

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

The following discussion and analysis is provided by the management of Seaview Energy Inc. ("Seaview" or the "Company") as of November 22, 2011 and should be read in conjunction with the unaudited condensed interim consolidated financial statements and selected notes for the periods ended September 30, 2011 and 2010 and the audited consolidated financial statements and notes and MD&A of Seaview for the years ended December 31, 2010 and 2009. This financial data has been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting" ("IFRS"). The effective date of transition to IFRS was January 1, 2010. Previously, the Company prepared its interim and annual consolidated annual financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP" or "CGAAP"). The adoption of IFRS has not had an impact on the Company's operations, strategic decisions or operating netbacks. The reporting and the measurement currency is the Canadian dollar.

### Description of the Company

Seaview is a Calgary based, natural gas and light crude oil focused, exploration and development company established on December 13, 2006. The Company completed its Initial Public Offering on October 17, 2007. The primary area of operation is the Peace River Arch area of northwest Alberta. The Class A and Class B shares of Seaview trade on the TSX Venture Exchange ("TSX – Venture") under the symbols CVU.A and CVU.B. As Seaview commenced operations in October, 2007, and has since completed several material acquisitions, the financial results may not be indicative of future periods.

### Non-GAAP measures

This MD&A contains the terms "funds flow from operations" and "funds flow from operations per share" which do not have any standardized meaning prescribed by IFRS. Management uses funds flow from operations and funds flow from operations per share to analyze operating performance and leverage and considers funds flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds flow from operations should not be considered an alternative to, or more meaningful than, cash flow from operating activities, as determined in accordance with IFRS, as an indicator of the Company's performance. Therefore, references to funds flow from operations or funds flow from operations per share (basic and diluted) may not be comparable with the calculation of similar measures of other entities. Funds flow from operations per share is calculated using the basic and diluted weighted average number of shares for the period. The reconciliation between funds flow from operations and cash flow from operating activities after changes in working capital for the three and nine months ended September 30, 2011 and 2010 is as follows:

	Three months ended September 30		Nine months ended September 30	
(\$ thousands except per share amounts)	2011	2010	2011	2010
Funds flow from operations	\$ 2,773	\$ 4,389	\$ 10,017	\$ 13,150
Decommissioning expenditures	-	-	(2)	(21)
Changes in non-cash working capital	52	205	(768)	2,201
Cash provided by operating activities	\$ 2,825	\$ 4,594	\$ 9,247	\$ 15,330
Funds flow from operations per share (basic)	\$ 0.04	\$ 0.07	\$ 0.15	\$ 0.20
Expenditures on abandonments	0.00	0.00	0.00	0.00
Changes in non-cash working capital per share (basic)	0.00	0.00	(0.01)	0.03
Cash provided by operating activities per share (basic)	\$ 0.04	\$ 0.07	\$ 0.14	\$ 0.23

Management uses certain industry benchmarks such as operating netback to analyze financial and operating performance. This benchmark, as presented, does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures for other entities. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. The Company uses these measures to help evaluate its performance and in capital allocation decisions.

### Boe presentation

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet ("mcf") to one barrel ("bbl") is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting natural gas to oil in the ratio of six mcf of gas to one barrel of oil. A list of other commonly used abbreviations is included at the end of this report.

## Forward-looking information

Certain information regarding the Company set forth in this document, including management's assessment of the Company's future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing, and transportation, such as loss of market, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

## SELECTED INFORMATION

<b>Financial</b> (\$000's except per share amounts)	<b>Q3 2011</b>	<b>Q2 2011</b>	<b>% Change</b>
Petroleum and natural gas sales	\$ 6,562	\$ 8,478	(23%)
Funds flow from operations <sup>(1)</sup>	2,773	4,297	(35%)
Basic and diluted per share <sup>(2)</sup>	0.04	0.07	(43%)
Net loss	(2,929)	(1,650)	(78%)
Basic and diluted per share <sup>(2)</sup>	(0.04)	(0.03)	(33%)
Capital expenditures <sup>(3)</sup>	3,809	3,712	3%
<b>Shares Outstanding at period end (000's)</b>			
Class A	65,553	65,553	-
Class B	1,054	1,054	-
<b>Operations</b>			
Daily production			
Natural gas (mcf/d)	11,121	13,810	(19%)
Light oil and NGLs (bbl/d)	410	437	(6%)
Total production (boe/d)	2,263	2,739	(17%)
Average realized sales price (net of risk management gains)			
Natural gas (per mcf)	\$ 4.41	\$ 4.56	(3%)
Light oil and NGL (per bbl)	62.39	75.97	(18%)
Netback per boe <sup>(1)</sup>			
Sales price	\$ 31.51	\$ 34.01	(7%)
Realized risk management gains	1.44	1.10	31%
Sales price (net of realized risk management gains)	32.95	35.11	(6%)
Royalties	(3.83)	(4.90)	(22%)
Operating expenses	(8.91)	(8.39)	6%
Transportation	(1.50)	(1.37)	9%
Operating netback <sup>(1)</sup>	\$ 18.71	\$ 20.45	(8%)

(1) The Company uses "funds flow from operations" and "funds flow from operations per share" which do not have any standardized meaning prescribed by IFRS. The terms are used to analyze operating performance and leverage. The Company uses "Netback per boe" and "Operating Netback" which do not have any standardized meaning prescribed by IFRS. The terms are used to evaluate performance and in capital allocation decisions.

(2) Weighted average diluted shares outstanding for all periods exclude both the impact of the conversion of the Class B shares and the effect of the granted options as they would have been anti-dilutive.

(3) Capital expenditures include only the cash additions for the period.

## FINANCIAL AND OPERATIONS OVERVIEW OF THIRD QUARTER 2011

- Average production for Q3 2011 was down 17% to 2,263 boe per day compared to Q2 2011 volumes of 2,739 boe per day;
- Production declines over Q3 2011 compared to Q2 2011 are primarily due to flush production and declines from the Company's Wapiti Cardium horizontal wells tied-in during early Q2 2011. In addition, the Sinclair property disposition reduced Q3 2011 volumes by 66 boe per day over the quarter;

- Funds flow from operations for Q3 2011 decreased 35% to \$2.8 million compared to Q2 2011 funds flow of \$4.3 million. The decrease in funds flow is primarily attributed to the combination of the 17% production decrease and 7% decrease in realized prices;
- During the quarter, the Company executed the completion and testing of the 100/16-12-066-08W6/00 ("16-12 well") Cardium horizontal location using LPG fracing technology. The 16-12 well was placed on production on October 30, 2011 and therefore had nominal impact on Q3 2011 production results;
- Based on field estimates for the first 15 days of production, the 16-12 well averaged 145 boe per day consisting of 377 mcf per day of sales gas, 25 bbl per day of Natural Gas Liquids and 81 bbl per day of crude oil while flowing up tubing. Recently a pump-jack has been installed to optimize production;
- During the quarter, on August 3, 2011, the Company disposed of a minor natural gas asset in the Sinclair area of the Peace River Arch, for net proceeds of \$4.34 million. The proceeds have been used, initially, to reduce net debt.

## **SUBSEQUENT EVENT – STRATEGIC BUSINESS COMBINATION AND REORGANIZATION**

On November 21, 2011, Seaview announced that it had entered into an Arrangement Agreement (the "Arrangement Agreement") dated November 11, 2011 with Charger Energy Corp ("Charger"), Silverback Energy Ltd. ("Silverback") and Sirius Energy Inc. ("Sirius") to form a light oil focused, growth oriented junior exploration and production company to be lead by the current Charger management team.

The transaction will be completed by way of a Plan of Arrangement (the "Arrangement") whereby Charger, Silverback and Sirius will exchange all of their issued and outstanding shares for class A shares of Seaview. Each of the companies involved in the business combination is at arm's length with the others. Once the Arrangement is completed, the resulting entity will be renamed Charger Energy Inc.

Under the Arrangement, the share exchange will occur on the following basis:

- Each common share of Charger ("Charger Share") will be exchanged for 3.6364 class A shares of Seaview ("Seaview Shares") for a deemed aggregate acquisition cost of approximately \$72.5 million, using the November 11, 2011 closing price of \$0.53 for each Seaview Share
- Each common share of Silverback ("Silverback Share") will be exchanged for 5.8182 Seaview Shares for a deemed aggregate acquisition cost of approximately \$54.4 million, using the November 11, 2011 closing price of \$0.53 for each Seaview Share
- Each common share of Sirius ("Sirius Share") will be exchanged for 0.80 of a Seaview Share, for a deemed aggregate acquisition cost of approximately \$11.1 million, using the November 11, 2011 closing price of \$0.53 for each Seaview Share

As part of the Arrangement, each class B share of Seaview will, in accordance with the articles of Seaview, be exchanged for 10.0 Seaview Shares (class A) and, as a final step, all of the issued and outstanding Seaview Shares will be consolidated on a one for five basis.

The current directors and management of Charger will form the directors and management of the Resulting Entity upon closing, with a director nominee from the existing board of directors of Seaview.

It is estimated that there will be approximately 67.3 million Class A shares outstanding following completion of the Arrangement and the share consolidation, with shareholders of Charger, Silverback, Sirius and Seaview holding approximately 41%, 31%, 6% and 23% outstanding shares, on a non-diluted basis, respectively. The common shares of the Resulting Issuer will be listed and posted for trading on the TSX-V upon closing.

Michael Wuetherick, President and CEO of Seaview commented "This transaction achieves several strategic long term goals which will immediately benefit the shareholders of Seaview as well as Charger, Silverback and Sirius. Specifically, this transaction creates an entity with greater financial flexibility to support profitable growth from a portfolio of quality light oil resource plays. The Charger management team has a proven track record of delivering growth and shareholder value".

## **THE ARRANGEMENT**

The Arrangement is subject to the approval of 66 2/3 percent of the votes cast by the respective shareholders of each of Seaview, Silverback and Sirius and the securityholders of Charger. A joint information circular is expected to be mailed in December 2011 and it is expected that the shareholder meetings for all of the companies will occur in January 2012 with closing of the Arrangement expected shortly thereafter.

The Arrangement will also require stock exchange, court and regulatory approvals as is normally required for transactions of this nature. The Arrangement Agreement contains a number of representations, warranties and conditions that are customary for

agreements of this type and also provides for non-solicitation covenants, rights to match superior proposals and reciprocal non-completion fees payable in certain circumstances. The complete Arrangement Agreement and the Plan of Arrangement will be accessible in due course on Seaview's SEDAR profile at [www.sedar.com](http://www.sedar.com).

#### **SEAVIEW BOARD OF DIRECTORS RECOMMENDATION**

The Board of Directors of Seaview has unanimously determined that the Arrangement is in the best interests of its shareholders and has recommended that its shareholders approve the Arrangement, including the change of management and the reconstitution of the Board of Directors of Seaview. The members of the Board of Directors and Officers and other shareholders, who, in the aggregate, control approximately 38 percent of the outstanding Seaview Shares, have entered into support agreements pursuant to which they have agreed to vote such shares in favour of the Arrangement.

#### **OUTLOOK**

Upon successful closing of the Arrangement, the combined entities will have the following attributes.

##### **Asset Base**

The Arrangement will create a focused, growth-oriented junior energy company with light oil development opportunities in the Viking and the Cardium resource plays in Central and Northwest Alberta. The resulting entity will have access to more than 350,000 net acres of land comprised of 120,000 net undeveloped acres under lease and 230,000 net acres available through farm-in and option agreements. These holdings represent an inventory of locations targeting light oil through horizontal drilling and multi stage fracturing.

##### **2012 Guidance**

The management of the resulting entity is anticipating 2012 capital expenditures of approximately \$75 million for the resulting entity, subject to market conditions, which will include drilling approximately 41 wells primarily targeting Viking, Manneville, Cardium, Pekisko and Nisku light oil opportunities. This light oil focused capital program is expected to result in 2012 average daily production between 4,600 boe/d and 5,100 boe/d with oil and liquids production increasing to represent approximately 41% to 45% of total production. This increased weighting towards oil and liquids is also expected to improve operating netbacks.

##### **Key opportunities for growth in 2012 are:**

- Viking resource play: Access to approximately 600 sections of land in the Halkirk/Provost area of Alberta targeting Viking and Ellerslie light oil;
- Multi-zone resource play: Access to approximately 95 sections of land in the Ghost Pine area of Alberta targeting Viking, Manville and Pekisko light oil; and
- Cardium resource play: 42.5 sections (22.8 net) of land in the Wapiti area of Alberta targeting Cardium light oil and liquids rich natural gas.

##### **Key Attributes of Pro Forma Resulting Entity**

Following the Arrangement, the resulting entity will have, on a pro-forma basis, the following key financial and operational attributes:

##### **Financial Attributes (unaudited, as at November 1, 2011)**

- Consolidated Pro Forma common shares outstanding of approximately 67.3 million (basic) and approximately 77.3 million (fully diluted). Fully diluted shares include approximately 8.0 million warrants and 2.0 million options of the resulting entity to be issued to the officers, directors and employees of Charger (that will replace the existing warrants and options of Charger to be cancelled pursuant to the Arrangement) on an economically equivalent basis to the securities cancelled under the Arrangement, at exercise prices ranging between \$1.38 and \$2.41 on a post-consolidated basis;
- Enterprise value of approximately \$214 million reflecting the negotiated exchange ratios, current estimated net debt and the closing price for Seaview Shares on November 11, 2011 of \$0.53;
- Estimated pro forma net debt and working capital of approximately \$36 million. Management has received an indicative proposal from a Canadian Chartered Bank for a \$65 million operating credit facility for the resulting entity; and
- Tax pools of approximately \$150 million.

## Operational Attributes

- Estimated production for December 2011 of 3,500 to 3,800 boe/d (30 to 33% oil & NGL);
- Increases Seaview's pro forma oil and liquids production weighting to 30% from 15% prior to the Arrangement;
- Reserve weighting of combined entity reflects proved plus probable oil and liquids reserves of 39%, up from 28% prior to the Arrangement;
- As at September 30, 2011, proved plus probable reserves of 19.3 MMboe (57% proved) consisting of 6.6 MMbbl of crude oil, 70,755 MMcf of natural gas and 0.9 MMbbl of natural gas liquids. The reserves as presented here reflect a reduction to the reserves to account for property dispositions and a roll forward to back out production of the respective entities reserve reports from differing reserve report effective dates to September 30, 2011. Detailed reserve information will be provided in the Information Circular;
- Undeveloped land inventory of 120,000 net acres and 230,000 net acres of farm-in or option lands;
- Value attributed to undeveloped land of approximately \$12 million (excluding farm-in and option lands), based on a value of \$100 per acre (management estimate based on land sale results during 2011 from the Plains area of Alberta, where the majority of the undeveloped land is situated);
- Total proved plus probable reserve life index of approximately 14 years at current production levels; and
- High working interest and operatorship in key growth areas.

## RESULTS OF OPERATIONS

### Disposition of Assets

On August 3, 2011, the Company sold a minor producing natural gas asset in the Peace River Arch area of northwest Alberta for net proceeds of \$4.3 million resulting in a loss on disposal of approximately \$2.3 million. On September 23, 2011, the Company sold a minor land asset in northeast British Columbia for net proceeds of \$0.3 million, resulting in a minor gain on disposal. Proceeds have been used to pay down bank debt and may be redirected towards the Company's capital program.

### Operations

For the three and nine months ended September 30, 2011, the Company recorded a net loss of \$2.9 million and \$7.4 million, respectively, (net loss of \$0.8 million for the three months ended September 30, 2010 and net income of \$8.9 million nine months ended September 30, 2010).

The following table summarizes selected information for the three months ended September 30, 2011 (the "Quarter" or "Q3 2011"), for the three months ended June 30, 2011 (the "Previous Quarter" or "Q2 2011") and for the third quarter of 2010 (the "Prior Year Q3" or "Q3 2010"), as well as the year to date information for the periods ended September 30, 2011 ("YTD 2011") and September 30, 2010 ("YTD 2010"):

	Q3 2011	Q2 2011	Q3 2010	YTD 2011	YTD 2010
Daily Production					
Natural gas (mcf/d)	11,121	13,810	13,299	12,401	15,630
Crude oil and NGL's (bbl/d)	410	437	322	375	391
Boe/d day @ 6:1	2,263	2,739	2,538	2,442	2,996
Petroleum and natural gas sales (\$000's)	\$ 6,562	\$ 8,478	\$ 6,486	\$ 21,422	\$ 26,436
Funds flow from operations (\$000's)	2,773	4,297	4,389	10,017	13,150
Per share – basic	0.04	0.07	0.07	0.15	0.20
Per share – diluted	0.04	0.07	0.07	0.15	0.17
Net income (loss) (\$000's)	(2,929)	(1,650)	(834)	(7,357)	8,941
Per share – basic	(0.04)	(0.03)	(0.01)	(0.11)	0.13
Per share – diluted	(0.04)	(0.03)	(0.01)	(0.11)	0.12

## Commodity prices

Average realized prices	Q3 2011	Q2 2011	Q3 2010	YTD 2011	YTD 2010
Light crude oil (per bbl)	\$ 89.43	\$ 94.52	\$ 73.54	\$ 89.79	\$ 75.65
after realized risk management gains/losses	80.26	83.95	69.36	79.27	71.90
Natural gas (per mcf)	3.93	4.18	3.68	4.04	4.38
after realized risk management gains/losses	4.41	4.56	4.34	4.45	4.70
Natural gas liquids (per bbl)	39.80	68.75	56.60	58.62	64.50
Total per boe	31.51	34.01	27.77	32.13	32.32
after realized risk management gains	32.95	35.11	30.89	33.36	33.66
<b>BENCHMARK PRICES</b>					
WTI oil (US\$ per bbl)	89.75	102.54	76.18	95.46	77.56
AECO Daily Index (CAD\$ per gj)	3.47	3.67	3.36	3.57	3.90
Currency (US\$/CAD\$)	0.9800	0.9676	1.039	0.9778	1.034

The AECO Daily Index gas price averaged \$3.47 per gj or \$3.66 per mcf for Q3 2011 as compared to \$3.67 per gj or \$3.87 per mcf during the Previous Quarter. The natural gas price received by Seaview, before risk management gains, was \$3.93 per mcf for the Quarter compared to \$4.18 per mcf for Q2 2011. Seaview receives a premium to the stated AECO Indexes as the Company produces high heat content natural gas that attracts premium market prices.

The price of West Texas Intermediate ("WTI") crude averaged US\$89.75 per bbl during the Quarter compared to US\$102.54 per bbl during Q2 2011. Seaview received a combined average price, including natural gas liquids, and before risk management effects, of \$67.51 per bbl during the Quarter compared to \$81.00 during the Previous Quarter.

The Canadian dollar averaged US\$0.9800 during the Quarter as compared to \$0.9676 during the Previous Quarter. As the price of WTI crude oil and Nymex natural gas is quoted in US dollars, appreciation in the Canadian dollar decreases the average Canadian price received. Seaview mitigates exposure to the impact of exchange rate fluctuations by economically hedging a portion of the production in Canadian dollar denominated puts, swaps and collars.

### Commodity price risk management

The prices received for petroleum and natural gas can fluctuate significantly due to weather patterns, the economic environment or political uncertainty.

Seaview's commodity price risk management program is designed to provide price protection on a portion of the future production in the event of adverse commodity price movement, while retaining the opportunity to participate in favourable price movements. This practice allows the Company to generate stable funds flow for capital development and acquisition activities, and to ensure positive economic returns on those activities. The Company may also sell a portion of its natural gas production on the AECO Monthly Index in addition to the AECO Daily Index to mitigate the volatility in price movement.

The Company has elected not to use hedge accounting and consequently will record the fair value of any crude oil and natural gas financial contract at each reporting period, with the change in the fair value being classified as unrealized gains and losses in revenue in the statement of earnings. The fair value of the commodity price risk contracts is estimated based on the mark-to-market method of accounting, using publicly quoted market prices or, in their absence, third-party market indications and forecasts priced on the last trading day of the applicable period and are therefore classified as Level 2. For the three and nine months ended September 30, 2011, realized gains of \$0.3 million and \$0.8 million, respectively, were recorded as revenue (nine months ended September 30, 2010 – realized gains of \$1.1 million). As at September 30, 2011, the Company recorded a liability related to the unrealized losses on financial contracts of \$1.5 million reflecting the fair value of the crude oil and natural gas contracts outstanding at September 30, 2011 (December 31, 2010 – a liability of \$1.0 million; September 30, 2010 – an asset of \$0.7 million).

As at September 30, 2011, the Company had the following financial contracts:

<b>Natural gas</b>	Volume	Pricing Point	Price	Term
Put <sup>(1)</sup>	2,000 gj/d	AECO Monthly	\$ 4.75/gj	January '10 – December '11
Put	6,140 gj/d	AECO Monthly	\$ 4.00/gj	January '11 – December '11
Call	3,000 gj/d	AECO Monthly	\$ 7.40/gj	January '13 – December '13
<b>Crude Oil</b>				
Put <sup>(2)</sup>	200 bbl/d	WTI – Nymex CAD	\$ 75.00/bbl	January '10 – December '11
Call	100 bbl/d	WTI – Nymex CAD	\$ 88.25/bbl	January '13 – December '13
Call	200 bbl/d	WTI – Nymex	\$ 72.50/bbl	January '13 – December '13

(1) The net floor for this contract reflects the deferred cost of \$1.05/gj paid over the course of the contract. The strike price of the put is \$5.80/gj before the deferred cost.

(2) The net floor for this contract reflects the deferred cost of \$11.00/bbl paid over the course of the contract. The strike price of the put is \$86.00/bbl before the deferred cost.

The total volumes economically hedged for the period of October 2011 to December 2013 are detailed below.

<b>Natural Gas</b>	<b>Q4 '11</b>	<b>2013</b>
<b>Puts</b>		
Volumes – gj/d	8,140	
Net floor (\$/gj)	\$4.18	
<b>Call</b>		
Volumes – gj/d		3,000
Net ceiling (\$/gj)		\$7.40
<b>Crude Oil</b>		
<b>Put</b>		
Volumes – bbl/d	200	
Net floor (CAD\$/bbl)	\$75.00	
<b>Call</b>		
Volumes – bbl/d		300
Net ceiling (CAD\$/bbl)		\$77.75

The Company will continue to monitor forecasted volumes and commodity prices and may layer in additional downside protection, generally using puts, in order to allow full exposure to any positive price movements.

The Company's financial derivative trading activities are conducted pursuant to the Company's Hedging Policy Manual approved by the board of directors. The Hedging Policy Manual has the objectives of reducing risk exposure to budgeted annual funds generated from operations resulting from uncertainty or changes in commodity prices; limiting financial contract volumes up to a maximum of 50% of forecasted production when using collars or swaps, unless otherwise approved by the Board of Directors; and limiting financial derivative trading activity to counter-parties that provide sufficient collateral in support of payment or have investment grade credit ratings.

#### **Petroleum and natural gas sales**

(\$000's)	<b>Q3 2011</b>	Q2 2011	Q3 2010	<b>YTD 2011</b>	YTD 2010
Natural gas	\$ 4,017	\$ 5,254	\$ 4,501	\$ 13,665	\$ 18,679
Crude oil and natural gas liquids	2,545	3,224	1,985	7,757	7,757
Realized risk management gains	298	273	727	821	1,093
Petroleum and natural gas sales (net)	\$ 6,860	\$ 8,751	\$ 7,213	\$ 22,243	\$ 27,529
\$/boe	\$ 32.95	\$ 35.11	\$ 30.89	\$ 33.36	\$ 33.66

Petroleum and natural gas sales for the Quarter, before royalties and transportation costs, were \$6.9 million (\$8.8 million – Previous Quarter; \$7.2 million – Q3 2010). The decrease from Q2 2011 is attributable to a 17% decrease in production as well as a 7% decrease in realized prices during the Quarter. The Company realized gains of \$0.3 million, net of premiums, on crude oil and natural gas financial contracts during the Quarter (gains of \$0.3 million – Previous Quarter).

## Royalties

(\$000's)	Q3 2011	Q2 2011	Q3 2010	YTD 2011	YTD 2010
Royalties	\$ 798	\$ 1,223	\$ 499	\$ 2,785	\$ 3,638
Percentage of petroleum and natural gas sales (before realized risk management gains)	12.2%	14.4%	7.7%	13.0%	13.8%
\$/boe	\$ 3.83	\$ 4.90	\$ 2.14	\$ 4.18	\$ 4.45

Royalties are paid to the owners of the mineral rights with whom leases are held, including provincial governments. Overriding royalties are also paid to other parties according to contracts. In Alberta, a Crown royalty is invoiced on the Crown's share of production based on a monthly established Alberta Reference Price. The Alberta Reference Price is a monthly weighted average price of gas consumed in Alberta and gas exported from Alberta reduced for transportation and marketing allowances. Gas cost allowance and other incentive schemes serve to reduce the effective royalty rate.

With the introduction of a New Royalty Framework ("NRF") by the Province of Alberta, commencing January 1, 2009, and the Amended Royalty Framework ("ARF") which took effect January 1, 2011, Crown royalties are sensitive to production rates for each well and to changes in the commodity price. In this low commodity price environment, the decrease in the reference price used for the calculation of Crown royalties has had a significant impact on the royalty rates charged by the Crown. Additionally, the Province of Alberta introduced a reduced royalty rate of 5% for wells that are brought on production after April 1, 2009. This applies for the first 12 months of production or to a maximum of 500,000 Mcfs for natural gas wells or 50,000 barrels for crude oil wells, amended to 60,000 barrels and 24 months for horizontal oil wells drilled on or after May 1, 2010 and more than 2,500 meters in total length. Seaview has brought on several new wells since April 1, 2009 which qualified for this reduced royalty rate, several of which currently remain at this rate.

Royalties for the Quarter totaled \$0.8 million (\$1.2 million – Previous Quarter; \$0.5 million – Q3 2010). As a percentage of sales, royalties averaged 12.2% or \$3.83 per boe during the Quarter (14.4% and \$4.90 per boe for the Previous Quarter; 7.7% and \$2.14 per boe – Q3 2010). The royalty rate for Q3 2011 is lower than the Previous Quarter due to a lower Crown reference price on natural gas. The royalty rate for Q3 2010 was significantly lower than Q3 2011 as the Prior Year Q3 had significant adjustments for gas cost allowance realized during that quarter. The overall royalty rate remains lower than the YTD 2010 rates as the Company still has approximately 23% of its production attracting the 5% royalty rate.

## Operating expenses

(\$000's)	Q3 2011	Q2 2011	Q3 2010	YTD 2011	YTD 2010
Operating expenses	\$ 1,854	\$ 2,090	\$ 1,196	\$ 5,693	\$ 6,793
\$/boe	\$ 8.91	\$ 8.39	\$ 5.12	\$ 8.54	\$ 8.31

Operating expenses for the Quarter were \$1.9 million (\$2.1 million – Previous Quarter; \$1.2 million – Q3 2010) and on a unit-of-production basis, operating expenses averaged \$8.91 per boe (\$8.39 per boe – Previous Quarter; \$5.12 per boe – Q3 2010). The operating expenses on a per boe basis for the Quarter are somewhat higher than the Q2 2011 due mainly to the decrease in production during the quarter. The Q3 2010 operating expenses on a per boe basis were substantially lower than the expense for the Quarter as the Prior Year Q3 expense was reduced by approximately \$2.60/boe due to receipt of 13<sup>th</sup> month recoveries from operators of gas plants in which the Company has a working interest.

## Transportation expense

(\$000's)	Q3 2011	Q2 2011	Q3 2010	YTD 2011	YTD 2010
Transportation expense	\$ 312	\$ 341	\$ 345	\$ 953	\$ 1,126
\$/boe	\$ 1.50	\$ 1.37	\$ 1.48	\$ 1.43	\$ 1.38

For the Quarter, transportation expense totaled \$0.3 million or \$1.50 per boe (\$0.3 million or \$1.37 per boe – Previous Quarter; \$0.3 million or \$1.48 per boe – Q3 2010). As Seaview's production is weighted more than 80% to natural gas, the majority of Seaview's transportation expenses relate to natural gas pipeline tariff charges. Transportation expense per boe for the Quarter is consistent with both the Previous Quarter as well as Q3 2010.

## General and administrative (“G&A”)

(\$000's)	Q3 2011	Q2 2011	Q3 2010	YTD 2011	YTD 2010
G&A expenses	\$ 1,108	\$ 966	\$ 1,095	\$ 3,097	\$ 3,736
Capitalized G&A	(335)	(385)	(358)	(1,060)	(1,319)
Overhead recoveries	(75)	(171)	(111)	(427)	(375)
Net G&A expenses	698	410	626	1,610	2,042
\$/boe	\$ 3.35	\$ 1.65	\$ 2.68	\$ 2.41	\$ 2.50

During the Quarter, G&A, net of overhead recoveries on operated properties and capitalized expenditures, totaled \$0.7 million (\$0.4 million – Previous Quarter; \$0.6 million – Q3 2010). On a unit-of-production basis, G&A expenses were \$3.35 per boe (\$1.65 per boe – Previous Quarter; \$2.68 per boe – Q3 2010). The G&A per boe for the Quarter was higher than the Previous Quarter due in part to the decrease in production as well as the payment of annual director's fees during the quarter.

## Finance expense

(\$000's)	Q3 2011	Q2 2011	Q3 2010	YTD 2011	YTD 2010
Interest expense	\$ 380	\$ 377	\$ 158	\$ 959	\$ 780
Unrealized gain on financial contracts	-	-	-	-	(24)
Accretion on decommissioning obligations	44	46	40	134	132
Accretion on Convertible Class B share liability	190	186	175	558	516
Net finance expense	614	609	373	1,651	1,404
\$/boe	\$ 2.95	\$ 2.44	\$ 1.60	\$ 2.48	\$ 1.72

Interest expense, representing interest paid on drawn amounts of the secured credit facility, standby fees and banking fees, during the Quarter was \$0.4 million or \$1.82 per boe (\$0.4 million or \$1.51 per boe – Previous Quarter; \$0.2 million or \$0.68 per boe – Q3 2010). The average balance of debt drawn during the Quarter was \$29.5 million (\$30.1 million – Previous Quarter; \$10.0 million – Q3 2010), with an average interest rate of 5.1% per annum paid during the Quarter (4.1% per annum – Previous Quarter; 6.2% per annum – Q3 2010). Included in interest expense are standby fees of 0.4% per annum based on an average unutilized debt capacity of \$22.5 million for the Quarter (\$21.9 million – Previous Quarter; \$42.0 million – Q3 2010).

## Share based compensation

The Company has a stock option plan, which is fully described in Note 10 of the unaudited condensed interim consolidated financial statements. At September 30, 2011, 5,589,500 options were outstanding with an average exercise price of \$1.40 and a weighted average remaining contractual life of 2.4 years (5,510,750 options outstanding at September 30, 2010 at an average exercise price of \$1.40 with a weighted average remaining contractual life of 3.3 years). Of the total number of options outstanding at September 30, 2011, options totaling 3,671,518 are vested and available for exercise at a weighted average exercise price of \$1.56 per option.

For the Quarter and YTD 2011, the Company recorded a compensation expense of \$0.1 million and \$0.4 million, respectively (\$0.1 million – Previous Quarter; \$0.3 million and \$0.8 million, respectively – Q3 2010 and YTD 2010) and capitalized \$0.1 million and \$0.4 million, respectively (\$0.1 million – Previous Quarter; \$0.2 million and \$0.7 million, respectively – Q3 2010 and YTD 2010).

On January 5, 2011, the Company granted options to acquire up to 187,500 Class A shares at a price of \$1.19 per share, none of which were granted to officers or directors of the Company.

## Depletion and depreciation (“D&D”)

The Quarter and YTD 2011 provision for D&D totaled \$4.9 million and \$15.9 million, respectively (\$6.0 million – Previous Quarter; \$5.2 million and \$17.1 million, respectively – Q3 2010 and YTD 2010). On a unit-of-production basis, D&D costs averaged \$23.74 per boe for Q3 2011 and \$23.82 per boe for YTD 2011 (\$24.14 per boe – Previous Quarter; \$22.16 per boe and \$20.94 per boe, respectively – Q3 2010 and YTD 2010). D&D per boe for Q3 2011 is lower than Q2 2011 due to the sale of the minor producing natural gas asset as, on a proportionate basis, the decrease to the depletable base was greater than the decrease in the proven reserve base. In comparing the Quarter to the Prior Year Q3, D&D per boe has increased as, on a proportionate basis, the increase to the depletable base due to capital spending on the new Wapiti wells was greater than the increase in the proven reserve base.

## Exploration and evaluation expenditures (“E&E”)

During the Quarter, the Company expensed \$45,500 of pre-license exploration costs (\$12,700 – Previous Quarter; nil – Q3 2010 and YTD 2010). The expenditures are due to efforts relating to new core areas to the Company and relate mostly to geological and geophysical costs associated with new prospective plays.

## Unrealized gains (losses) on financial contracts

The Company has elected not to use hedge accounting and accordingly, the fair value of the financial contracts (as discussed in Note 4 of the unaudited condensed interim consolidated financial statements) is recorded at each period end. The fair value may change substantially from period to period based on the period ending commodity forward strip prices for the financial contracts outstanding at the balance sheet date. The change in fair value from period end to period end is reflected in the earnings for that period. As a result, earnings may fluctuate considerably based on the period ending commodity forward strip prices.

The fair value at September 30, 2011 of commodity contracts outstanding was an unrealized loss or a liability, net of unrealized gains, of \$1.5 million (December 31, 2010 – unrealized loss (liability) of \$1.0 million). During the Quarter, the Company recorded an unrealized gain of \$1.0 million, and YTD 2011 recorded an unrealized loss of \$0.5 million, as a result of the change in fair value over the respective periods (\$0.1 million loss – Previous Quarter; \$0.3 million and \$2.2 million gains, respectively – Q3 2010 and YTD 2010). Forward strip prices for both crude oil and natural gas have decreased during Q3 2011 from Q2 2011 resulting in unrealized gains for the quarter while crude oil prices have increased and natural gas prices have decreased from the year end 2010 prices resulting in net unrealized losses for YTD 2011.

## Deferred income taxes

A deferred income tax reduction of \$0.8 million and \$2.3 million has been recorded for the Quarter and YTD 2011, respectively (a reduction of \$0.5 million – Previous Quarter; a recovery of \$0.1 million and an expense of \$4.1 million, respectively – Q3 2010 and YTD 2010). As the Company has recorded a loss before taxes for the Quarter, a reduction of deferred income taxes is expected. No current tax expense has been recorded as Seaview is not subject to capital taxes and has no current income tax liability.

## Net income (loss) and funds flow from operations

Net loss for the Quarter and YTD 2011 was \$2.9 million and \$7.4 million, respectively (\$1.7 million net loss – Previous Quarter; \$0.8 million net loss and \$8.9 million net income, respectively – Q3 2010 and YTD 2010). Basic and diluted net loss per share for the Quarter and YTD 2011 was \$0.04 and \$0.11, respectively (basic and diluted net loss per share of \$0.03 – Previous Quarter; basic and diluted net loss per share of \$0.01 – Q3 2010, and basic net income per share and diluted net income per share of \$0.13 and \$0.12, respectively – YTD 2010). Funds flow from operations was \$2.8 million and \$10.0 million for the Quarter and YTD 2011, respectively (\$4.3 million – Previous Quarter; \$4.4 million and \$13.2 million – Q3 2010 and YTD 2010). Basic and diluted funds flow from operations per share for the Quarter and YTD 2011 was \$0.04 and \$0.15, respectively (basic and diluted funds flow from operations per share was \$0.07 – Previous Quarter; basic and diluted funds flow from operations per share was \$0.07 – Q3 2010, and basic funds flow from operations and diluted funds flow from operations per share was \$0.20 and \$0.17, respectively – YTD 2010).

<b>Netbacks, Funds Flow from Operations and Net Income (Loss) (\$/boe)</b>						
	<b>Q3 2011</b>	<b>Q2 2011</b>	<b>Q3 2010</b>	<b>YTD 2011</b>	<b>YTD 2010</b>	
Petroleum and natural gas sales	\$ 32.95	\$ 35.11	\$ 30.89	\$ 33.36	\$ 33.66	
Less:						
Royalties	3.83	4.90	2.14	4.18	4.45	
Operating expenses	8.91	8.39	5.12	8.54	8.31	
Transportation expense	1.50	1.37	1.48	1.43	1.38	
Net operating income (operating netback)	\$ 18.71	\$ 20.45	\$ 22.15	\$ 19.21	\$ 19.52	
General and administrative	3.35	1.65	2.68	2.41	2.50	
Finance expense	2.95	2.44	1.60	2.48	1.72	
Funds flow from operations	\$ 12.41	\$ 16.36	\$ 17.87	\$ 14.32	\$ 15.30	
Depletion and depreciation	23.74	24.14	22.16	23.82	20.94	
Unrealized (gain) loss on financial derivatives	(4.99)	0.38	(1.50)	0.69	(2.74)	
Stock option compensation	0.52	0.53	1.20	0.58	0.94	
Loss (gain) on sale of property, plant and equipment	11.03	-	(0.14)	3.44	(19.78)	
Pre-license expenditures and other	0.22	0.05	-	0.34	-	
Future income tax (reduction) expense	(4.04)	(2.12)	(0.28)	(3.51)	5.01	
Net income (loss) (\$/boe)	\$ (14.07)	\$ (6.62)	\$ (3.57)	\$ (11.04)	\$ 10.93	

## SELECTED QUARTERLY INFORMATION

Financial (\$000's except per share amounts) <sup>(4)</sup>	Q4 2009 (CGAAP)	Q1 2010 (restated under IFRS)	Q2 2010 (restated under IFRS)	Q3 2010 (restated under IFRS)	Q4 2010 (restated under IFRS)	Q1 2011	Q2 2011	Q3 2011
Petroleum and natural gas sales	\$ 10,377	\$ 11,056	\$ 8,894	\$ 6,486	\$ 6,950	\$ 6,382	\$ 8,478	\$ 6,562
Funds flow from operations <sup>(1)</sup>	5,024	4,441	4,320	4,389	3,938	2,947	4,297	2,773
Basic per share	0.08	0.07	0.07	0.07	0.06	0.05	0.07	0.04
Diluted per share <sup>(2)</sup>	0.08	0.07	0.05	0.07	0.06	0.05	0.07	0.04
Net income (loss)	(2,366)	(235)	10,010	(834)	(2,895)	(2,778)	(1,650)	(2,929)
Basic per share	(0.04)	0.00	0.15	(0.01)	(0.04)	(0.04)	(0.03)	(0.04)
Diluted per share <sup>(2)</sup>	(0.04)	0.00	0.13	(0.01)	(0.04)	(0.04)	(0.03)	(0.04)
Capital expenditures <sup>(3)</sup>	5,368	8,017	4,758	5,555	11,517	12,967	3,712	3,809
Property acquisitions (dispositions)	3,840	-	(16,807)	-	3,315	-	-	(6,816)
Net debt	40,309	43,896	11,230	12,395	23,240	33,244	32,659	29,175
<b>Shares outstanding at period end (000's)</b>								
Class A	65,433	65,454	65,479	65,489	65,537	65,553	65,553	65,553
Class B	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054
<b>Operations</b>								
Daily production								
Natural gas (mcf/d)	13,703	16,544	17,084	13,299	14,016	12,286	13,810	11,121
Light oil and NGLs (bbl/d)	445	480	374	322	305	277	437	410
Total production (boe/d)	2,729	3,237	3,221	2,538	2,641	2,325	2,739	2,263
Natural gas (per mcf)	\$ 6.06	\$ 5.12	\$ 4.59	\$ 4.34	\$ 4.48	\$ 4.38	\$ 4.56	\$ 4.41
Light oil and NGL (per bbl)	66.92	72.92	70.87	64.46	66.27	71.78	75.97	62.39
Netback per boe								
Sales price (net of risk management gains or losses)	\$ 41.33	\$ 36.98	\$ 32.57	\$ 30.89	\$ 31.45	\$ 31.70	\$ 35.11	\$ 32.95
Royalties	4.52	5.92	4.83	2.14	3.02	3.65	4.90	3.83
Operating expenses	11.80	11.10	8.07	5.12	5.44	8.36	8.39	8.91
Transportation	1.27	1.29	1.38	1.48	1.63	1.43	1.37	1.50
Operating netback	\$ 23.74	\$ 18.67	\$ 18.29	\$ 22.15	\$ 21.36	\$ 18.26	\$ 20.45	\$ 18.71

(1) The Company uses "funds flow from operations" and "funds flow from operations per share" which do not have any standardized meaning prescribed by IFRS. The terms are used to analyze operating performance and leverage. The Company uses "Netback per boe" and "Operating Netback" which do not have any standardized meaning prescribed by IFRS. The terms are used to evaluate performance and in capital allocation decisions.

(2) Weighted average diluted shares outstanding for Q2 2010 includes the impact of the conversion of the Class B shares and the effect of the granted options. All other quarters exclude both the conversion of the Class B shares and the effect of the granted options as they would have been anti-dilutive.

(3) Capital expenditures include the cash additions for the period.

(4) The quarterly table contains both IFRS and CGAAP numbers. Comparatives before 2010 have not been restated to reflect the changes in accounting policies as a result of adopting IFRS.

## SHARE INFORMATION

	Three months ended September 30		Nine months ended September 30	
	2011	2010	2011	2010
Weighted average shares outstanding				
Basic	<b>65,553,018</b>	65,482,611	<b>65,549,387</b>	65,464,000
Diluted	<b>65,553,018</b>	65,482,611	<b>65,549,387</b>	78,644,960
Outstanding securities at period end				
Class A shares			<b>65,553,018</b>	65,489,350
Convertible Class B shares			<b>1,053,540</b>	1,053,540
Options, Class A shares			<b>5,589,500</b>	5,510,750
Outstanding securities at November 22, 2011				
Class A shares			<b>65,553,018</b>	
Convertible Class B shares			<b>1,053,540</b>	
Options, Class A shares			<b>5,589,500</b>	

Per share amounts have been calculated using the weighted average number of shares outstanding during the year. The effect of the conversion of the Class B shares and the effect of options granted have both been excluded from the weighted average diluted share calculation for the three and nine months ended September 30, 2011 as they would have been anti-dilutive, while the impact of both the conversion of the Class B shares and the options granted have been included for the three and nine months ended September 30, 2010 as they were dilutive.

The Company's Class B shares are convertible (at the option of the Company) at any time after June 1, 2010 and before May 31, 2012, into Class A shares. The number of Class A shares obtained upon the conversion of each Class B share will be equal to \$10.00 divided by the greater of \$1.00 and the weighted average trading price of the Class A shares during a thirty consecutive trading day period prior to the conversion date. If conversion has not occurred by the close of business on May 31, 2012, the Class B shares become convertible (at the option of the holder) into Class A shares on the same basis. Effective June 30, 2012, all remaining Class B shares will automatically convert to Class A shares.

## CAPITAL EXPENDITURES

For the Quarter and YTD 2011, development capital expenditures totaled \$5.7 million and \$22.3 million, respectively (\$3.9 million – Previous Quarter; \$2.4 million and \$13.1 million, respectively – Q3 2010 and YTD 2010). The total capital expenditures for the Quarter and YTD 2011 include the disposition of the Sinclair assets in August 2011 for proceeds of \$4.3 million and disposition of lands located in British Columbia in September 2011 for proceeds of \$0.2 million. The dispositions resulted in a net loss on sale of \$2.3 million. The table below summarizes the capital expenditures during the Quarter, the Previous Quarter and Q3 2010 as well as YTD 2011 and YTD 2010.

(\$000's)	Q3 2011	Q2 2011	Q3 2010	YTD 2011	YTD 2010
Geological and geophysical	\$ (12)	\$ 12	\$ 742	\$ -	\$ 1,227
Drilling and Completions (gross)	<b>5,170</b>	2,760	741	<b>16,468</b>	10,256
Alberta Drilling Credits	-	-	-	-	(1,559)
Tangible equipment	<b>565</b>	1,132	962	<b>5,857</b>	3,207
Development Capital	\$ <b>5,723</b>	\$ 3,904	\$ 2,445	\$ <b>22,325</b>	\$ 13,131
Exploration & evaluation capital (note 9)	<b>(1,805)</b>	(55)	3,328	<b>(1,461)</b>	5,945
Asset retirement obligations (eliminations)	<b>(117)</b>	-	43	<b>(74)</b>	(641)
Property disposition	<b>(6,816)</b>	-	33	<b>(6,816)</b>	(16,913)
Total capital expenditures	\$ <b>(3,015)</b>	\$ 3,849	\$ 5,849	\$ <b>13,974</b>	\$ 1,522

For the quarter ending September 30, 2011, the Company finished the completion and equipped for production one Wapiti Cardium well (0.56 net). The well was completed with multi-frac completion techniques. The capital expenditures for the quarter included these completion costs and the pipeline and facility costs to bring the well on production as well as the drilling costs for the well which were transferred from exploration and evaluation capital during the quarter. As of September 30, 2011, the Company had earned a total of \$6.2 million dollars of Alberta Royalty Drilling Credits of which \$2.7 million had been collected. Due to the low commodity price environment during this credit program, the Company did not incur sufficient Crown royalty expense to collect the remaining \$3.5 million. As most companies that earned credits during this program also had excess credits over royalty expense, there was no market to sell any of these surplus credits and accordingly, these amounts expired at March 31, 2011.

## CAPITALIZATION AND CAPITAL RESOURCES

The Company's total capitalization was \$64.4 million at September 30, 2011 with the market value of Class A and Class B shares representing 55% of the total capitalization (\$109.9 million at December 31, 2010 with the market value of Class A and Class B shares representing 79%). The market value of the Company's shares at September 30, 2011 was \$35.2 million (\$86.6 million – December 31, 2010).

Capitalization	September 30, 2011	December 31, 2010
Bank debt (\$000's)	\$ 25,964	\$ 16,494
Working capital deficiency (\$000's) <sup>(1)</sup>	3,211	6,746
Net debt (\$000's)	29,175	23,240
Class A shares outstanding	65,553,018	65,536,768
Class A share price <sup>(2)</sup>	\$ 0.46	\$ 1.19
Class A market capitalization (\$000's)	\$ 30,154	\$ 77,989
Class B shares outstanding	1,053,540	1,053,540
Class B share price <sup>(2)</sup>	\$ 4.79	\$ 8.20
Class B market capitalization (\$000's)	\$ 5,047	\$ 8,639
Total market capitalization (\$000's)	\$ 35,201	\$ 86,628
<b>Total capitalization (\$000's)</b>	<b>\$ 64,376</b>	<b>\$ 109,868</b>
Net debt as a percent of total capitalization	45%	21%
Funds flow from operations (\$000's) <sup>(3)</sup>	\$ 13,356	\$ 17,088
Net debt to funds flow from operations ratio	2.18	1.36

(1) Working Capital excludes the current portion of deferred income taxes and financial contracts.

(2) Represents the closing price on the TSX Venture Exchange at period end.

(3) Funds flow from operations is calculated as cash flow from operations before the change in non-cash operating working capital and expenditures on abandonments. Funds flow from operations at September 30, 2011 is the nine months funds flow of \$10.0 million annualized.

### Bank facility

As at September 30, 2011, the Company had a revolving demand credit facility with an authorized borrowing amount of \$40 million, with interest and other fees charged at the bank's prime rate plus a rate as determined by a pricing grid. The Company also has a development line in the amount of \$8 million that can be accessed for development projects, subject to lender review. Collateral for the facility consists of a general security agreement, providing a security interest over all present and after acquired personal property and a floating charge on all present and after acquired land interests of the Company.

At September 30, 2011, the revolving demand credit facility was drawn to \$26.0 million. The Company also had an issued letter of credit in the amount of approximately \$0.1 million.

The next interim review is scheduled for April, 2012. These reviews are based primarily on reserves and using commodity prices estimated by the lender, as well as other factors. A decrease in the borrowing base could result in a reduction to the credit facility available upon the next scheduled review which may require a repayment to the bank.

### Investing program funding

(\$000's)	Three months ended September 30		Nine months ended September 30	
	2011	2010	2011	2010
Funds flow from operations	\$ 2,773	\$ 4,389	\$ 10,017	\$ 13,150
Changes in non-cash working capital	3,036	(300)	(3,535)	(1,026)
Expenditures on abandonments	-	-	(2)	(21)
Proceeds from issuance of shares/options (net of costs)	-	4	19	27
Proceeds from (repayment of) bank debt	(6,519)	1,462	9,470	(26,890)
Proceeds from property disposition	4,519	-	4,519	33,090
Change in cash during the period	-	-	-	-
Capital expenditures funded by cash during the period	\$ 3,809	\$ 5,555	\$ 20,488	\$ 18,330

The Company's capital investment program during the relevant periods was funded by the issuance of equity, sale of assets, draws or repayments on credit facilities and cash flows.

## Working capital

The capital intensive nature of the Company's activities may create a negative working capital position in periods with high levels of capital investment. The working capital (excluding the current portion of financial contracts) increased from a deficit of \$23.2 million as at December 31, 2010 and a deficit of \$12.4 million as at September 30, 2010 to a deficit of \$29.2 million as at September 30, 2011 as a result of the capital program during the respective periods.

Substantially all of the Company's petroleum and natural gas production is marketed to purchasers with investment grade credit ratings. The industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of crude oil and natural gas. This occurs on the 25<sup>th</sup> day following the month of sale. As a result, the Company's production revenues are collected in a timely fashion. The Company monitors its revenue counterparty credit positions to mitigate any potential credit losses. To the extent the Company has joint interest partners in its activities it must collect, on a monthly basis, all of its partners' share of capital and operating expenses. These are subject to normal collection risk. The Company normally collects significant amounts related to partners' share of capital amounts in advance of expenditures taking place, in accordance with standard industry operating procedures. Accounts payable consist of amounts payable to suppliers on field operating activities and capital spending activities. These invoices are processed within the Company's normal payment period. At September 30, 2011, the Company had no material accounts receivable that it deemed uncollectible.

The Company actively manages its capital structure. The Company's objectives when managing capital are to maintain a flexible capital structure to allow it to execute on its capital investment program, which includes investing in oil and gas activities that may or may not be successful. The Company will strive to balance the proportion of debt and equity in its capital structure to take into account the level of risk being incurred in its capital expenditures.

## GUARANTEES/OFF-BALANCE SHEET ARRANGEMENTS

The Company has no guarantees or off-balance sheet arrangements, except for certain lease agreements. Seaview has certain lease agreements that are entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or G&A expense depending on the nature of the lease. No asset or liability value has been assigned to these leases on the balance sheet as at September 30, 2011. The total future obligation from these operating leases is described below in the section "Contractual obligations and commitments".

## CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company must pay Crown royalties, surface rentals, mineral taxes and abandonment and reclamation costs with respect to its ongoing ownership of hydrocarbon production rights. The amounts paid with respect to these burdens will depend on the future ownership, production, commodity prices and regulatory environment at the time.

The Company enters into natural gas and crude oil financial contracts from time to time, some of which may have premiums attached to them (see Note 4). The future premiums Seaview is committed to pay are included in the table below.

The Company's future contractual commitments are highlighted below:

	Total	2011	2012
Operating leases	\$ 335	72	263
Financial instrument premiums	\$ 396	396	-
Total contractual obligations	\$ 731	468	263

## CRITICAL ACCOUNTING ESTIMATES

The reader is advised that the critical accounting estimates, policies and practices as described in the MD&A at December 31, 2010 in conjunction with those discussed in the notes to the unaudited condensed interim consolidated financial statements at March 31, 2011 continue to be critical in determining Seaview's financial results as at September 30, 2011.

## CHANGES IN ACCOUNTING POLICIES AND RECENT ACCOUNTING PRONOUNCEMENTS

### *International Financial Reporting Standards ("IFRS")*

On January 1, 2011, the Company transitioned to IFRS, with the date of adoption of January 1, 2010. On the date of adoption, the Company restated the account balances to IFRS and the financial reporting will be in accordance with IFRS hereafter. A full description of the new accounting policies is outlined in Note 3 to the unaudited condensed interim consolidated financial statements for the Company for the period ended March 31, 2011. Additionally, transition date information and reconciliations between IFRS and previous GAAP for comparative periods in 2010 are described in Note 15 to the unaudited condensed interim consolidated financial statements for the Company for the periods ended March 31, 2011, June 30, 2011 and September 30, 2011. The adoption of IFRS has not led to any changes in the business operations, capital strategies or funds flow of the Company.

Seaview's significant areas of impact include property, plant and equipment, share based payments, depletion, depreciation and accretion and Class B share classification. The following discussion provides an overview of these areas as well as the exemptions available under IFRS 1, "First-time Adoption of International Financial Reporting Standards" ("IFRS 1"). IFRS 1 provided entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS.

- **Property, plant and equipment ("PP&E"):** Under previous GAAP, Seaview applied full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of natural gas and crude oil reserves were capitalized on a country-by-country cost centre basis. Costs accumulated within each country cost centre were depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, Seaview has adopted new accounting policies for upstream activities, including pre-exploration costs, exploration and evaluation costs and development costs, as discussed below.

Pre-exploration costs are expenditures incurred prior to obtaining the legal right to explore and must be expensed under IFRS. Under previous GAAP, Seaview capitalized and depleted such costs within the full cost pool. These costs are not anticipated to be significant to the Company.

Exploration and Evaluation costs ("E&E") are expenditures incurred for an area or property for which technical feasibility and commercial viability has not been determined. Upon transition to IFRS, Seaview has re-classified all E&E expenditures that were included in the PP&E balance under previous GAAP on the consolidated balance sheet. This includes the cost for Seaview's undeveloped exploratory land that relates to exploration properties. Seaview will not amortize its E&E assets but will assess them for impairment when there are indicators for possible impairment, such as allowing the mineral rights lease to expire or a decision to no longer pursue exploration and evaluation of a specific E&E asset, at which time the costs would be expensed. Upon transition to IFRS, approximately \$0.4 million of PP&E was reclassified on the balance sheet to intangible exploration costs representing E&E assets.

Development costs are expenditures incurred for an area or property where technical and commercial feasibility has been determined. Seaview will continue to capitalize these costs. Under previous GAAP, these costs were depleted on a unit-of-production basis at a country cost centre level but under IFRS these costs will be depleted on a unit-of-production basis over an area level (unit of account). Also under IFRS, a company has the option of choosing the reserve base that it will use for its depletion calculation, whether proven reserves, which is consistent with previous GAAP, or proven plus probable reserves. Seaview has determined that it will use proven reserves as the basis over which its depletion will be calculated. Accordingly, depletion costs will be consistent with the amount that would have been calculated under previous GAAP.

Divestitures of an oil and gas property under IFRS will generally result in a gain or loss recognized in earnings. Under previous GAAP, proceeds of divestitures were deducted from the full cost pool without recognition of a gain or loss unless such a deduction resulted in a change to the depletion rate of 20 percent or greater. Seaview has a restatement to the comparative second quarter 2010 financial statements showing a gain on sale regarding the disposition of our Saskatchewan properties in April 2010.

As at the date of transition, being January 1, 2010, for entities using the full cost accounting method, IFRS 1 provided an option to deem the cost of its PP&E assets to equal its previous GAAP net book value. Seaview has applied this option. The IFRS E&E costs will be equal to those that would have been recognized as such under previous GAAP using proved plus probable reserves as a basis for determining technical feasibility and commercial viability. The remaining net book value of the full cost pool on the date of transition following the removal of E&E costs was allocated to the unit of account development cost centres on the basis of Seaview's proved plus probable reserve values.

- Impairment of PP&E assets: Under IFRS, impairment tests of PP&E must be performed at a cash-generating unit level instead of at the country cost centre under previous GAAP using the greater of value in use or fair value less costs to sell. Assets will be assessed for impairment when indicators suggest the possibility of impairment; therefore, there may be more frequent impairments of assets under IFRS. Under IFRS, impairment losses, other than goodwill, are reversed when there is an increase in the recoverable amount. Seaview has grouped its assets into cash-generating units, which were identified on the basis of cash inflows being independent from other assets or groups of assets, and will test them for impairment using the greater of value in use or fair value less costs to sell. Assets were required to be assessed for impairment upon transition to IFRS. A small impairment of oil and gas assets of approximately \$2.5 million was calculated on transition to IFRS, having used the fair value less costs to sell to measure the fair value of its cash-generating units. As well, Seaview has determined an impairment to its Goodwill balance at transition which has been written off from its opening IFRS balance sheet as at January 1, 2010.
- Provisions: Under IFRS, decommissioning obligations, disclosed as asset retirement obligations under previous GAAP, can be calculated using either a risk free discount rate, which differs from previous GAAP, or a credit adjusted risk-free interest rate, which is consistent with previous GAAP, to discount future cash flows. Seaview has used the credit adjusted risk-free rate and therefore charges remain the same as the amount that had been calculated under previous GAAP. Under IFRS, the unwinding of the discount rate is charged as interest expense versus accretion expense under previous Canadian standards.
- Share based compensation: Under IFRS 2 “Share-based Payments”, awards that vest in installments must be accounted for as though each installment is a separate award and amortized using a graded vesting model. This results in front loading of share based compensation expense. In addition, under IFRS, a forfeiture rate must be included in the initial expense calculation, and adjusted prospectively if required, rather than accounting for forfeitures as they occur. IFRS 1 allows for an exemption from IFRS 2 for share based payments which have vested before Seaview’s transition to IFRS. As a result of applying IFRS 2, the Company has an increase to contributed surplus of approximately \$1.3 million with a corresponding increase to the January 1, 2010 deficit.
- Income taxes: IFRS does not use the terminology of future income taxes; IFRS refers to deferred income taxes. The transition to IFRS requires the Company to re-measure its deferred income taxes for its January 1, 2010 balance sheet. Adjustments to deferred income taxes were made accordingly in conjunction with other transitional IFRS adjustments discussed earlier, with an offsetting adjustment to the January 1, 2010 deficit.

In addition to the adjustments required to deferred income taxes as a result of the January 1, 2010 transitional adjustments, the Company has made adjustments for its comparative periods in 2010 for share issue costs, flow-through shares and the reclassification of the Class B shares as a liability. Under previous GAAP, the accounting treatment of flow-through shares is addressed by EIC 146 – “Flow-Through Shares”. The proceeds received for the flow-through shares are credited to shareholders’ capital and the deferred tax liability is recognized when the company files the renouncement documents with the tax authorities to renounce the tax credits associated with the expenditures.

Under IFRS, Seaview has set up a liability for the difference between the proceeds received and the market price of the shares on the date of the transaction (the “premium”). As the qualifying expenditures are incurred, Seaview will record the tax liability associated with the expenditures and renouncements of the tax benefits and reverse the deferred liability originally set up related to those costs incurred in a particular quarter. The difference between the deferred tax liability and the original liability set up will go through profit and loss.

A temporary difference exists for share issue costs under previous GAAP and IFRS. The difference between previous GAAP and IFRS result in a deferred tax liability being recorded. Unlike previous GAAP, changes in the deferred tax liability are recognized where they were originally recognized; therefore, changes in the deferred tax liability related to share issue costs are recorded against share capital as opposed to profit and loss. The Company does not have any transitional adjustments related to share issue costs.

- Risk-Sharing Arrangements and Dispositions: Under IFRS, risk-sharing agreements in which Seaview cedes a portion of its working interest to a third party are generally considered to be disposals of property, plant and equipment, potentially resulting in a gain or loss on disposition. Under previous GAAP, no gain or loss was recorded on these or other dispositions where the change in consolidated depletion is less than 20 percent. There is no equivalent exemption in IFRS. As a result, Seaview will record gains or losses on risk-sharing arrangements and other disposition transactions under IFRS. There is no impact on transition to IFRS as a result of this requirement. Subsequent to transition, the significance of these gains or losses will be dependent on the details of specific transactions.
- Business Combinations: An exemption under IFRS 1 provides the entity with relief on the restatement of business combinations prior to the transition date. Under IFRS 3 – “Business Combinations”, the determination of the fair value of share consideration differs from the determination under previous Canadian accounting standards. Any difference in the fair value calculation would have a resulting impact on the carrying amount of net assets acquired, non-controlling

interest and any goodwill. The Company has made the election under IFRS 1, allowing Seaview to be exempt from restating business combinations prior to the transition date to IFRS.

- Convertible Class B share liability: Under previous GAAP, the Company's convertible Class B shares were presented as equity while under IFRS, the Class B shares do not qualify for equity presentation and must be presented as a liability. This is because the number of Class A shares required to be issued on conversion is not known until the Company exercises the conversion. As such, the Company has retrospectively adjusted the presentation of its \$11.7 million Initial Public Offering ("IPO") on October 17, 2007, which included the convertible Class B shares.
- Seaview does not expect changes to its financial statements as a result of IFRS to affect any covenants related to bank debt.

Seaview is determining which additional changes to internal controls over financial reporting will be required to deal with the changes in accounting policies. This will be ongoing throughout the balance of 2011 to ensure all changes in accounting policies include appropriate additional controls and procedures for future IFRS reporting requirements. Seaview does not expect any material changes to internal controls.

## **NEW AND PENDING ACCOUNTING STANDARDS**

The following pronouncements from the IASB will become effective for financial reporting periods beginning on or after January 1, 2013 and have not yet been adopted by the Company. All of these new or revised standards permit early adoption with transitional arrangements depending upon the date of initial application.

IFRS 10 – *Consolidated Financial Statements* builds on existing principles and standards and identifies the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company.

IFRS 11 – *Joint Arrangements* establishes the principles for financial reporting by entities when they have an interest in arrangements that are jointly controlled.

IFRS 12 – *Disclosure of Interest in Other Entities* provides the disclosure requirements for interests held in other entities including joint arrangements, associates, special purpose entities and other off balance sheet entities.

IFRS 13 – *Fair Value Measurement* defines fair value, requires disclosure about fair value measurements and provides a framework for measuring fair value when it is required or permitted within the IFRS standards.

IAS 12 – *Income Taxes* removes subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through sale of the asset.

IAS 28 – *Investments in Associate and Joint Ventures* revised the existing standard and prescribes the accounting for investments and sets out the requirements for the application of the entity method when accounting for investments in associates and joint ventures.

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

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

## **RISK ASSESSMENT**

The reader is advised that the risk assessment for the Company is fully described in the MD&A at December 31, 2010 and is relevant to the readers' understanding of the Company's financial results as at September 30, 2011.

## **ADDITIONAL INFORMATION**

Additional information relating to the Company is filed on SEDAR and can be viewed at [www.sedar.com](http://www.sedar.com). Information can also be obtained by contacting the Company at Seaview Energy Inc. 1500, 444 - 5th Avenue S.W., Calgary, Alberta, Canada T2P 2T8 or by email at [info@Seaviewenergy.com](mailto:info@Seaviewenergy.com). Information is also accessible on the Company's web site at [www.Seaviewenergy.com](http://www.Seaviewenergy.com).

## COMMONLY USED ABBREVIATIONS

boe	Barrel of oil equivalent
boe/d	Barrel of oil equivalent per day
gj	Gigajoule
gj/d	Gigajoule per day
mboe	Thousand barrels of oil equivalent
mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
mmcf	Million cubic feet
mmcf/d	Million cubic feet per day
bbl	Barrel
bbl/d	Barrels per day
MMBTU	Million British Thermal Units
6:1	Boe conversion ratio of six mcf to one bbl

# CORPORATE INFORMATION

## OFFICERS AND SENIOR MANAGEMENT

**Michael J.J. Wuetherick**, P.Eng  
President and Chief Executive Officer

**H. Scott Oldale**  
Vice President, Exploration and Chief Operating Officer

**Stephanie A. Bunch**, CA  
Vice President, Finance and Chief Financial Officer

**Davin Chandler**, P.Eng  
Vice President, Engineering

**Timothy L. Campbell**  
Vice President, Land

## DIRECTORS

**Daryl Gilbert**, P.Eng, Calgary, Alberta  
Chairman  
Reserves Committee Chair and  
Health, Safety & Environment Committee Chair

**James Howe**, <sup>(4)</sup> CA, Calgary, Alberta  
Audit Committee Chair

**Gregory Turnbull**, <sup>(3)</sup> LLB, Calgary, Alberta  
Corporate Governance Committee Chair

**Steven VanSickle**, <sup>(1),(2),(5)</sup> Calgary, Alberta  
Compensation Committee Chair

**Robert Peters**, <sup>(3),(4)</sup> Calgary, Alberta  
Director

**Michael Culbert**, <sup>(1)</sup> Calgary, Alberta  
Director

**Bruce Francis**, <sup>(2),(5)</sup> P.Eng, Calgary, Alberta  
Director

**Michael J.J. Wuetherick**, P.Eng, Calgary, Alberta  
President, Chief Executive Officer and Director

**H. Scott Oldale**, Calgary, Alberta  
Vice President, Exploration, Chief Operating Officer and Director

**Sanjib Gill**, LLB, Calgary, Alberta  
Corporate Secretary

<sup>(1)</sup> Member of the Audit Committee

<sup>(2)</sup> Member of the Reserves Committee

<sup>(3)</sup> Member of the Compensation Committee

<sup>(4)</sup> Member of the Corporate Governance Committee

<sup>(5)</sup> Member of the Health, Safety and Environment Committee

## BANKERS

National Bank of Canada

## PETROLEUM CONSULTANTS

Sproule Associates Limited  
Calgary, Alberta

## LEGAL COUNSEL

McCarthy Tétrault LLP  
Calgary, Alberta

## AUDITORS

KPMG LLP  
Calgary, Alberta

## REGISTRAR AND TRANSFER AGENT

Olympia Trust Company  
Calgary, Alberta

## STOCK EXCHANGE LISTING

TSX - Venture: CVU.A & CVU.B

## INVESTOR RELATIONS

Telephone: (403) 450-3713  
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E-mail: info@seaviewenergy.com

# SEAVIEW ENERGY INC

The logo for Seaview Energy Inc features the company name in a bold, black, sans-serif font. The word "SEAVIEW" is on the top line and "ENERGY INC" is on the bottom line. A thin blue horizontal bar is positioned below the text, with a thin orange horizontal bar overlapping it from the left side. A stylized orange sun or globe icon is partially visible behind the letter "V" in "SEAVIEW".

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