FORM 6-K

Current report of foreign issuer pursuant to Rules 13a-16 and 15d-16 Amendments

Filing Date: **2011-11-07** | Period of Report: **2011-09-30**
SEC Accession No. 0001279569-11-001234

(HTML Version on secdatabase.com)

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COMPTON PETROLEUM CORP

CIK:**1043572**| IRS No.: **000000000**
Type: **6-K** | Act: **34** | File No.: **001-32643** | Film No.: **111183142**
SIC: **1311** Crude petroleum & natural gas

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER
PURSUANT TO RULE 13a-16 OR 15d-16 OF
THE SECURITIES EXCHANGE ACT OF 1934

For the month of November, 2011

COMPTON PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Suite 500, Bankers Court
850 – 2nd Street SW
Calgary, Alberta, Canada
T2P 0R8
(403) 237-9400

(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F ☐ Form 40-F ☒

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1):_______

Note: Regulation S-T Rule 101(b)(1) only permits the submission in paper of a Form 6-K if submitted solely to provide an attached annual report to security holders.

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7):_______

Note: Regulation S-T Rule 101(b)(7) only permits the submission in paper of a Form 6-K if submitted to furnish a report or other document that the registrant foreign private issuer must furnish and make public under the laws of the jurisdiction in which the registrant is incorporated, domiciled or legally organized (the registrant's "home country"), or under the rules of the home country exchange on which the registrant's securities are traded, as long as the report or other document is not a press release, is not required to be and has not been distributed to the registrant's security holders, and, if discussing a material event, has already been the subject of a Form 6-K submission or other Commission filing on EDGAR.

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes ☐ No ☒

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-_______

Exhibit No.	Description
99.1	Q3 Financial Statements for the Period Ending September 30, 2011
99.2	Q3 Managment's Discussion and Analysis for the Period Ending September 30, 2011
99.3	CEO Certificate
99.4	CFO Certificate

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

COMPTON PETROLEUM CORPORATION

Date: November 7, 2011

By: /s/ Theresa Kosek
Theresa Kosek
Title: Vice President, Finance and Chief Financial Officer

Exhibit 99.1

Compton Petroleum Corporation
Consolidated Balance Sheets

(Unaudited) (000's)

As a	September 30, 2011	December 31, 2010 (note 20)	January 1, 2010 (note 20)
Assets			
Current assets:			
Cash	**$ 1,103**	$ -	$ -
Trade and other accounts receivable	**22,354**	29,515	37,389
Risk management, note 15a	**4,950**	8,041	198
Other current assets, note 17	**4,981**	4,812	14,287
	33,388	42,368	51,874
Non-current assets:			
Development and production, note 3	**590,573**	751,382	1,609,874
Exploration and evaluation, note 4	**41,698**	68,550	72,378
Risk management, note 15a	**32**	-	-
Other long term assets, note 17	**2,631**	2,620	2,494
Total assets	**$ 668,322**	$ 864,920	$ 1,736,620
Liabilities			
Current liabilities:			
Trade and other accounts payable	**$ 37,114**	$ 57,755	$ 67,909
Credit facility, note 5a	**-**	145,584	107,183
Risk management, note 15a	**-**	116	94
Senior term notes, note 6	**-**	44,757	-
MPP term financing, note 7	**5,835**	11,098	4,601
	42,949	259,310	179,787
Non-current liabilities:			
Credit facility, note 5a	**103,130**	-	-
Senior term notes, note 6	**-**	192,455	461,741
Risk management, note 15a	**-**	-	1,331
MPP term financing, note 7	**27,150**	34,522	46,807
Provisions, note 9	**163,211**	184,424	138,998
Deferred income taxes	**-**	7,011	186,210
Total liabilities	**336,440**	677,722	1,014,874
Shareholders' equity			
Share capital, note 10b	**283,128**	416,433	416,425
Share purchase warrants, note 10c	**32,255**	13,800	13,800
Other reserves	**-**	40,112	37,043
Retained earnings (deficit)	**-**	(289,682)	250,279
Non-controlling interest, note 7	**16,499**	6,535	4,199
Total equity	**331,882**	187,198	721,746
Total liabilities and shareholders' equity	**$ 668,322**	$ 864,920	$ 1,736,620

Commitments and contingent liabilities, note 18

Subsequent events, note 19

see accompanying notes to the consolidated interim financial statements

On behalf of the Board

A. Loader, M.A.	J. Stephens Allan, C.A.
Director	Director

Compton Petroleum Corporation

Consolidated Interim Statements of Operations and Comprehensive Earnings (Loss)

(Unaudited) (000's)

	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Revenue, net of royalties, note 16	**$ 38,971**	$ 36,728	**$ 109,304**	$ 146,400
Expenses				
Operating	**12,213**	12,173	**36,103**	42,707
Transportation	**1,650**	2,424	**4,477**	5,816
Administrative	**2,179**	5,391	**11,082**	16,630
Royalty obligations, note 16	**2,345**	2,749	**8,849**	12,599
Depletion and depreciation	**15,284**	18,028	**44,330**	63,373
Exploration and evaluation, note 4	**11,358**	525	**20,975**	651
Share based compensation, note 12f	**231**	975	**40**	3,039
Foreign exchange and other (gain) loss, note 14	**(50,183)**	(10,828)	**(72,430)**	(3,911)
Risk management (gain) loss, note 15c	**(6,498)**	(9,246)	**(7,305)**	(23,191)
Impairment expense (reversal), note 3	**(148)**	44,907	**(435)**	117,664
Finance costs				
Accretion of decommissioning liabilities	**1,131**	1,114	**3,718**	3,400
Interest and financing costs, note 13	**6,829**	11,436	**25,695**	39,561
Earnings (loss) before taxes	**42,580**	(42,920)	**34,205**	(131,938)
Income taxes				
Current	**-**	-	**-**	-
Deferred	**14,273**	(9,865)	**10,115**	(34,334)
	14,273	(9,865)	**10,115**	(34,334)
Net earnings (loss)	**$ 28,307**	$ (33,055)	**$ 24,090**	$ (97,604)
Net earnings (loss) attributable to:				
Non-controlling interest, note 7	**$ 6,691**	$ 346	**$ 9,964**	$ 1,443
Majority shareholders	**21,616**	(33,401)	**14,126**	(99,047)
Net earnings (loss) and comprehensive earnings (loss)	**$ 28,307**	$ (33,055)	**$ 24,090**	$ (97,604)
Net earnings (loss) per share, note 11				
Basic	**$ 3.26**	$ (25.08)	**$ 6.34**	$ (74.05)
Diluted	**$ 2.43**	$ (25.08)	**$ 3.03**	$ (74.05)

see accompanying notes to the consolidated interim financial statements

Compton Petroleum Corporation
Consolidated Interim Statements of Changes in Equity
(Unaudited) (000's)

	Capital stock	Share purchase warrants	Other reserves	Retained earnings/ Deficit	Non-controlling interest	Total
Balance at January 1, 2010	$ 416,425	$ 13,800	$ 37,043	$ 250,279	$ 4,199	$ 721,746
Net earnings (loss)	-	-	-	(99,047)	1,443	(97,604)
Share based payments	-	-	2,266	-	-	2,266
Options exercised	8	-	-	-	-	8
Balance at September 30, 2010, note 20	$ 416,433	$ 13,800	$ 39,309	$ 151,232	$ 5,642	$ 626,416
Balance at January 1, 2011	**$ 416,433**	**$ 13,800**	**$ 40,112**	**$ (289,682)**	**$ 6,535**	**$ 187,198**
Net earnings (loss)	**-**	**-**	**-**	**14,126**	**9,964**	**24,090**
Share issuance, net	**197,450**	**18,455**	**-**	**-**	**-**	**215,905**
Share based payments	**-**	**-**	**(1,259)**	**-**	**-**	**(1,259)**
IFRS fair value adjustment, net of tax, note 6	**-**	**-**	**-**	**(94,052)**	**-**	**(94,052)**
Reduction of stated capital and other reclassification	**(330,755)**	**-**	**(38,853)**	**369,608**	**-**	**-**
Balance at September 30, 2011	**$ 283,128**	**$ 32,255**	**$ -**	**$ -**	**$ 16,499**	**$ 331,882**

see accompanying notes to consolidated interim financial statements

Compton Petroleum Corporation
Consolidated Interim Statements of Cash Flow
(Unaudited) (000's)

	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Operating activities				
Net earnings (loss)	**$ 28,307**	$ (33,055)	**$ 24,090**	$ (97,604)
Amortization and other	**(104)**	425	**547**	6,287
Depletion and depreciation	**15,284**	18,028	**44,330**	63,373
Unrealized foreign exchange and other (gains) losses	**5,841**	(13,860)	**(1,528)**	(7,560)
Deferred income taxes	**14,273**	(9,865)	**10,115**	(34,334)
Share based compensation	**(554)**	753	**(1,259)**	2,266
Accretion of decommissioning liabilities	**1,131**	1,114	**3,718**	3,400
Decommissioning expenditures	**(774)**	(5,680)	**(1,127)**	(12,708)
Unrealized risk management (gain) loss	**(3,344)**	(5,594)	**2,943**	(15,319)
Impairment	**(148)**	44,907	**(435)**	117,664
Exploration and evaluation	**11,358**	525	**20,975**	651
Non-cash gain on debt extinguishment, note 6	**(56,623)**	-	**(56,623)**	-
(Gain) loss on asset disposition	**-**	3,148	**(16,329)**	5,688
	14,647	846	**29,417**	31,804
Change in non-cash working capital	**(8,993)**	5,133	**(13,407)**	(10,075)
	5,654	5,979	**16,010**	21,729
Financing activities				
Repayment of credit facility	**(26,401)**	-	**(43,124)**	(107,183)
MPP term financing repayment	**(7,381)**	(1,314)	**(12,634)**	(3,925)
Proceeds from equity financing, net of issuance costs, note 6	**36,962**	-	**36,962**	5
	3,180	(1,314)	**(18,796)**	(111,103)
Investing activities				
Development and production additions	**(5,343)**	(3,148)	**(18,390)**	(14,248)
Exploration and evaluation additions	**(2,388)**	(2,266)	**(3,859)**	(4,443)
Property acquisitions	**-**	94	**-**	(56)
Development and production dispositions	**-**	35,983	**9,489**	153,540
Exploration and evaluation dispositions	**-**	-	**16,649**	-
Royalty dispositions	**-**	-	**-**	23,469
	(7,731)	30,663	**3,889**	158,262
Change in cash	**1,103**	35,328	**1,103**	68,888
Cash, beginning of period	**-**	33,560	**-**	-
Cash, end of period	**$ 1,103**	$ 68,888	**$ 1,103**	$ 68,888

see accompanying notes to the consolidated interim financial statements

Compton Petroleum Corporation (the "Corporation" or "Compton"), incorporated under the laws of Alberta and domiciled in Canada, is in the business of the exploration for and production of petroleum and natural gas reserves in the Western Canada Sedimentary Basin. The registered office of the Corporation is as follows:

Suite 500, Bankers Court
850 2nd Street, SW
Calgary, Alberta, Canada
T2P 0R8

1. BASIS OF PRESENTATION

(a) Statement of compliance

The consolidated interim financial statements are unaudited and have been prepared in accordance with IAS 34 "Interim Financial Reporting" ("IAS 34"), using accounting policies consistent with the International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB") and Interpretations of the International Financial Reporting Interpretations Committee ("IFRIC").

These interim consolidated financial statements present the results of operations and financial position as at and for the three and nine month periods ended September 30, 2011 and 2010 and will form part of the Corporation's first IFRS consolidated annual financial statements for the year ending December 31, 2011. As a result, they have been prepared in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards", with retrospective application of accounting standards as required. These consolidated interim financial statements do not include all of the necessary annual disclosures in accordance with IFRS. Previously, the Corporation prepared its consolidated annual and consolidated interim financial statements in accordance with Canadian Generally Accepted Accounting Principles ("Previous GAAP").

(b) Basis of measurement

The consolidated interim financial statements have been prepared on the historical cost basis except for the revaluation of certain non-current assets and financial instruments. Historical cost is generally based on the fair value of the consideration given in exchange for assets recorded on the date of the transaction. The consolidated interim financial statements have been prepared on a going concern basis.

These interim financial statements have been prepared following the same accounting policies as presented and disclosed in the Q1 2011 interim financial statements (see Note 2). These policies have been retrospectively and consistently applied except where specific exemptions permitted alternative treatment upon transition to IFRS in accordance with IFRS 1 as disclosed in Note 20 - "Transition to IFRS".

The consolidated interim financial statements were authorized on November 4, 2011 by the Board of Directors.

(c) Functional and presentation currency

The functional currency of Compton, and all its consolidated subsidiaries, is Canadian dollars, and all amounts are presented in thousands (000's) of Canadian dollars herein unless otherwise stated.

2. SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of consolidation

The consolidated interim financial statements include the accounts of the Corporation and its wholly owned subsidiaries. The consolidated interim financial statements also include the accounts of Mazeppa Processing Partnership (the "Partnership" or "MPP") in accordance with Standing Interpretations Committee Standards 12 ("SIC-12"), Special Purpose Entities, as outlined in Note 7 - "MPP Term Financing and Non-Controlling Interest".

Interests in jointly controlled assets are included in these financial statements using the proportionate consolidation method and included in the accounts is the Corporation's proportionate share of revenues, expenses, assets and liabilities.

All inter-company transactions, balances, income and expenses are eliminated in full on consolidation.

(b) Critical accounting judgments and key sources of measurement uncertainty

The timely preparation of consolidated interim financial statements requires that Management make estimates and assumptions and use judgment regarding the measurement of assets, liabilities, revenues, and expenses. Such estimates relate primarily to transactions and events that have not settled as of the date of the interim financial statements. Accordingly, actual results may materially differ from estimated amounts as future confirming events occur.

Amounts recorded for depletion and depreciation, and amounts used in impairment test calculations are based upon estimates of petroleum and natural gas reserves and future costs to develop those reserves. By their nature, these estimates of reserves, costs, and related future cash flows are subject to uncertainty, and the impact on the consolidated financial statements of future periods could be material.

Development and production assets are grouped into cash generating units ("CGUs") identified as having largely independent cash flows and are geographically integrated. The determination of these CGUs was based on Management's interpretation and judgment.

The calculation of decommissioning liabilities includes estimates of the ultimate settlement amounts, inflation factors, risk free rates, and timing of settlement. The impact of future revisions to these assumptions on the consolidated financial statements of future periods could be material.

The amount of share based compensation expense is subject to uncertainty as it reflects the Corporation's best estimate of whether or not performance will be achieved and obligations incurred.

The amount ascribed to share purchase warrants upon issue is subject to uncertainty as it reflects the Corporation's best estimate of fair value at the time of issue.

The estimated inventory allowance recognized to present inventory balances at the lower of cost and net realizable value.

The estimated fair value of risk management contracts is subject to measurement uncertainty as future commodity prices and exchange rates are used in the valuation.

The values of pension assets and obligations and the amount of pension costs charged to earnings depend on certain actuarial and economic assumptions which by their nature are subject to measurement uncertainty.

Tax interpretations, regulations and legislation in which the Corporation and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

(c) Recent accounting pronouncements

All accounting standards effective for periods on or after January 1, 2011 have been adopted as part of the transition to IFRS. The following new IFRS pronouncements have been issued or are outstanding in the third quarter, are effective on January 1, 2013, and may have an impact on the Corporation in the future.

- IFRS 9, "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.
- IFRS 10, "Consolidated Financial Statements", which is the result of the IASB's project to replace Standing Interpretations Committee 12, "Consolidation - Special Purpose Entities" and the consolidation requirements of IAS 27, "Consolidated and Separate Financial Statements". The new standard eliminates the current risk and rewards approach and establishes control as the single basis for determining the consolidation of an entity.
- IFRS 11, "Joint Arrangements", which is the result of the IASB's project to replace IAS 31, "Interests in Joint Ventures". The new standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted. Under IAS 31, joint ventures could be proportionately consolidated.
- IFRS 12, "Disclosure of Interests in Other Entities", which outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosures require information that will assist financial statement users to evaluate the nature, risks and financial effects associated with an entity's interests in subsidiaries and joint arrangements.
- IFRS 13, "Fair Value Measurement", which provides a common definition of fair value, establishes a framework for measuring fair value under IFRS and enhances the disclosures required for fair value measurements. The standard applies where fair value measurements are required and does not require new fair value measurements.
- IAS 19, "Post Employment Benefits", which amends the recognition and measurement of defined benefit pension expense and expands disclosures for all employee benefit plans.

The Corporation is currently assessing the impact of the new standards, but does not anticipate that the adoption of the standards will have a significant impact on the Corporation's consolidated financial statements.

3. DEVELOPMENT AND PRODUCTION

	Development costs (1)	MPP Facility	Corporate Assets	Total
Cost or deemed cost:				
Balance at January 1, 2010	$ 1,545,269	$ 53,703	$ 12,538	$1,611,510
Additions	42,430	-	1,449	43,879
Transfer from E&E (Note 4)	47	-	-	47
Disposals	(186,490)	-	-	(186,490)
Decommissioning adjustment and other	60,972	-	-	60,972
Balance at December 31, 2010	**$ 1,462,228**	**$ 53,703**	**$ 13,987**	**$1,529,918**
Additions	**18,781**	**-**	**168**	**18,949**
Transfer from E&E (Note 4)	**3,564**	**-**	**-**	**3,564**
Disposals	**(15,346)**	**-**	**-**	**(15,346)**
Decommissioning adjustment and other	**(19,639)**	**-**	**-**	**(19,639)**
Balance at September 30, 2011	**$ 1,449,588**	**$ 53,703**	**$ 14,155**	**$1,517,446**
Accumulated depletion, depreciation and impairment losses:				
Balance at January 1, 2010	$ (1,636)	$ -	$ -	$ (1,636)
Depletion and depreciation	(83,767)	(2,224)	(3,043)	(89,034)
Impairment loss	(695,395)	-	-	(695,395)
Disposals	7,529	-	-	7,529
Other	-	-	-	-
Balance at December 31, 2010	**$ (773,269)**	**$ (2,224)**	**$ (3,043)**	**$ (778,536)**
Depletion and depreciation	**(40,300)**	**(1,668)**	**(2,362)**	**(44,330)**
Impairment loss, net of reversal	**(106,697)**	**-**	**-**	**(106,697)**
Disposals	**2,643**	**-**	**-**	**2,643**
Other	**47**	**-**	**-**	**47**
Balance at September 30, 2011	**$ (917,576)**	**$ (3,892)**	**$ (5,405)**	**$ (926,873)**
Net book value:				
As at January 1, 2010	$ 1,543,633	$ 53,703	$ 12,538	$1,609,874
As at December 31, 2010	688,959	51,479	10,944	751,382
As at September 30, 2011	**$ 532,012**	**$ 49,811**	**$ 8,750**	**$ 590,573**

(1) Included in equipment and facilities are finance leases with a cost of $1.6 million (January 1, 2010 - $11.5 million; December 31, 2010 - $8.5 million) and accumulated depletion of $0.3 million (January 1, 2010 - $1.6 million; December 31, 2010 - $1.6 million)

During the nine months ended September 30, 2011, $1.4 million (2010 - $3.3 million) was capitalized directly attributable to compensation, insurance, and other costs. These costs were a reduction of administrative expenses for the period.

Minor property dispositions at Niton and Centron during the first quarter of 2011 resulted in total proceeds of $26.2 million, and a net gain on sale of $16.4 million. Net gains include components of both development and production ($1.5 million), and exploration and evaluation ($14.9 million). (See Note 4 - “Exploration and Evaluation”). There were no significant dispositions in the second and third quarters of 2011.

During 2010, the disposition of properties at Niton and Gilby resulted in gross proceeds of $153.0 million, and a net loss on sale of $5.7 million. Net losses include components of both development and production ($5.2 million), and exploration and evaluation ($0.5 million). (See Note 4 - “Exploration and Evaluation”).

Gains and losses on disposition are presented in foreign exchange and other gains (losses).

An impairment test is performed on capitalized property and equipment costs, at the CGU level, when indicators of impairment exist. On transition to IFRS on January 1, 2010, the value of Compton's development costs were written down by $263.9 million (see Note 20 - "Transition to IFRS"). Throughout 2010, a further write down of $695.4 million was recorded based on the estimated recoverable amount of Compton's assets. The recoverable amount represents the assets value in use, under a 10% discounted cash flow. These write downs reflect the low natural gas price environment during that time. At September 30, 2010, $117.2 million impairment was recognized, using a value in use approach at 10% discounted cash flow.

Following the Recapitalization plan (the "Recapitalization") completed in September 2011, the Corporation's assets were reduced to their underlying event-driven fair market values, under an optional IFRS 1 election. The election resulted in a write down to Development and Production assets of $107.1 million, leaving a deemed cost carrying value of $590.6 million. See Note 6 - "Senior Term Notes" for additional details on the Recapitalization.

At September 30, 2011, no indicators of impairment were identified that would imply a further decline in development and production asset carrying values below the determined deemed cost.

4. EXPLORATION AND EVALUATION

Balance at January 1, 2010	$ 72,378
Additions	6,925
Disposals	(8,620)
Impairment / land expiries	(2,086)
Transfers to D&P (Note 3)	(47)
Balance at December 31, 2010	**$ 68,550**
Additions	**3,859**
Disposals	**(2,126)**
Impairments / land expiries	**(25,021)**
Transfers to D&P (Note 3)	**(3,564)**
Balance at September 30, 2011	**$ 41,698**

An impairment test is performed on the costs capitalized to exploration and evaluation when indicators of impairment exist. On transition to IFRS on January 1, 2010, the value of Compton's exploration and evaluation assets were tested for impairment and no write down was required. Throughout 2010, a total of $2.1 million of undeveloped land expired and was charged to exploration and evaluation expense. Land expiries and impairment on exploratory well costs charged to exploration and evaluation expense during the nine months ended September 30, 2011 totaled $21.0 million (2010 - $0.7 million).

Following the Recapitalization completed in September 2011, the Corporation's assets were written down to their underlying event driven fair market values, under an optional IFRS 1 election. The election resulted in the write down of Exploration and Evaluation assets of $4.0 million, to a $41.7 million deemed cost carrying value. See Note 6 - "Senior Term Notes" for additional details on the Recapitalization.

At September 30, 2011, no indicators of impairment were identified that would imply a further decline in exploration and evaluation asset carrying values below the determined deemed cost.

5. DEBT

(a) Credit facility

	September 30, 2011	December 31, 2010	January 1, 2010
Authorized credit facility	**$ 160,000**	$ 170,000	$ 220,000
Prime rate loans	**$ 104,000**	$ -	$ 37,000
Bankers' acceptance term loans	**-**	144,700	70,000
Bank indebtedness, prime rate	**-**	2,576	1,462
Discount to maturity	**(870)**	(1,692)	(1,279)
Advances under the credit facility	**$ 103,130**	$ 145,584	$ 107,183

On September 27, 2011, Compton reached an agreement with a new syndicate of lenders for a credit facility of $160.0 million, including a working capital facility of $15.0 million and a syndicated facility of $145.0 million. The facility term ends September 26, 2012, with a maturity one year thereafter if not renewed. The facility is subject to re-determination of the borrowing base semi-annually at September 30 and May 31. The borrowing base is determined based on, among other things, the Corporation's current reserve report, results of operations, the lenders view of the current and forecasted commodity prices and the current economic environment.

In addition to the drawn portion of the facility, $0.9 million (December 31, 2010 - $4.3 million) of letters of credit were outstanding in favour of service providers to Compton at September 30, 2011.

Advances under the syndicated facility bear interest at margins determined on the ratio of total consolidated debt to consolidated cash flow which are currently as follows:

Prime rate and US Base rate plus 1.75%; and

Bankers' Acceptances rate and LIBOR rate plus 2.75%.

The effective interest rate on the credit facility at September 30, 2011, was 6.17% (2010 - 5.44%).

The credit facility is secured by a first fixed and floating charge debenture in the amount of $500 million covering all the Corporation's assets and undertakings.

(b) Finance leases

Finance leases relate to operating equipment with lease terms ranging from 3 to 5 years. Finance leases have been recognized as assets based on the lower of the respective fair values and present value of future lease payments and any related buyout costs. The Corporation's obligations under finance leases are secured by the lessors' title to the underlying property. The fair value of the finance lease liabilities approximates the carrying amount.

	Minimum lease payments	
	September 30, 2011	December 31, 2010
Not later than one year	**$ 1,119**	$ 1,033
Later than one year and not later than five years	**447**	1,680
Later than five years	**-**	-
Less future finance charges	**(329)**	$ (469)
Present value of minimum lease payments	**$ 1,237**	$ 2,244
Current finance lease obligations	**$ 832**	$ 864
Long-term finance lease obligations	**405**	1,380

Present value of minimum lease payments[1]	**$**	**1,237**	$	2,244

(1) Finance leases are included in development and production assets, and trade and other accounts payable

6. SENIOR TERM NOTE

	September 30, 2011	December 31, 2010	January 1, 2010
US$193.5 million, 10% due Sept. 15, 2017	$ -	$ 192,455	$ -
US$45.0 million, 10% due Sept. 15, 2011	-	44,757	-
US$450.0 million, 7.625% due Dec. 1, 2013	-	-	470,970
Unamortized transaction costs	-	-	(9,229)
Carrying value	$ -	$ 237,212	$ 461,741
Current	$ -	$ 44,757	$ -
Non-current	-	192,455	461,741
Senior term notes	$ -	$ 237,212	$ 461,741

During the period, the senior term notes were fully extinguished as part of the approved Recapitalization plan and related elections. The recognition of key transactional items, in chronological order, are itemized as follows:

- August 10, 2011 - Common shares are consolidated on a 200:1 basis (see Note 10 - "Share Capital" and Note 11 - "Per Share Amounts");
- August 23, 2011 - Senior term notes are extinguished for common shares, rights, and cashless warrants. These instruments were valued based on individually available market prices. A net gain of $56.0 million was recognized in current period earnings on extinguishment (see Note 14 - "Foreign Exchange and Other (Gains) Losses"). Of the $56.0 million gain on debt extinguishment, $56.6 million was considered non-cash and has been excluded from operating cash flow;
- September 27, 2011 - The $37.0 million (gross proceed of $50.0 million, net of issuance costs of $13.0 million) rights offering closes, completing the Recapitalization plan (see Note 10(b) - "Share Capital");
- September 27, 2011 - The Corporation elected, under IFRS transitional provisions, to take an optional event driven revaluation of the book value of its assets and liabilities based on the negotiated value underlying the transactions, as provided in the approved Management proxy circular dated July 24, 2011. This resulted in a combined $111.1 million ($94.1 million, net of tax) write-down of its development and production, and exploration and evaluation assets. The net adjustment was charged directly to retained earnings having no impact on current period earnings or cashflows. See Note 3 - "Development and Production" and Note 4 - "Exploration and Evaluation";
- September 30, 2011 - Further to the shareholder resolution approved July 25, 2011, the Corporation reduced its stated capital by eliminating the balances in other reserves, and deficit. The total stated capital reduction was $330.8 million, and did not affect current period earnings (see Note 10(b) - "Share Capital").

In October 2010, the Corporation had issued US $193.5 million of senior term notes due September 15, 2017, and US $45.0 million of mandatory convertible notes due September 15, 2011.

7. MPP TERM FINANCING AND NON-CONTROLLING INTEREST

MPP is a limited partnership organized under the laws of the Province of Alberta and owns certain midstream facilities, including gas plants and pipelines in southern Alberta, through which Compton processes a significant portion of its production from the area. Compton's interaction with MPP is governed by agreements (the "MPP Agreements") which provide for:

(a)Compton's management of the midstream facility;

(b)the payment by Compton to MPP of a base processing fee and the reimbursement of MPP's net out-of-pocket costs;

(c)the dedication of Compton’s production and reserves from the defined area through the facilities; and

(d)an option granted to Compton to purchase the MPP partnership at a predetermined amount on April 30, 2014.

Compton is considered to be the primary beneficiary of MPP’s operations, although it does not have an ownership interest in the midstream facilities. Pursuant to the IASB’s Standing Interpretation’s Committee (“SIC”) 12, Consolidation - Special Purpose Entities, the assets, liabilities, and operations of the Partnership are consolidated in these financial statements. The equity in MPP is attributable to its third party owners and is recorded as a non-controlling interest in these consolidated financial statements, comprised of the following:

		September 30, 2011		December 31, 2010		January 1, 2010
Non-controlling interest, beginning of period	**$**	**6,535**	$	4,199	$	59,762
Earnings attributable to non-controlling interest		**9,964**		2,336		3,259
Distributions to limited partner		**-**		-		(3,822)
MPP term financing		**-**		-		(55,000)
Non-controlling interest, end of period[(1)]	**$**	**16,499**	$	6,535	$	4,199

(1) Non-controlling interest includes all purchase option prepayments made prior to April 30, 2014.

On April 30, 2009, Compton completed the renegotiation of the MPP Agreements for a further term of five years. All agreements expire on April 30, 2014 with the exception of the agreement that dedicates Compton’s production and reserves from the defined area to the facilities which continues through April 30, 2024. At the time of the renegotiation, $55.0 million of the non-controlling interest was transferred to the MPP term financing caption in these consolidated financial statements, with a corresponding reduction in the non-controlling interest. The MPP term financing is comprised of:

		September 30, 2011		December 31, 2010		January 1, 2010
Present value of the base processing fee	**$**	**15,685**	$	19,552	$	24,287
Purchase option		**17,700**		26,588		27,800
Unamortized transaction costs		**(400)**		(520)		(679)
MPP term financing	**$**	**32,985**	$	45,620	$	51,408

The base processing fee component of the MPP term financing is accounted for as an amortizing obligation paid in full over its term to April 30, 2014, through a monthly principal and interest payment totaling $0.8 million per month. The effective rate of interest is 11.68% per annum.

In these consolidated financial statements, the MPP net out-of-pocket costs are included in operating expense, the interest component of the base processing fee is included in interest and financing charges expense and the principal component of the base processing fee is recorded as a reduction in the MPP term financing liability.

The purchase option represents the pre-determined price at which Compton may, at its discretion, purchase the MPP partnership on April 30, 2014. If Compton does not exercise this purchase option it may renew the MPP Agreements with terms and conditions to be negotiated at that time, or enter into an arrangement with the owners of the MPP facilities to process natural gas for the Corporation at a fee to be determined at that time.

The MPP Agreements prescribe minimum throughput volumes and dedicated reserves which, if not exceeded, may require a buy-down of the purchase option. The minimum throughput volume of 56.0 mmcf/d is an average of the throughput volume of the preceding two consecutive calendar quarters. The prepayment amount is $400,000 per 1.0 mmcf/d of shortfall. Each prepayment of the purchase option will cause the minimum throughput volume to be adjusted downward to the average throughput volume of the preceding two consecutive calendar quarters. In the event that the estimated dedicated reserves, as projected at April

30, 2014, are less than 200 BCF or have a discounted reserve value of less than $250 million using a 10% discount rate, the prepayment amount is the greater of $108,000 per $1 million of reserve value shortfall and $135,000 per 1.0 BCF of the reserves shortfall.

As of September 30, 2011, the threshold throughput volume was reduced to 55.2 mmcf/d. The cumulative prepayment of the purchase option since the renewal of the MPP Agreements in April 2009 is $10.1 million, including $8.9 million in 2011. The prepayments have reduced the amount of the MPP term financing liability. Subsequent to quarter end, a payment of $0.3 million was made for the period ending September 30, 2011.

8. CAPITAL STRUCTURE

The Corporation's capital structure is comprised of working capital, long-term debt, and shareholders' equity. The Corporation's objectives when managing its capital structure are to:

(a)ensure the Corporation can meet its financial obligations;

(b)retain an appropriate level of leverage relative to the risk of Compton's underlying assets; and

(c)finance internally generated growth and potential acquisitions.

Compton manages its capital structure based on changes in economic conditions and the Corporation's planned capital requirements. Compton has the ability to adjust its capital structure by making modifications to its capital expenditure program, divesting of assets and by altering debt levels or issuing equity.

The Corporation monitors its capital structure and financing requirements using non-GAAP measures consisting of total net debt to capitalization and total net debt to "Adjusted EBITDA". Adjusted EBITDA is defined as net earnings before interest and finance charges, income taxes, depletion and depreciation, accretion of decommissioning liabilities, unrealized foreign exchange and other gains (losses), unrealized risk management gains (losses) and other non-recurring expenses.

Compton targets a total net debt to capitalization ratio of between 40% and 50% calculated as follows:

	September 30, 2011	December 31, 2010	January 1, 2010
Working capital (surplus) deficiency(1)	**$ 8,676**	$ 23,428	$ 16,233
Credit facility(2)	**103,130**	145,584	107,183
MPP term financing(3)	**32,985**	45,620	51,408
Senior term notes(4)	**-**	237,212	461,741
Total net debt	**144,791**	451,844	636,565
Total shareholders' equity	**331,882**	187,198	721,746
Total capitalization	**$ 476,673**	$ 639,042	$ 1,358,311
Total net debt to capitalization ratio	**30.4%**	70.7%	46.9%

(1) Adjusted working capital excludes risk management, current MPP term financing and the credit facility

(2) Includes unamortized transaction costs of $870 (December 31, 2010 - $1,692; January 1, 2010 - $1,279)

(3) Includes unamortized financing fees of $400 (December 31, 2010 - $520; January 1, 2010 - $679)

(4) Includes unamortized original issue discount and related transaction costs of $nil (December 31, 2010 - $nil; January 1, 2010 - $9,229)

Following the Recapitalization, the Corporation met the targeted net debt to capitalization ratio as well as the net debt to adjusted EBITDA target at September 30, 2011. Previously, both metrics had fallen outside of Management's target ranges.

In the first quarter of 2011, property sales for gross proceeds of $26.2 million were used to repay a portion of the credit facility with the balance applied to working capital. In the third quarter of 2011, the extinguishment of the senior term notes and gross share issuance proceeds of $50.0 million significantly reduced total net debt.

In 2010, the final 1.25% component of an overriding royalty interest (totaling 5%) was sold for gross proceeds of $23.8 million, which along with sale proceeds of $153.0 million from property dispositions were applied to reduce the credit facility. In addition, the completion of the Arrangement in respect of the Notes further reduced Compton's net debt position; see Note 6 - "Senior Term Notes".

Shareholder equity was reduced as part of the transition to IFRS and the resulting adjustments recorded during 2010 negatively impacted net loss and deficit. These adjustments are disclosed in more detail in Note 20 - "Transition to IFRS".

Compton targets a total net debt to Adjusted EBITDA of 2.5 to 3.0 times. At September 30, 2011, total net debt to Adjusted EBITDA was 1.7x (December 31, 2010 - 4.1x) calculated on a trailing 12 month basis as follows:

	September 30, 2011	December 31, 2010
Total net debt	**$ 144,791**	$ 451,844

12 months ended	**September 30, 2011**	December 31, 2010
Net loss	**$ (426,787)**	$ (539,961)
Add (deduct)		
Interest and finance charges	**36,422**	50,288
Income taxes	**(134,823)**	(179,272)
Depletion and depreciation	**70,372**	89,415
Accretion of decommissioning liabilities	**4,822**	4,504
Unrealized foreign exchange (gains) losses	**1,190**	(4,842)
Unrealized risk management (gains) losses	**9,111**	(9,151)
Loss (Gain) on sale of assets	**(15,553)**	5,252
Gain on debt extinguishment	**(65,002)**	(9,040)
Other expenses	**5,039**	5,039
Exploration and evaluation	**22,410**	2,086
Impairment	**577,296**	695,395
Adjusted EBITDA	**$ 84,497**	$ 109,713
Total net debt to adjusted EBITDA	**1.7x**	4.1x

Low natural gas prices over the past two years have affected the Corporation's Adjusted EBITDA. Compton's total net debt to Adjusted EBITDA at September 30, 2011, was below the internal targeted ratio of 2.5 to 3.0 times. The Corporation has taken significant steps to reduce its overall debt to achieve its internal targets, including the Recapitalization completed in the quarter.

Compton is subject to certain covenants relating to its credit facility. At September 30, 2011, the Corporation was in compliance with the covenants of the credit facility.

9. PROVISIONS

(a) Decommissioning liabilities

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the liabilities associated with the decommissioning of oil and natural gas assets:

	September 30, 2011	December 31, 2010
Decommissioning liabilities, beginning of period	**$ 184,424**	$ 125,105
Liabilities incurred	**154**	4,754
Liabilities settled and disposed	**(4,833)**	(10,911)
Accretion expense	**3,718**	4,504
Revision of estimate	**(20,252)**	60,972
Decommissioning liabilities, end of period	**$ 163,211**	$ 184,424

The total undiscounted amount of estimated cash flows required to settle the liabilities, net of salvage, at September 30, 2011 was $156.3 million (December 31, 2010 - $234.3 million, January 1, 2010 - $139.0 million). Salvage values included in determining the undiscounted cash flows were $103.5 million at September 30, 2011 (December 31, 2010 - $108.5 million, January 1, 2010 - $135.5 million). The decommissioning liability has been determined without inclusion of the salvage values, and discounted using a risk free rate ranging from 1.4% to 2.8% (December 31, 2010 - 2.4% to 3.5%, January 1, 2010 - 2.8% to 4.1%) depending on the reserve life. Due to the Corporation's long reserve life, the majority of these liabilities are not expected to be settled until well into the future. Settlements are expected to be funded from general Corporation resources at the time of decommissioning and removal.

(b) Lease surrender obligations

Included in provisions at the time of transition to IFRS was $13.9 million related to the surrender of unused office space. The lease was determined by Management to be an onerous contract, and the provision included in these financial statements reflects the present value of estimated net cash flows to the end of the original lease term. The provision for unused office space was settled in third quarter of 2010.

10 SHARE CAPITAL

(a) Authorized

The Corporation is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares, issuable in series.

(b) Issued, outstanding and fully paid

	Number of Shares	Amount
Common shares outstanding,		
January 1, 2010	263,660	$ 416,425
Shares issued under stock option plan	6	8
Common shares outstanding,		
December 31, 2010	263,666	$ 416,433
Share consolidation(1)	(262,347)	-
Shares issued under Recapitalization plan, net(2)	25,040	197,450
Stated capital reduction(3)	-	(330,755)
Common shares outstanding,		
September 30, 2011	**26,359**	**$ 283,128**

1) Effective August 10, 2011, the Corporation completed a 200:1 consolidation of its common shares. The share consolidation was affected prior to the issuance of common shares and cashless warrants under the Recapitalization plan.

2) The Recapitalization plan included the issuance of common shares on the conversion of the senior term notes, and a $50.0 million rights offering; net of share issuance costs of $13.0 million

3) On July 25, 2011, the shareholders of the Corporation approved a stated capital reduction to transfer balances within Shareholders' Equity. The adjustments, eliminating other reserves of $38.9 million and deficit of $369.6 million, have been affected as of September 30, 2011 following the Recapitalization.

(c) Cashless warrants

A total of 3,690,982 cashless warrants, expiring August 24, 2014, were issued to existing shareholders. Two cashless warrants were issued for each common share held post consolidation. Cashless warrants were valued at $5.00 per unit, based on market exchange pricing at the time of issue. The cashless warrants will be settled with common shares subject to the share price triggers and dates noted below:

Prior to August 23, 2012	$11.92
August 24, 2012 to August 23, 2013	$12.52
August 24, 2013 to August 23, 2014	$13.14

(d) Shareholder rights plan

The Corporation has a shareholder rights plan (the “Plan”) to ensure all shareholders are treated fairly in the event of a take-over offer or other acquisition of control of the Corporation.

Pursuant to the Plan, the Board of Directors authorized and declared the distribution of one Right in respect of each common share outstanding. In the event that an acquisition of 20% or more of the Corporation’s shares is completed and the acquisition is not a permitted bid, as defined by the Plan, each Right will permit the holder, other than holders not in compliance with the Plan, to acquire a common share at a 50% discount to the market price at that time.

The Recapitalization completed during the quarter did not trigger the shareholder rights plan.

11. PER SHARE AMOUNTS

The following table summarizes the common shares used in calculating net loss per common share:

	three months ended, September 30,		**nine months ended September 30,**	
	2011	2010	**2011**	2010
Weighted average common shares outstanding - basic[1]	**8,684**	1,318	**3,801**	1,318
Effect of mandatory convertible notes	**3,241**	-	**4,753**	-
Effect of stock options and warrants	**-**	-	**-**	-
Weighted average common shares outstanding - diluted[1] [2]	**11,925**	1,318	**8,554**	1,318

(1) Effective August 10, 2011, the Corporation completed a 200:1 consolidation of its common shares. Prior period weighted average shares were restated for comparative purposes.

(2) $0.7 million and $1.8 million related to interest expense on the mandatory convertible notes for the three and nine months ended September 30, 2011, respectively, have been added to net earnings for the determination of dilutive earnings per share.

In calculating diluted loss per common share for the nine months ended September 30, 2011, the Corporation excluded 1,913 options (2010 - 76,799) and 690,000 share purchase warrants (2010 - 690,000) as the exercise price was greater than the average price of its common shares in these periods.

12. SHARE BASED COMPENSATION PLANS

(a) Stock option plan and employee long term incentive

In conjunction with the Recapitalization, substantially all of the employees, officers and directors voluntarily surrendered their stock options in June 2011. The Corporation may issue new stock options at some point in the future as determined by the compensation committee of the Board of Directors. A total of 1,913 options remain outstanding at September 30, 2011 with an average exercise price of $690.23. The outstanding stock options have been restated to reflect the share consolidation.

In 2011, the Corporation implemented a fixed value long term incentive award for employees to replace of the historical stock option plan. The fixed awards were to vest over three years, and were payable in cash or common shares at the discretion of the Corporation. The 2011 awards were settled for cash following the change in control triggered by the Recapitalization.

(b) Share purchase plan

The Corporation offers a share purchase plan to all of its employees. This program enables employees to receive corporate contributions, in the form of Compton Petroleum Corporation common shares, at a matched percentage to individual contributions (subject to a maximum). The corporate contributions vest to the employee immediately and are made with each payroll deposit.

(c) Restricted share unit plan

In 2008, the Corporation implemented a Restricted Share Unit Plan (“RSU” or “the RSU Plan”) for employees, officers and directors. At September 30, 2011, all RSUs issued under the RSU Plan were fully settled, and the program discontinued.

The Corporation has proposed a new RSU plan that was still pending Board of Director ratification at September 30, 2011.

(d) Deferred share unit plan

In 2011, the Corporation implemented a Deferred Share Unit Plan (“DSU” or “the DSU Plan”) for directors. The purpose of the DSU Plan is to attract and retain qualified, high caliber and talented individuals to serve as members of the Board and to promote a greater alignment of interests between independent members of the Board and the shareholders of the Corporation. DSU awards vest immediately, and are expensed in the current period. Awards are payable upon cessation of each directors role in cash or in common shares at the discretion of Management. A maximum of 9,375 common shares have been authorized by the Board of Directors for settlement of DSU awards outstanding.

At September 30, 2011, a total of 1,186 DSUs were outstanding, issued at a price of $59.00 per unit. During the quarter, 2,458 DSUs were settled for cash at a price of $12.60 per unit. The DSUs have been restated to reflect the share consolidation.

(e) Retention share plan

In 2011, the Corporation implemented a Retention Share Plan (“Retention Shares” or “the Retention Plan”) for executives. The Retention Plan was put in place following the revision of compensation arrangements with the executive. The Retention Plan provided for fixed awards to executives totaling $1.5 million, payable equally over a three year term. Awards were payable to a maximum of 50% in common shares, and minimum 50% in cash at the discretion of the Corporation. The Retention Plan was settled entirely for cash following the change in control triggered by the Recapitalization.

(f) Share based compensation expense

The following table presents amounts charged to share based compensation expense:

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Stock option plan[(1)] [(2)]	**$ (22)**	$ 753	**$ (1,443)**	$ 2,266
Employee long term incentive[(1)]	**66**	-	**397**	-
Deferred share unit plan	**-**	-	**215**	-
Retention share plan[(1)]	**59**	-	**325**	-
Share purchase plan	**128**	222	**546**	773
	$ 231	$ 975	**$ 40**	$ 3,039

(1) The Corporation is currently reviewing share based compensation plans following the close of the Recapitalization.

(2) Included in stock based compensation expense for the three and nine months ended September 30, 2011, there were non-cash components of $(554) and $(1,259), respectively (three months 2010 - $753, nine months 2010 - $2,266).

13. INTEREST AND FINANCE CHARGES

During the period, the following financing charges were expensed through net earnings:

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Interest on senior term notes	**$ 3,397**	$ 9,379	**$ 14,910**	$ 28,023
Interest on credit facility	**2,202**	14	**6,413**	2,692
Interest on capital lease obligations	**23**	39	**70**	1,187
Other interest and finance charges	**1,207**	2,004	**4,302**	7,659
	$ 6,829	$ 11,436	**$ 25,695**	$ 39,561

During the nine months ended September 30, 2011, no borrowing costs were capitalized (2010 - $nil) in respect of capital projects currently in process.

Other finance charges include bank service charges and fees as well as other miscellaneous interest revenue and expenses.

14. FOREIGN EXCHANGE AND OTHER (GAINS) LOSSES

During the period, the following foreign exchange and other (gains) losses were charged through net earnings:

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Foreign exchange loss/(gain) on translation of US$ debt	**$ 5,841**	$ (13,860)	**$ (1,528)**	$ (7,560)
Gain on extinguishment of US$ debt(1)	**(55,962)**	-	**(55,962)**	-
(Gain)/loss on disposition of assets	**(83)**	3,148	**(15,117)**	5,688
Other	**21**	(116)	**177**	(2,039)
Foreign exchange and other (gains) losses	**$ (50,183)**	$ (10,828)	**$ (72,430)**	$ (3,911)

(1) On August 23, 2011 the USD senior term notes were converted to equity and fully extinguished (see Note 6 - "Senior Term Notes").

15. RISK MANAGEMENT

At September 30, 2011, the Corporation's financial assets and liabilities consist of cash, trade and other accounts receivable, trade and other accounts payable, credit facility, risk management assets and liabilities relating to the use of derivative financial instruments and MPP term financing.

The following summarizes a) fair value of financial assets and liabilities, b) risk management assets and liabilities, c) risk management gains and losses and d) risk associated with financial assets and liabilities.

(a) Fair value of financial assets and liabilities

The carrying amount and fair value of financial assets and liabilities were as follows:

	September 30, 2011		December 31, 2010		January 1, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets						
Fair value through profit or loss						
Risk management(1)	**$ 4,982**	**$ 4,982**	$ 8,041	$ 8,041	$ 198	$ 198
Loans and receivables						
Accounts receivable	**22,354**	**22,354**	29,515	29,515	37,389	37,389
Cash	**1,103**	**1,103**	-	-	-	-
Financial liabilities						
Fair value through profit or loss						
Risk management(1)	**$ -**	**$ -**	$ 116	$ 116	$ 1,425	$ 1,425
Financial liabilities measured at amortized cost						
Accounts payable	**37,114**	**37,114**	57,755	57,755	67,609	67,609
Credit facility	**103,130**	**104,000**	145,584	147,276	107,183	108,462
MPP term financing(1)	**32,985**	**33,385**	45,620	46,140	51,408	52,087
Senior term notes	**-**	**-**	237,212	202,810	461,741	362,647

(1) Includes current and long term

Financial instruments of the Corporation carried on the consolidated interim balance sheets are carried at amortized cost with the exception of financial derivative instruments, which are carried at fair value. The Corporation classifies the fair value of these transactions according to the following hierarchy.

- *Level 1* - quoted prices in active markets for identical financial instruments.

- *Level 2* - quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant and significant value drivers are observable in active markets.

- *Level 3* - valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable.

The Corporation's financial derivative instruments have been assessed on the fair value hierarchy described above and classified Level 2.

The carrying amount of cash, trade and other accounts receivable, and trade and other accounts payable approximate fair value due to the short term nature of these instruments and variable rates of interest. The credit facility and MPP term financing fair values approximate their carrying value, without the effect of amounts being amortized for accounting purposes. The senior term notes traded in the US and the estimated fair value was determined using quoted market prices. Risk management assets and liabilities are recorded at their estimated fair value based on the mark to market method of accounting, using quoted market prices, third-party indicators and forecasts. Management also considers credit risk exposure on all assets and liabilities, and adjusts fair values where appropriate.

The following table reconciles the changes in the fair value of financial instruments outstanding. Changes in fair value are the result of comparing external counterparty information, which is compared to observable market data.

Risk management	**September 30, 2011**	December 31, 2010
Balance, beginning of period	**$ 7,925**	$ (1,227)
Unrealized gain (loss) on financial instruments:		
Commodity collars and swaps	**(3,301)**	9,146
Electricity swaps	**305**	59
Foreign exchange forwards	**53**	(53)
Fair value, end of period	**$ 4,982**	$ 7,925
Total fair value consists of the following:		
Fair value - current portion, net	**$ 4,950**	$ 7,925
Fair value - long-term portion, net	**32**	-
Total fair value, end of period	**$ 4,982**	$ 7,925

(b) Risk management assets and liabilities

(i) Net risk management positions

Risk management assets and liabilities relate to unrealized gains and losses associated with commodity price risk management and foreign currency risk management and are classified on the balance sheet as follows:

	September 30, 2011	December 31, 2010	January 1, 2010
Risk management asset			
Current asset	**$ 4,950**	$ 8,041	$ 198
Non-current asset	**32**	-	-
Risk management liability			
Current liability	**-**	(116)	(94)
Non-current liability	**-**	-	(1,331)
Net risk management asset (liability)	**$ 4,982**	$ 7,925	$ (1,227)

(ii)Net fair value of commodity positions

On September 30, 2011, the Corporation had the following commodity contracts in place, expressed in Canadian dollars unless otherwise noted:

Commodity	Term	Volume	Average Price	Mark-to-Market Gain (Loss)
Commodity				
Natural Gas				
Collar	Jul./09 - Oct./11	10,000 GJ/d	$4.50 - $7.00/GJ$	313
US$ Swap	Apr./11 - Oct./11	15,000 MMBtu/d	$4.64 / MMBtu	426
US$ Basis	Apr./11 - Oct./11	15,000 MMBtu/d	($0.64) / MMBtu	(181)
Swap	Jul./11 - Dec./11	10,000 GJ/d	$5.00 / GJ	1,390
US$ Swap	Jul./11 - Dec./12	10,000 MMBtu/d	$4.65 / MMBtu	4,516
Oil				
US$ Option	Jan./12 - Dec./12	1,000 Bbl/d	$100.00 / Bbl	(1,689)
US$ Option	Jul./11 - Dec./11	1,000 Bbl/d	$101.60 / Bbl	(35)
Electricity				
Swap	Jan./10 - Dec./11	84 MWh/d	$50.74 / MWh	242
Total unrealized commodity gain (loss)			$	4,982

(c) Risk management gains and losses

Risk management gains and losses recognized in net earnings during the period relating to commodity prices and foreign currency transactions are summarized below:

Nine months ended September 30	Commodity Contracts	Foreign Currency	**2011 Total**	2010 Total
Unrealized change in fair value	$ 2,996	$ (53)	**$ 2,943**	$ (15,319)
Realized cash settlements	(10,248)	-	**(10,248)**	(7,872)
Total (gain) loss	$ (7,252)	$ (53)	**$ (7,305)**	$ (23,191)

Three months ended September 30	Commodity Contracts	Foreign Currency	**2011 Total**	2010 Total
Unrealized change in fair value	$ (2,985)	$ (359)	**$ (3,344)**	$ (5,594)
Realized cash settlements	(3,154)	-	**(3,154)**	(3,652)
Total (gain) loss	$ (6,139)	$ (359)	**$ (6,498)**	$ (9,246)

The gains and losses realized during the year on the electricity contract are included in operating expenses.

(d) Risk associated with financial assets and liabilities

The Corporation is exposed to financial risks arising from its financial assets and liabilities which fluctuate in value due to movements in market prices and is comprised of the following:

(i) Market risk

Market risk is the risk that the fair value or future cash flows from financial assets or liabilities will fluctuate due to movements in market prices and is comprised of the following:

— **Commodity price risk**

The Corporation is exposed to commodity price movements as part of its normal oil and gas operations. Under guidelines established and approved by the Board of Directors, Compton enters into economic hedge transactions relating to crude oil, natural gas and electricity prices to mitigate volatility in commodity prices and the resulting impact on cash flows. The contracts entered into are forward transactions providing the Corporation with a range of prices on the commodities sold. Prices are marked to industry benchmarks specifically to AECO and Henry Hub monthly prices for gas contracts, WTI Nymex for crude oil contracts and AESO for electricity contracts. Prices are valued in Canadian and United States dollars unless otherwise disclosed. The Corporation does not use derivative contracts for speculative purposes.

With respect to AECO settled commodity contracts in place at September 30, 2011, an increase of $0.25/mcf in the price of natural gas, holding all other variables constant, would have reduced the fair value of the derivative financial instrument and decreased after tax earnings by approximately $1.0 million (2010 - $1.7 million). A similar decline in commodity prices would have had the opposite impact.

An increase of US$0.25/MMBtu in the price of NYMEX gas settled contracts, holding all other variables constant, would have reduced the fair value of the derivative financial instrument and decreased after tax earnings by approximately $0.2 million (2010 - N/A). A similar decline in commodity prices would have had the opposite impact.

An increase of US$0.25/bbl in the price of crude oil, holding all other variables constant, would have reduced the fair value of the derivative financial instrument and decreased after tax earnings by approximately $0.1 million (2010 - N/A). A similar decline in commodity prices would have had the opposite impact.

— **Foreign exchange rate risk**

The Corporation is exposed to fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil and to a certain extent natural gas prices are based upon reference prices denominated in US dollars, while the majority of the Corporation's expenses are denominated in Canadian dollars.

— **Interest rate risk**

The Corporation is exposed to interest rate risk principally associated with borrowings. Floating rates, associated with bank debt, expose the Corporation to short-term movements in interest rates.

The Corporation's cash flows are impacted by changes in interest rates on the floating rate bank debt. At September 30, 2011, a 100bps change in interest rates would have impacted after tax earnings by $1.0 million (2010 - $0.3 million) assuming the change in interest rates occurred at the beginning of the year.

(ii) Credit risk

The Corporation is exposed to credit risk, which is the risk that a counterparty will fail to perform an obligation or settle a liability, resulting in a financial loss to the Corporation.

A significant portion of Compton's trade and other accounts receivable and other current asset balances are with entities in the oil and gas industry and subject to normal industry credit risks. The allowance for doubtful accounts is less than 5% of total balances and relates to receivables acquired through corporate acquisitions and unresolved differences with partners. Substantially all of the receivable balances at September 30, 2011 were current.

In-the-money derivative financial instrument contracts are with investment grade Canadian and US financial institutions that are also members of the Corporation's banking syndicate. At September 30, 2011, three financial institutions held all of the outstanding financial instrument contracts.

The Corporation regularly assesses the financial strength of its marketing customers and limits the total exposure to individual counterparties based on management determined criteria. As well, a number of contracts contain provisions that allow Compton to demand the posting of collateral in the event of a downgrade to a non-investment grade credit rating.

The maximum credit risk exposure associated with the Corporation's financial assets is the carrying amount.

(iii) Liquidity risk

Compton is exposed to liquidity risk, which is the risk that the Corporation will be unable to generate or obtain sufficient cash to meet its commitments as they come due. Mitigation of this risk is achieved through the active management of cash and debt requirements over the next 12 months. In managing liquidity risk, in addition to cash flow generated from operating activities, the Corporation has funds available under its credit facility. The credit facility provides for accommodations by way of prime loan, bankers' acceptance, US base rate loan or LIBOR loan. Canadian and US direct advances bear interest at the bank's prime lending rate plus applicable margins. Amounts drawn through bankers' acceptance or LIBOR loans bear interest at the market rate for these products plus a stamping fee based on the Corporation's debt to trailing cash flow ratio. On September 27, 2011, the Corporation entered into a new syndicated credit facility to September 26, 2012 under conditions outlined in Note 5a - "Debt". Compton believes it has the ability to adjust its capital structure by making modifications to its capital expenditure program, divesting of assets and by issuing new debt or equity to maintain liquidity. See also Note 18 - "Commitments and Contingent Liabilities".

16. ROYALTIES

Revenue recognized in net earnings is reduced by crown and freehold royalties. The Corporation's total royalty expense for the nine months ended September 30, 2011 was $27.3 million (2010 - $38.3 million).

	three months ended September 30,		**nine months ended September 30,**	
	2011	2010	**2011**	2010
Crown	**$ 2,597**	$ 4,861	**$ 12,808**	$ 19,046
Freehold	**1,825**	1,884	**5,675**	6,705
Offset to revenue	**4,422**	6,745	**18,483**	25,751
Overriding royalty	**1,947**	1,957	**5,728**	7,445
Other royalties	**508**	790	**1,517**	2,833
Freehold mineral taxes	**(110)**	2	**1,604**	2,321
Royalty obligations expense	**2,345**	2,749	**8,849**	12,599
Total royalties	**$ 6,767**	$ 9,494	**$ 27,332**	$ 38,350

17. OTHER ASSETS

	September 30, 2011	December 31, 2010	January 1, 2010
Prepaid expenses	**$ 2,518**	$ 1,602	$ 538
Marketable securities	**-**	-	3,830
Deposits	**2,463**	3,210	9,919
Other current assets	**$ 4,981**	$ 4,812	$ 14,287
Inventory(1)	**$ 2,076**	$ 2,175	$ 2,175
Pension asset	**470**	470	344
Other	**85**	(25)	(25)
Other long term assets	**$ 2,631**	$ 2,620	$ 2,494

(1) Presented net of allowance of $1.5 million (December 31, 2010 - $1.5 million, January 1, 2010 - $1.5 million), to adjust to realizable value

18. COMMITMENTS AND CONTINGENT LIABILITIES

(a) Commitments

The Corporation has committed to certain payments over the next five years, as follows:

	2011	2012	2013	2014	2015	Thereafter
Credit facility	$ -	$ -	$ 104,000	$ -	$ -	$ -
MPP term financing(1)	2,702	9,592	9,592	20,594	-	-
Accounts payable	37,114	-	-	-	-	-
Finance leases	90	1,030	224	224	-	-
Office facilities	473	1,938	2,001	2,001	2,046	5,449
	$ 40,379	$ 12,560	$ 115,817	$ 22,819	$ 2,046	$ 5,449

(1) Represents monthly fixed base fee payments; the 2011 amount includes purchase option repayments of $0.3 million

Payments to MPP relate to payments made pursuant to a processing agreement between the Corporation and MPP which, together with associated management and option agreements, expire on April 30, 2014

Commitments on finance leases relate to arrangements on certain production facilities (see Note 5b - “Finance Leases”), and include monthly rental payments as well as the buyout option at the end of the lease term. It is the Corporation’s intention to purchase these assets as they come due.

The Corporation has an overriding royalty (“ORR”) obligation of 5.0% to a third party. The ORR represents a commitment of the Corporation’s future gross production revenue, less certain transportation costs and marketing fees, on the existing land base as at September 26, 2009.

(b) Legal proceedings

The Corporation is involved in various legal claims associated with normal operations. In Management’s opinion, it has accrued adequate amounts based on its assessment of probability for these claims, and although unresolved at the current time, are not significant and are not expected to have a material impact on the financial position or results of operations of the Corporation.

19. SUBSEQUENT EVENTS

Subsequent to the quarter end, the Corporation announced the signing of a farmout and joint venture agreement related its 79,000 net acres of undeveloped land holdings in northern Montana. The farmout joint venture grants the joint venture partner the ability to earn a 50% interest in this area by incurring capital expenditures on the exploration and development of the property. Compton will retain a 50% working interest in the area without incurring any capital expenditure commitments. At their cost, the joint venture partner has committed to the completion of a survey program at a minimum cost of $2.0 million on or before July 31, 2012 and the drilling of a test well on or before December 31, 2012.

On October 5, 2011, 690,000 warrants, adjusted for the share consolidation, issued in October 2009 expired without being exercised.

20. TRANSITION TO IFRS

The Corporation's consolidated interim financial statements for the nine months ended September 30, 2011 are presented under IFRS and prepared in accordance with IAS 34 and IFRS 1, and as such include the application of IFRS 1 "First-Time Adoption of International Financial Reporting Standards" ("IFRS 1").

IFRS 1 requires all first-time adopters to retrospectively apply all effective IFRS standards as of the transition date of January 1, 2010. However, it also provides certain optional exemptions and certain mandatory exceptions for first time IFRS adopters.

The Corporation has taken the following key optional exemptions upon transition to IFRS:

Deemed cost election for petroleum and natural gas assets

Under IFRS 1, the Corporation was allowed and elected to deem the value of its petroleum and natural gas assets, at the date of transition, based on the historical cost under Previous GAAP.

Decommissioning liabilities included in the cost of development and production

Under Previous GAAP, decommissioning liabilities were discounted at a credit adjusted risk free rate. Under IFRS the estimated cash flow to abandon and remediate the wells and fields has been risk adjusted; therefore the provision recognized on the balance sheet has been discounted at a risk free rate.

Business combinations

Compton has entered into business combinations before the date of transition of January 1, 2010. Compton has not elected to adopt IFRS 3 "Business Combinations" retrospectively. As a result, the classification of acquisitions under Previous GAAP will remain the same with no change in the recognition of assets and liabilities, excluding goodwill.

Reconciliations of Previous GAAP to IFRS

IFRS 1 requires an entity to reconcile balance sheets, equity, net earnings, comprehensive income and cash flows for prior periods. The following reconciliations present the adjustments made to the Corporation's previously reported financial results in compliance with IFRS 1. Reconciliations include the consolidated balance sheet as at September 30, 2010, and consolidated statements of operation and comprehensive loss for the three and nine months ended September 30, 2010 and equity for the nine months ended September 30, 2010. Full transitional disclosures under IFRS 1 were provided in the Corporation's first interim financial statements for the three months ended March 31, 2011.

The Corporation's first time adoption of IFRS did not have a significant impact on the total operating, investing or financing cash flows.

Balance Sheet
As at September 30, 2010

	Notes	Previous GAAP	Effect of transition to IFRS	IFRS
CURRENT ASSETS				
Cash		$ 68,888	$ -	$ 68,888
Trade and other accounts receivable		24,346	-	24,346
Risk management		14,054	-	14,054
Other assets		7,255	-	7,255
Deferred income tax	[a]	55	(55)	-
		114,598	(55)	114,543
Development and production	[b, c, d, h, j]	1,701,226	(411,734)	1,289,492
Exploration and evaluation	[c]	-	67,551	67,551
Risk management		283	-	283
Other assets	[d]	743	1,815	2,558
TOTAL ASSETS		**$1,816,850**	**$(342,423)**	**$1,474,427**
CURRENT LIABILITIES				
Trade and other accounts payable	[h]	$ 51,923	$ 4,337	$ 56,260
Risk management		207	-	207
Credit facility		-	-	-
Senior term notes		-	-	-
MPP term financing		5,657	-	5,657
Deferred income taxes	[a]	3,724	(3,724)	-
		61,511	613	62,124
Risk management		37	-	37
Senior term notes		455,728	-	455,728
MPP term financing		41,826	-	41,826
Provisions	[e]	38,968	97,367	136,335
Deferred income taxes	[a]	258,955	(106,994)	151,961
TOTAL LIABILITIES		**857,025**	**(9,014)**	**848,011**
NON-CONTROLLING INTEREST	[f]	5,297	(5,297)	-
EQUITY				
Capital stock	[k]	386,714	29,719	416,433
Share purchase warrants		13,800	-	13,800
Other reserves	[i]	38,029	1,280	39,309
Non-controlling interest	[f]	-	5,642	5,642
Retained earnings	[a, b, d, h, i]	515,985	(364,753)	151,232
TOTAL EQUITY		**954,528**	**(328,112)**	**626,416**
TOTAL LIABILITIES and EQUITY		**$1,816,850**	**$(342,423)**	**$1,474,427**

Reconciliation of Equity

	Notes	As at September 30, 2010
TOTAL EQUITY UNDER PREVIOUS GAAP		**$ 954,528**
Recognition of impairment write-downs, depletion, and disposition adjustments	**[b, c, j]**	$ (366,520)
Revaluation of decommissioning liabilities	**[e]**	(73,904)
Recognition of inventory	**[d]**	(3,508)
Elimination of unamortized pension assets	**[d]**	(360)
Recognition of leases	**[h]**	218
Recognition of provisions	**[e]**	-
		$ (444,074)
Tax effect of above	**[a]**	110,665
TOTAL ADJUSTMENT TO EQUITY		**$ (333,409)**
Reclassification of non-controlling interest	**[f]**	5,297
TOTAL EQUITY UNDER IFRS		**$ 626,416**

Effect of IFRS Adoption for the Consolidated Statement of Operations and Comprehensive Loss

	Notes	For the Three Months Ended September 30, 2010 Previous GAAP	Effect of transition to IFRS	IFRS
REVENUE				
Oil and natural gas revenues		$ 43,473	$ -	$ 43,473
Royalties	[g]	(5,612)	(1,133)	(6,745)
TOTAL NET REVENUE		**37,861**	**(1,133)**	**36,728**
EXPENSES				
Operating	[g]	15,452	(3,279)	12,173
Transportation		2,424	-	2,424
Administrative		5,391	-	5,391
Shared based payments	[i]	922	53	975
Foreign exchange and other gains	[b,h]	(13,976)	3,148	(10,828)
Risk management		(9,246)	-	(9,246)
Other royalty obligations	[g]	-	2,749	2,749
Depletion, depreciation and amortization	[b, j]	28,545	(10,517)	18,028
Exploration and evaluation	[c]	-	525	525
Impairment write-downs	[b]	-	44,907	44,907
Other expenses	[e]	-	-	-
TOTAL EXPENSES		**29,512**	**37,586**	**67,098**
FINANCE COSTS				
Interest and finance charges	[h]	11,397	39	11,436
Accretion of decommissioning liabilities	[e]	1,068	46	1,114
TOTAL FINANCE COSTS		**12,465**	**85**	**12,550**
LOSS BEFORE TAXES AND NON-CONTROLLING INTEREST		(4,116)	(38,804)	(42,920)
INCOME TAXES				
Current		-	-	-
Deferred	[a]	(125)	(9,740)	(9,865)
TOTAL INCOME TAXES		**(125)**	**(9,740)**	**(9,865)**
LOSS BEFORE NON-CONTROLLING INTEREST		(3,991)	(29,064)	(33,055)
NON-CONTROLLING INTEREST	[f]	354	(8)	346
NET LOSS AND COMPREHENSIVE LOSS		**$ (4,345)**	**$ (29,056)**	**$ (33,401)**
NET LOSS PER SHARE				
Basic		$ (3.30)	$ (22.04)	$ (25.34)
Diluted		$ (3.30)	$ (22.04)	$ (25.34)

Effect of IFRS Adoption for the Consolidated Statement of Operations and Comprehensive Loss

	Notes	For the 9 Months Ended September 30, 2010 Previous GAAP	Effect of transition to IFRS	IFRS
REVENUE				
Oil and natural gas revenues		$ 172,151	$ -	$ 172,151
Royalties	**[g]**	(28,342)	2,591	(25,751)
TOTAL NET REVENUE		**143,809**	**2,591**	**146,400**
EXPENSES				
Operating	**[g]**	51,936	(9,229)	42,707
Transportation		5,816	-	5,816
Administrative		16,630	-	16,630
Shared based payments	**[i]**	2,698	341	3,039
Foreign exchange and other gains	**[b, h]**	(9,599)	5,688	(3,911)
Risk management		(23,191)	-	(23,191)
Other royalty obligations	**[g]**	-	12,599	12,599
Depletion, depreciation and amortization	**[b, j]**	96,910	(33,537)	63,373
Exploration and evaluation	**[c]**	-	651	651
Impairment write-downs	**[b]**	-	117,664	117,664
Other expenses	**[e]**	14,834	(14,834)	-
TOTAL EXPENSES		**156,034**	**79,343**	**235,377**
FINANCE COSTS				
Interest and finance charges	**[h]**	38,374	1,187	39,561
Accretion of decommissioning liabilities	**[e]**	3,178	222	3,400
TOTAL FINANCE COSTS		**41,552**	**1,409**	**42,961**
LOSS BEFORE TAXES AND NON-CONTROLLING INTEREST		(53,777)	(78,161)	(131,938)
INCOME TAXES				
Current		-	-	-
Deferred	**[a]**	(15,233)	(19,101)	(34,334)
TOTAL INCOME TAXES		**(15,233)**	**(19,101)**	**(34,334)**
LOSS BEFORE NON-CONTROLLING INTEREST		(38,544)	(59,060)	(97,604)
NON-CONTROLLING INTEREST	**[f]**	1,098	345	1,443
NET LOSS AND COMPREHENSIVE LOSS		**$ (39,642)**	**$ (59,405)**	**$ (99,047)**
NET LOSS PER SHARE				
Basic		$ (30.08)	$ (45.07)	$ (75.15)
Diluted		$ (30.08)	$ (45.07)	$ (75.15)

Notes to reconciliation

(a) Deferred taxes

Under Previous GAAP, the Corporation has recognized deferred tax assets and liabilities, primarily associated with its exploration and evaluation, development and production, and risk management activities. Under IFRS, current deferred tax balances have been re-classed for presentation entirely as long term assets/liabilities.

In addition, each of the balances adjusted through equity on transition to IFRS have been tax effected based on the Corporation's estimated reversal rate of approximately 25%. As at September 30, 2010, the cumulative impact on the deferred tax liability was a decrease of $110.7 million. See the reconciliation of equity for adjustments that required a tax effect.

(b) Development and production

Under Previous GAAP, the Corporation followed full cost accounting for its petroleum and natural gas assets. This methodology enabled the capitalization of amounts exceeding those acceptable for IFRS. Under IFRS 1 on transition, the Corporation elected to allocate its full cost pool to its identified CGUs and then performed an impairment test.

Under the transitional election, an impairment test of the Corporation's assets was required at a CGU level subsequent to the allocation. The Corporation recognized an impairment write-down of $263.9 million on its petroleum and natural gas assets at January 1, 2010. Write-downs were based on the recoverable amount of assets, representing value in use, under a 10% discounted cash flow. The write-downs were primarily recognized in two Southern Alberta CGUs with long reserve lives where the discount rates have the most impact on the value in use assessment.

For the three months ended September 30, 2010, an impairment write-down of $44.9 million was recognized across certain CGUs. An impairment write-down of $117.7 million was recognized for the nine months ended September 30, 2010. The impairments reflect the historically low natural gas pricing environment and outlook.

The restated IFRS balances also reflect gains and losses on the derecognition of assets disposed of during 2010 at Niton and Gilby. The combined net losses of $5.7 million have been included in the foreign exchange and other gains and losses presentation in net loss. Under Previous GAAP, proceeds on sales were deducted from the full cost pool without gain or loss recognition unless the disposition changed the depletion rate by more than 20%.

(c) Exploration and evaluation

IFRS 6 “Exploration and Evaluation of Mineral Resources” requires the separate recognition of exploration assets that have not yet established a determinable future value in the form of technically feasible and commercially viable reserves. The $72.4 million of exploration and evaluation costs recognized under IFRS on transition at January 1, 2010 represent the Corporation's interest in undeveloped lands and mineral rights, and exploratory wells under evaluation.

For the three months ended September 30, 2010, the expiry of undeveloped mineral rights resulted in the derecognition of $0.5 million of exploration and evaluation assets, and have been presented as exploration expense in net loss.

For the nine months ended September 30, 2010, land expiries charged to exploration and evaluation expense totaled $0.7 million.

(d) Other assets

Under a transitional election contained in IFRS 1, the Corporation eliminated unamortized actuarial gains of $0.2 million associated with the Mazeppa Processing Partnership defined benefit pension plan. In addition, vested past service costs of the pension plan totaling $0.6 million were also adjusted through equity on transition. The net result of both entries was a reduction in other assets of $0.4 million. There were no additional adjustments at September 30, 2010.

Also on transition, the Corporation adopted an accounting policy to recognize identifiable inventory items that are currently being marketed for sale or redeployment. Identifiable inventory of $2.2 million was initially recognized on transition at January 1, 2010 and is included for presentation purposes in other assets at the lower of cost and recoverable amounts. The recognition of inventory reduced development and production by $5.7 million, and a valuation allowance of $3.5 million was reflected in equity.

(e) Provisions

The estimated provision for decommissioning liabilities associated with the Corporation's petroleum and natural gas assets has been adjusted on transition to IFRS. The adjustment reflects the application of a risk free rate for the discounting of the liability (based on the underlying assets), where under Previous GAAP this was measured using a credit risk adjusted rate. The adjustment to the discounted decommissioning liability recognized at September 30, 2010 was $97.4 million.

In addition, a provision of $13.9 million was recognized at January 1, 2010 for lease surrender costs payable, and a reduction of other corporate assets of $0.9 million in related leasehold improvements. The provision reflects the lower estimated cost of surrender for a portion of the corporate office space under lease, compared to the cost of fulfilling the contract. The undeveloped and unutilized space was determined by Management to be an onerous contract. The entire adjustment of $14.8 million was reflected in equity on transition. The provision was settled during the second quarter of 2010.

(f) Non-controlling interest

The presentation of non-controlling interest has been changed on transition from Previous GAAP to IFRS. Under IFRS, non-controlling interest is considered a component of equity and presentation reclassification was made. Minor adjustments in 2010 relating to the recognition and depletion of MPP facility assets, pension and decommissioning liabilities were also made.

For the nine months ended September 30, 2010, the impact of transitional IFRS adjustments was $0.3 million. No significant impact for the three months ended September 30, 2010.

(g) Royalties

The presentation of royalties under IFRS has changed from previous disclosures under Previous GAAP. Previously, royalties were aggregated in a single line and shown as a reduction of total revenue in net loss. Under IFRS, crown and freehold royalties have been netted from revenues, all other royalties have been presented as "Other royalty obligations" in the expenses. In addition, gas cost allowances have been presented as a recovery of related processing fees included in operating expense.

(h) Leases

On transition to IFRS at January 1, 2010, the classification of certain leases were changed to be recognized as finance leases under IFRS. These leases have been included in trade and other accounts payable for financial statement purposes as they are not individually material. As a result of the reclassification, at September 30, 2010, development and production was increased by $7.6 million (net), capital lease obligations increased $4.3 million, and the impact of interest and depreciation expense of $1.2 million and $0.5 million respectively, was recorded through net loss.

(i) Share based payments

Under Previous GAAP, share based payments were recognized as an expense on a straight-line basis through the date of full vesting. Under IFRS, the expense is required to be recognized over the individual vesting periods for graded vesting awards.

For the three months ended September 30, 2010, there was no significant increase in share based compensation expense from the revised valuation methodology. For the nine months ended September 30, 2010, the increase was $0.3 million.

(j) Depletion

Upon transition to IFRS, the Corporation adopted a policy of depleting its petroleum and natural gas assets on a unit of production basis over proved plus probable reserves, by depletable component. The depletion policy under Previous GAAP was a unit of production over proved reserves in a single pool.

For the three months ended September 30, 2010, a decrease in depletion of $10.5 million resulted from the reduction of the Corporation's petroleum and natural gas asset base and the revised depletion methodology. For the nine months ended September 30, 2010, depletion expense was reduced by $33.5 million.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") for Compton Petroleum Corporation ("Compton" or the "Corporation") should be read with the unaudited interim consolidated financial statements and related notes for the three and nine months ended September 30, 2011 and March 31, 2011, as well as the audited consolidated financial statements and MD&A for the year ended December 31, 2010. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this document. Disclosure regarding use of BOE Equivalents is contained in the "Advisories" section located at the end of this document.

The unaudited interim consolidated financial statements and comparative information has been prepared in accordance with International Financial Reporting Standard 1, "First-time Adoption of International Financial Reporting Standards", and with International Accounting Standard 34, "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IFRS"). Previously, the Corporation prepared its interim and audited annual consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles ("Previous GAAP").

Included in this document are measures that do not have any standardized meaning as prescribed under IFRS or Previous GAAP and are considered to be non-GAAP Financial Measures, defined fully in the "Advisories" section located at the end of this document.

Further information regarding Compton, including the Annual Information Form for the year ended December 31, 2010 can be accessed under the Corporation's public filings found on SEDAR at www.sedar.com, EDGAR at www.sec.gov, and on the Corporation's website at www.comptonpetroleum.com.

Amounts presented in this MD&A are stated in thousands (000's) of dollars except per share and boe amounts, unless otherwise stated. This document is dated as at November 7, 2011.

I. COMPTON'S BUSINESS

Compton Petroleum Corporation is a public corporation actively engaged in the exploration, development and production of natural gas, natural gas liquids, and crude oil in western Canada. The majority of the Corporation's operations are located in the Deep Basin fairway of the Western Canada Sedimentary Basin, providing multi-zone potential for future development and exploration opportunity.

With approximately 84% natural gas, Compton has shifted its strategy to focus on developing its high-return, liquids-rich natural gas areas at Niton and balancing its portfolio through emerging crude oil opportunities to offset continued low natural gas prices. The Corporation maximizes value by concentrating on properties that generate strong returns on capital investment, such as the Rock Creek Formation at Niton, and developing new horizons such as the Wilrich and Notikewin.

Compton's emerging oil plays target the Bakken/Big Valley, Ellerslie and Glauconite Formations in the Southern Plains area as well as future exploratory potential through the joint venture on its Montana Bakken/Big Valley lands. The successful development of these areas is expected to provide growth in oil production and reserves, further augmenting the Corporation's large natural gas reserves that can be capitalized on when natural gas markets recover.

Through further improving operating efficiencies, maximizing returns on capital invested and focusing on higher return assets, Compton will create value by providing appropriate investment returns for shareholders.

II. RESULTS FROM CORPORATE STRATEGY

Management's strategy throughout 2011 has been to strengthen its capital structure and position itself for growth through improving its operating efficiencies. Management has continued to deliver on commitments, improving the operational and financial performance of the Corporation by lowering debt, reducing its cost structure, improving capital efficiencies and generating positive cash flow within a low commodity price environment. Results for third quarter of 2011 include:

- Completed the Recapitalization plan of arrangement (the "Recapitalization") to return Compton's capital structure to levels more consistent with current natural gas producers (see "Liquidity and Capital Resources - Capital Structure"), substantially improving financial strength and comparability with industry peers;
    - Reduced net debt by 68% to $144.8 million since December 31, 2010, and by 83% from $854.7 million as at September 30, 2009;
- Negotiated an industry standard borrowing base credit facility of $160.0 million with a new syndicate of lenders for a one year term, and one year maturity thereafter if not renewed;
- Continued to reduce key cost structures by a combined $7.8 million (or 46%) from the third quarter of 2010:
    - Administrative costs decreased by 60% or $3.2 million due to restructuring completed at the end of 2010; and
    - Interest and finance charges decreased by 40% or $4.6 million as a result of lower debt levels in 2011 compared to 2010;
- Generated average daily production of 13,429 boe/d, attaining a relatively flat production profile with limited capital spending in 2011;
- Participated in a non-operated Wilrich (Spirit River) horizontal well (33.3% working interest) in the Niton area. Located in the centre of the Corporation's core lands, the well was tied-in and is currently on production at approximately 2.9 mmcf/d. Liquid rates are still being confirmed but are expected to be greater than 20 bbl/mmcf; and
- Signed a farmout and joint venture agreement on its Montana Bakken property subsequent to the quarter. At their cost, the joint venture partner has committed to completion of a survey program at a minimum cost of $2.0 million on or before July 31, 2012 and the drilling of a test well on or before December 31, 2012.

With the completion of the Recapitalization in late September, 2011, Management is now positioned to focus on drilling and liquids exploration to develop its high-return, liquid-rich natural gas areas at Niton and emerging crude oil opportunities in the Southern Plans. These activities are expected to provide the opportunity for accretive growth over a multi-year horizon.

III. RESULTS OF OPERATIONS

	three months ended September 30, 2011	2010	nine months ended September 30, 2011	2010
Average production (boe/d)	**13,429**	15,931	**13,557**	18,261
Capital expenditures[2]	**$ 7,805**	$ 11,900	**$ 23,173**	$ 37,902
Cash flow [1][2]	**$ 15,308**	$ 846	**$ 30,078**	$ 31,804
Per share - basic	**$ 1.76**	$ 0.64	**$ 7.91**	$ 24.13
- diluted	**$ 1.28**	$ 0.64	**$ 3.52**	$ 24.13
Operating earnings (loss)[1][2]	**$ (2,022)**	$ (16,291)	**$ (1,096)**	$ (29,932)
Net earnings (loss)	**$ 28,307**	$ (33,055)	**$ 24,090**	$ (97,604)
Per share - basic	**$ 3.26**	$ (25.08)	**$ 6.34**	$ (74.05)
- diluted	**$ 2.43**	$ (25.08)	**$ 3.03**	$ (74.05)
Revenue	**$ 38,971**	$ 36,728	**$ 109,304**	$ 146,400
Field netback (per boe) [1][2]	**$ 20.97**	$ 15.71	**$ 18.96**	$ 18.68

(1)Cash flow, operating loss and field netback are non-GAAP measures that are defined in this document
(2)Prior periods have been revised to conform to current period presentation

(3)Total shares outstanding changed from 263.6 million to 26.4 million on August 10, 2011 in accordance with the Recapitalization

CASH FLOW

Cash flow is considered a non-GAAP measure and it is commonly used in the oil and gas industry and by Compton to assist Management and investors in measuring the Corporation's ability to finance capital programs and repay its debt. Cash flow should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net earnings as determined in accordance with IFRS, as an indicator of the Corporation's performance or liquidity. The following schedule sets out the reconciliation of cash flow from operations to cash flow.

	three months ended September 30, 2011	2010	nine months ended September 30, 2011	2010
Cash flow from operating activities	**$ 5,654**	$ 5,979	**$ 16,010**	$ 21,729
Add: Recapitalization cost[2]	**661**	-	**661**	-
Less: change in non-cash working capital	**(8,993)**	5,133	**(13,407)**	(10,075)
Cash Flow [1]	**$ 15,308**	$ 846	**$ 30,078**	$ 31,804

(1) Cash flow is a non-GAAP measure that is defined in this document

(2) On August 23, 2011 the USD Senior Term Notes were converted to equity and fully extinguished

Cash flow for the third quarter of 2011 was $15.3 million, an increase of approximately $14.5 million compared to 2010. The increase in cash flow during the quarter was a result of:

- higher average realized natural gas prices, excluding financial hedges, which increased 4% to $4.01 per mcf compared to $3.84 per mcf in 2010;

- higher average realized liquids prices, which increased 32% to $78.10 per bbl compared to $59.39 per bbl in 2010;
- a decline in interest and finance charges of $4.6 million in 2011, resulting from reduced debt levels compared to 2010; and
- a decline in administrative costs of $3.2 million in 2011, resulting from the restructuring completed at the end of 2010.

These factors were partially offset by:

- a 17% decline in natural gas production volumes to 67 mmcf/d from 81 mmcf/d in 2010, resulting from the impact of asset sales, normal production declines, and the reduced level of capital expenditures;
- a 9% decline in liquids production volumes to 2,240 bbls/d from 2,452 bbls/d in 2010, resulting from the impact of asset sales, normal production declines, and the reduced level of capital expenditures; and
- realized risk management gains of $3.1 million compared to 3.7 million in 2010.

On a year-to-date basis, cash flow decreased by approximately $1.7 million or 5% when compared to 2010 as a result of:

- a 26% decline in natural gas production volumes to 68 mmcf/d from 92 mmcf/d in 2010, resulting from the impact of asset sales, normal production declines, and the reduced level of capital expenditures;
- a 24% decline in liquids production volumes to 2,213 bbls/d from 2,919 bbls/d in 2010, resulting from the impact of asset sales, normal production declines, and the reduced level of capital expenditures; and
- lower average realized gas prices, which decreased 12% to $4.04 per mcf compared to $4.59 per mcf in 2010.

These factors were partially offset by:

- higher average realized liquids prices, which increased 20% to $77.83 per bbl compared to $64.71 per bbl in 2010;
- realized risk management gains of $10.2 million compared to $7.9 million in 2010;
- a decline in interest and finance charges of $13.9 million in 2011, resulting from reduced debt levels compared to 2010;
- a decline in operating costs of $6.6 million in 2011, resulting from reduced production levels, and the continued focus on efficiency; and
- a decline in administrative costs of $5.5 million in 2011, resulting from the restructuring completed at the end of 2010.

NET EARNINGS (LOSS)

Net earnings for the third quarter of 2011 were $28.3 million, an increase of $61.4 million when compared to the $33.1 million net loss in the same period for 2010. In addition to the factors that impacted cash flow, third quarter 2011 net earnings was affected by:

- an impairment expense of $44.9 million in 2010;
- a gain on extinguishment of the senior term notes of $56.0 million; and
- lower depletion and depreciation expense of $15.3 million compared to $18.0 million in 2010, following asset impairments recognized on transition to IFRS throughout 2010.

These factors were partially offset by:

- an increase in exploration and evaluation expense to $11.4 million compared to $0.5 million in 2010, relating to costs associated with exploratory wells, and the expiry of undeveloped land;
- an increase in the deferred tax expense to $14.3 million, compared to a recovery of $9.9 million in 2010;
- a decline in unrealized risk management gains of $3.3 million compared to a gain of $5.6 million in 2010; and
- a decline in unrealized foreign exchange and other losses of $5.8 million compared to gain of $13.9 million 2010.

On a year-to-date basis, net earnings were $24.1million, an improvement of $121.7 million when compared to the $97.6 million net loss in the same period for 2010. In addition to the factors that impacted cash flow, year-to-date net earnings were favourably affected by:

- a gain on extinguishment of the Senior Term Notes of $56.0 million;
- an impairment reversal of $0.4 million in 2011 compared to a $117.7 million impairment expense in 2010;
- a decline in depletion and depreciation expense to $44.3 million compared to $63.4 million in 2010, following asset impairments recognized on transition to IFRS throughout 2010; and
- a decline in share based compensation expense to $0.1 million compared to $3.0 million in 2010, following the restructuring of staff completed in early 2011.

These factors were partially offset by:

- an increase in exploration and evaluation expense to $21.0 million compared to $0.7 million in 2010, relating to costs associated with exploratory wells, and the expiry of undeveloped land;
- an increase in the deferred tax expense to $10.1 million, compared to a recovery of $34.3 million in 2010;
- a decline in unrealized risk management losses to $2.9 million compared to a gain of $15.3 million in 2010; and
- a decline in unrealized foreign exchange and other gains to $1.5 million compared to gain of $7.6 million 2010.

OPERATING EARNINGS (LOSS)

Operating earnings is an after tax non-GAAP measure used by the Corporation to facilitate comparability of earnings between periods. Operating earnings is derived by adjusting net earnings for certain items that are largely non-operational in nature, or one-time non-recurring items. Operating earnings should not be considered more meaningful than or an alternative to net earnings as determined in accordance with IFRS. The following provides the calculation of operating loss for period end.

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Net earnings (loss), as reported	**$ 28,307**	$ (33,055)	**$ 24,090**	$ (97,604)
Non-operation items				
Unrealized foreign exchange and other (gains) losses	**5,839**	(13,860)	**(1,528)**	(7,560)
Unrealized mark to market hedging (gains) losses	**(3,344)**	(5,594)	**2,943**	(15,319)
Exploratory land expiries	**11,358**	525	**20,975**	651
Impairment expense (reversals)	**(148)**	44,907	**(435)**	117,664
Gain on Senior Term Notes extinguishment	**(55,962)**	-	**(55,962)**	-
Other expenses	**-**	-	**-**	23
Tax effect	**11,928**	(9,214)	**8,821**	(27,787)
Operating earnings (loss) (1)	**$ (2,022)**	$ (16,291)	**$ (1,096)**	$ (29,932)
Per share basic (2)	**$ (0.23)**	$ (12.36)	**$ (0.29)**	$ (22.71)
diluted (2)	**$ (0.23)**	$ (12.36)	**$ (0.29)**	$ (22.71)

(1) Prior periods have been revised to conform to current period presentation

(2) Total shares outstanding changed from 263.6 million to 26.4 million on August 10, 2011 in accordance with the Recapitalization

Operating loss for the three and nine months ended September 30, 2011, has improved considerably over 2010 comparable periods, despite continuing low natural gas prices. Operating earnings are expected to increase going forward with the continued efficiencies from reductions in interest, administrative and operating costs. (See “Forward Looking Statements” in the “Advisory” section of the MD&A.)

CAPITAL EXPENDITURES

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Exploration & evaluation				
Land	**$ 1,939**	$ 1,078	**$ 2,896**	$ 3,051
Drilling and completions	**448**	1,188	**963**	1,392
Development & production				
Drilling and completions	**3,035**	6,963	**11,061**	24,870
Alberta Drilling Credits	**-**	394	**-**	(4,327)
Production facilities and equipment	**2,325**	2,188	**8,085**	12,446
Corporate and other	**58**	89	**168**	470
Total capital investment	**7,805**	11,900	**23,173**	37,902
Divestitures				
Property	**8**	(36,077)	**(8,058)**	(153,484)
Production facilities and equipment	**-**	-	**(405)**	-
Overriding royalty	**-**	-	**-**	(23,469)
Land	**-**	-	**(2,126)**	-
Acquisitions (divestitures), net	**8**	(36,077)	**(10,589)**	(176,953)
Total capital expenditures	**$ 7,813**	$ (24,177)	**$ 12,584**	$(139,051)

Current natural gas prices have limited internally generated cash flow available to invest in drilling activities. As a result, capital spending, before acquisitions and divestments decreased by 34% in the third quarter and 39% on a year-to-date basis in 2011 compared to 2010. In order to maximize return on capital in 2011, Management has focused its expenditures towards higher return, liquids rich natural gas in Niton and emerging oil properties in Southern Plains. Compton participated in one non-operated well (0.3 net well), during the third quarter of 2011 as compared to a total of 4 wells (2.7 net wells) drilled during 2010. Capital expenditures in 2010 were partially offset by the implementation of the Alberta drilling credit program. No credits have been recognized in 2011 as the amount available is tied to the amount of crown royalties paid which has been insufficient to qualify the Corporation under the program for credits to offset the 2011 drilling program.

During the third quarter, Compton participated in a non-operated Wilrich (Spirit River) horizontal well (33.3% working interest) in the Niton area. Located in the centre of the Corporation's core lands, the well was tied-in and is currently on production at approximately 2.9 mmcf/d. Liquids rates are being confirmed but are expected to be greater than 20 bbl/mmcf. Compton also completed the acquisition of 25 sections of land in the Southern Plains area, prospective for the Big Valley/Bakken Formation. The Corporation has secured all prospective land holdings for developing the new play and with initial success, the play has the potential to expand into approximately 90 locations.

Compton's winter drilling program commenced at the beginning of October with two rigs operating at present. Two vertical oil wells were drilled to target the Basal Quartz and Ellerslie Formations in the Southern Plains, and a Rock Creek horizontal well is currently being drilled in Niton. A third rig is expected in Niton for mid-November to drill the first Wilrich well. With the drilling program ramping up, it's anticipated that five to seven wells will be drilled prior to year-end in Niton and the Southern Plains.

Subsequent to the quarter end, the Corporation announced the signing of a farmout and joint venture agreement related its 79,000 net acres of undeveloped land holdings in northern Montana. The farmout joint venture grants the joint venture partner with the ability to earn a 50% interest in this area by incurring capital expenditures on the exploration and development of the property. Compton will retain a 50% working interest in the area without incurring any capital expenditure commitments. At their cost, the joint venture partner has committed to completion of a survey program at a minimum cost of $2.0 million on or before July 31, 2012 and the drilling of a test well targeting the Bakken Formation on or before December 31, 2012.

FREE CASH FLOW

Free cash flow is a non-GAAP measure that Compton defines as cash flow in excess of capital investment, excluding net acquisitions and divestitures, and is used by Management to determine the funds available for other investing activities and/or other financing activities. Compton's third quarter 2011 free cash flow of $7.5 million is higher compared to the deficit in the third quarter of 2010 due to lower capital expenditures in 2011 and the focused cost reduction initiatives implemented during the strategic review and restructuring process completed in 2010. On a year-to-date basis, free cash flow is $13.0 million higher as compared to 2010 for the same reasons.

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Cash flow	**$ 15,308**	$ 846	**$ 30,078**	$ 31,804
Less: capital investment	**(7,805)**	(11,900)	**(23,173)**	(37,902)
Free cash flow	**$ 7,503**	$ (11,054)	**$ 6,905**	$ (6,098)
Production volumes and revenues				
Average production				
Natural gas (mmcf/d)	**67**	81	**68**	92
Liquids (bbls/d)	**2,240**	2,452	**2,213**	2,919
Total (boe/d)	**13,429**	15,931	**13,557**	18,261
Benchmark prices				
AECO ($/GJ)				
Monthly index	**$ 3.53**	$ 3.52	**$ 3.93**	$ 4.09
Daily index	**$ 3.47**	$ 3.36	**$ 3.57**	$ 3.91
WTI (US$/bbl)	**$ 89.76**	$ 76.23	**$ 95.45**	$ 77.66
Edmonton sweet light ($/bbl)	**$ 91.78**	$ 74.44	**$ 94.29**	$ 76.59
Realized prices				
Natural gas ($/mcf)	**$ 4.01**	$ 3.84	**$ 4.04**	$ 4.59
Liquids ($/bbl)	**$ 78.10**	$ 59.39	**$ 77.83**	$ 64.71
Total ($/boe)	**$ 33.06**	$ 28.61	**$ 32.98**	$ 33.46
Sales Revenue(1)(2)				
Natural gas	**$ 24,745**	$ 28,534	**$ 75,028**	$ 115,268
Liquids	**18,648**	14,939	**52,759**	56,883
Total	**$ 43,393**	$ 43,473	**$ 127,787**	$ 172,151

(1) Sales revenues are before crown and freehold royalties

(2) Prior periods have been revised to conform to current period presentation

Production volumes for the third quarter of 2011 were 16% lower than in 2010 primarily due to natural declines, a reduced asset base following property dispositions throughout 2010 and limited new production additions in 2011.

Compared to 2010, sales revenue remained consistent for the third quarter of 2011. The lower production volumes in 2011 were offset by increased realized natural gas and liquids prices. Realized prices and revenues are before any hedging gains or losses. The impact from hedging on realized natural gas prices in the third quarter of 2011 was a $0.51 per mcf compared to $1.05 per mcf in 2010.

FIELD NETBACK AND FUNDS FLOW NETBACK

Field netback and funds flow netback are non-GAAP measures used by the Corporation to analyze operating performance. Field netback equals the total petroleum and natural gas sales, including realized gains and losses on commodity hedge contracts, less royalties and operating and transportation expenses, calculated on a $/boe basis. Funds flow netback equals field netback less administrative and interest costs. Field netback and funds flow netback should not be considered more meaningful than or an alternative to net earnings as determined in accordance with IFRS.

Field netback and funds flow netback has increased for both the third quarter and year-to-date 2011 compared to 2010 despite reduced volumes and higher percentages of fixed operating costs. The following provides the calculation of field netback and funds flow netback.

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
($/boe)				
Realized price (1)	**$ 33.06**	$ 28.61	**$ 32.98**	$ 33.46
Processing revenue	**2.07**	1.05	**1.55**	1.07
Realized commodity hedge gain	**2.55**	2.49	**2.77**	1.58
Royalties	**(5.48)**	(6.48)	**(7.38)**	(7.69)
Operating Expenses	**(9.89)**	(8.31)	**(9.75)**	(8.57)
Transportation	**(1.34)**	(1.65)	**(1.21)**	(1.17)
Field netback	**$ 20.97**	$ 15.71	**$ 18.96**	$ 18.68
Administrative	**$ (1.76)**	$ (3.68)	**$ (2.99)**	$ (3.34)
Interest	**(5.53)**	(7.80)	**(6.94)**	(7.94)
Funds flow netback	**$ 13.68**	$ 4.23	**$ 9.03**	$ 7.40

(1) Prior periods have been revised to conform to current period presentation

ROYALTIES

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Crown Royalties (3)	**$ 2,597**	$ 4,861	**$ 12,808**	$ 19,046
Freehold royalties	**1,825**	1,884	**5,675**	6,705
Royalties included in revenue	**4,422**	6,745	**18,483**	25,751
Overriding Royalty (2)	**1,947**	1,957	**5,728**	7,445
Other royalties	**508**	790	**1,517**	2,833
Freehold mineral taxes	**(110)**	2	**1,604**	2,321
Other royalty obligations expense	**2,345**	2,749	**8,849**	12,599
Total royalties	**$ 6,767**	$ 9,494	**$ 27,332**	$ 38,350
Percentage of sales revenue	**15.6%**	21.8%	**21.4%**	22.2%

(1) Gas cost allowance received on crown volumes are presented as a reduction of Operating Expenses

(2) The overriding royalty obligation represents a 5% commitment of the Corporation's future gross production revenue, less certain transportation costs and marketing fees, on the existing land base at September 26, 2009

(3) September 30, 2011 includes $1.9 million for a one-time adjustment of deep gas royalty credits relating to prior periods

Total royalties decreased by 29% for the third quarter of 2011 compared to 2010, largely due to deep gas royalty credit received during the third quarter of 2011, and the reduction in produced volumes. The decrease was offset by a higher proportion of fixed rate freehold royalties, resulting in a 6.2% net decrease in royalties as a percentage of sales revenue. On a year-to-date basis, total royalties decreased by 29% due to lower natural gas prices, deep gas royalty credit received during the third quarter of 2011 and the reduction in produced volumes, offset by a higher proportion of fixed rate freehold royalties resulted in a 0.8% net decrease in royalties as a percentage of sales revenue during the first three quarters of 2011.

OPERATING EXPENSES

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Operating expenses	**$ 12,213**	$ 12,173	**$ 36,103**	$ 42,707
Operating expenses ($/boe)	**$ 9.89**	$ 8.31	**$ 9.75**	$ 8.57

There was no significant change in operating expense in the third quarter of 2011, while per boe costs increased by 19% from 2010. On a year-to-date basis, operating expense decreased by 15% while per boe costs increased by 14%. The decrease on a total dollar basis was a result of continued cost control initiatives identified and implemented by the Corporation, partially offset by rising electricity and power costs. The increase in per boe costs reflects the higher percentage of fixed cost component of certain operating costs, spread over reduced production levels quarter-over-quarter.

TRANSPORTATION

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Transportation costs	**$ 1,650**	$ 2,424	**$ 4,477**	$ 5,816
Transportation costs ($/boe)	**$ 1.34**	$ 1.65	**$ 1.21**	$ 1.17

Pipeline tariffs and trucking rates for liquids are primarily dependent upon production location and distance from the sales point. Regulated pipelines transport natural gas within Alberta at tolls approved by the government. Compton incurs charges for the transportation of its production from the wellhead to the point of sale.

Transportation expenses decreased by 32% and per boe amounts decreased by 19% in the third quarter of 2011. On a year-to-date basis, transportation expenses decreased by 23% while per boe amounts increased by 3%. The decrease in transportation costs is attributable to reduced production in 2011, partially offset by an increase in pipeline tariffs of approximately 25%. Increased per boe costs are a result of lower production volumes and higher tariffs.

ADMINISTRATIVE EXPENSES

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Gross administrative expenses	**$ 3,350**	$ 7,142	**$ 15,099**	$ 23,025
Capitalized administrative expenses	**(295)**	(741)	**(1,403)**	(3,304)
Operator recoveries	**(876)**	(1,010)	**(2,614)**	(3,091)
Administrative expenses	**$ 2,179**	$ 5,391	**$ 11,082**	$ 16,630
Administrative expenses ($/boe)	**$ 1.76**	$ 3.68	**$ 2.99**	$ 3.34

Administrative expenses per boe decreased 52% in the third quarter of 2011 compared to 2010 due to total administrative cost reductions of 53% on gross expenditures as well as a reduction in capitalized costs and operator recoveries. On a year-to-date basis, administrative expenses per boe decreased 10% in 2011 compared to 2010 due to total administrative cost reduction of 34% on gross expenditures as well as reductions in capitalized costs and operator recoveries. The decreases were a result of continued cost control initiatives as well as reduced staff levels following the 2010 restructuring.

SHARE BASED COMPENSATION

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Stock option plan	**$ (22)**	$ 753	**$ (1,443)**	$ 2,266
Employee long term incentive	**66**	-	**397**	-
Deferred share unit plan	**-**	-	**215**	-
Retention share plan	**59**	-	**325**	-
Share purchase plan	**128**	222	**546**	773
Share based compensation	**$ 231**	$ 975	**$ 40**	$ 3,039

At June 30, 2011, substantially all of the outstanding stock options were voluntarily forfeited by employees leading to the significant recovery of the expense for the three and nine month periods in 2011.

The Corporation has instituted various compensation arrangements, the value of which is determined in relation to the market value of Compton's capital stock. These arrangements are designed to attract, motivate and retain individuals, and to align their success with that of shareholders. Details relating to share based compensation arrangements are presented in Note 12 to the unaudited consolidated interim financial statements. Management and the Board of Directors are currently reviewing the share based compensation plans following the Recapitalization.

IMPAIRMENTS

Management has assessed both internal and external economic factors to determine if any indicators of asset impairment exist at the quarter end. When indictors exist, an impairment test is completed, at the cash generating unit ("CGU") level, to determine if any asset impairment exists. Each identified CGU has largely independent cash flows and is geographically integrated.

As part of the Recapitalization, the Corporation elected to have the fair value of the underlying transactions become the deemed costs of its assets and liabilities. The optional IFRS 1 election, made effective September 30, 2011, is only available in the year of transition to IFRS and with the presence of a market event, such as the Recapitalization, that gives rise to an externally derived fair value.

Under the election, the Corporation recognized a write-down of $107.1 million to development and production assets, and $4.0 million of exploration and evaluation assets. Following the revaluation, the deemed cost of development and production assets totalled $590.6 million, and exploration and evaluation assets totalled $41.7 million. This election has established the cost basis of assets and eliminated any potential reversal of impairments previously recognized under IFRS since transition on January 1, 2010.

Excluding the IFRS 1 election described above, there were no impairments of the Corporation's assets based on Management assessment of economic and internal indicators for the first three quarters of 2011. In 2010, following the sale of a significant portion of Niton and Gilby properties, an impairment of $117.7 million was recognized on development and production assets.

EXPLORATION AND EVALUATION

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Exploration and evaluation	**$ 11,358**	$ 525	**$ 20,975**	$ 651
Total costs ($/boe)	**$ 9.20**	$ 0.36	**$ 5.67**	$ 0.13

Exploration and evaluation expense relate to uneconomic exploratory wells and the expiry of mineral land rights, prospecting costs and geophysical work prior to the acquisition of mineral land rights. During the quarter, based on current price forecasts for natural gas and the Corporation's development strategy, it was determined that the value of certain natural gas exploratory drilling costs and mineral land leases would not be recovered in the near term and were written off.

INTEREST AND FINANCE CHARGES

	three months ended September 30, 2011	2010	nine months ended September 30, 2011	2010
Interest on Senior Term Notes	**$ 3,397**	$ 9,379	**$ 14,910**	$ 28,023
Interest on credit facility	**2,202**	14	**6,413**	2,692
Interest on finance leases	**23**	39	**70**	1,187
Interest expense	**$ 5,622**	$ 9,432	**$ 21,393**	$ 31,902
Finance Charges and amortization of transaction costs	**1,207**	2,004	**4,302**	7,659
Total Interest and finance charges	**$ 6,829**	$ 11,436	**$ 25,695**	$ 39,561
Total interest and finance charges ($/boe)	**$ 5.53**	$ 7.80	**$ 6.94**	$ 7.94

Interest expense decreased by 40% for the third quarter of 2011 and 35% on a year-to-date basis compared to the same periods in 2010. Although interest rates have increased, part of the overall decrease was a result of reduced borrowings on the revolving credit facility. Interest paid on the Senior Term Notes was reduced in part through the October 2010 and August 2011 restructuring and the related reduction of the amount outstanding. In addition, the strengthening of the Canadian dollar in relation to the US dollar has reduced the Canadian dollar equivalent amount paid. The expiry of certain finance leases in 2010 also reduced the interest component of lease obligation recognized.

Finance charges and amortization of transaction costs for the third quarter of 2011 decreased by $0.8 million or 40% compared to the same period in 2010, as a result of lower fees for unutilized credit. On a year-to-date basis, finance charges and amortization of transaction costs decreased by $3.4 million or 44% compared to the same period in 2010 for the same reason.

Interest and finance charges decreased on a per boe basis due to lower overall borrowing costs, despite reduced production volumes.

The Corporation's capital structure following the Recapitalization will significantly reduce interest and finance charges and related rates. (See "Forward Looking Statements" in the "Advisory" section of this MD&A.)

Effective interest rates on a weighted average debt basis are presented below.

	Three months ended September 30, 2011	2010	nine months ended September 30, 2011	2010
Credit facility	**$ 133,717**	$ 1,717	**$ 138,468**	$ 66,018
Effective interest rate	**6.59%**	6.81%	**6.17%**	5.44%
2013 Senior Term Notes (US$)	**$ -**	$ 450,000	**$ -**	450,000
Coupon Rate (US$)	**-**	7.625%	**-**	7.625%
Effective interest rate (Cdn$)	**-**	8.150%	**-**	8.150%
2011 Mandatory convertible senior term notes (US$)	**$ 26,413**	$ -	**$ 38,736**	$ -
Coupon Rate (US$)	**10.00%**	-	**10.00%**	-
Effective interest rate (Cdn$)	**9.71%**	-	**9.68%**	-
2017 Senior Term Notes (US$)	**$ 113,576**	$ -	**$ 166,566**	$ -
Coupon Rate (US$)	**10.00%**	-	**10.00%**	-
Effective interest rate (Cdn$)	**9.71%**	-	**9.68%**	-

RISK MANAGEMENT

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Commodity contracts				
Realized (gain) loss	**$ (3,154)**	$ (3,652)	**$ (10,248)**	$ (7,872)
Unrealized (gain) loss	**(2,985)**	(4,322)	**2,996**	(14,047)
Foreign currency contracts				
Unrealized (gain) loss	**(359)**	(1,272)	**(53)**	(1,272)
Total risk management (gain) loss	**$ (6,498)**	$ (9,246)	**$ (7,305)**	$ (23,191)
Realized (gain) loss	**$ (3,154)**	$ (3,652)	**$ (10,248)**	$ (7,872)
Unrealized (gain) loss	**(3,344)**	(5,594)	**2,943**	(15,319)
Total risk management (gain) loss	**$ (6,498)**	$ (9,246)	**$ (7,305)**	$ (23,191)

The Corporation's financial results are impacted by external market risks associated with fluctuations in commodity prices, interest rates, and the Canadian/US dollar exchange rate. Compton utilizes various financial instruments for non-trading purposes to manage and mitigate exposure to these risks. Financial instruments are not designated for hedge accounting and accordingly are recorded at fair value on the consolidated balance sheets, with subsequent changes recognized in consolidated net earnings.

Financial instruments utilized to manage risk are subject to periodic settlements throughout the term of the instruments. Such settlements may result in a gain or loss, which is recognized as a realized risk management gain or loss at the time of settlement.

The mark-to-market values of financial instruments outstanding at the end of a reporting period reflect the values of the instruments based upon market conditions existing as of that date. Any change in the fair values of the instruments from that determined at the end of the previous reporting period is recognized as an unrealized risk management gain or loss. Unrealized risk management gains or losses may or may not be realized in subsequent periods depending upon subsequent moves in commodity prices, interest rates or exchange rates affecting the financial instruments.

The Corporation uses hedges for natural gas denominated in giga joules ("GJ") and million British thermal units ("MMBtu"), oil denominated in barrels and electricity denominated in megawatt hours ("MWH") to stabilize fluctuations in commodity pricing. Compton's outstanding hedging instruments at September 30, 2011, are as follows, expressed in Canadian dollars unless otherwise noted:

Commodity	Term	Volume	Average Price	Index
Natural Gas				
Collars	July 2009 - Oct 2011	10,000 GJ/d	$4.50 - $7.00/GJ	AECO
US$ Swap	Apr 2011 - Oct 2011	15,000 MMBtu/d	$4.64/MMBtu	NYMEX
US$ Basis	Apr 2011 - Oct 2011	15,000 MMBtu/d	$(0.64)/MMBtu	NYMEX
US$ Swap	Jul 2011 - Dec 2012	10,000 MMBtu/d	$4.65/MMBtu	AECO
Swap	Jul 2011 - Dec 2011	10,000 GJ/d	$5.00/GJ	*AECO*
Oil				
US$ Option	Jan 2012 - Dec 2012	1,000 Bbl/d	$100.00/Bbl	WTI
US$ Option	Jul 2011 - Dec 2011	1,000 Bbl/d	$101.60/Bbl	WTI
Electricity				
Swap	Jan 2010 - Dec 2011	84 MWh/d	$50.74/MWh	AESO

DEPLETION AND DEPRECIATION

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Total depletion and depreciation	**$ 15,284**	$ 18,028	**$ 44,330**	$ 63,373
Depletion and depreciation (S/boe)	**$ 12.38**	$ 12.30	**$ 11.98**	$ 12.71

Total depletion and depreciation expense decreased 15% during the third quarter and 30% on a year-to-date basis as compared to 2010, largely due to a decrease in the asset base following impairments recognized under IFRS, and the reduction in overall production volumes. Depletion and depreciation expense per boe during the third quarter of 2011 increased by 1% and decreased by 6% on a year-to-date basis over the same period in 2010.

FOREIGN EXCHANGE AND OTHER (GAINS) AND LOSSES

	three months ended September 30,		nine months ended September 30,	
	2011	2010	**2011**	2010
Foreign exchange on translation of US$ debt	**$ 5,841**	$ (13,860)	**$ (1,528)**	$ (7,560)
Gain on extinguishment, USD Notes	**(55,962)**	-	**(55,962)**	-
(Gain)/loss on disposition of assets	**(83)**	3,148	**(15,117)**	5,688
Other	**21**	(116)	**177**	(2,039)
Foreign exchange and other (gains) losses	**$ (50,183)**	$ (10,828)	**$ (72,430)**	$ (3,911)

Foreign exchange and other gains and losses recognized year to date relate primarily to the Recapitalization including the conversion of the senior term notes to equity. Previously recognized valuation allowances were reversed and a $56.0 million gain on extinguishment was realized. Comparative periods were most significantly impacted by translation gains recognized on the US denominated senior term notes and losses recorded in association with property dispositions.

INCOME TAXES

Income taxes are recorded using the liability method of accounting. Deferred income taxes are calculated based on the temporary difference between the accounting and income tax basis of an asset or liability. Deferred income tax assets and liabilities are considered long term in nature under IFRS reporting.

A deferred income tax expense of $14.3 million was recognized in the third quarter of 2011 as compared to a recovery of $9.9 million for the comparable period in 2010. On a year-to-date basis, income tax expense of $10.1 million was recognized in 2011 as compared to a recovery of $34.3 million for the same period in 2010.

At September 30, 2011, the Corporation had available future income tax assets of $10.7 million that were not recorded in the financial statements due to the uncertainties associated with historical earnings performance, and its ability to utilize these balances in the future. The benefit of these balances does not deteriorate over time and will be available to the Corporation in the future with the improvement of natural gas prices and the generation of taxable income.

Recoveries arise as a result of the change in timing for settlement of deferred tax assets and liabilities, and the change in tax rates applied. The impact of restatements and temporary differences related to IFRS has been adjusted for in deferred tax balances at September 30, 2011.

IV. LIQUIDITY AND CAPITAL RESOURCES

CAPITAL STRUCTURE

The Corporation's capital structure is comprised of bank debt, working capital, MPP term financing and shareholders' equity. Compton's objectives when managing its capital structure are to:

(a) Ensure the Corporation can meet its financial obligations;

(b) Retain an appropriate level of leverage relative to the risk of Compton's underlying assets; and

(c) Finance internally generated growth and potential acquisitions.

Compton manages its capital structure based on changes in economic conditions and the Corporation's planned capital requirements. Compton has the ability to adjust its capital structure by making modifications to its capital expenditure program, divesting of assets and by issuing new debt or equity.

The Corporation monitors its capital structure and financing requirements using non-GAAP measures consisting of total net debt to capitalization and total net debt to "Adjusted EBITDA" to steward its debt position as measures of Compton's overall financial strength.

Adjusted EBITDA is a non-GAAP measure defined as net earnings (loss) before interest and finance charges, income taxes, depletion and depreciation, accretion of decommissioning liabilities, unrealized foreign exchange and other gains (losses), and unrealized risk management gains (losses). The Corporation targets a total net debt to Adjusted EBITDA of 2.5 to 3.0 times.

Capitalization is a non-GAAP measure defined as working capital, long-term debt including current portion, MPP term financing, and shareholders' equity. Compton targets at total net debt to Capitalization ratio of between 40% and 50%.

	as at September 30, 2011	as at December 31, 2010
Working capital deficit(1)	$ 8,676	$ 23,428
Credit facility (2)	103,130	145,584
MPP term financing (3)	32,985	45,620
Senior Term Notes	-	237,212
Total net debt	144,791	451,844
Shareholders' equity	331,882	187,198
Total capitalization	$ 476,673	$ 639,042
Total net debt to adjusted EBITDA (4)	1.7x	4.1x
Total net debt to total capitalization	30.4%	70.7%

(1) Adjusted working capital excludes risk management, current MPP term financing and facility

(2) Includes unamortized transaction costs of $870 (December 31, 2010 - $1,692)

(3) Includes unamortized financing fees of $400 (December 31, 2010 - $520)

(4) Based on trailing 12 month adjusted EBITDA

Following the Recapitalization, the Corporation met the targeted net debt to capitalization ratio, as well as the net debt to adjusted EBITDA target at September 30, 2011. Previously, both metrics fell outside of Management's target ranges.

In the first quarter of 2011, property sales for gross proceeds of $26.2 million were used to repay a portion of the facility with the balance applied to working capital. In the third quarter of 2011, the extinguishment of the Senior Term Notes, and gross share issuance proceeds of $50.0 million significantly reduced total net debt.

Shareholder equity was reduced as part of the transition to IFRS and the resulting adjustments recorded during 2010 negatively impacted net loss and deficit. These adjustments are disclosed in more detail in Note 20 - “Transition to IFRS”.

WORKING CAPITAL

Compton had a working capital deficiency of $8.7 million at September 30, 2011, as compared to a deficiency of $23.4 million as at December 31, 2010. Typically in the oil and gas industry, there is not a direct correlation between amounts receivable from the sale of production and trade payables, which results from operating activities that vary seasonally and also with activity levels. This will result in fluctuations in working capital and often result in a working capital deficit. Management anticipates that the Corporation will continue to meet the payment terms of suppliers. (See “Forward Looking Statements” in the “Advisory” section of this MD&A.)

CREDIT FACILITY

The Corporation’s outstanding bank debt at September 30, 2011 was $103.1 million.

Effective September 27, 2011, Compton reached an agreement with a new syndicate of lenders for a credit facility of $160.0 million, including a working capital facility of $15.0 million and a syndicated facility of $145.0 million. The facility term ends September 26, 2012, with a maturity one year thereafter unless renewed. The facility is subject to re-determination of the borrowing base semi-annually at September 30 and May 31. The borrowing base is determined based on, among other things, the Corporation’s current reserve report, results of operations, the lenders view of the current and forecasted commodity prices and the current economic environment.

The Credit facility provides that advances may be made by way of prime loans, bankers’ acceptances; US base rate loans, LIBOR loans and letters of credit. Advances will bear interest at the applicable lending rate plus a margin based on Compton’s debt to Adjusted EBITDA ratio. The Credit facility is secured by a fixed and floating charge debenture on the assets of the Corporation.

As a result of the improvement in the Corporation’s capital structure and under the terms of the new credit facility, margins have been reduced by 50 bps across all ranges.

SENIOR TERM NOTES

The USD $238.5 million senior term notes were fully extinguished on August 23, 2011 as part of the approved Recapitalization plan. The notes were converted entirely to equity with the issuance of common shares, cashless warrants, and share purchase rights. The recognition of key transactional items, in chronological order, is itemized as follows:

- August 10, 2011 - Common shares are consolidated on a 200:1 basis (see Note 10 - “Share Capital” and Note 11 - “Per Share Amounts”);
- August 23, 2011 - Senior term notes are extinguished for common shares, rights, and cashless warrants. These instruments were valued based on individually available market prices. A net gain of $56.0 million was recognized in current period earnings on extinguishment (see Note 14 - “Foreign Exchange and Other (Gains) Losses”. Of the $56.0 million gain on debt extinguishment, $56.6 million was considered non-cash and has been excluded from operating cash flow;
- September 27, 2011 - The $37.0 million (gross proceed of $50.0 million, net of issuance costs of $13.0 million) rights offering closes, completing the Recapitalization plan (see Note 10(b) - “Share Capital”);
- September 27, 2011 - The Corporation elected, under IFRS transitional provisions, to take an optional, event driven, revaluation of the book value of its assets and liabilities based on the negotiated value underlying the transactions, as provided in the approved Management proxy circular dated July 24, 2011. This resulted in a combined $111.1 million ($94.1 million, net of tax) write-down of its development and production, and exploration and evaluation assets. The adjustment was charged directly to retained earnings having no impact on current period earnings or cash flows. See Note 3 - “Development and Production” and Note 4 - “Exploration and Evaluation”; and
- September 30, 2011 - Further to the shareholder resolution approved July 25, 2011, the Corporation reduced its stated capital by eliminating the balances in other reserves, and deficit. The total stated capital reduction was $330.8 million, and did not affect current period earnings (see Note 10(b) - “Share Capital”).

MPP TERM FINANCING

On April 30, 2009, Compton completed the renegotiation of the MPP processing and other related agreements for a further term of five years, expiring on April 30, 2014. In connection with the renewal, the Corporation has reclassified a portion of the non-controlling interest associated with MPP as MPP term financing. MPP term financing in the aggregate amount of $33.0 million was included as a liability in the consolidated financial statements. The fixed base fee payments under the MPP term financing includes a principal and interest component. The effective rate of interest is 11.68% per annum. The principal amount of the MPP term financing is equal to the purchase option price of the MPP partnership units at the end of the five year term, plus the principal portion of monthly base fee payments.

The purchase option represents the pre-determined price at which Compton may, at its discretion, purchase the MPP partnership on April 30, 2014. If Compton does not exercise this purchase option it may renew the MPP agreements with terms and conditions to be negotiated at that time, or enter into an arrangement with the owners of the MPP facilities to process natural gas for Compton at a fee to be determined at that time.

The MPP Agreements prescribe minimum throughput volumes and dedicated reserves which, if not exceeded, may require a buy-down of the purchase option. The minimum throughput volume is an average of the throughput volume of the preceding two consecutive calendar quarters. The prepayment amount is $400,000 per 1.0 mmcf/d of shortfall. Each prepayment of the purchase option will cause the minimum throughput volume to be adjusted downward to the average throughput volume of the preceding two consecutive calendar quarters for the balance of the contract period. In the event that the estimated dedicated reserves, as projected at April 30, 2014, are less than 200 BCF or have a discounted reserve value of less than $250 million using a 10% discount rate, the repayment amount is the greater of $108,000 per $1 million of reserve value shortfall and $135,000 per 1.0 BCF of the reserves shortfall.

As of September 30, 2011, the threshold throughput volume was reduced to 55.2 mmcf/d. The cumulative prepayments of the purchase option are $10.1 million (2011 - $8.9 million, 2010 - $1.2 million, 2009 - $nil), reducing the amount of the MPP term financing liability. Subsequent to quarter end, an additional minimum payment of $0.3 million was made.

DEBT REPAYMENT AND LEASE OBLIGATIONS

As part of normal business, Compton has entered into arrangements and incurred obligations that will impact future operations and liquidity, some of which are reflected as liabilities in the consolidated financial statements. The following table summarizes all contractual obligations, with anticipated payment timing, as at September 30, 2011.

	2011	2012	2013	2014	2015	Thereafter
Credit facility	$ -	$ -	$ 104,000	$ -	$ -	$ -
MPP term financing (1)	2,702	9,592	9,592	20,594	-	-
Accounts payable	37,114	-	-	-	-	-
Finance leases	90	1,030	224	224	-	-
Office facilities	473	1,938	2,001	2,001	2,046	5,449
	$ 40,379	$ 12,560	$ 115,817	$ 22,819	$ 2,046	$ 5,449

(1) Represents monthly fixed base fee payments. The 2011 amount includes purchase option repayments of $0.3 million

V. OUTLOOK

The current outlook for natural gas in North America remains weak throughout the remainder of 2011 and into 2012. As a result, Management's strategy is focused on developing its high-return, liquids-rich natural gas area at Niton and emerging crude oil opportunities to offset continued low natural gas prices. Compton's assets provide significant upside potential through their multiple zone development opportunities, contiguous land blocks and impact of horizontal multi-stage fracture technology.

Compton is on track to meet or exceed its 2011 guidance targets, including the lower end of its production range despite lower than anticipated capital expenditures to date. As a result of the Corporation's focus on improving capital efficiencies and reducing costs, Management is revising its 2011 cash flow guidance upwards to between $35.0 and $40.0 million on a calendar year basis. Compton is in the process of finalizing its future development plan and 2012 budget, which is expected to be released prior to year-end. With a revised capital structure, Compton is focused on the development of its asset base and new opportunities for future growth.

VI. INTERNAL CONTROL OVER FINANCIAL REPORTING

The adoption of IFRS effected Compton's presentation of financial results and the accompanying disclosure. The impact on processes, controls and financial reporting systems have been evaluated and modifications made to the control environment accordingly. There were no significant changes to internal control over financial reporting during the period beginning January 1, 2011 and ending on September 30, 2011 that materially affected or are reasonably likely to materially affect Compton's internal control over financial reporting.

Effective January 1, 2011, the Corporation engaged a third party service provider to support the development and testing of internal controls over financial reporting.

VII. RISKS

The following discussion highlights key risks which could negatively impact Compton's business, financial condition, and results of operations, cash flows and prospects.

Business Risks

Compton's exploration and production activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from small junior producers, intermediate and senior producers, to much larger integrated petroleum companies. Compton is subject to a number of risks that are also common to other organizations involved in the oil and gas industry. Such risks include: finding and developing oil and gas reserves at economic costs; estimating amounts of recoverable reserves; production of oil and gas in commercial quantities; marketability of oil and gas produced; fluctuations in commodity prices, financial and liquidity risks, and environmental and safety risks.

In order to reduce exploration risk, Compton employs highly qualified and motivated professionals who have demonstrated the ability to generate high-quality proprietary geological and geophysical prospects. To maximize drilling success, Compton explores in areas that afford multi-zone prospect potential, targeting a range of shallower low to moderate risk prospects with some exposure to select deeper high-risk prospects that offer high-reward opportunities.

Compton engages an independent engineering consulting firm that assists the Corporation in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of factors and assumptions such as commodity prices, projected production, future production costs and government regulation. Such estimates may vary from actual results.

The Corporation mitigates its risk related to producing hydrocarbons through the utilization of advanced technology and information systems. In addition, Compton operates the majority of its prospects, thereby maintaining operational control. The Corporation relies on its partners in jointly owned properties that Compton does not operate.

Compton is exposed to market risk to the extent that the demand for oil and gas produced by the Corporation exists within Canada and the United States. External factors beyond the Corporation's control may affect the marketability of oil and gas. These factors include commodity prices and variations in the Canada-United States currency exchange rate, which in turn respond to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Compton may periodically use futures and options contracts to hedge its exposure against the potential adverse impact of commodity price volatility.

Exploration and production for oil and gas is very capital intensive. As a result, the Corporation relies on debt and equity markets as a source of capital. In addition, Compton utilizes bank financing to support on-going capital investment. Funds from operations also provide Compton with capital required to grow its business. Equity and debt capital is subject to market conditions and availability may increase or decrease from time to time. Funds from operations also fluctuate with changing commodity prices.

Safety and Environment

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Corporation conducts its operations with high standards in order to protect the environment and the general public. Compton maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.

Additional Risk Factors

For a more detailed discussion of the business risk factors affecting the Corporation refer to Compton's Annual Information Form for the year ended December 31, 2010, available on www.sedar.com.

VIII. FORTHCOMING AND NEWLY ADOPTED ACCOUNTING POLICIES

INTERANTIONAL FINANCIAL REPORTING STANDARDS

The Corporation's consolidated interim financial statements for the nine months ended September 30, 2011 are the third consolidated interim financial statements under IFRS and prepared in accordance with IAS 34 and IFRS 1 and as such include the application of IFRS 1 "First -Time Adoption of International Financial Reporting Standards".

IFRS 1 requires all first-time adopters to retrospectively apply all effective IFRS standards as of the transition date of January 1, 2010. However, it also provides certain optional exemptions and certain mandatory exceptions for first time IFRS adopters.

The Corporation has taken the following key optional exemptions upon transition to IFRS.

Deemed cost election for petroleum and natural gas assets

The Corporation has development and production recognized in the opening IFRS balance sheet. Under IFRS 1, the Corporation was allowed and elected to deem the value of its petroleum and natural gas assets, at the date of transition, based on the historical cost under Previous GAAP.

Decommissioning liabilities included in the cost of development and production

Under Previous GAAP, decommissioning liabilities were discounted at a credit adjusted risk free rate. Under IFRS the estimated cash flow to abandon and remediate the wells and fields has been risk adjusted; therefore, the provision recognized on the balance sheet has been discounted at a risk free rate.

Business combinations

Compton has entered into business combinations before the date of transition of January 1, 2010. Compton has not elected to adopt IFRS 3 "Business Combinations" retrospectively. As a result, the classification of previous acquisitions under Previous GAAP will remain the same with no change in the recognition of assets and liabilities, excluding goodwill.

The impact of accounting policy selections under IFRS resulted in the following significant adjustments to the previously reported financial statement balances.

(a) Deferred taxes

Under Previous GAAP, the Corporation had recognized deferred tax assets and liabilities, primarily associated with its exploration and evaluation, development and production, and risk management activities. Under IFRS, current deferred tax balances have been re-classed for presentation entirely as long term assets/liabilities.

In addition, each of the balances adjusted through equity on transition to IFRS have been tax effected based on the Corporation's estimated rate of reversal, which approximates 25%. For the nine months ended September 30, 2010, the cumulative impact on the deferred tax liability was a decrease of $110.7 million. See the reconciliation of equity for adjustments that required a tax effect.

(b) Development and production

Under Previous GAAP, the Corporation followed full cost accounting for its petroleum and natural gas assets. This methodology enabled the capitalization of amounts exceeding those acceptable for IFRS. Under IFRS 1 on transition, the Corporation elected to allocate its full cost pool to its identified CGUs and then perform an impairment test.

Under the transitional election, an impairment test of the Corporation's assets was required at a CGU level subsequent to the allocation. The Corporation recognized an impairment write-down of $263.9 million on its petroleum and natural gas assets at January 1, 2010. Write-downs were based on the recoverable amount of assets, representing value in use, under a 10% discounted cash flow. The write-downs were primarily recognized in two Southern Alberta CGUs with long reserve lives where the discount rates have the most impact on the value in use assessment.

For the three months ended September 30, 2010, an impairment write-down of $44.9 million was recognized across certain CGUs. An impairment write-down of $117.7 million was recognized for the nine months ended September 30, 2010. The impairments reflect the historically low natural gas pricing environment and outlook.

The restated IFRS balances also reflect gains and losses on the derecognition of assets disposed of during 2010 at Niton and Gilby. The combined net losses of $5.7 million have been included in the foreign exchange and other gains and losses presentation in net earnings (loss). Under Previous GAAP, proceeds on sales were deducted from the full cost pool without gain or loss recognition unless the disposition changed the depletion rate by more than 20%.

(c) Exploration and evaluation

IFRS 6 "Exploration and Evaluation of Mineral Resources" requires the separate recognition of exploration assets that have not yet established a determinable future value in the form of technically feasible and commercially viable reserves. The $72.4 million exploration and evaluation costs recognized under IFRS on transition at January 1, 2010 represent the Corporation's interest in undeveloped lands and mineral rights, and exploratory wells under evaluation.

For the three months ended September 30, 2010, the expiry of undeveloped mineral rights resulted in the derecognition of $0.5 million of exploration and evaluation assets, and have been presented as exploration expense in net loss.

For the nine months ended September 30, 2010 land expiries charged to exploration and evaluation expense totalled $0.7 million.

(d) Other assets

Under a transitional election contained in IFRS 1, the Corporation eliminated unamortized actuarial gains of $0.2 million associated with the Mazeppa Processing Partnership defined benefit pension plan. In addition, vested past service costs of pension plan totalling $0.6 million were also adjusted through equity on transition. The net result of both entries was a reduction in other assets of $0.4 million. There were no additional adjustments at September 30, 2010.

Also on transition, the Corporation adopted an accounting policy to recognize identifiable inventory items that are currently being marketed for sale or redeployment. Identifiable inventory of $2.2 million was initially recognized on transition at January 1, 2010 and is included for presentation purposes in other assets at the lower of cost and recoverable amounts. The recognition of inventory reduced development and production by $5.7 million, and a valuation allowance of $3.5 million was reflected in equity.

(e) Provisions

The estimated provision for decommissioning liabilities associated with the Corporation's petroleum and natural gas assets has been adjusted on transition to IFRS. The adjustment reflects the application of a risk free rate for the discounting of the liability (based on the underlying assets), where under Previous GAAP this was measured using a credit risk adjusted rate. The adjustment to the discounted decommissioning liability recognized at September 30, 2010 was $97.4 million.

In addition, a provision of $13.9 million was recognized at January 1, 2010 for lease surrender costs payable, and a reduction of other corporate assets of $0.9 million in related leasehold improvements. The provision reflects the lower estimated cost of surrender for a portion of the corporate office space under lease, compared to the cost of fulfilling the contract. The undeveloped and unutilized space was determined by Management to be an onerous contract. The entire adjustment of $14.8 million was reflected in equity on transition.

(f) Non-controlling interest

The presentation of non-controlling interest has been changed on transition from Previous GAAP to IFRS. Under IFRS, non-controlling interest is considered a component of equity and presentation reclassification was made. Minor adjustments in 2010 relating to the recognition and depletion of MPP facility asset, pension and decommissioning liabilities were also made.

For the nine months ended September 30, 2010, the impact of transitional IFRS adjustments was $0.3 million. No significant impact for the three months ended September 30, 2010.

(g) Royalties

The presentation of royalties under IFRS has changed from previous disclosures under Pervious GAAP. Previously, royalties were aggregated in a single line and shown as a reduction of total revenue in net earnings. Under IFRS, crown and freehold royalties have been netted from revenues, all other royalties have been presented as "Other royalty obligations" in the expenses. In addition, gas cost allowances have been presented as a recovery of related processing fees included in operating expense.

(h) Leases

On transition to IFRS at January 1, 2010, the classification of certain leases were changed to be recognized as finance leases under IFRS. These leases have been included in trade and other accounts payable for financial statement purposes as they are not individually material. As a result of the reclassification, at September 30, 2010, development and production was increased by $7.6 million (net), capital lease obligations increased $4.3 million, and the impact of interest and depreciation expense of $1.2 million and $0.5 million respectively, was recorded through net loss.

(i) Share based payments

Under Pervious GAAP, share based payments were recognized as an expense on straight-line basis through the date of full vesting. Under IFRS, the expense is required to be recognized over the individual vesting periods for graded vesting awards.

For the three months ended September 30, 2010, there was no significant increase in share based compensation expense from the revised valuation methodology. For the nine months ended September 30, 2010, the increase was $0.3 million.

(j) Depletion

Upon transition to IFRS, the Corporation adopted a policy of depleting its petroleum and natural gas assets on a unit of production basis over proved plus probable reserves, by depletable component. The depletion policy under Previous GAAP was a unit of production over proved reserves in a single pool.

For the three months ended September 30, 2010, a decrease in depletion of $10.5 million resulted from the reduction of the Corporation's petroleum and natural gas asset base and the revised depletion methodology. For the nine months ended September 30, 2010, depletion expense was reduced by $33.5 million.

CHANGES IN ACCOUNTING POLICY

Recent Accounting Pronouncements

All accounting standards effective for periods on or after January 1, 2011 have been adopted as part of the transition to IFRS. The following new IFRS pronouncements have been issued or are outstanding in the third quarter, are effective on January 1, 2013, and may have an impact on the Corporation's financial statements in the future.

- IFRS 9, "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

IFRS 10, "Consolidated Financial Statements", which is the result of the IASB's project to replace Standing Interpretations Committee 12, "Consolidation - Special Purpose Entities" and the consolidation requirements of IAS 27, "Consolidated and Separate Financial Statements". The new standard eliminates the current risk and rewards approach and establishes control as the single basis for determining the consolidation of an entity.

- IFRS 11, "Joint Arrangements", which is the result of the IASB's project to replace IAS 31, "Interests in Joint Ventures". The new standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted. Under IAS 31, joint ventures could be proportionately consolidated.

- IFRS 12, "Disclosure of Interests in Other Entities", which outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosures require information that will assist financial statement users to evaluate the nature, risks and financial effects associated with an entity's interests in subsidiaries and joint arrangements.

- IFRS 13, "Fair Value Measurement", which provides a common definition of fair value, establishes a framework for measuring fair value under IFRS and enhances the disclosures required for fair value measurements. The standard applies where fair value measurements are required and does not require new fair value measurements.

- IAS 19, "Post Employment Benefits", which amends the recognition and measurement of defined benefit pension expense and expands disclosures for all employee benefit plans.

The Corporation is currently assessing the impact of the new standards, but does not anticipate that the adoption of the standards will have a significant impact on the Corporation's consolidated financial statements.

IX. QUARTERLY INFORMATION

The following table sets forth certain quarterly financial information of the Corporation for the first seven most recent quarters.

	2011			2010			
($millions, except where noted)	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	$ 39	$ 34	$ 36	$ 39	$ 37	$ 49	$ 61
Cash Flow	$ 15	$ 7	$ 8	$ 10	$ 1	$ 10	$ 21
Per share - basic	$ 1.76	$ 5.42	$ 5.79	$ 7.59	$ 0.64	$ 7.64	$ 15.85
- diluted	$ 1.28	$ 2.24	$ 3.85	$ 5.47	$ 0.64	$ 7.64	$ 15.85
Net earnings (loss)	$ 28	$ (8)	$ 4	$ (440)	$ (33)	$ (90)	$ 25
Per share - basic	$ 3.26	$ (5.82)	$ 2.63	$ (333.84)	$ (25.08)	$ (68.29)	$ 19.31
- diluted	$ 2.43	$ (5.82)	$ 1.75	$ (333.84)	$ (25.08)	$ (68.29)	$ 19.31
Operating earnings (loss)	$ (2)	$ (6)	$ 7	$ (28)	$ (16)	$ (16)	$ 3
Production							
Natural gas (mmcf/d)	67	65	72	75	81	98	97
Liquids (bbls/d)	2,240	1,947	2,455	2,411	2,452	3,076	3,237
Total (boe/d)	13,429	12,748	14,507	14,852	15,931	19,481	19,411
Average price							
Natural gas ($/mcf)	$ 4.01	$ 4.10	$ 4.01	$ 3.87	$ 3.84	$ 4.15	$ 5.67
Liquids ($/bbl)	$ 78.10	$ 88.39	$ 69.11	$ 69.30	$ 59.39	$ 66.00	$ 67.59
Total ($/boe)	$ 33.06	$ 34.35	$ 31.68	$ 30.70	$ 28.61	$ 31.41	$ 39.62

(1) Prior periods have been revised to conform to current period presentation. Due to the transition to IFRS comparable information is only available from the date of transition, January 1, 2011.

(2) Total shares outstanding changed from 263.6 million to 26.4 million on August 10, 2011 in accordance with the Recapitalization.

Fluctuations in quarterly results are due to a number of factors, some of which are not within the Corporation's control such as seasonality and exchange rates. Continued depressed commodity prices and lower production volumes due to asset sales and natural declines contributed to decreased revenues throughout 2010 and 2011. Despite this, cash flow has increased due to Management's focus on continued cost reductions and improvement to capital efficiencies. Seasonality of winter operating conditions results in production increases that are typically higher in the third and fourth quarters.

Net earnings (loss) for each of the last three quarters in 2010 include impairment adjustments for petroleum and natural gas assets following the transition to IFRS.

Cash flow and operating earnings (loss) are affected by changes in the US dollar against the Canadian dollar and realized hedging impacts over the periods presented.

X. ADVISORIES

NON-GAAP FINANCIAL MEASURES

Included in this document are references to terms used in the oil and gas industry such as, cash flow, operating earnings (loss), free cash flow, funds flow per share, adjusted EBITDA, field netback, cash flow netback, debt and capitalization. Non-GAAP measures do not have any standardized meaning as prescribed by IFRS nor Previous GAAP and therefore reported amounts may not be comparable to similarly titled measures reported by other companies. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Corporation's liquidity and its ability to generate funds to finance its operations.

Use of BOE Equivalents

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("boe") basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. Compton uses the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. However, boes do not represent a value equivalency at the well head and therefore may be a misleading measure if used in isolation.

Forward-Looking Statements

Certain information regarding the Corporation contained herein constitutes forward-looking information and statements and financial outlooks (collectively, "forward-looking statements") under the meaning of applicable securities laws, including Canadian Securities Administrators' National Instrument 51-102 Continuous Disclosure Obligations and the United States Private Securities Litigation Reform Act of 1995 and the United State Securities and Exchange Act of 1934, as amended.

Forward-looking information and statements involve risks, uncertainties and other factors that could cause actual results to differ materially from those expressed or implied by them. Forward-looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance, or other statements that are not statements of fact, including statements regarding (i) cash flow and capital and operating expenditures, (ii) exploration, drilling, completion, and production matters, (iii) results of operations, (iv) financial position, and (v) other risks and uncertainties described from time to time in the reports and filings made by Compton with securities regulatory authorities. Although Compton believes that the assumptions underlying, and expectations reflected in, such forward looking statements are reasonable, it can give no assurance that such assumptions and expectations will prove to be correct. There are many factors that could cause forward-looking statements not to be correct, including risks and uncertainties inherent in the Corporation's business. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate fluctuations, availability of services and supplies, operating hazards, access difficulties and mechanical failures, weather related issues, uncertainties in the estimates of reserves and in projection of future rates of production and timing of development expenditures, general economic conditions, and the actions or inactions of third-party operators, and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Compton. Statements relating to "reserves" and "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements contained herein are made as of the date of this document solely for the purpose of generally disclosing Compton's views of its prospective activities. Compton may, as considered necessary in the circumstances, update or revise the forward-looking statements, whether as a result of new information, future events, or otherwise, but Compton does not undertake to update this information at any particular time, except as required by law. Compton cautions its readers that the forward-looking statements may not be appropriate for purposes other than their intended purposes and that undue reliance should not be placed on any forward-looking statement. The Corporation's forward-looking statements are expressly qualified in their entirety by this cautionary statement.

Exhibit 99.3

FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS
FULL CERTIFICATE

I, Tim Granger, President & C.E.O. of Compton Petroleum Corporation certify the following:

1. ***Review:*** I have reviewed the interim financial report and interim MD&A (together, the "interim filings") of Compton Petroleum Corporation (the "issuer") for the interim period ended September 30, 2011.

2. ***No misrepresentations:*** Based on my knowledge, having exercised reasonable diligence, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings.

3. ***Fair presentation:*** Based on my knowledge, having exercised reasonable diligence, the interim financial report together with the other financial information included in the interim filings fairly present in all material respects the financial condition, financial performance and cash flows of the issuer, as of the date of and for the periods presented in the interim filings.

4. ***Responsibility:*** The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, for the issuer.

5. ***Design:*** Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer's other certifying officer(s) and I have, as at the end of the period covered by the interim filings

A. designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that

   I. material information relating to the issuer is made known to us by others, particularly during the period in which the interim filings are being prepared; and

   II. information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and

B. designed ICFR, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP.

5.1 ***Control framework:*** The control framework the issuer's other certifying officer(s) and I used to design the issuer's ICFR is the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control - Integrated Framework.

5.2 N/A

5.3 N/A

6. ***Reporting changes in ICFR:*** The issuer has disclosed in its interim MD&A any change in the issuer's ICFR that occurred during the period beginning on January 1, 2011 and ended on September 30, 2011 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

Date: November 7, 2011

(Signed) "Tim Granger"

Tim Granger
President & C.E.O.

Exhibit 99.4

FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS
FULL CERTIFICATE

I, Theresa Kosek, Vice President, Finance & C.F.O. of Compton Petroleum Corporation certify the following:

1. ***Review:*** I have reviewed the interim financial report and interim MD&A (together, the “interim filings”) of Compton Petroleum Corporation (the “issuer”) for the interim period ended September 30, 2011.

2. ***No misrepresentations:*** Based on my knowledge, having exercised reasonable diligence, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings.

3. ***Fair presentation:*** Based on my knowledge, having exercised reasonable diligence, the interim financial report together with the other financial information included in the interim filings fairly present in all material respects the financial condition, financial performance and cash flows of the issuer, as of the date of and for the periods presented in the interim filings.

4. ***Responsibility:*** The issuer’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 *Certification of Disclosure in Issuers’ Annual and Interim Filings*, for the issuer.

5. ***Design:*** Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer’s other certifying officer(s) and I have, as at the end of the period covered by the interim filings

A. designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that

   I. material information relating to the issuer is made known to us by others, particularly during the period in which the interim filings are being prepared; and

   II. information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and

B. designed ICFR, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer’s GAAP.

5.1 ***Control framework:*** The control framework the issuer’s other certifying officer(s) and I used to design the issuer’s ICFR is the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”) framework in Internal Control - Integrated Framework.

5.2 N/A

5.3 N/A

6. ***Reporting changes in ICFR:*** The issuer has disclosed in its interim MD&A any change in the issuer’s ICFR that occurred during the period beginning on January 1, 2011 and ended on September 30, 2011 that has materially affected, or is reasonably likely to materially affect, the issuer’s ICFR.

Date: November 7, 2011

(Signed) "Theresa Kosek"
Theresa Kosek
Vice President, Finance & C.F.O.