of wells; (k) commodity prices, exchange rates and interest rates; (l) the utilization and effectiveness of commodity price risk management techniques; (m) Open Range's ability to grow or sustain production and reserves through prudent management; (n) the Corporation's future operating and financial results; and (o) treatment under governmental and other regulatory regimes and tax, environmental and other laws.

With respect to forward-looking statements contained in this MD&A, the Corporation has made a number of assumptions. The key assumptions underlying the aforementioned forward-looking statements, include but are not limited to: (i) future oil and natural gas prices will not deteriorate significantly; (ii) capital, undeveloped lands and skilled personnel will continue to be available at the level Open Range has enjoyed to date; (iii) Open Range will be able to obtain equipment in a timely manner to carry out exploration, development and exploitation activities; (iv) Open Range will be able to obtain financing on acceptable terms; (v) Open Range will be able to renew its credit facilities on acceptable terms; (vi) Open Range will be able to continue to add production and reserves through exploration and development activities at a satisfactory rate; and (vii) the current tax and regulatory regimes will remain substantially unchanged. Certain or all of the foregoing assumptions may prove to be incorrect.

Open Range's actual results could differ materially from those anticipated in these forward-looking statements as a result of substantial known and unknown risks and uncertainties, certain of which are beyond the Corporation's control. Such risks and uncertainties include, without limitation, risks associated with oil and natural gas exploration, development, exploitation, production, marketing and transportation; loss of markets; volatility of commodity prices; counterparty credit risk; currency fluctuations; imprecision of reserve estimates; environmental risks; increased competition from other producers; inability to retain drilling rigs and other services; delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient debt or equity capital from internal and external sources; the limited operating history of the Poseidon Concepts business unit; demand for fracturing fluid handling systems; risks associated with the manufacture and supply of fracturing fluid handling systems; competition from other fluid handling system suppliers; the ability of the Poseidon Concepts business unit to attract and retain clientele; the ability of the Poseidon Concepts business unit to fund its ongoing capital requirement from cash flow from operations; the impact of general economic conditions in Canada, the United States and overseas; industry conditions; changes in laws and regulations (including the adoption of new environmental laws and regulations) and changes in how they are interpreted and enforced; changes in federal and provincial tax laws and legislation (including the adoption of new royalty regimes); the lack of availability of qualified personnel or management; fluctuations in foreign exchange or interest rates; stock market volatility and market valuations of companies with respect to announced transactions and the final valuations thereof; and obtaining required approvals of regulatory authorities. Readers are cautioned that the foregoing list of risks to Open Range's performance is not exhaustive and reference is made to the items under "Risk Factors" in the Corporation's Annual Information Form (AIF) for the year ended December 31, 2010, which is filed on SEDAR and available for review at [www.sedar.com](http://www.sedar.com). All subsequent forward-looking statements, whether written or oral, attributable to the Corporation or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Furthermore, the forward-looking statements contained in this MD&A are made as at the date hereof and the Corporation does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

## EXPLORATION & PRODUCTION OPERATIONS (E&P)

### Production

	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Production				
Natural gas (mcf per day)	20,467	15,814	20,606	13,293
Oil and NGL (bbls per day)	386	282	349	241
Total (boe per day)	3,797	2,918	3,783	2,457
Total (mboe)	349	268	1,381	897
Natural gas % of production	90	90	91	90

Open Range's production for the three months and year ended December 31, 2010 increased from the comparative periods in 2009. The increase was primarily the result of the full year's effect of the Corporation's working interest acquisition at Ansell/Sundance in November 2009 and the tie-in of new horizontal wells drilled at Ansell/Sundance more than offsetting the divestiture of certain non-core holdings in the fourth quarter of 2010. Production in the three months and year ended December 31, 2010 averaged 3,797 boe per day and 3,783 boe per day, respectively. This represented an increase of 30 percent and 54 percent from production of 2,918 boe per day and 2,457 boe per day for the respective three months and year ended December 31, 2009. Natural gas production in the three months and year ended December 31, 2010 increased to 20,467 mcf per day and 20,606 mcf per day, respectively, from 15,814 mcf per day and 13,293 mcf per day, respectively, for the three months and year ended December 31, 2009. Oil and natural gas liquids (NGL) production in the three months ended December 31, 2010 increased to 386 barrels per day from 282 barrels per day in the fourth quarter of 2009. For the year ended December 31, 2010 oil and NGL production increased to 349 barrels per day from 241 barrels per day for 2009. Open Range is forecasting average production of 4,200 boe per day in the first half of 2011.

### Oil and Natural Gas Revenues

	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Revenue (thousands)				
Natural gas	\$ 7,395	\$ 7,110	\$ 32,353	\$ 20,935
Oil and NGL	2,306	1,559	8,347	4,523
Realized gain on commodity contracts	582	585	2,101	2,745
<b>Total</b>	<b>\$ 10,283</b>	<b>\$ 9,254</b>	<b>\$ 42,801</b>	<b>\$ 28,203</b>
Average realized price				
Natural gas (\$ per mcf)	3.93	4.89	4.30	4.31
Oil and NGL (\$ per bbl)	64.93	60.09	65.52	51.41
Realized gain on commodity contracts (\$ per mcf)	0.31	0.40	0.28	0.57
<b>Combined average (\$ per boe)</b>	<b>29.43</b>	<b>34.47</b>	<b>30.99</b>	<b>31.45</b>
Benchmark pricing				
Alberta Spot (Cdn\$ per mcf)	3.65	4.50	3.91	3.85
Edmonton Par (Cdn\$ per bbl)	80.30	76.73	77.28	66.30

Revenue, including realized gains on commodity contracts, for the three months ended December 31, 2010 increased by 11 percent to \$10.3 million from \$9.3 million in the comparative period in 2009. The increase in revenue was primarily a result of a 30 percent increase in production volumes partially offset by a 15 percent decrease in the combined average sales price from the fourth quarter of 2009. In the year ended December 31, 2010, revenue, including realized gains on commodity contracts, increased by 52 percent to \$42.8 million from \$28.2 million in the comparative period in 2009. The increase was due to a 54 percent increase in production volumes slightly offset by a decrease in the combined average sales price. The period-over-period changes in average sales prices for crude oil, NGL and natural gas realized by Open Range were consistent with the fluctuations in benchmark oil and natural gas prices over the same periods. Open Range's average sales price for natural gas continued to be at a premium to the Alberta natural gas spot benchmark price due to the high energy content of the Corporation's natural gas production.

Open Range realized gains on commodity contracts of \$0.6 million for the three months ended December 31, 2010. These realized gains related to natural gas commodity contracts and amounted to additional revenue of \$0.31 per mcf on the Corporation's natural gas production for the fourth quarter of 2010. For the year ended December 31, 2010, the Corporation realized gains on commodity contracts of \$2.1 million, which amounted to additional revenue of \$0.28 per mcf on the Corporation's 2010 natural gas production.

#### **Unrealized Gain (Loss) on Commodity Contracts**

Open Range's management utilizes commodity contracts as a risk management technique to reduce volatility in cash flows and mitigate the unpredictable commodity price environment. For the three months and year ended December 31, 2010, the Corporation recorded an unrealized loss on commodity contracts of \$1.2 million and \$0.3 million, respectively. These amounts represented the change in the fair value of the commodity contracts held by the Corporation during the three months and year ended December 31, 2010.

Natural gas and crude oil hedging contracts entered into as at December 31, 2010 and expired contracts presented for comparative purposes are as follows:

(thousands except as noted)									
Period	Volume (GJ/d)	Type of contract	Average AECO Spot Floor (Cdn\$/GJ)	Average AECO Spot Ceiling (Cdn\$/GJ)	Unrealized gain (loss) for the three months ended Dec. 31, 2010	Unrealized gain (loss) for the three months ended Dec. 31, 2009	Unrealized gain (loss) for the year ended Dec. 31, 2010	Unrealized gain (loss) for the year ended Dec. 31, 2009	
Nov. 2008 to Mar. 2009	1,500	Costless Collar	\$ 6.75	\$ 11.09	\$ -	\$ -	\$ -	\$ (103)	
Jan. to Dec. 2009	1,000	Costless Collar	\$ 6.50	\$ 9.00 - 13.00	-	(199)	-	(265)	
Apr. 2009 to Mar. 2010	5,000	Costless Collar	\$ 4.00	\$ 5.84	-	29	32	(32)	
Apr. 2009 to Mar. 2010	1,000	Costless Collar	\$ 4.25	\$ 5.92	-	(9)	4	(4)	
Jul. to Dec. 2009	1,500	Swap	\$ 5.00	\$ 5.00	-	(86)	-	-	
Jan. to Dec. 2010	1,500	Call Option	n/a	\$ 7.75	-	73	75	(75)	
Apr. to Oct. 2010	3,000	Put Option	\$ 4.25	n/a	(29)	(22)	225	(225)	
Apr. to Oct. 2010	1,000	Put Option	\$ 4.50	n/a	(21)	(7)	35	(35)	
Apr. to Oct. 2010	1,500	Put Option	\$ 4.25	n/a	(21)	(69)	69	(69)	
Apr. to Oct. 2010	1,000	Put Option	\$ 4.50	n/a	(19)	(44)	44	(44)	
Jan. to Dec. 2010	1,500	Costless Collar	\$ 4.40	\$ 7.00	(129)	(11)	11	(11)	
Apr. to Oct. 2010	1,500	Swap	\$ 5.51	\$ 5.51	(99)	61	(61)	61	
Feb. to Dec. 2010	1,500	Costless Collar	\$ 4.00	\$ 6.89	(76)	-	-	-	
Feb. to Dec. 2010	1,500	Costless Collar	\$ 4.25	\$ 6.95	(109)	-	-	-	
Apr. to Oct. 2010	1,500	Put Option	\$ 4.50	n/a	(41)	-	-	-	
Jan. to Dec. 2011	2,000	Swap	\$ 5.33	\$ 5.33	1,111	-	1,111	-	
Jan. to Dec. 2011	2,000	Put Option	\$ 3.80 <sup>(1)</sup>	n/a	(64)	-	(64)	-	
Jan. to Dec. 2011	2,000	Swap	\$ 3.80	\$ 3.80	3	-	3	-	
Jan. to Dec. 2011	2,000	Swap	\$ 3.80	\$ 3.80	3	-	3	-	
Jan. to Dec. 2011	2,000	Put Option	\$ 3.80 <sup>(2)</sup>	n/a	(77)	-	(77)	-	
					<b>\$ 432</b>	<b>\$ (284)</b>	<b>\$ 1,410</b>	<b>\$ (802)</b>	

<sup>(1)</sup> Cost of put option to the Corporation is \$0.422 per GJ and payment is due on the fifth business day following each contract month.

<sup>(2)</sup> Cost of put option to the Corporation is \$0.440 per GJ and payment is due on the fifth business day following each contract month.

(thousands except as noted)								
Period	Volume (bbls/d)	Type of contract	Average WTI-Nymex Floor (US\$/bbl)	Average WTI-Nymex Ceiling (US\$/bbl)	Unrealized loss for the three months ended Dec. 31, 2010	Unrealized gain (loss) for the three months ended Dec. 31, 2009	Unrealized loss for the year ended Dec. 31, 2010	Unrealized gain (loss) for the year ended Dec. 31, 2009
Jan. 2011 to Dec. 2012	200	Call Option	n/a	\$ 90.00	\$ (1,665)	\$ –	\$ (1,665)	\$ –
					<b>\$ (1,665)</b>	<b>\$ –</b>	<b>\$ (1,665)</b>	<b>\$ –</b>

For more details on these contracts refer to note 11, Financial Instruments, in the audited consolidated financial statements for the year ended December 31, 2010.

## Royalties

(thousands except per unit amounts)					
	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009	
Royalty expense – natural gas	\$ 337	\$ 111	\$ 1,734	\$ 1,661	
Royalty expense – oil & NGL	260	306	2,099	1,102	
<b>Total</b>	<b>\$ 597</b>	<b>\$ 417</b>	<b>\$ 3,833</b>	<b>\$ 2,763</b>	
Per boe (\$)	1.71	1.55	2.78	3.08	
% of revenue <sup>(1)</sup>	6	5	9	11	

<sup>(1)</sup> Revenue before the realized gains or losses on commodity contracts.

Royalties totalled \$0.6 million and \$3.8 million for the three months and year ended December 31, 2010, respectively, compared to \$0.4 million and \$2.8 million, respectively, for the comparative periods in 2009. Royalties as a percentage of revenue increased in the three months ended December 31, 2010 over the fourth quarter of 2009 and decreased in the year ended December 31, 2010 from 2009. Three new horizontal wells and two new vertical wells brought on-production at Ansell/Sundance in 2010 took advantage of the 5 percent front-end royalty rate and contributed to the year-over-year decline in the average corporate royalty rate. On a per-unit-of-production basis, royalty costs for the three months ended December 31, 2010 were up slightly from the comparative quarter in 2009, mainly due to the timing of the tie-in of new wells that benefit from the front-end royalty incentives. Royalty costs per boe of production for the year ended December 31, 2010 were down by 10 percent from the comparative periods in 2009, mainly due to the impact of the 5 percent front-end royalty rate on the corporations natural gas wells brought on-production in 2010.

Open Range estimates that royalty rates for 2011 will amount to an average of 8 percent to 10 percent of revenue. This reflects the impact of current commodity prices resulting in lower royalty rates and the impact of the now-permanent 5 percent front-end royalty rate announced in 2010 by the Alberta government on newly tied in wells.

## Operating Costs

(thousands except per unit amounts)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Operating costs	\$ 1,565	\$ 1,412	\$ 6,524	\$ 5,008
Transportation costs	340	200	1,247	860
<b>Total</b>	<b>\$ 1,905</b>	<b>\$ 1,612</b>	<b>\$ 7,771</b>	<b>\$ 5,868</b>
Operating costs (\$ per boe)	4.48	5.26	4.73	5.58
Transportation costs (\$ per boe)	0.97	0.75	0.90	0.96
<b>Total (\$ per boe)</b>	<b>5.45</b>	<b>6.01</b>	<b>5.63</b>	<b>6.54</b>

Operating costs were \$1.6 million and \$6.5 million, respectively, for the three months and year ended December 31, 2010 compared to \$1.4 million and \$5.0 million, respectively, for the comparative periods in 2009. On a per-unit-of-production basis, operating costs for the three months and year ended December 31, 2010 were \$4.48 per boe and \$4.73 per boe, respectively. This represented decreases of 15 percent from \$5.26 per boe and \$5.58 per boe for each of the respective comparative periods in 2009. This reduction was due primarily to continued operating efficiencies being realized at Ansell/Sundance where, following the Corporation's working-interest acquisition in November 2009, increasing production volumes are handled at the Corporation-operated plant and facilities. Transportation costs for the three months and year ended December 31, 2010 were \$0.3 million or \$0.97 per boe and \$1.2 million or \$0.90 per boe, respectively, compared to \$0.2 million or \$0.75 per boe and \$0.9 million or \$0.96 per boe for the respective periods in 2009. The period-over-period increases in transportation costs in total dollar terms mainly reflect higher rates of production throughput at Ansell/Sundance.

## Operating Netback

(\$ per boe)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Average realized sales price	29.43	34.47	30.99	31.45
Royalty expenses	(1.71)	(1.55)	(2.78)	(3.08)
Operating costs	(4.48)	(5.26)	(4.73)	(5.58)
Transportation costs	(0.97)	(0.75)	(0.90)	(0.96)
<b>Operating netback</b>	<b>22.27</b>	<b>26.91</b>	<b>22.58</b>	<b>21.83</b>

The Corporation's operating netback for the three months ended December 31, 2010 decreased to \$22.27 per boe from \$26.91 per boe in 2009. This 17 percent decline was mainly due to the period-over-period decrease in natural gas prices driving down the Corporation's average realized sales price, slightly mitigated by increased operating efficiencies resulting in lower operating costs per unit of production. The Corporation's operating netback for the year ended December 31, 2010 increased to \$22.58 per boe from \$21.83 per boe in 2009. This slight increase can be attributed to lower royalties and operating costs per unit of production more than offsetting the decrease in the Corporation's average realized sales price.

## General and Administrative (G&A) Costs

(thousands except per unit amounts)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Gross G&A costs	\$ 1,811	\$ 1,507	\$ 6,595	\$ 6,225
Partner recovery	(294)	(289)	(720)	(758)
Capitalized	(680)	(702)	(2,749)	(2,693)
Net G&A costs	\$ 837	\$ 516	\$ 3,126	\$ 2,774
Per boe, net (\$)	2.40	1.92	2.26	3.09

Net G&A costs for the three months ended December 31, 2010 totalled \$0.8 million or \$2.40 per boe after overhead recoveries and capitalization of \$1.0 million. For the year ended December 31, 2010, net G&A costs per boe decreased by 27 percent to \$2.26 per boe from \$3.09 per boe in 2009. The decrease on a per-unit-of-production basis in 2010 was mainly due to increased production volumes as net G&A costs increased slightly. Capitalized G&A costs represented 38 percent and 42 percent, respectively, of gross G&A costs for the three months and year ended December 31, 2010, as the Corporation continued to focus its efforts on future-oriented exploration and development activities and capitalized its exploration, geological and geophysical expenses. The Corporation's gross G&A costs for the year ended December 31, 2010 increased by 6 percent from the comparative period of 2009, much less than the 54 percent increase in the Corporation's production, reflecting the Corporation's success at limiting overall G&A costs through the industry cycles.

## Capital Expenditures

(thousands)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Drilling and completions	\$ 6,543	\$ 3,730	\$ 32,081	\$ 18,318
Equipment and facilities	3,168	(258)	11,407	1,985
Land	631	2,211	7,193	3,037
Property acquisitions (dispositions), net	(11,395)	58,516	(11,395)	58,516
Capitalized G&A	680	662	2,749	2,483
Geological and geophysical	16	1,089	233	1,439
Total capital expenditures	(357)	65,950	42,268	85,778
Capital items not involving cash:				
Stock-based compensation, including related future tax liability	370	253	1,403	709
Asset retirement obligations	(2,033)	818	(1,644)	1,008
Total capital expenditures including non-cash items	\$ (2,020)	\$ 67,021	\$ 42,027	\$ 87,495

Open Range's 2010 capital budget was heavily focused at Ansell/Sundance and included drilling, completing and bringing on-production three horizontal natural gas wells and two vertical wells (all 100% working interest), expanding the gross capacity of its natural gas plant from 20 mmcf per day to 40 mmcf per day and acquiring additional Crown lands in the area. The Corporation also participated in the drilling and completion of four (1.2 net) horizontal Cardium oil wells in west central Alberta and one (0.2 net) horizontal natural gas well at its Ferrier property. In the fourth quarter of 2010 the Corporation divested of certain non-core holdings at Big Bend, Garrington, Ferrier and Pembina with combined production of 307 boe per day for total cash proceeds of \$11.4 million, net of closing adjustments, and eliminated \$2.2 million in associated asset retirement obligations. Fourth-quarter activities focused on completion operations on the Corporation's first Wilrich horizontal well (100 percent working interest) and commencing the first two of four planned horizontal wells of the Corporation's 2010-11 winter drilling program at Ansell/Sundance.

	Three months ended Dec. 31, 2010		Three months ended Dec. 31, 2009		Year ended Dec. 31, 2010		Year ended Dec. 31, 2009	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
<b>Wells drilled</b>								
Exploration	–	–	–	–	2	1.4	2	2
Development	1	0.4	–	–	9	5.6	–	–
<b>Total</b>	<b>1</b>	<b>0.4</b>	<b>–</b>	<b>–</b>	<b>11</b>	<b>7</b>	<b>2</b>	<b>2</b>
Average working interest		38%		–		64%		100%
Success rate		100%		–		100%		50%

### Depletion, Depreciation and Accretion

(thousands except per unit amounts)	Three months ended Dec. 31, 2010		Three months ended Dec. 31, 2009		Year ended Dec. 31, 2010		Year ended Dec. 31, 2009	
Depletion and depreciation	\$	8,328	\$	6,326	\$	33,309	\$	21,839
Accretion		24		50		191		178
<b>Total</b>	<b>\$</b>	<b>8,352</b>	<b>\$</b>	<b>6,376</b>	<b>\$</b>	<b>33,500</b>	<b>\$</b>	<b>22,017</b>
Depletion and depreciation (\$ per boe)		23.86		23.56		24.12		24.36
Accretion (\$ per boe)		0.07		0.19		0.14		0.19
<b>Total (\$ per boe)</b>		<b>23.93</b>		<b>23.75</b>		<b>24.26</b>		<b>24.55</b>

Depletion and depreciation are calculated based upon cumulative capital expenditures, production rates, reserves and estimated useful lives. Open Range recorded \$8.3 million or \$23.86 per boe in depletion and depreciation for the three months ended December 31, 2010, compared to \$6.3 million or \$23.56 per boe for the comparative period in 2009. Depletion and depreciation for 2010 increased on a total dollar basis to \$33.3 million from \$21.8 million but decreased slightly on a per-unit-of-production basis to \$24.12 per boe from \$24.36 per boe.

Open Range estimates depletion on a quarterly basis throughout the year using independent inputs such as reserve and land reports when available. Undeveloped land, seismic and salvage value of \$23.0 million have been excluded from the calculation and future development costs of \$106.2 million have been included in the capital base used in the calculation.

## POSEIDON CONCEPTS

(thousands except percentages)	Three months ended Dec. 31, 2010 <sup>(1)</sup>	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010 <sup>(1)</sup>	Year ended Dec. 31, 2009
Fracturing fluid handling tank rental revenue	\$ 3,657	\$ –	\$ 5,320	\$ –
Operating costs	(485)	–	(586)	–
G&A costs	(172)	–	(225)	–
Operating earnings <sup>(2)</sup>	\$ 3,000	\$ –	\$ 4,509	\$ –
Operating margin	82%	–	85%	–

<sup>(1)</sup> Includes inter-corporate activities that have been eliminated upon consolidation.

<sup>(2)</sup> Operating earnings are before interest, taxes, depreciation and amortization.

During the year ended December 31, 2010 the Corporation designed, manufactured and commenced operating an innovative fracturing fluid handling system. The Corporation began offering the system, on a rental basis, to exploration and production companies in western Canada through its wholly-owned business unit, Poseidon Concepts, commencing late in the second quarter of 2010. Demand for the Corporation's fracturing fluid handling system increased following the introduction of this technology for application in fracturing operations and by year-end 2010 was being offered in central and northwest Alberta, northeast B.C. and North Dakota. Fracturing fluid handling tank rental revenue of \$3.7 million and \$5.3 million was recognized for the three months and year ended December 31, 2010, respectively. Operating earnings in the three months and year ended December 31, 2010 were \$3.0 million and \$4.5 million, respectively. Operating margins were 82 percent and 85 percent for the three months and year ended December 31, 2010, respectively. The solid operating margins were being driven by a strong operating environment for fracturing services and related equipment and a high utilization rate for the Corporation's expanding tank fleet driven mainly by the cost advantages of the Poseidon system over conventional steel tanks.

## CORPORATE ACTIVITIES

### Net Interest Expense

	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Net interest expense (thousands)	\$ 502	\$ 469	\$ 1,909	\$ 1,199
Per boe, net (\$)	1.44	1.75	1.38	1.34

Net interest expense for the three months and year ended December 31, 2010 was \$0.5 million or \$1.44 per boe and \$1.9 million or \$1.38 per boe, respectively. The increase in net interest expense for each reporting period was primarily the result of increased borrowings on the Corporation's credit facilities. The Corporation had \$51.1 million drawn on its extendable revolving credit facility at December 31, 2010 compared to \$40.1 million drawn at December 31, 2009. The Corporation continues to manage debt levels prudently and expects net interest expense to remain relatively flat through the first half of 2011 as its planned capital investment program will be funded primarily from cash flow from operations.

## Stock-Based Compensation

(thousands)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Total stock-based compensation	\$ 597	\$ 375	\$ 2,092	\$ 1,084
Capitalized stock-based compensation	(293)	(191)	(1,068)	(532)
Stock-based compensation expense	\$ 304	\$ 184	\$ 1,024	\$ 552

During the fourth quarter of 2010, stock-based compensation of \$0.3 million was expensed and \$0.3 million was capitalized. This resulted in total stock-based compensation for the three months ended December 31, 2010 of \$0.6 million, compared to \$0.4 million for the fourth quarter of 2009. For the year ended December 31, 2010 stock-based compensation of \$1.0 million was expensed and \$1.1 million was capitalized, compared to \$0.6 million expensed and \$0.5 million capitalized for 2009. The increase in stock-based compensation expense in 2010 was mainly due to new stock options granted in 2009 and 2010. At December 31, 2010 there were 6.1 million stock options outstanding compared to 5.8 million outstanding at December 31, 2009.

## Income Taxes

Open Range did not incur any cash tax expense in 2010, nor does it expect to pay any cash taxes in 2011 based on current oil and natural gas prices, existing tax pools, planned capital expenditures and forecast earnings before income taxes. For the year ended December 31, 2010, a future income tax reduction of \$0.7 million was recorded. The future income tax liability of \$1.8 million associated with the Corporation's \$7.0 million flow-through share issuance in 2009 was recorded in the first quarter of 2010.

The estimated tax pools of the Corporation are included in the table below:

(thousands except percentages)	Maximum Annual Deduction	December 31, 2010	December 31, 2009
Canadian exploration expense	100%	\$ 34,000	\$ 33,600
Canadian development expense	30%	36,600	22,600
Undepreciated capital cost	25%	32,300	27,500
Share issue costs	20%	3,100	4,700
Canadian oil and gas property expense	10%	65,400	77,800
Total		\$ 171,400	\$ 166,200

## Net Loss

(thousands)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Net loss (thousands)	\$ (515)	\$ (517)	\$ (3,529)	\$ (6,137)
Net loss per basic and diluted share	\$ (0.01)	\$ (0.01)	\$ (0.06)	\$ (0.20)

The Corporation recorded a net loss of \$3.5 million or \$0.06 per basic and diluted share for the year ended December 31, 2010, compared to a net loss of \$6.1 million or \$0.20 per basic and diluted share for the comparative period in 2009. The net loss for the three months ended December 31, 2010 was \$0.5 million or \$0.01 per basic and diluted share compared to a net loss of \$0.5 million or \$0.01 per basic and diluted share for the comparative period in 2009. The smaller loss in 2010 is mainly attributable to weak natural gas prices being partially offset by strong operating earnings from the Corporation's Poseidon Concepts business unit.

### Funds from Operations and Cash Flow from Operating Activities

(thousands except per share and per boe amounts)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Funds from operations	\$ 9,293	\$ 6,243	\$ 30,522	\$ 15,341
Funds from operations per boe	\$ 26.61	\$ 23.26	\$ 22.10	\$ 17.11
Funds from operations per basic share	\$ 0.15	\$ 0.14	\$ 0.50	\$ 0.50
Funds from operations per diluted share	\$ 0.15	\$ 0.14	\$ 0.50	\$ 0.50
Cash flow from operating activities (per GAAP)	\$ 5,381	\$ 781	\$ 26,793	\$ 13,365

In the three months and year ended December 31, 2010, Open Range generated funds from operations of \$9.3 million and \$30.5 million, respectively, compared to \$6.2 million and \$15.3 million for the comparative periods in 2009. Fourth-quarter funds from operations increased by 49 percent and funds from operations per share increased by 7 percent from the comparative quarter in 2009. For the year ended December 31, 2010, funds from operations increased by 99 percent and funds from operations per share remained the same from 2009. The increase in funds from operations and cash flow from operating activities for both reporting periods was primarily due to increased revenues driven by increased production volumes and the rental of fracturing fluid handling systems.

### Share Capital

(thousands)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Weighted average basic and diluted common shares outstanding	60,936	44,132	60,935	30,980

Options to purchase 6.1 million common shares for the three months and year ended December 31, 2010 were not included in the computation of weighted average diluted shares outstanding because they were anti-dilutive.

Outstanding securities (thousands except percentages)	December 31, 2010	March 22, 2011
Common shares	60,949	67,996
Stock options	6,087	6,092
Total outstanding securities	67,036	74,088
Proportion of outstanding securities held by officers and directors	12%	12%

Under the Corporation's share option plan, 6.1 million options to purchase shares had been granted to employees, consultants, officers and directors as at December 31, 2010. The exercise price of each option equals the market price of the Corporation's stock on the date of grant.

On November 8, 2010, the Corporation implemented a performance warrant plan relating to one of its wholly owned subsidiaries. Under the performance warrant plan the Corporation granted 0.6 million performance warrants to employees, officers and directors with exercise prices ranging from \$1.00-\$12.50. Performance warrants are exercisable into units of the subsidiary.

(thousands except per share amounts) Equity financings since inception	Date of issue	Issue price per share	Shares issued	Gross proceeds
Common shares <sup>(1)</sup>	November 29, 2005	\$ 3.10	2,000	\$ 6,200
Common shares	January 10, 2006	4.25	1,649	7,008
Flow-through common shares	May 16, 2006	5.70	1,000	5,700
Common shares	November 9, 2006	3.55	2,324	8,251
Flow-through common shares	February 22, 2007	4.00	3,000	12,000
Flow-through common shares	December 20, 2007	3.45	2,029	7,000
Common shares	April 4, 2008	4.20	3,095	13,000
Flow-through common shares	April 4, 2008	5.00	2,400	12,000
Flow-through common shares	November 4, 2009	2.30	3,050	7,015
Common shares	November 16, 2009	1.85	31,350	57,997
Common shares	March 21, 2011	2.85	7,025	20,021
<b>Total</b>		<b>\$ 2.65</b>	<b>58,922</b>	<b>\$ 156,192</b>

<sup>(1)</sup> Initial private placement financing.

## **RELATED-PARTY AND OFF-BALANCE-SHEET TRANSACTIONS**

During the year ended December 31, 2010, the Corporation incurred \$0.1 million in legal costs to a law firm in which the Chairman of the Board of Directors and the Corporate Secretary of the Corporation are partners.

During the year ended December 31, 2010, the Corporation received \$0.1 million in office rent from a private corporation in which the Chairman of the Board of Directors and the President and Chief Executive Officer were directors.

Open Range was not involved in any off-balance-sheet transactions during the three months and year ended December 31, 2010.

## LIQUIDITY AND CAPITAL RESOURCES

Open Range had a working capital deficiency, excluding the fair value of commodity contracts and future income taxes, of \$49.8 million at December 31, 2010. As at December 31, 2010, Open Range had available a \$70 million extendable revolving-credit facility and a \$10 million non-revolving acquisition and development facility with a syndicate of Canadian chartered banks. The interest rate on the extendable revolving facility is calculated using the syndicate's prime rate plus an applicable facility margin based on the Corporation's net-debt-to-cash flow ratio for the trailing calendar quarter. The interest rate on the non-revolving facility is calculated using the syndicate's prime rate plus 50 basis points above an applicable facility margin based on the Corporation's net-debt-to-cash flow ratio for the trailing calendar quarter. The facilities are borrowing-base facilities that are determined based on, among other things, the Corporation's reserve report, production and operating results, and current and forecast commodity prices. Pursuant to the terms of the credit facilities, the Corporation has provided the covenant that at all times its working capital ratio shall be not less than 1 to 1. The working capital ratio is defined under the terms of the facilities as current assets, including the undrawn portion of the revolving credit facility, to current liabilities, excluding any current bank indebtedness. The Corporation was in compliance with this covenant as at December 31, 2010. As at December 31, 2010, \$51.1 million had been drawn on these facilities. The facilities are open for review semi-annually with the next review occurring in April 2011.

(thousands)	As at December 31, 2010
Bank lines available	\$ 80,000
Working capital deficiency, excluding fair value of commodity contracts and future income taxes	(49,820)
Capital resources available	\$ 30,180

During periods of commodity market instability Open Range actively manages its capital structure to ensure it maintains financial flexibility so as to preserve the ability to meet all of its financial obligations while continuing to finance the Corporation's future growth. The Corporation manages its capital structure in part by using the non-GAAP financial metric of net debt to annualized funds from operations ratio. The Corporation's strategy is to maintain a ratio of no more than 2 to 1. As at December 31, 2010, the Corporation's ratio of net debt to annualized funds from operations was 1.3 to 1, which was within the targeted range established by the Corporation. The Corporation expects the ratio will continue to decrease during the first half of 2011 as it anticipates increased cash flow from operations driven by lower operating costs and increased fracturing fluid handling tank rental revenues, as well as lower debt levels as proceeds from the most recent issuance of equity are applied against debt. For more details on the calculation of this ratio refer to note 9, Capital Management, in the audited consolidated financial statements for the year ended December 31, 2010. The Corporation's initial capital expenditure budget for the first half of 2011 is \$25.0 million.

The Corporation considers itself to have sufficient liquidity and capital resources based on the available bank lines shown above, the \$20.0 million equity financing closed in March 2011 and its ability to accelerate or defer capital projects to reflect changing market or industry conditions.

## SELECTED QUARTERLY INFORMATION

	2010				2009			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
<b>Production</b>								
Natural gas (mcf per day)	20,467	20,139	22,120	19,695	15,814	12,612	12,078	12,642
Oil and NGL (bbls per day)	386	328	366	316	282	201	232	249
Total (boe per day)	3,797	3,685	4,053	3,598	2,918	2,303	2,245	2,356
Quarterly total (mboe)	349	339	369	324	268	212	204	212
% natural gas	90	91	91	91	90	91	90	89
<b>Consolidated Financial</b>								
(\$thousands except as noted)								
Revenue <sup>(1)</sup>	13,791	11,158	11,516	11,507	9,254	5,901	5,727	7,321
Net earnings (loss)	(515)	(1,337)	(2,495)	818	(517)	(2,389)	(1,927)	(1,304)
Per share (\$)								
– basic and diluted	(0.01)	(0.02)	(0.04)	0.01	(0.01)	(0.09)	(0.07)	(0.05)
Funds from operations	9,293	7,103	7,228	6,898	6,243	3,264	2,508	3,326
Per share (\$)								
– basic and diluted	0.15	0.12	0.12	0.11	0.14	0.12	0.09	0.13
Cash flow from								
operating activities	5,381	6,617	8,145	6,650	782	4,210	3,920	4,453
Total assets (end of period)	217,697	224,065	224,439	229,800	209,009	140,498	140,086	145,379
Capital expenditures, net	(357)	7,279	7,868	27,478	65,950	5,176	1,576	13,076
Weighted average basic and diluted shares (thousands)	60,936	60,934	60,934	60,934	44,132	26,534	26,534	26,576
<b>Per Unit</b>								
Oil and NGL revenue (\$ per bbl)	64.93	61.95	64.97	70.70	60.09	53.67	48.13	42.57
Natural gas revenue (\$ per mcf) <sup>(1)</sup>	4.24	4.29	4.48	5.36	5.29	4.23	4.29	5.60
Combined revenue (\$ per boe) <sup>(1)</sup>	29.43	29.01	30.32	35.52	34.47	27.85	28.03	34.53
Operating netback (\$ per boe)	22.27	21.10	21.83	25.04	26.91	19.94	18.84	20.15

<sup>(1)</sup> Includes the realized gain or loss on commodity contracts.

Open Range's steady growth in funds from operations and total assets is attributable to successful exploration and development drilling at the Corporation's Deep Basin properties, particularly the Ansell/Sundance core area, and the rental of fracturing fluid handling systems in 2010. Production growth in 2010 was primarily the result of the drilling, completion and tie-in of three horizontal wells and two vertical wells at Ansell/Sundance.

## SELECTED ANNUAL INFORMATION

	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009	Year ended Dec. 31, 2008
<b>Production</b>			
Natural gas (mcf per day)	20,606	13,293	7,733
Oil and NGL (bbls per day)	349	241	167
Total (boe per day)	3,783	2,457	1,456
Annual total (mboe)	1,381	897	531
% natural gas	91	90	89

### Consolidated Financial

(\$thousands except as noted)

Revenue <sup>(1)</sup>	47,972	28,203	23,912
Net earnings (loss)	(3,529)	(6,137)	523
Net earnings (loss) per basic and diluted share (\$)	(0.06)	(0.20)	0.03
Funds from operations	30,522	15,341	15,159
Funds from operations per basic and diluted share (\$)	0.50	0.50	0.78
Cash flow from operating activities	26,793	13,365	13,590
Total assets (end of period)	217,697	209,009	97,517
Total liabilities (end of period)	71,875	60,013	25,034
Capital expenditures, net	42,268	85,778	42,004
Weighted average basic and diluted shares (thousands)	60,935	30,980	19,403

### Per Unit

Oil and NGL revenue (\$ per bbl)	65.52	51.41	62.46
Natural gas revenue (\$ per mcf) <sup>(1)</sup>	4.58	4.88	7.13
Combined revenue (\$ per boe) <sup>(1)</sup>	30.99	31.45	45.00
Operating netback (\$ per boe)	22.58	21.83	33.63

<sup>(1)</sup> Includes the realized gain or loss on commodity contracts.

### CONTRACTUAL OBLIGATIONS <sup>(2)(3)</sup>

(thousands) As at December 31, 2010	Total	Less than 1 Year	2-3 Years	4-5 Years	More than 5 Years
Bank indebtedness <sup>(1)</sup>	\$ 51,053	\$ 51,053	–	–	–
Office lease	3,476	534	\$ 1,417	\$ 1,525	–
Office equipment leases	55	14	26	15	–
Firm natural gas transportation agreements	11,153	1,186	4,018	4,134	\$ 1,815
Total	\$ 65,737	\$ 52,787	\$ 5,461	\$ 5,674	\$ 1,815

<sup>(1)</sup> Amount is drawn against the Corporation's extendable revolving demand facility. As the facility is demand in nature amounts outstanding are classified as current liabilities, implying they are due in one year or less. Management fully expects the term of the facility to be extended.

<sup>(2)</sup> The Corporation has entered into farm-in agreements in the normal course of its business which are not included in this table.

<sup>(3)</sup> The Corporation has entered into commodity contracts which are not included in this table. For a complete listing refer to note 11, Financial Instruments, in the audited consolidated financial statements for the year ended December 31, 2010.

## **RISK FACTORS**

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

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

Open Range's principal risks are finding and developing economic hydrocarbon reserves efficiently and being able to fund the capital program. The Corporation's need for capital will be both short-term and long-term in nature. Short-term working capital will be required to finance accounts receivable, drilling deposits and other similar short-term assets, while the acquisition and development of oil and natural gas properties require large amounts of long-term capital. Open Range has budgeted a \$25.0 million capital program in the first half of 2011, of which the majority has been expended to date. The capital program will be funded through a combination of anticipated funds from operations, proceeds from the recent equity issuance and the bank credit facilities. If any components of the business plan are missing, the Corporation may not be able to execute the entire business plan.

Open Range mitigates exploration risk by employing a team of highly qualified and experienced professionals to pursue exploration and exploitation activities and to carry out and control the capital spending program. All aspects of exploration projects are reviewed at a very early stage, including: corporate fit, environmental issues, timing, costs and reward potential. Identified risks are addressed and excessive risks are mitigated to the extent possible before any project is approved.

Open Range maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution or other business interruptions. The Open Range assets are in compliance, in all material respects, with current environmental legislation and Open Range will work with government environmental agencies to maintain this level of compliance, as well as maintain a proactive approach to all safety and environmental issues.

Operational risk is mitigated by having Open Range staff address the continued development of a new or established reservoir, on a go-forward basis, using the same procedure that is used to address exploration risk. Reserves are produced based on the amount of capital employed, production practices and reservoir quality. Open Range evaluates reservoir development based on the timing and amount of additional capital required and the expected change in production volumes. Finding and development costs are controlled when capital is employed cost-effectively.

The financial risks of global credit conditions, equity availability from the capital markets, commodity prices, interest rates, royalty rates, government intervention or taxation levels in the oil and natural gas industry are largely beyond Open Range's control. The Corporation's approach to managing these risks is to maintain a prudent level of debt and to employ forecasting and budgeting projections. In addition, from time to time Open Range may use financial instruments to reduce corporate risk in certain situations. For a listing of commodity contracts entered into in 2010 refer to note 11, Financial Instruments, in the audited financial statements for the year ended December 31, 2010.

The Poseidon Concepts business unit was formed in 2010 and has a limited operating history. There is no assurance that the Poseidon Concepts business unit will be able to achieve and maintain profitable operations. The Corporation cannot be certain that its operating strategy for Poseidon Concepts will be successful. The success of Poseidon Concepts will be affected by, among other factors, the volatility in market prices for oil, NGLs and natural gas; the level of drilling activity in the western Canadian and U.S. oil and gas industries; levels of competition in the fracturing fluid storage industry; and the ability of the business unit to attract and retain clientele. Any of these factors could negatively affect the performance of the Poseidon Concepts business unit.

## **CRITICAL ACCOUNTING ESTIMATES**

### **Oil and Natural Gas Reserves**

Under National Instrument 51-101 (N.I. 51-101), proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable, i.e., that it is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. In accordance with this definition, the level of certainty targeted by the reporting corporation should result in at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated reserves. In the case of probable reserves, which are obviously less certain to be recovered than proved reserves, N.I. 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. With respect to the consideration of certainty, in order to report reserves as proved plus probable, the reporting corporation must believe that there is at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves. The implementation of N.I. 51-101 has resulted in a more rigorous and uniform standardization of reserve evaluation.

The oil and natural gas reserve 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 a change in the Corporation's plans. The effect of changes in proved oil and natural gas reserves on the financial results and position of the Corporation is described under "Depletion Expense" and "Impairment of Petroleum and Natural Gas Properties" below.

### **Financial Instruments Valuation**

The fair value of the Corporation's derivative contracts is determined using forward price curves as at the balance sheet date in combination with the remaining contracted petroleum and natural gas volumes and includes a volatility factor in the calculations. Changes in the forward price curves or volatility factor will result in a corresponding increase or decrease in the fair value of the derivative contracts.

### **Depletion Expense**

The Corporation uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether or not the activities funded were successful. The aggregate of net capitalized costs and estimated future development costs, less estimated salvage values, is amortized using the unit-of-production method based on estimated proved oil and natural gas reserves.

An increase or decrease in estimated proved oil and natural gas reserves would result in a corresponding reduction or increase in depletion expense. An increase or decrease in estimated future development costs would result in a corresponding increase or reduction in depletion expense.

### **Withheld Costs**

Certain costs related to unproved properties may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or in the ceiling test for impairment, for which any write-down would be charged to depletion and depreciation expense.

### **Impairment of Petroleum and Natural Gas Assets**

The Corporation is required to review the carrying value of all petroleum and natural gas assets for potential impairment. Impairment is indicated if the carrying value of the petroleum and natural gas assets is not recoverable by the future undiscounted funds from operations. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the property, plant and equipment is charged to earnings. The assessment of impairment is dependent on estimates of reserves, production rates, prices, future costs and other relevant assumptions.

### **Asset Retirement Obligations**

The Corporation is required to provide for future removal and site restoration costs. The Corporation must estimate these costs in accordance with existing laws, contracts or other policies. The fair value of the liability of \$1.2 million for the Corporation's asset retirement obligation is recorded in the period in which it is expected to be incurred between 2011 and 2064, discounted to its present value using the Corporation's 8-10 percent credit-adjusted, risk-free interest rate and 2 percent inflation rate. The offset to the liability is recorded in the carrying amount of petroleum and natural gas properties. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated or amount of the original estimated undiscounted cost, the estimated inflation rate or the estimated discount rate could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

### **Stock-Based Compensation**

The Corporation uses the fair value method for valuing stock option and warrant grants. The fair value of each option and warrant grant is estimated on the date of grant using the Black-Scholes option-pricing model. Stock options have the following weighted-average assumptions used for grants in 2010: zero dividend yield, average expected volatility of 70 percent, risk-free rate of 2.58 percent, and expected life of five years. The weighted-average fair value of stock options granted during the year ended December 31, 2010 was \$1.04 per option. Warrants have the following weighted-average assumptions used for grants in 2010: zero dividend yield, average expected volatility of 50 percent, risk-free rate of 2.10 percent, and expected life of five years. The weighted-average fair value of stock options granted during the year was \$0.18 per warrant. A zero dividend yield is used as the Corporation does not issue dividends. The volatility is a calculation based on trading history. The risk-free rate is from the Bank of Canada. An increase in dividends would decrease the option expense and an increase in the volatility or the risk-free rate would increase the calculated expense.

### **Legal, Environmental Remediation and Other Contingent Matters**

The Corporation is required to determine whether a loss is probable based on judgment and interpretation of laws and regulations and whether the loss can reasonably be estimated. When the loss is determined, it is charged to earnings. The Corporation's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstance.

### **Income Tax Accounting**

The determination of the Corporation's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Future tax assets and liabilities are booked using substantively enacted future income tax rates which include rate reductions over several years. The rate used by the Corporation is based on estimated reversals of temporary differences. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

## **INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)**

### **Transition Plan**

On January 1, 2011, Canadian publicly traded companies are required to adopt IFRS as their generally accepted accounting principles. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010. The transition from Canadian GAAP to IFRS is significant, with differences affecting the financial position and results of operations.

The Corporation continues its work to finalize the impact on its financial statements of the transition from Canadian GAAP to IFRS. Open Range's transition to IFRS is being implemented by an internally-staffed project team supplemented by some external consultants as required. Open Range management regularly reports its progress on its IFRS conversion to the Audit Committee of the Board of Directors. The Corporation continues to train key personnel within the accounting and finance functions as well as update its management on potential impacts and key policy choices available under IFRS.

Open Range's transition to IFRS consists of three key phases:

- Scoping and diagnostic phase – This phase involved performing a high-level impact analysis to identify areas that may be affected by the transition to IFRS including information systems, internal controls over financial reporting and disclosure controls and procedures.
- Impact analysis, quantification and evaluation phase – This phase involved analyzing policy choices allowed under IFRS and their potential impact on the Corporation's financial statements. In addition, certain potential differences were further investigated to assess whether there may be a broader impact to Open Range's management reporting systems or credit facility agreements. The conclusion of the impact analysis, quantification and evaluation phase required the Audit Committee of the Board of Directors to review and approve all accounting policy choices as proposed by management.
- Implementation phase – This phase involves implementation of all changes approved in the impact analysis phase including changes to information systems, business processes and modification of agreements, where necessary, and training of all staff who are impacted by the conversion.

Open Range has completed the scoping and diagnostic phase and is working to finalize the impact analysis, quantification and evaluation phase. The Corporation also continues to make significant progress with its implementation phase including the drafting of IFRS-compliant financial statements and the development of accounting entries that will comply with the proposed IFRS accounting policies. Management has not yet finalized the quantification of the impact of their IFRS policy choices on the Corporation's 2010 financial statements. Subsequent to the year ended December 31, 2010, the Corporation continued its work to finalize the convergence of GAAP with IFRS and this process is expected to be completed in time for the first IFRS-compliant reporting required for the period ended March 31, 2011.

### **Petroleum and Natural Gas Assets**

IFRS standards require that a corporation choose to report its petroleum and natural gas assets either at the amount which would have been recorded had the Corporation always followed current IFRS standards or at fair value on the date of adoption of IFRS. Alternatively, IFRS standards allow for a conversion exemption whereby petroleum and natural gas corporations can choose to record opening petroleum and natural gas properties at a deemed cost equal to historical cost as calculated under Canadian GAAP. Open Range has elected to record petroleum and natural gas assets at historical cost as calculated under Canadian GAAP on January 1, 2010. The Corporation, under the exemption, will allocate historic costs to cash generating units and components subject to depletion based on reserve values.

Under Canadian GAAP, all petroleum and natural gas assets are accounted for under the full cost accounting guideline. Under IFRS, petroleum and natural gas assets will be divided into exploration and evaluation properties ("exploration assets") and petroleum and natural gas properties and equipment ("development assets"). Exploration assets will initially be capitalized and accumulated pending determination of technical feasibility and economic viability. Exploration assets will not be depreciated and will be carried at cost less any accumulated impairment losses. Development assets will be measured at cost less accumulated depletion and depreciation and any accumulated impairment losses. The Corporation has determined that it has \$9.1 million of exploration assets with the balance of \$187.7 million considered to be development assets on transition to IFRS.

Both exploration assets and development assets will be assessed to determine whether impairment losses exist under IFRS as at January 1, 2010. These impairment tests will differ from the current Canadian GAAP full cost ceiling test in several significant ways. Assets will be allocated to cash generating units (CGU) and a separate impairment test will be completed for each CGU identified. Under current Canadian GAAP the ceiling test is a two-step test conducted over the single full cost pool for Open Range. The carrying value of assets is first compared to the undiscounted future cash flows. If the carrying value of the assets exceeds the undiscounted future cash flows of proved reserves, then the second step of the test is required whereby the assets are written down to the value of the discounted future cash flows of proved plus probable reserves. Under IFRS, the impairment test compares the carrying value of the assets to the greater of the fair value of the assets and the value-in-use of the assets, which is a discounted cash flow measure. Future impairment tests will be required when management determines that indicators of impairment exist. Should impairment losses be recorded in accordance with IFRS, certain of those losses can be reversed in future if facts and circumstances change. On transition, the Corporation will not recognize any impairment in its exploration or development assets.

Depreciation under Canadian GAAP is calculated using a unit-of-production method based on total proved reserves for all accumulated costs, excluding unproved properties. Under IFRS, the net carrying value of development assets will still be depleted using a unit-of-production method; however, significant components with different useful lives will be accounted for as separate items and depreciated separately. In addition, IFRS allows depreciation to be calculated using either proved reserves or proved plus probable reserves. Open Range has decided to depreciate using proved plus probable reserves which should result in a reduction to depreciation and depletion expense.

Under the full cost accounting guideline, gains or losses are not recognized upon the disposition of petroleum and natural gas assets unless the disposition results in a significant change in the depletion rate. Under IFRS, gains and losses are recognized in net income on the disposal of an item of petroleum and natural gas assets. The amount of the gain or loss is determined by comparing the proceeds from disposal with the carrying amount of the item. This will include transactions such as sales of assets, farm-outs, asset swaps and other non-monetary transactions which typically did not result in gains or losses being recorded under Canadian GAAP.

The quantitative impact to Open Range of these changes to accounting for petroleum and natural gas assets has not been determined yet for the 2010 comparative year.

### **Decommissioning Liabilities**

Under IFRS, decommissioning liabilities (referred to as “asset retirement obligations” under Canadian GAAP) are likely to increase as a result of the change from a credit-adjusted risk-free rate to a risk-free rate in the discounting of the liabilities to their present value. In addition, any change in the discount rate would affect the entire liability and not just current-period additions. The Corporation estimates the impact on transition to be \$2.1 million with a corresponding increase to the deficit as allowed for under the IFRS elective exemption.

### **Stock-Based Compensation**

IFRS standards require stock-based awards that vest in instalments, such as on anniversaries of the grant date, to be accounted for as though each instalment or vesting date were a separate award. This will result in stock-based compensation expense likely increasing in the earlier vesting periods immediately following new grants. Under IFRS, estimates of the number of stock-based awards expected to vest or expected to be forfeited prior to their expiry will also have a quantitative impact on the amount of stock-based compensation expense recorded over the vesting period. Canadian GAAP allowed for forfeitures to be recognized as they occurred.

### **Income Taxes**

Canadian GAAP and IFRS follow the liability method of accounting for income taxes whereby tax liabilities and assets are recognized on temporary differences. The Corporation's future income tax liability will be affected by the tax effects resulting from the IFRS changes discussed in this section. The tax effect resulting from the IFRS changes have not yet been finalized. In addition, while Canadian GAAP separated future income taxes between current and non-current, IFRS allows only for the presentation of non-current future income tax assets and liabilities.

IFRS also differs in the measurement of flow-through shares issued by the Corporation, with the premium initially set-up as a liability when the flow-through common shares are issued and then released through earnings subsequently when the tax impact is recorded on renouncement. The Corporation estimates this change to result in a deferred liability of \$1.4 million being recognized on transition, an increase to share capital of \$1.6 million with the offsetting \$3.0 million recognized against the deficit.

### **DISCLOSURE CONTROLS AND PROCEDURES**

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Corporation is accumulated and communicated to the Corporation's management as appropriate to allow timely decisions regarding required disclosure. The Corporation's Chief Executive Officer (CEO) and Chief Financial Officer (CFO) concluded based on their evaluation as at December 31, 2010 that disclosure controls and procedures were effective, with the exception of the weaknesses in the internal controls over financial reporting noted in the following section, to provide reasonable assurance that material information related to the Corporation is made known to them by others within the Corporation. It should be noted that while the Corporation's CEO and CFO believe that disclosure controls and procedures provide a reasonable level of assurance and are effective, they do not expect that the disclosure controls and procedures would prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

### **FINANCIAL REPORTING**

Open Range's CEO and CFO are responsible for designing internal controls over financial reporting, or causing them to be designed under their supervision, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Such officers of the Corporation are also responsible for evaluating, or causing to be evaluated under their supervision, the operating effectiveness of Open Range's internal controls over financial reporting at the financial year-end of the Corporation.

The Corporation evaluated the design and operating effectiveness of its internal controls over financial reporting as at December 31, 2010. During this evaluation the Corporation identified weaknesses due to the limited number of finance and accounting personnel at the Corporation dealing with complex and non-routine accounting transactions that may arise. Notwithstanding the weaknesses identified with regards to complex and non-routine accounting matters, the Corporation concluded that all other of its internal controls over financial reporting have been designed and are operating effectively at December 31, 2010.

No material changes in the Corporation's internal controls over financial reporting, including identified weaknesses, were identified during the year ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, the Corporation's internal financial reporting processes.

As a result of the weaknesses identified in the Corporation'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 transactions of the Corporation. In addition, the Audit Committee reviews on a quarterly basis the financial statements and key risks of the Corporation and queries management about significant transactions, the Corporation's auditors conduct a quarterly review of the financial statements of the Corporation, and senior management of the Corporation perform daily oversight of the accounting records.

#### **ADDITIONAL INFORMATION**

Additional information relating to Open Range, including the Annual Information Form (AIF), is available on SEDAR at [www.sedar.com](http://www.sedar.com) or the Corporation's website at [www.openrangeenergy.com](http://www.openrangeenergy.com).

# MANAGEMENT'S REPORT

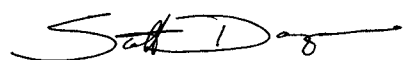
Management is responsible for the integrity and objectivity of the information contained in the accompanying financial statements, management's discussion and analysis and message to shareholders (collectively, the "annual release") and for the consistency between the consolidated financial statements and other financial and operating data contained in the other sections described. In the preparation of these statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgments and have been properly reflected with all information available up to March 22, 2011. The consolidated financial statements have been prepared using policies and procedures established by management in accordance with Canadian generally accepted accounting principles and reflect fairly Open Range's financial position, results of operations and cash flow.

Management has established and maintains a system of internal controls which are designed to ensure that financial information is relevant, reliable and accurate and to provide assurance that assets are safeguarded from loss or unauthorized use and transactions are executed in accordance with management's authorization.

KPMG LLP, independent auditors appointed by the shareholders, have examined the consolidated financial statements and GLJ Petroleum Consultants Ltd. has evaluated the corporate reserves. Their examinations provide independent views as to the amounts and disclosures in the financial statements.

The Audit Committee of the Corporation's Board of Directors, consisting exclusively of independent directors, has reviewed in detail the consolidated financial statements with management and the external auditors and has recommended their approval to the Board of Directors.

The Board of Directors has approved the consolidated financial statements and information as presented in this annual release.



A. Scott Dawson  
President and Chief Executive Officer



Lyle D. Michaluk  
Vice-President, Finance and Chief Financial Officer

March 22, 2011

# INDEPENDENT AUDITORS' REPORT

## **To the Shareholders of Open Range Energy Corp.**

We have audited the accompanying consolidated financial statements of Open Range Energy Corp., which comprise the consolidated balance sheets as at December 31, 2010 and 2009, the consolidated statements of operations, comprehensive loss and deficit 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 Canadian generally accepted accounting principles, 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 financial position of Open Range Energy Corp. as at December 31, 2010 and 2009, and the results of its consolidated operations and its consolidated cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

**KPMG LLP**

Chartered Accountants  
Calgary, Canada  
March 22, 2011

# CONSOLIDATED BALANCE SHEETS

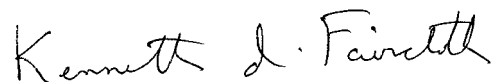
December 31 (thousands)	2010	2009
<b>ASSETS</b>		
Current assets:		
Accounts receivable	\$ 9,668	\$ 10,501
Prepaid expenses and deposits	2,291	1,575
Fair value of commodity contracts (note 11)	213	–
Future income taxes (note 7)	–	126
	<b>12,172</b>	<b>12,202</b>
Property, plant and equipment (note 4)	<b>205,525</b>	<b>196,807</b>
	<b>\$ 217,697</b>	<b>\$ 209,009</b>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
Current liabilities:		
Bank indebtedness (note 5)	\$ 51,053	\$ 40,065
Accounts payable and accrued liabilities	10,726	9,582
Fair value of commodity contracts (note 11)	–	434
Future income taxes (note 7)	56	–
	<b>61,835</b>	<b>50,081</b>
Fair value of commodity contracts (note 11)	902	–
Future income taxes (note 7)	7,920	6,746
Asset retirement obligations (note 6)	1,218	3,186
Shareholders' equity:		
Share capital (note 8)	144,940	146,678
Contributed surplus (note 8)	8,027	5,934
Deficit	(7,145)	(3,616)
	<b>145,822</b>	<b>148,996</b>
Commitments (note 10)		
Subsequent event (note 14)		
	<b>\$ 217,697</b>	<b>\$ 209,009</b>

See accompanying notes to financial statements.

Approved on behalf of the Board:



Dean Jensen  
Director



Ken Faircloth  
Director

# CONSOLIDATED STATEMENTS OF OPERATIONS, COMPREHENSIVE LOSS AND DEFICIT

Years ended December 31 (thousands, except per share amounts)	2010	2009
<b>Revenues:</b>		
Petroleum and natural gas	\$ 40,700	\$ 25,458
Royalties	(3,833)	(2,763)
Fracturing fluid tank rentals	5,171	–
Realized gain on commodity contracts (note 11)	2,101	2,745
Unrealized loss on commodity contracts (note 11)	(255)	(802)
Interest	69	3
	<b>43,953</b>	<b>24,641</b>
<b>Expenses:</b>		
Operating	8,357	5,868
General and administrative	3,351	2,774
Bad debts (note 11)	–	258
Stock-based compensation	1,024	552
Interest	1,978	1,202
Depletion and depreciation	33,309	21,839
Accretion of asset retirement obligations	191	178
	<b>48,210</b>	<b>32,671</b>
Loss before income taxes	(4,257)	(8,030)
Future income tax reduction (note 7)	728	1,893
Net loss and comprehensive loss	(3,529)	(6,137)
Retained earnings (deficit), beginning of year	(3,616)	2,521
Deficit, end of year	\$ (7,145)	\$ (3,616)
<b>Loss per share (note 8):</b>		
Basic	\$ (0.06)	\$ (0.20)
Diluted	\$ (0.06)	\$ (0.20)

See accompanying notes to financial statements.

# CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31 (thousands)	2010	2009
Cash provided by (used in):		
Operating:		
Net loss	\$ (3,529)	\$ (6,137)
Items not involving cash:		
Depletion and depreciation	33,309	21,839
Accretion of asset retirement obligations	191	178
Future income tax reduction	(728)	(1,893)
Stock-based compensation	1,024	552
Unrealized loss on commodity contracts	255	802
Asset retirement expenditures	(515)	(475)
Change in non-cash working capital	(3,214)	(1,501)
	<b>26,793</b>	<b>13,365</b>
Financing:		
Bank indebtedness	10,988	8,646
Issuance of common shares, net of costs	12	61,281
Repurchase of common shares	–	(54)
	<b>11,000</b>	<b>69,873</b>
Investing:		
Acquisition of property, plant and equipment	(53,663)	(27,262)
Acquisition of properties	–	(58,516)
Disposition of properties	11,395	–
Change in non-cash working capital	4,475	2,540
	<b>(37,793)</b>	<b>(83,238)</b>
Change in cash	–	–
Cash, beginning of year	–	–
Cash, end of year	\$ –	\$ –
Interest received	\$ 69	\$ 3
Interest paid	\$ 1,978	\$ 1,304

Cash is defined as cash and cash equivalents.

See accompanying notes to financial statements.

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

## YEARS ENDED DECEMBER 31, 2010 AND 2009

(all amounts in text and tabular format are stated in thousands, except per share amounts and other exceptions as noted)

### 1. NATURE OF BUSINESS

Open Range Energy Corp. (“Open Range” or the “Corporation”) is organized under the laws of the province of Alberta. The Corporation is engaged in the acquisition of, exploration for and development of oil and natural gas in the Western Canada Sedimentary Basin. The Corporation also rents fracturing fluid handling tanks primarily used in well completion operations in the oil and natural gas industry.

### 2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Corporation have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). The preparation of these consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the statements and accompanying notes. As a result, actual amounts could differ from estimated amounts.

Specifically, the amounts recorded for depletion and depreciation of petroleum and natural gas properties and fracturing tanks and the provision for asset retirement obligations and abandonment costs are based on estimates. The ceiling test is based on estimates of reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. The amounts for stock-based compensation are based on estimates of risk-free interest rates, expected lives and volatility. The fair-value estimates for derivatives are based on expected future petroleum and natural gas prices and volatility in those prices. Future income taxes are based on estimates as to the timing of the reversal of temporary differences and tax rates currently substantively enacted. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

#### (A) Principles of Consolidation

The consolidated financial statements include the accounts of the Corporation and its wholly owned subsidiaries Poseidon Concepts Corp. and Poseidon Concepts Inc., and a partnership, Poseidon Concepts Limited Partnership. All inter-entity balances and transactions have been eliminated.

#### (B) Property, Plant and Equipment

The Corporation’s activities are primarily related to the acquisition of, exploration for and development of petroleum and natural gas properties. The Corporation follows the full cost method of accounting for petroleum and natural gas operations.

All costs of exploring for and developing petroleum and natural gas properties and related reserves are capitalized into a cost centre. Such costs include those related to lease acquisition, geological and geophysical activities, lease rentals on non-producing properties, drilling of productive and non-productive wells, tangible production equipment, asset retirement costs, and that portion of general and administrative expenses directly attributable to exploration and development activities. Proceeds received from the disposal of properties are normally deducted from the full cost pool without recognition of a gain or loss. When a significant portion of properties is sold, resulting in a change to the depletion rate of 20 percent or more, a gain or loss is recorded and reflected in the statement of operations.

Depletion of petroleum and natural gas properties and depreciation of production equipment, excluding costs related to unproved properties, are calculated using the unit-of-production method based upon estimated proved reserves, before royalties, as determined by independent petroleum engineers. For purposes of the calculation, natural gas reserves and production are converted to equivalent volumes of petroleum based upon relative energy content.

Costs of acquiring unproved properties are initially excluded from the full cost pool and are assessed at each reporting period to ascertain whether impairment has occurred. When proved reserves are assigned to the property or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the full cost pool.

Petroleum and natural gas properties are evaluated in each reporting period through a ceiling test to determine whether the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

The carrying amounts are assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount of the cost centre. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects of the cost centre. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

Other assets, including fracturing fluid tanks, are recorded at cost and depreciated on a declining-balance basis using the following annual rates:

Computer hardware	30 percent
Office furniture and fixtures	20 percent
Other assets	20 percent

The other assets, including fracturing fluid tanks, are assessed for impairment periodically. When an indication of impairment is present, the Corporation tests for impairment by comparing the carrying value of the asset to its net recoverable amount. If the carrying amount is greater than the net recoverable amount, the asset is written down to its estimated fair value.

**(C) Interests in Joint Operations**

A portion of the Corporation's exploration and development activities is conducted jointly with others and, accordingly, the financial statements reflect only the Corporation's proportionate interest in such activities.

**(D) Cash and Cash Equivalents**

Cash and cash equivalents are comprised of cash and all investments that are highly liquid in nature and generally mature in three months or less.

**(E) Asset Retirement Obligations**

The Corporation uses the asset retirement obligation method of recording the future cost associated with removal, site restoration and asset retirement costs. The fair value of the liability for the Corporation's asset retirement obligation is recorded in the period in which it is incurred, is discounted to its present value using the Corporation's credit-adjusted, risk-free interest rate, and the corresponding amount is recognized by increasing the carrying amount of petroleum and natural gas properties. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

**(F) Financial Instruments**

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Upon initial recognition all financial instruments, including all derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then based on the financial instruments being classified into one of five categories: held-for-trading, held-to-maturity, loans and receivables, available-for-sale and other liabilities. The Corporation has designated its cash and cash equivalents as held-for-trading, which are measured at fair value. Accounts receivable are classified as loans and receivables, which are measured at amortized cost. Accounts payable and accrued liabilities and bank debt are classified as other liabilities, which are measured at amortized cost, which is determined using the effective interest rate method.

For each reporting period the Corporation will assess whether a financial asset is impaired with any impairment recorded in earnings.

The Corporation uses risk management contracts from time to time to manage its exposure to fluctuations in commodity prices. The Corporation does not enter into risk management contracts for trading or speculative purposes.

The risk management contracts are executed within the guidelines of the Corporation's risk management procedures. The contracts, when deemed appropriate, are entered into with commodities trading institutions and may include costless collars, put or call options or fixed-price contracts. The Corporation has elected not to designate any of its risk management activities as accounting hedges and, accordingly, accounts for all derivatives using the fair value method. Under this method, gains and losses resulting from changes in the fair value of the unrealized portion of such risk management contracts are recognized in earnings when those changes occur. The fair value is based on an estimate of the amounts that would have been paid to or received from counter-parties to settle these instruments given future market prices and other relevant factors. Proceeds and costs realized from holding the contracts are recognized in earnings at the time that each transaction under a contract is settled.

The Corporation has elected to account for its physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items, in accordance with its expected purchase, sale or usage requirements as executory contracts on an accrual basis rather than as non-financial derivatives.

The Corporation measures and recognizes embedded derivatives separately from the host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when the embedded derivative meets the definition of a derivative and when the entire contract is not measured at fair value. Embedded derivatives are recorded at fair value.

The Corporation nets all transaction costs incurred, in relation to the acquisition of a financial asset or liability, against the related financial asset or liability. Bank debt is presented net of deferred interest payments, with interest recognized in net earnings on an effective interest rate basis.

The Corporation applies trade-date accounting for the recognition of a purchase or sale of cash equivalents and derivative contracts.

#### **(G) Future Income Taxes**

The Corporation uses the asset and liability method for calculating future income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and the carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using the currently enacted, or substantively enacted, tax rates anticipated to apply in the periods that the temporary differences are expected to reverse. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

#### **(H) Flow-Through Shares**

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. The future tax liability and share capital are adjusted by the estimated cost of the renounced tax deductions when the expenditures are renounced.

**(I) Stock-Based Compensation Plans**

The Corporation uses the fair value method for valuing stock option and performance warrant grants. Under this method, compensation cost attributable to all share options and performance warrants granted is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the stock options or performance warrants, consideration received together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

**(J) Revenue Recognition**

Petroleum and natural gas revenues are recognized when the title and risks pass to the purchaser and collection is reasonably assured.

Fracturing fluid tank rental revenues are generally derived from the provision of rentals and related services which are based on contracts that include fixed or determinable prices based upon daily rates. Revenue is recognized when tank rentals and related services are provided and only when collectability is reasonably assured.

**(K) Per Share Amounts**

Basic per share information is computed by dividing income by the weighted average number of common shares outstanding for the period. The treasury stock method is used to determine the diluted per share amounts, whereby any proceeds from the stock options, warrants or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

**(L) Comparative Figures**

Certain comparative figures have been reclassified to conform to the current year's presentation.

**3. FUTURE CHANGES IN ACCOUNTING POLICIES**

**International Financial Reporting Standards**

On January 1, 2011, International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board will become the generally accepted accounting principles in Canada. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010. The transition from Canadian GAAP to IFRS is significant with differences affecting the financial position and results of operations. Subsequent to the year ended December 31, 2010, the Corporation continued its work to finalize the impact on its financial statements of the convergence of GAAP with IFRS and this process was expected to be completed in time for the first IFRS-compliant reporting required for the period ended March 31, 2011.

#### 4. PROPERTY, PLANT AND EQUIPMENT

December 31,	2010	2009
Petroleum and natural gas assets and related equipment	\$ 298,244	\$ 256,245
Other assets	2,464	2,436
	<b>300,708</b>	258,681
Accumulated depletion and depreciation	<b>(95,183)</b>	(61,874)
Net book value	<b>\$ 205,525</b>	\$ 196,807

During 2010 the Corporation capitalized \$3,818 (2009 – \$3,225) of overhead-related costs to petroleum and natural gas properties, of which \$1,069 (2009 – \$532) related to stock-based compensation. The future tax liability of \$334 (2009 – \$177) associated with the capitalized stock-based compensation was also capitalized.

Costs associated with unproved properties, including undeveloped land and seismic, and salvage value excluded from costs subject to depletion at December 31, 2010 totalled \$23,033 (2009 – \$32,903). Future development costs of proved reserves of \$106,199 at December 31, 2010 (2009 – \$69,155) have been included in the depletion calculation.

During 2010 the Corporation disposed of certain interests in petroleum and natural gas properties for cash proceeds of \$11,395, with associated asset retirement obligations of \$2,156 also eliminated.

On November 16, 2009 the Corporation acquired certain working interests in petroleum and natural gas properties for cash consideration of \$58,516 and recognized \$519 in associated asset retirement obligations.

The Corporation performed a ceiling test calculation at December 31, 2010 to assess the recoverable value of the petroleum and natural gas assets. As at December 31, 2010 there was no impairment required. For purposes of the ceiling test calculation, the Corporation used the January 1, 2011 commodity price forecast of its independent reserve evaluators. The following table summarizes the benchmark prices used in the calculation:

	Currency exchange rate (US\$/Cdn\$)	W.T.I. crude oil (\$US/bbl)	Edmonton Par crude oil (Cdn\$/bbl)	Open Range NGL price (Cdn\$/bbl)	AECO natural gas (Cdn\$/mcf)	Open Range natural gas price (Cdn\$/mcf)
2011	\$ 0.980	\$ 88.00	\$ 86.22	\$ 68.59	\$ 4.16	\$ 4.45
2012	0.980	89.00	89.29	70.69	4.74	5.08
2013	0.980	90.00	90.92	71.94	5.31	5.68
2014	0.980	92.00	92.96	73.90	5.77	6.17
2015	0.980	95.17	96.19	76.81	6.22	6.66
2016	0.980	97.55	98.62	79.00	6.53	6.99
2017	0.980	100.26	101.39	81.47	6.76	7.23
2018	0.980	102.74	103.92	83.73	6.90	7.39
2019	0.980	105.45	106.68	86.21	7.06	7.55
2020	0.980	107.56	108.84	88.13	7.21	7.72
2021 and thereafter	\$ 0.980	+2.0%/yr	+2.0%/yr	\$ 90.08	+2.0%/yr	\$ 7.87

## 5. BANK DEBT

The Corporation has available a \$70,000 extendable revolving credit facility and a \$10,000 non-revolving acquisition/development demand facility as at December 31, 2010. These facilities are with a syndicate of Canadian chartered banks. The interest rate on the extendable revolving credit facility is calculated using the syndicate's prime rate plus an applicable facility margin based on the Corporation's net debt to cash flow ratio for the previous trailing calendar quarter. The interest rate on the non-revolving facility is calculated using the syndicate's prime rate plus 50 basis points above the applicable facility margin based on the Corporation's net debt to cash flow ratio for the previous trailing calendar quarter. The credit facilities are secured by a first fixed and floating charge debenture in the minimum face amount of \$150,000 and a general security agreement. Pursuant to the terms of the credit facilities, the Corporation has provided the covenant that at all times its working capital ratio shall be not less than 1 to 1. The working capital ratio is defined under the terms of the facilities as current assets, including the undrawn portion of the revolving credit facility, to current liabilities, excluding any current bank indebtedness. The Corporation is in compliance with this covenant as at December 31, 2010. The facilities are open for review semi-annually with the next review occurring in April 2011. As the available lending limits of the facilities are based on the bank's interpretation of the Corporation's reserves and future commodity prices there can be no assurance as to the amount of available facilities that will be determined at each scheduled review.

As at December 31, 2010, \$51,053 (2009 – \$40,065) has been drawn against the revolving credit facility. Letters of credit totalling \$770 are held against this facility. As at December 31, 2010, no amount (2009 – \$nil) has been drawn against the non-revolving demand facility. The revolving facility had an effective interest rate of 4.5 percent at December 31, 2010 (2009 – 4.75 percent).

## 6. ASSET RETIREMENT OBLIGATIONS

The Corporation's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Corporation estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations at December 31, 2010 to be approximately \$6,477 (2009 – \$10,640), to be incurred between 2011 and 2050. The majority of the costs will be incurred between 2020 and 2040. A credit-adjusted, risk-free rate of 8-10 percent (2009 – 8-10 percent) was used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	2010	2009
Balance, beginning of year	\$ 3,186	\$ 2,475
Liabilities incurred	115	21
Change in estimates	397	468
Liabilities related to property acquisitions (note 4)	–	519
Liabilities related to property dispositions (note 4)	(2,156)	–
Liabilities settled	(515)	(475)
Accretion expense	191	178
Balance, end of year	\$ 1,218	\$ 3,186

## 7. INCOME TAXES

The difference between the expected tax provision obtained by applying the combined federal and provincial income tax rate for 2010 of 28 percent (2009 – 29 percent) to the loss before income taxes and the reported income tax provision is summarized below:

Years ended December 31,	2010	2009
Loss before income taxes	\$ (4,257)	\$ (8,030)
Statutory tax rate	28%	29%
Computed income tax reduction at the statutory tax rate	\$ (1,192)	\$ (2,329)
Increase in taxes resulting from:		
Non-deductible expenses	16	9
Stock-based compensation	287	160
Future tax rate changes and other	161	267
Future income tax reduction	\$ (728)	\$ (1,893)

The components of the net future income tax liability are as follows:

December 31,	2010	2009
Future tax assets:		
Asset retirement obligations	\$ 308	\$ 808
Share issuance costs	788	1,231
Fair value of commodity contracts	183	126
	1,279	2,165
Future tax liabilities:		
Property, plant and equipment	(9,255)	(8,785)
Future income tax liability	\$ (7,976)	\$ (6,620)

No taxes were paid during the years ended December 31, 2010 or 2009.

## 8. SHARE CAPITAL

### (A) Authorized

The authorized share capital consists of an unlimited number of common shares without par value and an unlimited number of first preferred shares.

### (B) Common Shares Issued and Outstanding

	Number of Shares	Amount
Balance, December 31, 2008	26,601	\$ 87,630
Issued pursuant to flow-through share offerings	3,050	7,015
Issued pursuant to common share offerings	31,350	57,997
Share issuance costs (net of tax of \$986)	–	(2,745)
Share repurchases	(67)	(219)
Tax effect of flow-through shares issued in 2008	–	(3,000)
Balance, December 31, 2009	60,934	\$ 146,678
Issued pursuant to private placement	15	24
Share issuance costs (net of tax of \$4)	–	(8)
Tax effect of flow-through shares issued in 2009	–	(1,754)
Balance, December 31, 2010	60,949	\$ 144,940

On October 23, 2008 the Corporation received regulatory approval under Canadian securities laws to purchase common shares under a Normal Course Issuer Bid (the “Bid”) which commenced on October 28, 2008 and ended on October 27, 2009. Pursuant to the Bid, Open Range was entitled to purchase for cancellation, from time to time, up to a maximum of 1,367 common shares. As of December 31, 2009 the Corporation had purchased and cancelled 800 common shares under the Bid for total consideration of \$1,172. The excess of the average book value over the market price totalling \$1,462 is recorded as contributed surplus as of December 31, 2009.

On November 4, 2009, following filing and obtaining receipt for its short-form prospectus, the Corporation issued 3,050 flow-through common shares upon the deemed exercise of an equivalent number of flow-through special warrants that were previously issued at a price of \$2.30 per special warrant for gross proceeds of \$7,015. Certain officers and directors of Open Range purchased 26 flow-through special warrants for total gross proceeds of \$60 from this issuance.

On November 16, 2009, following regulatory and shareholder approvals, the Corporation issued 31,350 common shares upon the deemed exercise of an equivalent number of subscription receipts that were previously issued at a price of \$1.85 per subscription receipt for gross proceeds of \$57,997. Certain officers and directors of Open Range purchased 56 subscription receipts for total gross proceeds of \$104 from this issuance.

During 2010 Open Range closed a private placement common share issuance for a total of 15 common shares with a new employee of the Corporation for gross proceeds of \$24.

### (C) Share Option and Warrant Plans

Under the Corporation's share option plan it may grant options to its employees for up to 6,095 shares, of which 6,087 had been granted as at December 31, 2010 (2009 – 5,793). The exercise price of each option equals the market price of the Corporation's stock on the date of grant. Options have terms of five years and vest as to one-third on each of the first, second and third anniversaries of the grant date.

	2010		2009	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Granted and outstanding, beginning of year	5,793	\$ 2.92	2,632	\$ 4.33
Granted	1,416	1.79	3,455	1.97
Forfeited	(117)	2.24	(294)	4.44
Cancelled	(222)	3.42	–	–
Expired	(783)	4.61	–	–
Granted and outstanding, end of year	6,087	\$ 2.43	5,793	\$ 2.92
Exercisable at year-end	2,318	\$ 3.03	1,786	\$ 4.19

The following table summarizes information about the fixed stock options outstanding at December 31, 2010:

Range of exercise prices	Options Outstanding			Options Exercisable	
	Number outstanding	Weighted average exercise price	Weighted average contractual life (years)	Number exercisable	Weighted average exercise price
\$ 1.44 – \$ 2.69	4,664	\$ 1.92	4.2	1,099	\$ 1.98
\$ 2.70 – \$ 3.95	714	3.35	1.2	669	3.33
\$ 3.96 – \$ 5.20	709	4.88	1.7	550	4.78
\$ 1.44 – \$ 5.20	6,087	\$ 2.43	3.5	2,318	\$ 3.03

On November 8, 2010, the Corporation implemented a performance warrant plan relating to one of its wholly owned subsidiaries. Under the performance warrant plan the Corporation granted 575 performance warrants to employees, officers and directors with exercise prices ranging from \$1.00-\$12.50. Performance warrants have terms of five years and vest as to one-third on each of the first, second and third anniversaries of the grant date. Performance warrants are exercisable into units of the subsidiary. As at December 31, 2010, 575 performance warrants are outstanding with none exercisable.

### (D) Stock-Based Compensation

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used for grants in the year ended December 31, 2010: zero dividend yield, average expected volatility of 67 percent (2009 – 71 percent), average risk-free interest rate of 2.58 percent (2009 – 2.58 percent), and expected life of five years (2009 – five years). The average fair value of stock options granted during the year was \$1.04 (2009 – \$1.18) per option.

The fair value of each performance warrant is estimated on the date of grant using the Black Scholes option-pricing model with the following assumptions used for the grant in the year ended December 31, 2010: zero dividend yield, average expected volatility of 50 percent, average risk-free interest rate of 2.10 percent, and expected life of five years. The average fair value of the performance warrants granted during the year was \$0.18 per performance warrant.

The Corporation has not re-priced any stock options or performance warrants. The Corporation has not incorporated an estimated forfeiture rate for stock options and performance warrants that will not vest; rather, the Corporation accounts for actual forfeitures as they occur.

**(E) Contributed Surplus**

Balance, December 31, 2008	\$	4,685
Stock-based compensation expense		1,084
Excess of book value over market value on share repurchases		165
<hr/>		
Balance, December 31, 2009	\$	5,934
Stock-based compensation expense		2,093
<hr/>		
Balance, December 31, 2010	\$	8,027
<hr/>		

**(F) Per Share Amounts**

Per share amounts have been calculated using the weighted average number of shares outstanding. The following table summarizes basic and diluted common shares outstanding:

	2010	2009
Weighted average basic and diluted common shares outstanding	<b>60,935</b>	30,980

Options to purchase 6,087 common shares for the year ended December 31, 2010 (2009 – 5,793) were not included in the computation because they were anti-dilutive.

**9. CAPITAL MANAGEMENT**

The Corporation’s objectives in managing its capital are: maintain financial flexibility so as to preserve the ability to meet its financial obligations, and finance its growth, which may include accessing capital markets and credit facilities to fund the drilling of exploration and development wells as well as potential property or corporate acquisitions.

The Corporation manages its capital structure and adjusts it as a result of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Corporation considers its capital structure to include shareholders’ equity, bank debt and working capital, which are shown in the table below. In order to maintain or adjust the capital structure, the Corporation may from time to time issue shares, dispose of non-core properties and adjust its capital spending to manage current and forecast debt levels.

December 31,	2010	2009
Shareholders' equity	\$ 145,822	\$ 148,996
Bank debt	51,053	40,065
Working capital excluding bank debt	\$ 1,390	\$ 2,186

The Corporation manages its capital and financing requirements using the non-GAAP financial metric of net debt to annualized funds from operations ratio. This ratio is calculated as net debt, defined as outstanding bank debt plus or minus working capital and excluding the fair value of commodity contracts and the current portion of future income taxes, divided by annualized funds from operations, defined as the most recent calendar quarter's cash flow from operating activities, before the change in non-cash working capital and asset retirement expenditures incurred, multiplied by four. The Corporation's strategy is to maintain a ratio of no more than 2 to 1. This ratio may increase at certain times as a result of acquisitions. This ratio is calculated as follows:

December 31,	2010	2009
Current liabilities, excluding fair value of commodity contracts and future income taxes	\$ 61,779	\$ 49,647
Current assets, excluding fair value of commodity contracts and future income taxes	(11,959)	(12,076)
Net debt	49,820	37,571
Quarterly cash flow from operating activities	5,381	781
Change in non-cash working capital	3,775	5,161
Asset retirement expenditures	137	301
Quarterly funds from operations	9,293	6,243
Annualized funds from operations	\$ 37,172	\$ 24,972
Net debt to annualized funds from operations ratio	1.3:1	1.5:1

As at December 31, 2010 and 2009, the Corporation's ratio of net debt to annualized funds from operations was within the targeted range established by the Corporation. The decrease in the ratio from December 31, 2009 to December 31, 2010 is primarily due to increased cash flow from operations driven by increased revenues due to increased production volumes and fracturing fluid tank rental revenues.

The Corporation's share capital is not subject to external restrictions; however, the bank debt facilities are based on petroleum and natural gas reserves (see note 5) and the Corporation is required to meet certain financial covenants to maintain the facilities. The Corporation has not paid or declared any dividends since the date of incorporation.

There were no changes in the Corporation's approach to capital management during the year.

## 10. COMMITMENTS

### (A) Future Payments

In the normal course of business, the Corporation is obligated to make future payments. These obligations represent contracts and other commitments that are known to the Corporation as at December 31, 2010:

	Total	2011	2012	2013	2014	2015	Thereafter
Payments for office lease	\$ 3,476	\$ 534	\$ 621	\$ 796	\$ 796	\$ 729	\$ -
Payments for office equipment leases	55	14	13	13	12	3	-
Firm natural gas transportation agreements	11,153	1,186	1,837	2,181	2,349	1,785	1,815
Total	\$ 14,684	\$ 1,734	\$ 2,471	\$ 2,990	\$ 3,157	\$ 2,517	\$ 1,815

## 11. FINANCIAL INSTRUMENTS

The Corporation has exposure to the following risks from its use of financial instruments: credit risk, liquidity risk, and market risk.

This note presents information about the Corporation's exposure to each of the above risks and the Corporation's objectives, policies and processes for measuring and managing risk. Further qualitative disclosures are included throughout these notes to financial statements.

### (A) Credit Risk

Credit risk is the risk of financial loss to the Corporation if a customer or counter-party to a financial instrument fails to meet its contractual obligations, and arises principally from the Corporation's receivables from purchasers of the Corporation's natural gas, crude oil and natural gas liquids, joint venture partners, and from customers of the Corporation's fracturing fluid handling tank rental business. As at December 31, 2010 the Corporation's receivables consisted of \$433 (2009 - \$3,173) from joint venture partners, \$4,029 (2009 - \$5,296) from purchasers of the Corporation's natural gas, crude oil and natural gas liquids, \$4,403 (2009 - \$nil) from customers of the Corporation's fracturing fluid handling tank rental business, and \$803 (2009 - \$2,032) of other trade receivables.

Receivables from purchasers of the Corporation's natural gas, crude oil and natural gas liquids are normally collected on the 25th day of the month following production. The Corporation's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers.

Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Corporation attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to commencement of the joint venture project. However, the receivables are from participants in the petroleum and natural gas sector, and collection of amounts outstanding is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venture partners as disagreements occasionally arise that increase the potential for non-collection. The Corporation does not typically obtain collateral from joint venture partners; however, the Corporation has the ability to withhold production from joint venture partners in the event of non-payment.

Collection of receivables from customers of the Corporation's fracturing fluid tank rental business is dependent on a number of industry-related and customer-specific factors. Industry-related factors that may affect collection include commodity prices and access to capital. Customer-specific factors that may affect collection include commodity prices, the success of drilling programs and access to capital. At December 31, 2010, the Corporation did not have significant exposure to any individual customer of its fracturing fluid tank rental business.

Cash and cash equivalents, when outstanding, consist of cash bank balances and short-term deposits maturing in less than 90 days. The Corporation manages the credit risk exposure related to short-term investments by selecting counter-parties based on credit ratings and monitoring all investments to ensure a stable return, and also by avoiding complex investment vehicles with higher risk such as asset-backed commercial paper.

Derivative assets, when outstanding, consist of commodity contracts used to manage the Corporation's exposure to fluctuations in commodity prices. The Corporation manages the credit risk exposure related to derivative assets by selecting counter-parties based on credit ratings and financial stability.

The carrying amount of accounts receivable, cash and cash equivalents, when outstanding, and the fair value of commodity contracts, when outstanding, represent the maximum credit exposure. No uncollectible amounts were written off in the year ended December 31, 2010 (2009 – \$94).

As at December 31, 2010 and 2009 the Corporation considers its receivables to be aged as follows:

	2010	2009
Not past due (less than 120 days)	\$ 9,659	\$ 10,494
Past due (over 120 days)	9	7
<b>Total</b>	<b>\$ 9,668</b>	<b>\$ 10,501</b>

## (B) LIQUIDITY RISK

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they are due. The Corporation utilizes prudent cash and debt management to mitigate the likelihood of encountering difficulties in meeting its financial obligations. As disclosed in note 9, the Corporation targets a net debt to annualized funds from operations ratio of no more than 2 to 1 to manage its overall liquidity risk.

The Corporation prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Corporation utilizes authorizations for expenditures on operated and non-operated projects to further manage capital expenditures. To facilitate the capital expenditure program, the Corporation has a revolving reserve-based credit facility, disclosed in note 5, that is reviewed semi-annually by the lender. The Corporation also attempts to match its payment cycle with collection of petroleum and natural gas revenues on the 25th day of each month.

The following are the contractual maturities of financial liabilities as at December 31, 2010:

Financial Liability	Less than 1 year	1 to 2 years	Total
Accounts payable and accrued liabilities	\$ 10,726	\$ –	\$ 10,726
Commodity contracts	–	902	902
Bank indebtedness – principal only <sup>(1)</sup>	\$ 51,053	\$ –	\$ 51,053

<sup>(1)</sup> Amount is drawn against the Corporation's extendable revolving demand facility. As the facility is demand in nature, amounts outstanding are classified as current liabilities, implying they are due in one year or less. Management fully expects the term of the facility to be extended.

## (C) Market Risk

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

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by the relationship between the Canadian and United States dollars and by continental and worldwide economic events and natural phenomena such as the weather, all of which influence the levels of supply and demand. The Corporation utilizes commodity contracts as a risk management technique to mitigate exposure to commodity price volatility. Because the large majority of the Corporation's production is natural gas, plus the associated natural gas liquids, the majority of the Corporation's current commodity contracts are for natural gas.

The following tables indicate the fair value of natural gas and crude oil hedging contracts outstanding as at December 31, 2010 and indicate the unrealized gains or losses and realized gains on natural gas and crude oil contracts for the year then ended:

Period	Volume (GJ/d)	Type of contract	Average AECO Spot floor (Cdn\$/GJ)	Average AECO Spot ceiling (Cdn\$/GJ)	Fair value of contract as at Dec. 31, 2010	Unrealized gain (loss) for the year ended Dec. 31, 2010	Realized gains for the year ended Dec. 31, 2010
Apr. 2009 to Mar. 2010	5,000	Costless Collar	\$ 4.00	\$ 5.84	\$ -	\$ 32	\$ -
Apr. 2009 to Mar. 2010	1,000	Costless Collar	\$ 4.25	\$ 5.92	-	4	-
Jan. to Dec. 2010	1,500	Call Option	n/a	\$ 7.75	-	75	-
Apr. to Oct. 2010	3,000	Put Option	\$ 4.25	n/a	-	225	80
Apr. to Oct. 2010	1,000	Put Option	\$ 4.50	n/a	-	35	104
Apr. to Oct. 2010	1,500	Put Option	\$ 4.25	n/a	-	69	84
Apr. to Oct. 2010	1,000	Put Option	\$ 4.50	n/a	-	44	95
Jan. to Dec. 2010	1,500	Costless Collar	\$ 4.40	\$ 7.00	-	11	361
Apr. to Oct. 2010	1,500	Swap	\$ 5.51	\$ 5.51	-	(61)	656
Feb. to Dec. 2010	1,500	Costless Collar	\$ 4.00	\$ 6.89	-	-	196
Feb. to Dec. 2010	1,500	Costless Collar	\$ 4.25	\$ 6.95	-	-	299
Apr. to Oct. 2010	1,500	Put Option	\$ 4.50	n/a	-	-	226
Jan. to Dec. 2011	2,000	Swap	\$ 5.33	\$ 5.33	1,111	1,111	-
Jan. to Dec. 2011	2,000	Put Option	\$ 3.80 <sup>(1)</sup>	n/a	(64)	(64)	-
Jan. to Dec. 2011	2,000	Swap	\$ 3.80	\$ 3.80	3	3	-
Jan. to Dec. 2011	2,000	Swap	\$ 3.80	\$ 3.80	3	3	-
Jan. to Dec. 2011	2,000	Put Option	\$ 3.80 <sup>(2)</sup>	n/a	(77)	(77)	-
					\$ 976	\$ 1,410	\$ 2,101

<sup>(1)</sup> Cost of put option to the Corporation is \$0.422 per GJ and payment is due on the fifth business day following each contract month.

<sup>(2)</sup> Cost of put option to the Corporation is \$0.440 per GJ and payment is due on the fifth business day following each contract month.

Period	Volume (bbls/d)	Type of contract	Average WTI- Nymex floor (US\$/bbl)	Average WTI- Nymex ceiling (US\$/bbl)	Fair value of contract as at Dec. 31, 2010	Unrealized loss for the year ended Dec. 31, 2010
Jan. 2011 to Dec. 2012	200	Call Option	\$ n/a	\$ 90.00	\$ (1,665)	\$ (1,665)
					\$ (1,665)	\$ (1,665)

The Corporation entered into the following natural gas hedging transaction subsequent to December 31, 2010:

Period	Volume (GJ/d)	Type of contract	Average AECO Spot floor (Cdn\$/GJ)	Average AECO Spot ceiling (Cdn\$/GJ)
Feb. to Dec. 2011	2,000	Put Option	\$ 3.80 <sup>(1)</sup>	n/a

<sup>(1)</sup> Cost of put option to the Corporation is \$0.355 per GJ and payment is due on the fifth business day following each contract month.

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Corporation's petroleum and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for petroleum and natural gas are affected by changes in the exchange rate between the Canadian and United States currencies. As at and during the year ended December 31, 2010 the Corporation did not have any fracturing fluid tank rental sales in the United States.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Corporation is exposed to interest rate fluctuations on its bank debt, which bears a floating rate of interest.

The Corporation had no foreign exchange rate contracts or interest rate swap contracts in place as at or during the years ended December 31, 2010 and 2009.

The following table summarizes the sensitivity of the fair value of the Corporation's market risk management positions to fluctuations in natural gas and crude oil prices and interest rates. All such fluctuations were evaluated independently, with all other variables held constant. In assessing the potential impact of these fluctuations, the Corporation believes that the volatilities presented below are reasonable measures. Fluctuations in natural gas and crude oil prices, which would impact the mark-to-market calculation of commodity contracts, and in interest rates could have had the following impact on the net earnings:

	Net earnings impact Year ended December 31, 2010	
	Increase	Decrease
Natural gas price – change of 10%	\$ (72)	\$ 1,566
Crude oil price – change of 10%	\$ (1,882)	\$ (686)
Interest rate – change of 10% <sup>(1)</sup>	\$ (137)	\$ 137

<sup>(1)</sup> As at December 31, 2010, a 10 percent change to the Corporation's effective interest rate would be equivalent to a change of 45 basis points or 0.45 percent in the rate charged by the Corporation's bank.

## (D) Fair Value of Financial Instruments

The Corporation's financial instruments as at December 31, 2010 and 2009 include accounts receivable, derivative contracts, accounts payable and accrued liabilities and bank debt. The fair value of accounts receivable and accounts payable and accrued liabilities approximates their carrying amount due to their short terms to maturity.

Bank debt bears interest at a floating market rate and, accordingly, the fair market value approximates the carrying value.

The Corporation's financial instruments recorded at fair value require disclosure about how the fair value was determined based on significant levels of inputs described in the following hierarchy:

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and value to provide pricing information on an ongoing basis.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The Corporation's commodity contracts are the only financial instruments recorded at fair value as at December 31, 2010 and are attributable to the following fair-value hierarchy:

Financial instrument	Fair value	Level 1	Level 2	Level 3
Derivative contracts	\$ 689	–	\$ 689	–

The fair value of derivative contracts is determined by discounting the difference between the contracted price and published forward price curves as at the balance sheet date, using the remaining contracted petroleum and natural gas volumes. As at December 31, 2010, the fair value of commodity contracts was determined using a forward price curve with a range of \$3.63 to \$4.38 per mcf of natural gas and a forward price curve with a range of USD\$88.81 to USD\$94.52 per bbl of crude oil.

## 12. RELATED-PARTY TRANSACTIONS

During the year ended December 31, 2010, the Corporation incurred \$72 in legal costs (2009 – \$276) to a law firm in which the Chairman of the Board of Directors and the Corporate Secretary of the Corporation are partners. The legal costs incurred were in the normal course of operations and were based on the exchange value of the services provided. Of the legal costs incurred in 2010, \$3 was included in accounts payable at December 31, 2010 (2009 – \$10).

During the year ended December 31, 2010, the Corporation received \$72 in office rent (2009 – \$383) from a private corporation in which the Chairman of the Board of Directors and the President and Chief Executive Officer are directors. The office rent received was in the normal course of operations and was based on the market value of the office space provided. Of the office rent received in 2010, no amounts were included in accounts receivable at December 31, 2010 (2009 – \$nil).

### 13. SEGMENTED INFORMATION

The Corporation operates in two main industry segments. These segments are Exploration and Production, which includes the exploration, development and production of oil and natural gas in the Western Canada Sedimentary Basin, and Fracturing Fluid Tank Rentals, which includes the design, manufacture and rental of fracturing fluid handling tanks primarily used in well completion operations in the oil and natural gas industry. This segment's operations were focused on western Canada in 2010 but, subsequent to December 31, 2010, were extended to the United States.

The segmented amounts are as follows:

December 31, 2010	Exploration & Production	Fracturing Fluid Tank Rentals	Other <sup>(1)</sup>	Total
Revenues <sup>(2)</sup>	42,801	5,320	(149)	47,972
Operating earnings (loss) <sup>(3)</sup>	27,941	4,509	(19)	32,431

<sup>(1)</sup> Other includes the Corporation's corporate activities and consolidation adjustments in 2010.

<sup>(2)</sup> Revenues includes petroleum and natural gas revenues plus realized gains on commodity contracts.

<sup>(3)</sup> Operating earnings includes revenues net of royalties, realized gains on commodity contracts, operating expenses and general administrative expenses.

### 14. SUBSEQUENT EVENT

On March 21, 2011, the Corporation issued 7,025 common shares at a price of \$2.85 per share for gross proceeds of \$20,021.

## **DIRECTORS**

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John A. Mueller  
Vice-President, Engineering  
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Vice-President, Finance  
and Chief Financial Officer

James F. Bland  
Vice-President, Exploration

James L. Beninger  
Vice-President, Land

David M. Griffith  
Vice-President and  
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## **CORPORATE SECRETARY**

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## **STOCK EXCHANGE LISTING**

Toronto Stock Exchange  
Symbol: ONR

## **INVESTOR RELATIONS**

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## **ABBREVIATIONS**

<b>bbls</b>	barrels of oil inclusive of NGL
<b>bcf</b>	billion cubic feet
<b>boe</b>	barrels of oil equivalent, converting natural gas to oil at a ratio of six mcf of gas to one barrel of oil
<b>boe/d</b>	barrels of oil equivalent per day
<b>GJ</b>	Gigajoule
<b>mboe</b>	thousand barrels of oil equivalent
<b>mcf</b>	thousand cubic feet
<b>mcfe</b>	thousand cubic feet equivalent
<b>mmcf</b>	million cubic feet
<b>NGL</b>	natural gas liquids



[www.openrangeenergy.com](http://www.openrangeenergy.com)