

## 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 August 17, 2011 and should be read in conjunction with the unaudited condensed interim consolidated financial statements and selected notes for the periods ended June 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 six months ended June 30, 2011 and 2010 is as follows:

	Three months ended June 30		Six months ended June 30	
(\$ thousands except per share amounts)	2011	2010	2011	2010
Funds flow from operations	\$ 4,297	\$ 4,320	\$ 7,244	\$ 8,761
Decommissioning expenditures	-	-	(2)	(21)
Changes in non-cash working capital	(1,090)	(576)	(820)	1,996
Cash provided by operating activities	\$ 3,207	\$ 3,744	\$ 6,422	\$ 10,736
Funds flow from operations per share (basic)	\$ 0.07	\$ 0.07	\$ 0.05	\$ 0.13
Expenditures on abandonments	0.00	0.00	0.00	0.00
Changes in non-cash working capital per share (basic)	(0.02)	(0.01)	0.00	0.03
Cash provided by operating activities per share (basic)	\$ 0.05	\$ 0.06	\$ 0.05	\$ 0.16

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 (\$000's except per share amounts)</b>	<b>Q2 2011</b>	<b>Q1 2011</b>	<b>% Change</b>
Petroleum and natural gas sales	\$ 8,478	\$ 6,382	33%
Funds flow from operations <sup>(1)</sup>	4,297	2,947	46%
Basic and diluted per share <sup>(2)</sup>	0.07	0.05	40%
Net loss	(1,650)	(2,778)	41%
Basic and diluted per share <sup>(2)</sup>	(0.03)	(0.04)	25%
Capital expenditures <sup>(3)</sup>	3,712	12,967	(71%)
<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)	13,810	12,286	12%
Light oil and NGLs (bbl/d)	437	277	58%
Total production (boe/d)	2,739	2,325	18%
Average realized sales price (net of risk management gains)			
Natural gas (per mcf)	\$ 4.56	\$ 4.38	4%
Light oil and NGL (per bbl)	75.97	71.78	6%
Netback per boe <sup>(1)</sup>			
Sales price	\$ 34.01	\$ 30.50	12%
Realized risk management gains	1.10	1.20	(8%)
Sales price (net of realized risk management gains)	35.11	31.70	11%
Royalties	(4.90)	(3.65)	34%
Operating expenses	(8.39)	(8.36)	-
Transportation	(1.37)	(1.43)	(4%)
Operating netback <sup>(1)</sup>	\$ 20.45	\$ 18.26	12%

(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 OPERATIONAL OVERVIEW OF SECOND QUARTER 2011

- o Average production for Q2 2011 was up 18% to 2,739 boe per day compared to Q1 2011 volumes of 2,325 boe per day;
- o Liquids production increased by 58% and natural gas increased by 12% compared to Q1 2011 as a result of the Cardium wells brought on stream;
- o Operating netbacks increased by 12% to \$20.45 per boe compared to \$18.26 per boe in Q1 2011;

- Funds flow from operations for Q2 2011 increased 46% to \$4.3 million compared to Q1 2011 funds flow of \$2.9 million. The increase in funds flow is primarily attributed to the combination of the 18% production increase and 11% increase in realized prices;
- Subsequent to the quarter end, 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, and will be redirected towards the Wapiti Cardium capital program.

## RESULTS OF OPERATIONS

### Operations

For the three and six months ended June 30, 2011, the Company recorded a net loss of \$1.7 million and \$4.4 million, respectively, (net income of \$10.0 million and \$9.8 million for the three and six months ended June 30, 2010).

The following table summarizes selected information for the three months ended June 30, 2011 (the "Quarter" or "Q2 2011"), for the three months ended March 31, 2011 (the "Previous Quarter" or "Q1 2011") and for the second quarter of 2010 (the "Prior Year Q2" or "Q2 2010"), as well as the year to date information for the periods ended June 30, 2011 ("YTD 2011") and June 30, 2010 ("YTD 2010"):

	Q2 2011	Q1 2011	Q2 2010	YTD 2011	YTD 2010
Daily Production					
Natural gas (mcf/d)	13,810	12,286	17,084	13,052	16,815
Crude oil and NGL's (bbl/d)	437	277	374	358	426
Boe/d day @ 6:1	2,739	2,325	3,221	2,533	3,229
Petroleum and natural gas sales (\$000's)	\$ 8,478	\$ 6,382	\$ 8,894	\$ 14,860	\$ 19,950
Funds flow from operations (\$000's)	4,297	2,947	4,320	7,244	8,761
Per share – basic	0.07	0.05	0.07	0.05	0.13
Per share – diluted	0.07	0.05	0.05	0.05	0.11
Net income (loss) (\$000's)	(1,650)	(2,778)	10,010	(4,428)	9,775
Per share – basic	(0.03)	(0.04)	0.15	(0.07)	0.15
Per share – diluted	(0.03)	(0.04)	0.13	(0.07)	0.13

The increase in volumes over Q1 2011 is attributed to Wapiti Cardium production additions at the end of Q1 2011 and beginning of Q2 2011.

### Commodity prices

Average realized prices	Q2 2011	Q1 2011	Q2 2010	YTD 2011	YTD 2010
Light crude oil (per bbl)	\$ 94.52	\$ 84.74	\$ 74.82	\$ 90.01	\$ 76.29
after realized risk management gains/losses	83.95	72.55	70.97	78.68	72.67
Natural gas (per mcf)	4.18	3.97	4.11	4.08	4.66
after realized risk management gains/losses	4.56	4.38	4.59	4.47	4.85
Natural gas liquids (per bbl)	68.75	70.36	70.64	69.22	69.73
Total per boe	34.01	30.50	30.35	32.41	34.14
after realized risk management gains	35.11	31.70	32.57	33.55	34.76
<b>BENCHMARK PRICES</b>					
WTI oil (US\$ per bbl)	102.54	94.13	77.85	98.36	78.27
AECO Daily Index (CAD\$ per gj)	3.67	3.58	3.69	3.63	4.18
Currency (US\$/CAD\$)	0.9676	0.9860	1.027	0.9768	1.034

The AECO Daily Index gas price averaged \$3.67 per gj or \$3.87 per mcf for Q2 2011 as compared to \$3.58 per gj or \$3.78 per mcf during the Previous Quarter. The natural gas price received by Seaview, before risk management gains, was \$4.18 per mcf for the Quarter compared to \$3.97 per mcf for Q1 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\$102.54 per bbl during the Quarter compared to US\$94.13 per bbl during Q1 2011. Seaview received a combined average price, including natural gas liquids and before risk management effects, of \$81.00 per bbl during the Quarter compared to \$79.72 during the Previous Quarter.

The Canadian dollar averaged US\$0.9676 during the Quarter as compared to \$0.9860 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 six months ended June 30, 2011, realized gains of \$0.3 million and \$0.5 million, respectively, were recorded as revenue (six months ended June 30, 2010 – realized gains of \$0.4 million). As at June 30, 2011, the Company recorded a liability related to the unrealized losses on financial contracts of \$2.5 million reflecting the fair value of the crude oil and natural gas contracts outstanding at June 30, 2011 (December 31, 2010 – a liability of \$1.0 million; June 30, 2010 – an asset of \$0.3 million).

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

Natural gas	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 hedged for the period of July 2011 to December 2013 are detailed below.

Natural Gas	Q3 '11	Q4 '11	2013
<b>Puts</b>			
Volumes – gj/d	8,140	8,140	
Net floor (\$/gj)	\$4.18	\$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	200	
Net floor (CAD\$/bbl)	\$75.00	\$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, 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)	Q2 2011		Q1 2011		Q2 2010		YTD 2011		YTD 2010	
Natural gas	\$	5,254	\$	4,394	\$	6,394	\$	9,648	\$	14,178
Crude oil and natural gas liquids		3,224		1,988		2,500		5,212		5,772
Realized risk management gains		273		250		649		523		366
Petroleum and natural gas sales (net)	\$	8,751	\$	6,632	\$	9,543	\$	15,383	\$	20,316
\$/boe	\$	35.11	\$	31.70	\$	32.57	\$	33.55	\$	34.76

Petroleum and natural gas sales for the Quarter, before royalties and transportation costs, were \$8.8 million (\$6.6 million – Previous Quarter; \$9.5 million – Q2 2010). The increase from Q1 2011 is attributable to an 18% increase in production as well as an 11% increase 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 \$0.2 million – Previous Quarter).

#### Royalties

(\$000's)	Q2 2011		Q1 2011		Q2 2010		YTD 2011		YTD 2010	
Royalties	\$	1,223	\$	764	\$	1,414	\$	1,987	\$	3,139
Percentage of petroleum and natural gas sales (before realized risk management gains)		14.4%		12.0%		15.9%		13.4%		15.7%
\$/boe	\$	4.90	\$	3.65	\$	4.83	\$	4.33	\$	5.37

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 \$1.2 million (\$0.8 million – Previous Quarter; \$1.4 million – Q2 2010). As a percentage of sales, royalties averaged 14.4% or \$4.90 per boe during the Quarter (12.0% and \$3.65 per boe for the Previous Quarter; 15.9% and \$4.83 per boe – Q2 2010). The royalty rate for Q2 2011 is higher than the Previous Quarter due to a higher Crown reference price as well as having several wells reaching their production limits for the above referenced 5% royalty rate during the quarter. The overall royalty rate remains lower than the Prior Year Q2 as the Company still has approximately 29% of its production attracting the 5% royalty rate.

## Operating expenses

(\$000's)	Q2 2011	Q1 2011	Q2 2010	YTD 2011	YTD 2010
Operating expenses	\$ 2,090	\$ 1,749	\$ 2,365	\$ 3,839	\$ 5,597
\$/boe	\$ 8.39	\$ 8.36	\$ 8.07	\$ 8.37	\$ 9.58

Operating expenses for the Quarter were \$2.1 million (\$1.7 million – Previous Quarter; \$2.4 million – Q2 2010) and on a unit-of-production basis, operating expenses averaged \$8.39 per boe (\$8.36 per boe – Previous Quarter; \$8.07 per boe – Q2 2010). The operating expenses on a per boe basis for the Quarter are consistent with both the Previous Quarter and Q2 2010.

## Transportation expense

(\$000's)	Q2 2011	Q1 2011	Q2 2010	YTD 2011	YTD 2010
Transportation expense	\$ 341	\$ 300	\$ 405	\$ 641	\$ 781
\$/boe	\$ 1.37	\$ 1.43	\$ 1.38	\$ 1.40	\$ 1.33

For the Quarter, transportation expense totaled \$0.3 million or \$1.37 per boe (\$0.3 million or \$1.43 per boe – Previous Quarter; \$0.4 million or \$1.38 per boe – Q2 2010). As Seaview's production is weighted approximately 85% 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 Q2 2010.

## General and administrative ("G&A")

(\$000's)	Q2 2011	Q1 2011	Q2 2010	YTD 2011	YTD 2010
G&A expenses	\$ 966	\$ 1,023	\$ 1,340	\$ 1,989	\$ 2,641
Capitalized G&A	(385)	(340)	(442)	(725)	(961)
Overhead recoveries	(171)	(181)	(147)	(352)	(264)
Net G&A expenses	410	502	751	912	1,416
\$/boe	\$ 1.65	\$ 2.40	\$ 2.56	\$ 1.99	\$ 2.42

During the Quarter, G&A, net of overhead recoveries on operated properties and capitalized expenditures, totaled \$0.4 million (\$0.5 million – Previous Quarter; \$0.8 million – Q2 2010). On a unit-of-production basis, G&A expenses were \$1.65 per boe (\$2.40 per boe – Previous Quarter; \$2.56 per boe – Q2 2010). The G&A per boe for the Quarter was lower than the Previous Quarter due to the increase in production with no corresponding increase in G&A expenses.

## Finance expense

(\$000's)	Q2 2011	Q1 2011	Q2 2010	YTD 2011	YTD 2010
Interest expense	\$ 377	\$ 202	\$ 288	\$ 579	\$ 622
Unrealized gain on financial contracts	-	-	(5)	-	(24)
Accretion on decommissioning obligations	46	44	39	90	92
Accretion on Convertible Class B share liability	186	182	172	368	341
Net finance expense	609	428	494	1,037	1,031
\$/boe	\$ 2.44	\$ 2.05	\$ 1.69	\$ 2.26	\$ 1.76

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 \$1.51 per boe (\$0.2 million or \$0.96 per boe – Previous Quarter; \$0.3 million or \$0.98 per boe – Q2 2010) which also included \$0.1 million of non-recurring renewal fees. The average balance of debt drawn during the Quarter was \$30.1 million (\$21.0 million – Previous Quarter; \$22.6 million – Q2 2010), with an average interest rate of 4.1% per annum paid during the Quarter (3.4% per annum – Previous Quarter; 3.2% per annum – Q2 2010). Included in interest expense are standby fees of 0.4% per annum based on an average unutilized debt capacity of \$21.9 million for the Quarter (\$31.0 million – Previous Quarter; \$29.4 million – Q2 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 June 30, 2011, 5,589,500 options were outstanding with an average exercise price of \$1.40 and a weighted average remaining contractual life of 2.7 years (5,233,750 options outstanding at June 30, 2010 at an average exercise price of \$1.51 with a weighted average remaining contractual life of 3.4 years). Of the total number of options outstanding at

June 30, 2011, options totaling 3,298,352 are vested and available for exercise at a weighted average exercise price of \$1.44 per option.

For the Quarter and YTD 2011, the Company recorded a compensation expense of \$0.1 million and \$0.3 million, respectively (\$0.1 million – Previous Quarter; \$0.2 million and \$0.5 million, respectively – Q2 2010 and YTD 2010) and capitalized \$0.1 million and \$0.3 million, respectively (\$0.1 million – Previous Quarter; \$0.2 million and \$0.5 million, respectively – Q2 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 \$6.0 million and \$10.9 million, respectively (\$4.9 million – Previous Quarter; \$6.0 million and \$12.0 million, respectively – Q2 2010 and YTD 2010). On a unit-of-production basis, D&D costs averaged \$24.14 per boe for Q2 2011 (\$23.54 per boe – Previous Quarter; \$20.45 per boe – Q2 2010 and YTD 2010). D&D per boe for Q2 2011 is higher than Q1 2011 as the increase in the depletable base due to completion and equip and tie-in capital spending on the new Wapiti wells during the quarter had no corresponding increase in the proven reserve base (reserves were added in prior quarters). In comparing the Quarter to the Prior Year Q2, 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 \$12,700 of pre-license exploration costs (\$0.2 million – Previous Quarter; nil – Q2 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 June 30, 2011 of commodity contracts outstanding was an unrealized loss or a liability, net of unrealized gains, of \$2.5 million (December 31, 2010 – unrealized loss (liability) of \$1.0 million). During the Quarter, the Company recorded an unrealized loss of \$0.1 million, and YTD 2011 recorded an unrealized loss of \$1.5 million, as a result of the change in fair value over the respective periods (\$1.4 million loss – Previous Quarter; \$0.8 million gain and a \$1.9 million loss, respectively – Q2 2010 and YTD 2010). Forward strip prices for crude oil have increased during Q2 2011 resulting in unrealized losses for the quarter while natural gas prices have decreased only slightly from the year end 2010 prices resulting in offsetting unrealized gains for Q2 2011.

#### **Deferred income taxes**

A deferred income tax reduction of \$0.5 million and \$1.5 million has been recorded for the Quarter and YTD 2011, respectively (a reduction of \$1.0 million – Previous Quarter; an expense of \$3.3 million and \$4.2 million, respectively – Q2 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 \$1.7 million and \$4.4 million, respectively (\$2.8 million net loss – Previous Quarter; \$10.0 million and \$9.8 million net income, respectively – Q2 2010 and YTD 2010). Basic and diluted net loss per share for the Quarter and YTD 2011 was \$0.03 and \$0.07, respectively (basic and diluted net loss per share of \$0.04 – Previous Quarter; basic net income per share of \$0.15 – Q2 2010 and YTD 2010, and diluted net income per share of \$0.13 – Q2 2010 and YTD 2010). Funds flow from operations was \$4.3 million and \$7.2 million for the Quarter and YTD 2011, respectively (\$2.9 million – Previous Quarter; \$4.3 million and \$8.8 million – Q2 2010 and YTD 2010). Basic and diluted funds flow from operations per share for the Quarter and YTD 2011 was \$0.07 and \$0.05, respectively (basic and diluted funds flow from operations per share was \$0.05 – Previous Quarter; basic funds flow from operations per share was \$0.07 and \$0.13, respectively – Q2 2010 and YTD 2010, and diluted funds flow from operations per share was \$0.05 and \$0.11, respectively – Q2 2010 and YTD 2010).

<b>Netbacks, Funds Flow from Operations and Net Income (Loss) (\$/boe)</b>						
	<b>Q2 2011</b>	<b>Q1 2011</b>	<b>Q2 2010</b>	<b>YTD 2011</b>	<b>YTD 2010</b>	
Petroleum and natural gas sales	\$ 35.11	\$ 31.70	\$ 32.57	\$ 33.55	\$ 34.76	
Less:						
Royalties	4.90	3.65	4.83	4.33	5.37	
Operating expenses	8.39	8.36	8.07	8.37	9.58	
Transportation expense	1.37	1.43	1.38	1.40	1.33	
Net operating income (operating netback)	\$ 20.45	\$ 18.26	\$ 18.29	\$ 19.45	\$ 18.48	
General and administrative	1.65	2.40	2.56	1.99	2.42	
Finance expense	2.44	2.05	1.69	2.26	1.77	
Funds flow from operations	\$ 16.36	\$ 13.81	\$ 14.04	\$ 15.20	\$ 14.29	
Depletion and depreciation	24.14	23.54	20.45	23.87	20.45	
Unrealized (gain) loss on financial derivatives	0.38	6.71	2.65	3.26	(3.23)	
Stock option compensation	0.53	0.69	0.61	0.61	0.84	
Gain on sale of property, plant and equipment	-	-	(55.08)	-	(27.63)	
Pre-license expenditures and other	0.05	0.80	-	0.40	-	
Future income tax (reduction) expense	(2.12)	(4.65)	11.26	(3.28)	7.13	
Net income (loss) (\$/boe)	\$ (6.62)	\$ (13.28)	\$ 34.15	\$ (9.66)	\$ 16.73	

## SELECTED QUARTERLY INFORMATION

<b>Financial</b> (\$000's except per share amounts) <sup>(4)</sup>	<b>Q3 2009</b> (CGAAP)	<b>Q4 2009</b> (CGAAP)	<b>Q1 2010</b> (restated under IFRS)	<b>Q2 2010</b> (restated under IFRS)	<b>Q3 2010</b> (restated under IFRS)	<b>Q4 2010</b> (restated under IFRS)	<b>Q1 2011</b>	<b>Q2 2011</b>
Petroleum and natural gas sales	\$ 8,664	\$ 10,377	\$ 11,056	\$ 8,894	\$ 6,486	\$ 6,950	\$ 6,382	\$ 8,478
Funds flow from operations <sup>(1)</sup>	4,110	5,024	4,441	4,320	4,388	3,938	2,947	4,297
Basic per share	0.06	0.08	0.07	0.07	0.07	0.06	0.05	0.07
Diluted per share <sup>(2)</sup>	0.06	0.08	0.07	0.05	0.07	0.06	0.05	0.07
Net income (loss)	(2,907)	(2,366)	(235)	10,010	(835)	(2,895)	(2,778)	(1,650)
Basic per share	(0.04)	(0.04)	0.00	0.15	(0.01)	(0.04)	(0.04)	(0.03)
Diluted per share <sup>(2)</sup>	(0.04)	(0.04)	0.00	0.13	(0.01)	(0.04)	(0.04)	(0.03)
Capital expenditures <sup>(3)</sup>	3,931	5,368	8,017	4,758	5,556	11,517	12,967	3,712
Property acquisitions (dispositions)	-	3,840	-	(16,807)	-	3,315	-	-
Net debt	36,131	40,309	43,896	11,230	12,395	23,240	33,244	32,659
<b>Shares outstanding at period end (000's)</b>								
Class A	65,419	65,433	65,454	65,479	65,489	65,537	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)	12,486	13,703	16,544	17,084	13,299	14,016	12,286	13,810
Light oil and NGLs (bbl/d)	432	445	480	374	322	305	277	437
Total production (boe/d)	2,513	2,729	3,237	3,221	2,538	2,641	2,325	2,739
Natural gas (per mcf)	\$ 5.43	\$ 6.06	\$ 5.12	\$ 4.59	\$ 4.34	\$ 4.48	\$ 4.38	\$ 4.56
Light oil and NGL (per bbl)	61.03	66.92	72.92	70.87	64.46	66.27	71.78	75.97
Netback per boe								
Sales price (net of risk management gains or losses)	\$ 37.47	\$ 41.33	\$ 36.98	\$ 32.57	\$ 30.89	\$ 31.45	\$ 31.70	\$ 35.11
Royalties	3.50	4.52	5.92	4.83	2.14	3.02	3.65	4.90
Operating expenses	11.34	11.80	11.10	8.07	5.12	5.44	8.36	8.39
Transportation	1.35	1.27	1.29	1.38	1.48	1.63	1.43	1.37
Operating netback	\$ 21.28	\$ 23.74	\$ 18.67	\$ 18.29	\$ 22.15	\$ 21.36	\$ 18.26	\$ 20.45

- (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 June 30		Six months ended June 30	
	2011	2010	2011	2010
Weighted average shares outstanding				
Basic	<b>65,553,018</b>	65,470,875	<b>65,547,541</b>	65,454,540
Diluted	<b>65,553,018</b>	79,906,564	<b>65,547,541</b>	79,902,614
Outstanding securities at period end				
Class A shares			<b>65,553,018</b>	65,479,350
Convertible Class B shares			<b>1,053,540</b>	1,053,540
Options, Class A shares			<b>5,589,500</b>	5,233,750
Outstanding securities at August 17, 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 six months ended June 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 six months ended June 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, capital expenditures totaled \$3.9 million and \$17.0 million, respectively (\$13.1 million – Previous Quarter; \$12.7 million and \$4.3 million recovery, respectively – Q2 2010 and YTD 2010). The table below summarizes the capital expenditures during the Quarter, the Previous Quarter and Q2 2010 as well as YTD 2011 and YTD 2010.

(\$000's)	Q2 2011	Q1 2011	Q2 2010	YTD 2011	YTD 2010
Geological and geophysical	\$ 12	\$ -	\$ 473	\$ 12	\$ 485
Drilling and Completions (gross)	<b>2,760</b>	8,538	5,007	<b>11,298</b>	9,515
Alberta Drilling Credits	-	-	-	-	(1,559)
Tangible equipment	<b>1,132</b>	4,160	584	<b>5,292</b>	2,245
Development Capital	\$ <b>3,904</b>	\$ 12,698	\$ 6,064	\$ <b>16,602</b>	\$ 10,686
Exploration & evaluation capital (note 9)	<b>(55)</b>	399	(1,063)	<b>344</b>	2,617
Asset retirement obligations	-	43	(757)	<b>43</b>	(684)
Property disposition	-		(16,946)	-	(16,946)
Total capital expenditures	\$ <b>3,849</b>	\$ 13,140	\$ (12,702)	\$ <b>16,989</b>	\$ (4,327)

For the quarter ending June 30, 2011, the Company finalized completions and equipped for production 3 Wapiti Cardium wells. These wells were completed with multi-frac completion techniques. The capital expenditures for the quarter included these completion costs as well as pipeline and facility costs to bring these wells on production at the end of the previous quarter or beginning of Q2 2011. As of June 30, 2011, the Company earned a total of \$6.2 million dollars of Alberta Royalty Drilling Credits of which \$2.6 million had been collected and \$0.1 million remains in accounts receivable. 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 \$105.8 million at June 30, 2011 with the market value of Class A and Class B shares representing 69% 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 June 30, 2011 was \$73.1 million (\$86.6 million – December 31, 2010).

<b>Capitalization</b>	<b>June 30, 2011</b>	December 31, 2010
Bank debt (\$000's)	\$ 32,483	\$ 16,494
Working capital deficiency (\$000's) <sup>(1)</sup>	176	6,746
<b>Net debt (\$000's)</b>	<b>32,659</b>	23,240
Class A shares outstanding	65,553,018	65,536,768
Class A share price <sup>(2)</sup>	\$ 0.99	\$ 1.19
Class A market capitalization (\$000's)	\$ 64,897	\$ 77,989
Class B shares outstanding	1,053,540	1,053,540
Class B share price <sup>(2)</sup>	\$ 7.78	\$ 8.20
Class B market capitalization (\$000's)	\$ 8,197	\$ 8,639
<b>Total market capitalization (\$000's)</b>	<b>\$ 73,094</b>	\$ 86,628
<b>Total capitalization (\$000's)</b>	<b>\$ 105,753</b>	\$ 109,868
Net debt as a percent of total capitalization	31%	21%
Funds flow from operations (\$000's) <sup>(3)</sup>	\$ 14,488	\$ 17,088
<b>Net debt to funds flow from operations ratio</b>	<b>2.25</b>	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 June 30, 2011 is the six months funds flow of \$7.2 million annualized.

### Bank facility

As at June 30, 2011, the Company had a revolving demand credit facility with an authorized borrowing amount of \$44 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 June 30, 2011, the revolving demand credit facility was drawn to \$32.5 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 September, 2011. 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 June 30		Six months ended June 30	
	2011	2010	2011	2010
Funds flow from operations	\$ 4,297	\$ 4,320	\$ 7,244	\$ 8,761
Changes in non-cash working capital	(6,546)	(6,357)	(6,571)	(726)
Expenditures on abandonments	-	-	(2)	(21)
Proceeds from issuance of shares/options (net of costs)	-	13	19	23
Proceeds from (repayment of) bank debt	5,961	(26,308)	15,989	(28,352)
Proceeds from property disposition	-	33,090	-	33,090
Change in cash during the period	-	-	-	-
<b>Capital expenditures funded by cash during the period</b>	<b>\$ 3,712</b>	<b>\$ 4,758</b>	<b>\$ 16,679</b>	<b>\$ 12,775</b>

The Company's capital investment program during the relevant periods was funded by the issuance of equity, 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 \$11.2 million as at June 30, 2010 to a deficit of \$32.7 million as at June 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 June 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 June 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	\$ 407	144	263
Financial instrument premiums	\$ 791	791	-
Total contractual obligations	\$ 1,198	935	263

## OUTLOOK

The Company's focused long-life, low cost Peace River Arch assets and available credit capacity provides a stable capital base to support continued capitalization of Seaview's emerging Wapiti Cardium light oil resource play. Management believes that continued improvement on the latest LPG based fracture treatments has significantly enhanced the economic viability of Wapiti.

The drilling program over the remainder of 2011 will be financed through available cash-flow and focus on completing earning on farm-in lands as first priority and drilling development locations offsetting existing Cardium horizontal producers offering the highest potential.

Seaview has the following characteristics:

- Total Proven reserves of 6,578 Mboe (23% light oil and natural gas liquids). Total Proven plus Probable reserves of 11,823 Mboe (26% light oil and natural gas liquids), effective December 31, 2010, as evaluated by Sproule Associates Ltd. using National Instrument 51-101 reserve definitions;
- Reserve life index is 11.8 years based on Total Proven plus Probable reserves and Q2 2011 production of 2,739 boe per day;
- Seaview has established significant positions in resource plays providing for longer-term growth potential in a diverse portfolio of assets targeting both light oil and natural gas plays, including:
  - In Wapiti, the Company has assembled a sizable land position targeting a Cardium light oil resource play:
    - Exposure to earn up to 42.5 sections (22.8 net) of prospective Cardium rights;
    - An extensive drilling inventory with over 170 horizontal development locations (91 net);
    - Scalable project targeting high quality light oil (41 degree API), and natural gas with high liquid recovery NGL's; and
    - Excellent operational focus featuring a large contiguous land position directly offsetting the Company's recent successful Cardium exploration activities.
  - In Pouce Coupe, the Company holds interests in 21 sections (4.5 net) of land targeting a Doig-Montney natural gas resource play. Seaview's land position is on trend with successful industry development activities further reducing the risk of full development when economics are more viable;
- Commodity hedging program providing for downside protection on 8,913 mcf per day for 2011 at a "net of cost" floor price of \$5.50/mcfe, providing minimum 2011 revenue of \$17.9 million; and
- 65.55 million Class A shares and 1.0 million Class B shares outstanding, as at June 30, 2011.

## 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 June 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 and June 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 19 – *Employee Benefits* revises the existing standard to eliminate options to defer the recognition of gains and losses in defined benefit plans, requires remeasurements of a defined benefit plan's assets and liabilities to be presented in other comprehensive income and increases disclosure.

IAS 27 – *Separate Financial Statements* revised the existing standard which addresses the presentation of parent company financial statements that are not consolidated financial statements.

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 June 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  
Investor Toll Free: 1-877-242-0222  
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 its bottom edge. A stylized orange sun or globe icon is partially visible behind the letter "V" in "SEAVIEW".

1500, 444-5th Avenue SW  
Calgary, Alberta  
Canada T2P 2T8

Telephone: (403) 450-3713  
Toll Free: 1-877-242-0222  
Facsimile: (403) 668-9177

Email: [info@seaviewenergy.com](mailto:info@seaviewenergy.com)  
Website: [www.seaviewenergy.com](http://www.seaviewenergy.com)