PACIFIC RUBIALES ENERGY CORP.
MANAGEMENT DISCUSSION AND ANALYSIS
March 14, 2012
Form 51-102 F1
For the year ended December 31, 2011

CONTENTS

1. Preface

This Management Discussion and Analysis ("**MD&A**") contains forward-looking information and is based on the current expectations, estimates, projections and assumptions of Pacific Rubiales Energy Corp. This information is subject to a number of risks and uncertainties, many of which are beyond the Company's control. Users of this information are cautioned that actual results may differ materially. For information on material risk factors and assumptions underlying our forward-looking information, see page 32.

This MD&A is management's assessment and analysis of the results and financial condition of the Company, and should be read in conjunction with the accompanying audited consolidated financial statements for the years ended December 31, 2011 and December 31, 2010 and related notes. The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standard 1 as issued by the International Accounting Standard Board ("**IASB**") unless otherwise noted. Note 25 to the annual consolidated financial statements contains a detailed description of the Company's first annual reporting under International Financial Reporting Standards ("**IFRS**"). All comparative percentages are between the years ended December 31, 2011 and December 31 2010, unless otherwise stated. The following financial measures: (i) EBITDA; (ii) funds flow from operations; and (iii) adjusted net earnings from operations, as referred to in this MD&A, are not prescribed by IFRS and are outlined under "Additional Financial Measures" on page 30. All references to net barrels or net production reflect only the Company's share of production after deducting royalties and the partner's working interest. A list of abbreviations for oil and gas terms is provided on page 34.

In order to provide shareholders of the Company with full disclosure relating to potential future capital expenditures, we have provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. For further discussion of the significant capital expenditures, see "Capital Expenditures" on page 16.

References to "**we**", "**our**", "**us**", "**Pacific Rubiales**", "**PRE**", or the "**Company**" mean Pacific Rubiales Energy Corp., its subsidiaries, partnerships and joint venture investments, unless the context otherwise requires. The table and charts in this document form an integral part of this MD&A.

Additional information relating to the Company filed with Canadian securities regulatory authorities, including the Company's quarterly and annual reports and the Annual Information Form, are available on SEDAR at www.sedar.com and on the Company's website at www.pacificrubiales.com. Information contained in or otherwise accessible through our website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

2. 2011 Year-End Highlights

During the year ended December 31, 2011, the Company continued its trend of production growth and exploratory success, leveraging its technical know-how and operational expertise. The results for this year underline the strength of the Company's assets, operational activity, capacity to increase production and delivery of robust financial results. Management is focused on meeting challenging operational goals, pursuing an ambitious exploration and production ("**E&P**") program, while delivering on its paramount strategic focus: Growth.

Set out below are the highlights of the Company's activities during the year-ended 2011:

- **Production continues to grow in 2011**. In 2011, average net production after royalties reached 86,497 boe/d (218,450 boe/d gross field), representing a 52% growth year-over-year, with production growth driven by the more than 180 development wells drilled mainly in the Rubiales and Quifa SW fields.

- **Significant growth in year-end 2011 total net after royalty Proved plus Probable reserves ("2P")**. Total 2P net reserves growth to 407 million barrels of oil equivalent ("**MMboe**") at December 31, 2011, up 52% from 269 MMboe at December 31, 2010. 2P reserve replacement increased to 547% and 2P Reserve Life Index ("**RLI**") increased to 13.0 from 11.5. Total net proved reserves ("**1P**") growth of 34% in the same period to 318 MMboe. Reserves additions include the first 2P (Probable) net reserves of 44 MMboe from the CPE-6 E&P block. At year-end 2011, the Rubiales field represented 29% of total 2P reserves (down from 51% a year ago), demonstrating successful diversification of the Company's reserve base.

- **Resource evaluation of 25 exploration blocks.** On October 21, 2011, the Company received independent resource assessment reports for the Company's exploration blocks in Colombia (21), Peru (3) and Guatemala (1), resulting in a Best Estimate (P50) for contingent and prospective resources of 2,778 MMboe for those exploration blocks.

- **Strong financial results.** The year ended December 31, 2011 confirmed the capacity of the Company to deliver strong financial results, driven by a significant increase in production and by improvements in realized prices. Consolidated net earnings in 2011 were $555 million or $2.04 per common share, exceeding a two fold increase as compared with net earnings of $265 million or $1.01 per common share in 2010. Adjusted net earnings in 2011 were $749 million compared to $347 million in 2010. Revenues increased to $3.381 million compared to $1,661 million in 2010.

- **EBITDA doubled.** EBITDA for the year ended on December 31, 2011 totaled $1,947 million, compared to $924 million for the previous year. EBITDA in 2011 represented a 58% margin in comparison to total revenues for the period. Funds flow from operations increased to $1,369 million, compared to $668 million in 2010.

- **Significant improvement in operating netbacks.** Crude oil operating netback during 2011 was $61.38/bbl, 42% higher in comparison to 2010 ($43.36/bbl), due to higher realized prices. Natural gas operating netback was $31.09/boe, 39% higher in comparison to 2010 ($22.41/boe).

- **First production from Quifa North and Sabanero exploration areas.** During the fourth quarter of 2011, the Company started production from the Quifa North exploration block and Maurel & Prom Colombia B.V. ("**Maurel & Prom Colombia**") started production at the Sabanero exploration block. The Company holds an indirect 49.999% equity interest in Maurel & Prom Colombia.

- **Total capital expenditure**. Capital expenditures during the year ended December 31, 2011, totaled $1,096 million ($954 million in 2010), of which $470 million were invested in the expansion and construction of production infrastructure; $267 million went into exploration activities (including drilling, seismic and other geophysical) in Colombia, Peru and Guatemala; $63 million for the acquisition cost of the 49.999% interest in Maurel & Prom Colombia; $207 million for development drilling; and $89 million in other projects including STAR.

- **Continuing drilling activity in the Colombian exploration blocks with a success rate of 84% in 2011**. During 2011, total net exploration capital expenditure of $267 million with exploration activity consisting of: drilling a total of 69 exploratory wells (58 successful); acquisition of 1557 km of 2D and 554 km^2 of 3D seismic; and initiation of exploration activity in the CPE-6 E&P Block, with four successful stratigraphic wells drilled during the period.

- **Optimization of oil transportation infrastructure.** During 2011, the Company continued its investment to increase and optimize oil transportation capacity through its pipeline systems. In December 2011, the Oleoducto de los Llanos Orientales S.A. pipeline (the "**ODL Pipeline**") reached a transportation capacity of 340 Mbbl/d with the start-up of two new pumping stations (Corocora and Jagüeyes). In addition, Oleoducto de los Llanos S.A. ("**ODL**") started the construction of new blending facilities in Cusiana in order to optimize the diluents required for transportation. Finally, the engineering for the new Cusiana-Araguaney pipeline to connect ODL with the Oleoducto Bicentenario de Colombia pipeline (the “**OBC Pipeline**”) was ongoing at the end of the year. This will ensure the increase of oil transportation capacity through pipelines for the Company.

- **Bicentenario OBC Pipeline**. The construction of Phase 1 of the OBC Pipeline started in 2011. This phase entail the construction of a 42 inches diameter pipeline, with a length of 230 kms between Araguaney and Banadía, will allow the transportation of up to 120 Mbbl/d of crude oil for the company, from the Llanos Basin to the Coveñas export terminal in the Caribbean, via the existing Caño Limón pipeline. The Company has a 32.88% equity stake in the OBC Pipeline, which when the Phase 1 is completed will result in a transportation capacity of up to 36 Mbbl/d.

- **Approval for BDR trading in Brazil**. On February 1, 2012 the Company received approval from the Comissão de Valores Mobiliários (the “**CVM**”), the Brazilian regulatory entity in charge of supervising public issuers, and the Brazilian stock exchange called BM&FBOVESPA S.A - Bolsa de Valores Mercadorias e Futuros (or the Brazilian stock exchange) (the “**BOVESPA**”) for the trading of Brazilian Depositary Receipts (the "**BDRs**") representing the Company's common shares. Pacific Rubiales is the first Canadian company to have BDRs listed on the BOVESPA.

- **Closing of new senior unsecured notes offering**. In December 2011 the Company successfully closed an offering of $300 million in senior unsecured notes at a rate of 7.25% due 2021 (the "**2011 Senior Notes**"). The net proceeds from the placement of the 2011 Senior Notes will be used by the Company for general corporate purposes, which may include acquisitions and investments in oil and gas sector assets and related infrastructure.

- **Senior note exchange offer**. An exchange offer was initiated in early December 2011 whereby the Company offered to exchange any or all of its existing $450 million 8.750% senior notes due 2016 (the “**2009 Senior Notes**”) for newly issued 2011 Senior Notes due 2021. A total of $359 million (or 79.8%) of the 2009 Senior Notes were exchanged for $412 million of the 2011 Senior Notes under the exchange offer.

- **Early conversion of convertible debentures**. The Company implemented an early conversion program for holders of its C$240 million 8% convertible unsecured subordinated debentures due August 29, 2013 (the “**Debentures**”). A total of C$236 million (or 98.9%) of the Debentures were converted.

- **Credit agency upgrades**. On November 3, 2011, the Fitch Ratings upgraded the Company's foreign and local currency Issuer Default Ratings (IDRs) to 'BB' from 'BB-'. In addition, on November 21, 2011 Moody´s Investors Service upgraded the Company's Corporate Family Rating to Ba2 from Ba3.

- **Cash dividend**. A cash dividend in the aggregate of $27 million or $0.093 per common share was paid on December 30, 2011 to shareholders of record as of December 20, 2011.

3. Financial and Operating Summary

Financial Summary

A summary of the financial results for the three and twelve months ended December 31, 2011 and 2010 are as follows:

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$ except per share amounts or as noted)	**2011**	**2010**	**2011**	**2010**
Oil and gas sales [1]	**$ 3,380,819**	$ 1,661,544	**$ 1,011,476**	$ 516,731
EBITDA [2]	**1,946,588**	924,063	**560,665**	275,360
EBITDA Margin (EBITDA/Revenues)	**58%**	56%	**55%**	53%
Per share - basic ($) [4]	**7.16**	3.51	**2.00**	1.03
- diluted ($)	**6.53**	3.36	**1.95**	0.99
Net earnings	**554,336**	265,087	**80,834**	61,370
Per share - basic ($) [4]	**2.04**	1.01	**0.29**	0.23
- diluted ($)	**1.97**	0.96	**0.28**	0.22
Cash Flow from Operations	**1,219,057**	939,929	**477,530**	353,433
Per share - basic ($) [4]	**4.48**	3.57	**1.70**	1.32
- diluted ($)	**4.09**	3.42	**1.66**	1.27
Adjusted Net earnings from operations [3]	**749,117**	346,881	**172,150**	93,443
Per share - basic ($) [4]	**2.75**	1.32	**0.61**	0.35
- diluted ($)	**2.51**	1.26	**0.60**	0.34
Non-operating items [5]	**194,781**	81,794	**91,316**	32,073
Funds Flow from Operations	**1,368,599**	667,769	**351,760**	208,571
Per share - basic ($) [4]	**5.03**	2.54	**1.26**	0.78
- diluted ($)	**4.59**	2.43	**1.22**	0.75

Adjusted Net Earnings from Operations

Net earnings for the year ended December 31, 2011 totaled $554.3 million and includes a number of non-operating items totaling $194.8 million mainly related to mark-to-market gains on derivatives, share-based compensation, equity tax, foreign exchange gain / losses and incentive for early conversion of debenture. These non-operating items may or may not materialize or reoccur in future periods. The adjusted net earnings from operations follow:

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$ except per share amounts or as noted)	**2011**	**2010**	**2011**	**2010**
Net earnings (loss) as reported	**$ 554,336**	$ 265,087	**$ 80,834**	$ 61,370
Non-operating items [5]				
Loss (gain) on risk management contracts	**(8,831)**	40,230	**46,458**	39,752
Share-based compensation	**48,783**	73,327	**316**	-
Equity tax	**68,446**	2,088	**-**	522
Foreign exchange (gain) loss	**39,894**	(33,851)	**(1,947)**	(8,201)
Incentive for early conversion of debenture	**46,489**	-	**46,489**	-
Total non-operating items	**$ 194,781**	$ 81,794	**$ 91,316**	$ 32,073
Adjusted earning from operations [3]	**$ 749,117**	$ 346,881	**$ 172,150**	$ 93,443
Per share - basic ($) [4]	**2.75**	1.32	**0.61**	0.35
Per share - diluted ($) [4]	**2.51**	1.26	**0.60**	0.34

(1) *See additional details in section 5 entitled "Discussion of 2011 Fourth Quarter and Annual Operating Results" – Reconciliation of barrels produced and purchased vs. barrels sold on page 10.*
(2) *See Section 9 entitled "Discussion of 2011 Fourth Quarter and Annual Financial Results – EBITDA" on page 22 and Section 7 entitled "Additional Financial Measures" on page 30.*
(3) *Adjusted earnings from operations are a non-IFRS financial measure that represents net earnings adjusted for certain items of a non-operational nature including non-cash items.The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations", lists the effects of certain non-operational items that are included in the Company´s financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies. See "Additional Financial Measures" on page 30.*
(4) *The basic weighted average number of common shares outstanding for the year ended December 31, 2011 and 2010 was 271,985,534(fully diluted – 298,271,197) and 262,945,271(fully diluted –274,788,797), respectively.*
(5) *See additional details explained in Section 9 entitled "Discussion of 2011 Fourth Quarter and Annual Financial Results" on page 17.*

Operating Summary

The Company produces and sells crude oil and natural gas. It also purchases crude oil from third parties as diluents and for trading purposes. The combined crude oil and gas operating netback improved during the year ended December 31, 2011 and was $58.24/boe, 44% higher as compared to the same period of 2010. Crude oil operating netback during 2011 was $61.38/bbl, 42% higher in comparison to 2010 ($43.36/bbl), due to higher realized prices. Natural gas operating netback was $31.09/boe, 39% higher in comparison to 2010 ($22.41/boe).

Set below is the operating netback for the year and three months ended December 31, 2011.

	Year ended December 31			
	2011 Oil	2011 Gas	2011 Combined	2010 Combined
Average net production (boe/day after royalties and field consumption)[(1)]	**75,539**	**10,958**	**86,497**	**56,974**
Average daily volume sold (boe/day)[(1)]	**90,013**	**10,433**	**100,446**	**69,992**
Operating netback ($/boe) [(2)]				
Crude oil and natural gas sales price	98.88	34.71	92.21	65.04
Cost of production [(3)]	5.59	2.70	5.29	4.74
Transportation (trucking and pipeline) [(4)]	11.58	0.38	10.41	6.07
Diluent cost [(5)]	15.40	-	13.80	11.29
Other costs [(6)]	4.63	1.46	4.30	1.84
Overlift/Underlift [(7)]	0.30	(0.92)	0.17	0.74
Operating netback ($/boe)	**61.38**	**31.09**	**58.24**	**40.36**

	Three months ended December 31			
	2011 Oil	2011 Gas	2011 Combined	2010 Combined
Average net production (boe/day after royalties and field consumption)[(1)]	**79,963**	**10,996**	**90,959**	**64,040**
Average daily volume sold (boe/day)[(1)]	**99,192**	**9,014**	**108,206**	**78,527**
Operating netback ($/boe) [(2)]				
Crude oil and natural gas sales price	107.14	40.74	101.61	71.52
Cost of production [(3)]	5.36	4.04	5.25	6.12
Transportation (trucking and pipeline) [(4)]	11.98	0.39	11.01	5.77
Diluent cost [(5)]	13.73	-	12.59	11.19
Other costs [(6)]	9.85	3.19	9.30	1.78
Overlift/Underlift [(7)]	(0.78)	0.96	(0.64)	3.31
Operating netback ($/boe)	**67.00**	**32.16**	**64.10**	**43.35**

(1) *The term "boe" is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet to barrels is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A we have expressed boe using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy.*
(2) *Combined operating netback data based on weighted average daily volume sold which includes diluents necessary for the upgrading of the Rubiales blend.*
(3) *Cost of production mainly includes lifting costs and other production costs such as personnel, energy, security, insurance and others.*
(4) *Includes the transport costs of crude oil and gas through pipelines and tank trucks incurred by the Company to take the products to the delivery points to customers. The increase over the prior period of 2010 is mainly due to the higher volume of crude oil transported via tank truck due to increased production, coupled with an increase in the overall land transport costs in Colombia during 2011.*
(5) *Net blending cost is estimated at $3.14 per bbl of Rubiales crude, considering an average diluent purchase price delivered at the Rubiales field of $103.13/bbl (Light Crude Oil 37º API and natural gas at 81.6º API), plus pipeline fees from the Rubiales field to Coveñas of $7.76 per bbl, less the average Rubiales Blend (Castilla) sale price of $97.23 per bbl, times the Rubiales average blending ratio of 23%. Dilution cost slightly increased over the previous period of 2010 ($3.12/bbl).*
(6) *Other costs mainly correspond to royalties on gas production, external road maintenance at the Rubiales field, inventory fluctuation, crude oil trading cost, storage cost and the net effect of the currency hedges of operating expenses incurred in Colombian pesos ("**COP**") during the period. Trading*

cost during 4Q, 2011 increased over the same period of 2010 due to higher volume traded towards the end of the year. See additional comments on page 24 – "Risk Management Contracts".

(7) *Corresponds to the net effect of the overlift position for the period amounting to $6.4 million, which generated a reduction in the combined production costs of $0.17/boe as explained in "Discussion of 2011 Fourth Quarter and Annual Financial Results– Financial Position – Operating Costs" on page 18.*

Volume Allocation for Certain Fields

a) Additional Production Share in Quifa SW field

The Company's share of production before royalties in the Quifa SW field is 60% and may decrease if the high-prices clause is triggered in the Quifa Association Contract which assigns additional production to Ecopetrol, S.A. ("**Ecopetrol**"). The additional Ecopetrol share is generated when the WTI oil price is higher than a reference price, as described in the contract, after cumulative oil production for each commercial field reaches 5 MMbbl gross (including royalties). It is effectively a sliding-scale overriding royalty interest which burdens the participation interest of Meta Petroleum Corp. ("**Meta**"). During the first half of 2011, the cumulative production of the Quifa SW field reached the 5 MMbbl threshold. The additional participation interest of Ecopetrol when the high prices clause applies is calculated using the equation below:

PI = (P-Po)/P X 0.30

Where:

PI = Ecopetrol Additional Participation Interest,
P = current oil price (WTI) in US$, and
$Po = Po_{(n-1)} \times (1 + I_{(n-2)})$

Po is the WTI reference price indicated in the Contract and $Po_{(n-1)}$ = Po at end of previous year (adjusted annually), and $I_{(n-2)}$ = US Producer Price Index (PPI) two years prior.

On September 27, 2011, Ecopetrol and the Company agreed on an arbitration process to define the interpretation due to the uncertainty of this clause in the Quifa Association Contract and its effect in the production split. In the meantime, both companies have agreed to apply the formula of the Agencia Nacional de Hidrocarburos (the "**ANH**") to assign the additional share to Ecopetrol, from April 2011, until the arbitration is concluded. Based on the formula, the additional production share to Ecopetrol totaled 542,697 bbl, for the period covering April 3, 2011 to September 30, 2011. This volume has been recognized in the consolidated financial statements as an overlift and is being delivered to Ecopetrol starting October 1, 2011 according to the applicable contractual terms. As of December 31, 2011, a total of 118,533 bbl has been delivered to Ecopetrol and the balance of 424,164 bbl was still outstanding, but it is estimated that it will be fully paid by the third quarter of 2012.

The volumes corresponding to Ecopetrol as per ANH formula from October 1, 2011 to December 31, 2011 totaled 278,471 bbl, which were completely delivered to Ecopetrol via reduced production share.

b) Deferred Production – Rubiales and Quifa SW Fields

The Company filed a claim before Ecopetrol requesting the payment of 191,103 bbl of crude oil production (net after royalties and field consumption) estimated at $13.9 million, calculated at the fair value price at the field as of the year end. This claim is due to a number of operational factors that have occurred in the past. The Company has not booked the value of this claim in the current year's results and will recognize it when realized.

4. Company Overview

Profile

Pacific Rubiales, a Canadian-based company and producer of natural gas and heavy crude oil, owns 100 percent of Meta, a Colombian oil branch which operates the Rubiales/Piriri and Quifa oil fields in the Llanos Basin in association with Ecopetrol; and Pacific Stratus Energy Colombia Corp. ("**Pacific Stratus**"), which operates the wholly-owned La Creciente gas field in the northern part of Colombia and other light and medium oil fields. In addition to its production assets, the Company has a significant investment in oil pipelines in Colombia, including the ODL Pipeline and the new OBC Pipeline, currently under construction. The Company, through intensive exploration activity and a large exploration portfolio, is focused on identifying opportunities primarily within the eastern Llanos Basin of Colombia, as well as in other areas in Colombia, Guatemala and Peru. Pacific Rubiales has interests in 41 blocks in Colombia, 2 blocks in Guatemala and 3 blocks in Peru as well as an equity interest in CGX Energy Inc., an E&P company operating in Guyana.

Vision

The Company's vision is to be the premier independent E&P Company in the Latin American region, noted for its technical excellence, operational capabilities and its outstanding ability to discover, develop and market new hydrocarbon reserves.

Strategy

The Company has an enviable strategic position with a balanced portfolio of production assets and exploration areas. The Company expects significant cash flows and profit from operations generated by production growth that will be utilized to support the Company's ambitious exploration and production activities. The Company's goal of increasing its reserves base and growing its production will be achieved through continuous exploration activities with an appropriate risk – reward balance. Our knowledge and talents can provide a significant advantage and through the use of appropriate technology will increase and optimize the recovery rates in our existing resource base. The Company will start making inroads on developing the bunker market within Colombia and the supply of finished products to wholesale markets and securing market access by participating in key oil and gas transportation and infrastructure projects such as the OBC Pipeline.

The cornerstone of the Company's strategy is the technical excellence of its people, coupled with the experience and the "know-how" of management to deliver its vision. Our management team is primed to take full advantage of present and future opportunities in exploration and production in the Latin American region.

5. Discussion of 2011 Fourth Quarter and Annual Operating Results

Exploration

During the fourth quarter of 2011, the Company continued drilling activity in the Quifa, Sabanero, La Creciente, Guama and Arauca blocks, and also started drilling activity in the CPE-6 E&P block (awarded in September 2011). This resulted in a total of 19 wells drilled during the period. The Company also started production in the Quifa North and Sabanero areas and initiated 2D and 3D seismic surveys in the CPO-12, CPO-1, Muisca, SSJN-7 and CR-1 blocks.

In the Quifa North area, the Company continued its exploration drilling activity with a total of nine wells consisting of four exploration and five appraisal wells drilled during the period. Three of the exploration wells (Azabache-1, Ambar-5 and Ambar-10) resulted in new discoveries and along with two vertical and three horizontal appraisal wells (Ambar-6ST and Ambar-7, Opalo-9H, Opalo-10H and Ambar-13H), are currently under extended production testing. The Rubi-1 exploration well resulted with uneconomic pay thickness and was abandoned. The Company started production in the Quifa North area in late December and reached a total gross field production of 3 Mbbl/d at the year-end.

On the CPE-6 E&P block, the Company started exploration activities including the drilling of six stratigraphic wells. During the period, the Company finished drilling the Hamaca-1, Hamaca-2, Hamaca-4 and Hamaca-6 wells and started drilling the Hamaca-3 and Hamaca-5 wells. All of the four drilled wells showed hydrocarbon columns between 9 and 54 feet of net pay. Also, during the fourth quarter, the Company initiated the process to obtain the environmental licensing for the entire block and finished the bidding process for the acquisition of 366 km^2 of 3D seismic to be executed during the first half of 2012.

On the Sabanero block, Maurel and Prom Colombia, the operator of the Block, drilled three stratigraphic and two appraisal wells. The Sab-Strat-3, Sab-Strat-4 and Sab-Strat-5 stratigraphic wells resulted in hydrocarbon columns between 3 and 15 feet thick and the horizontal appraisal wells Sab-2HZ1 and Sab-4HZ1, found oil pay between 965 and 1157 feet. The appraisal wells are the first horizontal wells drilled on the block and along with an earlier drilled deviated well are on long term production testing. Also, during the period, Maurel and Prom Colombia obtained the first production from the Sabanero block, with total gross field production reaching 1.8 Mbbl/d at year-end. The Company holds an indirect ownership interest of 49.999% in Maurel & Prom Colombia, which is party to the exploration and production contract relating to the Sabanero block.

In the Topoyaco block, the Company finished drilling the Yaraqui-1 exploration well, but production tests resulted in non-commercial flow of heavy oil from the Neme Member of the Rumiyaco Formation, and the well was subsequently suspended. The Company continues further evaluation of the block. On December 30, 2011, the ANH approved the assignment of its Topoyaco block rights from Trayectoria Oil and Gas to the Company.

On the Arauca block, the Company finished a production test on the VACO-1X exploration well. The well reached total depth ("**TD**") in late September but failed to produce hydrocarbons and was abandoned.

In the Guama block, the Company started drilling the Cotorra-1X exploration well, and reached final depth in early January and in February tested gas and condensate at economic rates (reported in news release on February 15, 2012). The Company also carried out a hydraulic frac workover on the Pedernalito-1X exploration well, drilled in 2010. The fracing operation was successful and the well produced at a stable rate of 1.6 Mmscf/d and 48 bbl/d of 57° API condensate.

In the La Creciente block, the Company continued drilling the Apamate-2 appraisal well. In February 2012, the well was tested but failed to flow at economic rates and was plugged and abandoned.

On block 138 in Peru, the Company started the environmental permits for the exploration well to be drilled during the second half of 2012, and in the Guatemala blocks: N-10-96 and O-10-96, the Company, through the operator of the blocks, Compañía Petrolera del Atlántico S.A. ("**CPA**"), continued with the contracting process for geophysical data acquisition in both blocks.

Also during the quarter, the Company started 376 km^2 of 3D seismic surveys targeting heavy oil prospects on blocks CPO-1 and CPO-12, and 651 km of 2D seismic surveys in the SSJN-7 and CR-1 Blocks, which will evaluate gas prospects.

Exploratory Drilling Activity (Number of Wells)

During 2011, the Company drilled a total of 69 exploratory wells (including appraisal and stratigraphic), of which 58 wells were successful. This represents a success rate of 84%. During the fourth quarter, the Company drilled 19 exploratory wells with a success rate of 89%, as shown in the table below:

	Year Ended December 31		**Three Months Ended December 31**	
	2011	2010	2011	2010
Succesful exploratory wells	9	7	3	5
Succesful appraisal wells	36	6	6	-
Succesful stratigraphic wells	13	8	8	1
Dry wells	11	4	2	1
Total	69	25	19	7
Sucess rate	**84%**	**84%**	**89%**	**86%**

Detail of Exploratory Wells during the Fourth Quarter of 2011

No. of wells	Well Name	Type	Block	Area / Field / Prospect
1	QUIFA-152	Appraisal	Quifa	Quifa Southwest field
2	QUIFA-116	Appraisal	Quifa	Quifa Southwest field
3	AMBAR-5	Exploratory	Quifa	Quifa North - Prospect R
4	AMBAR-6ST	Appraisal	Quifa	Quifa North - Prospect R
5	AMBAR-7	Appraisal	Quifa	Quifa North - Prospect R
6	AMBAR-10	Exploratory	Quifa	Quifa North - Prospect Z
7	OPALO-9H	Appraisal	Quifa	Quifa North - Prospect Q
8	OPALO-10H	Appraisal	Quifa	Quifa North - Prospect Q
9	RUBI-1	Exploratory	Quifa	Quifa North - Prospect Y
10	HAMACA-1	Stratigraphic	CPE-6	Hamaca prospect
11	HAMACA-2	Stratigraphic	CPE-6	Hamaca prospect
12	HAMACA-4	Stratigraphic	CPE-6	Hamaca prospect
13	HAMACA-6	Stratigraphic	CPE-6	Hamaca prospect
14	SAB-STRAT-2	Stratigraphic	Sabanero	Sabanero prospect
15	SAB-STRAT-3	Stratigraphic	Sabanero	Sabanero South prospect
16	SAB-STRAT-4	Stratigraphic	Sabanero	Sabanero South prospect
17	SAB-STRAT-5	Stratigraphic	Sabanero	Sabanero prospect
18	SAB-2HZ1	Appraisal	Sabanero	Sabanero prospect
19	YARAQUI-1	Exploratory	Topoyaco	Prospect D - Neme Mb. Rumiyaco Fm.

Production

Average Daily Oil and Gas Production – Net Volumes before and after Royalties

In 2011, net production after royalties and field consumption averaged 86,497 boe/d (total gross field 218,450 boe/d) for an increase of 29,523 boe/d (total gross field 74,143 boe/d). This represents a 52% increase in net production, which came mainly from increased production at the Rubiales, Quifa and La Creciente fields.

The following table sets out the average production of the year and three months ended December 31, 2011, at all of the Company's producing fields:

	Average Year Production (in boe/d)					
	Total field production		Share before royalties(1)		Net Share after royalties	
Producing Fields	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
Rubiales / Piriri	165,446	123,581	68,503	53,065	54,802	42,452
Quifa(2)	36,496	4,819	20,928	2,812	19,181	2,630
La Creciente (3)	10,801	10,055	10,586	9,923	10,584	9,920
Abanico (4)	2,183	2,821	643	896	617	843
Rio Ceibas (5)	1,754	1,871	475	506	380	405
Dindal / Rio Seco (6)	1,220	704	725	586	609	470
Other Producing fields (7)	550	456	330	271	324	254
Total	**218,450**	**144,307**	**102,190**	**68,059**	**86,497**	**56,974**

	Average Q4 Production (in boe/d)					
	Total field production		Share before royalties(1)		Net Share after royalties	
Producing Fields	**Q4 2011**	**Q4 2010**	**Q4 2011**	**Q4 2010**	**Q4 2011**	**Q4 2010**
Rubiales / Piriri	178,826	134,160	74,015	56,442	59,212	45,153
Quifa(2)	40,995	12,215	21,119	7,012	19,313	6,538
La Creciente (3)	10,898	10,623	10,623	10,451	10,621	10,449
Abanico (4)	1,908	2,560	561	699	539	666
Rio Ceibas (5)	1,733	1,819	472	487	378	389
Dindal / Rio Seco (6)	1,198	753	696	526	600	425
Other Producing fields (7)	490	735	274	441	296	420
Total	**236,048**	**162,865**	**107,760**	**76,058**	**90,959**	**64,040**

(1) *Share after royalties is net of internal consumption at the field.*

(2) *Includes Quifa SW field and early production from Quifa North prospects. The Company's share before royalties in the Quifa SW field is 60% and decreases according to a high-prices clause that assigns additional production to Ecopetrol. On September 27, 2011, Ecopetrol and the Company agreed to start an arbitration process to define the interpretation of this clause and its effect in the production split. In the meantime, both companies have agreed to apply the ANH formula to assign the additional share to ECP, from April 2011, until the arbitration is concluded. See additional comments on page 6 under the section entitled "Volume Allocation for Certain Fields".*

(3) *Royalties on the gas production from La Creciente field are payable in cash and accounted as part of the production cost. Royalties on the condensates are paid in kind, representing a small impact in the net share after royalties. The Company started activities to increase the process capacity to 120 MMcf/d in La Creciente Station and also in the Abocol project in order to increase to 4.5 MMcf/d of gas sales from this field.*

(4) *Ecopetrol agreed to drill one development and one injector well during the fourth quarter of 2011. The Company started the EPC for a new water treatment plant.*

(5) *During the second quarter of 2011, Ecopetrol confirmed that it will not extend the duration of the Caguan Contract, where the Rio Ceibas field (operated by Petrobras - Company's share 27.3%) is located. In consequence, the association contract was terminated on December 31, 2011.*

(6) *The increase in gross production in comparison to 2010 is caused by the sales of natural gas produced in the field, which commenced during the year and were included in this report starting second quarter of 2011. The compressed gas sales averaged 0.7 MMcf/d in December 2011. Remaining gas is currently being injected and used for power generation for internal consumption. The increase in production is also due to services completed in some of the producing well.*

(7) *Other producing fields located in the Cerrito, Puli, Moriche, Las Quinchas, Buganviles, Sabanero (holder of license is Maurel & Prom Colombia) and Guasimo blocks.*

(8) *The term "boe'' is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet to barrels is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A we have expressed boe using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy.*

Crude oil production increase over 52% in 2011 mainly attributable to the drilling of 121 producing wells at the Rubiales field and 62 producing wells at the Quifa SW field during 2011, as well as an increase in the production capacity at Rubiales and Quifa.

Net production at Rubiales increased 29% and the La Creciente natural gas field increased by 7% as compared to 2010, the latter due to an increase in domestic gas demand. The production in the La Creciente field is now only limited by the constraints in the natural gas downstream transport network and domestic markets.

New Facilities Construction

During 2011, new facilities were built at Rubiales and Quifa SW areas to complete the development phase of these fields. Total capacity of 190,000 bbl/d gross field production (1.9 million bbl/d of water treatment), and 45,000 bbl/d (0.45 million bbl/d of water treatment) was built for the Rubiales and Quifa SW fields, respectively. Additional details are set out below:

Rubiales Field

- Construction of a second FWKO and second skim tank.
- Construction of a fourth electrostatic dehydrator.
- Upgrade of water injection pads 2, 3, 4 and 5 in order to reach 1,120,000 bbl/d of capacity.
- Construction of water injection pad 6 with a capacity of 440,000 bbl/d.
- Construction of 84 km of trunk lines to handle the production increase in the field.
- Expansion of power distribution grid including 40 new sub-stations and over 100 km of electrical lines.
- Construction of 39 km of new roads.

Quifa Field

- Construction of a new storage tank with capacity for 100,000 bbl.
- Construction of the second FWKO Tank, the second skim tank and the second head tank.
- Construction of three water treatment trains to reach a capacity of 450,000 bbl/d.
- Installation of one electrostatic hydrotreater.
- Construction of 64 km of trunk lines.
- Construction of a second water transfer line to the Rubiales field.
- Construction of the first water injection pad in Quifa (ongoing).
- Construction of 65 km of new roads.

La Creciente

- Building compression plant at Abocol to increase transport (and sales) capacity.
- Installing conditioning train to ensure compliance with regulatory quality requirements.
- Started purchasing and construction activities to increase La Creciente Station processing capacity to 120 MMscfd.

Supply and Sales Balance

The following is the Company´s reconciliation of boe produced vs. boe sold for the year and the three months ended December 31, 2011:

	Year 2011	
Inventory Movements	**Total boe [5] Net**	**Aver. day Net**
Ending inventory as of December 31, 2010	1,204,058	3,299
Transactions in Year 2011		
Net oil and gas production	31,571,481	86,497
Settlement of overlift position from December 31, 2010 [1]	(291,830)	(800)
Purchases of diluents	5,007,356	13,719
Purchases of oil for trading	2,102,827	5,761
Total sales [2]	(36,869,166)	(101,011)
Overlift position as of December 31, 2011 [3]	(118,247)	(324)
Volumetric compensation and operational gains/losses	(167,395)	(459)
Ending inventory as of December 31, 2011 [4]	**2,439,084**	

	4Q 2011	
Inventory Movements	**Total boe [5] Net**	**Aver. day Net**
Ending inventory as of September 30, 2011	2,653,969	28,847
Transactions in Q4 2011		
Net oil and gas production	8,368,183	90,959
Settlement of overlift position from September 30, 2011 [1]	30,641	333
Purchases of diluents	1,181,539	12,843
Purchases of oil for trading	584,138	6,349
Total sales [2]	(10,161,226)	(110,448)
Overlift position as of December 31, 2011 [3]	(118,247)	(1,285)
Volumetric compensation and operational gains/losses	(99,913)	(1,086)
Ending inventory as of December 31, 2011 [4]	**2,439,084**	

(1) *This volume corresponds to the settlement of the overlift position for crude oil as of December 31, 2010 and September 31, 2011 respectively, which resulted in a lower volume of sales during the period it was settled.*
(2) *Includes the sales of crude oil and gas from producing fields as well as crude oil produced from successful exploratory wells under extended testing. The sale of the extended testing volume is booked as a lower amount of the investment according to IFRS accounting rules.*
(3) *This volume corresponds to a net overlift position of 118,247 boe of crude oil and gas as of December 31, 2011, which will be settled during future periods.*
(4) *Corresponds to crude oil inventory in tanks as of the end of December 31, 2011 at the fields and Coveñas Terminal as well as permanent inventory in the pipeline systems around 1.58 MMbbl in addition to the minimum operative volumes that the Company must remain available in all facilities. The Company recognizes revenue and the related costs on crude oil production when lifting has occurred and the title on the inventory has been transferred.*
(5) *The term "boe" is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet to barrels is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A we have expressed boe using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy.*

Commercial Activity

Year 2011 Market Overview

- During the first half of 2011, market conditions were linked to the United States where economic recovery was weakened by high unemployment levels, low consumer confidence, and currency volatility. The European debt crisis also dampened market sentiment, creating high levels of uncertainty. Geopolitical factors had a direct impact and maintained high volatility in crude oil prices. Civil turmoil in Libya caused a light crude deficit of negative 1.25 MMbbl/d affecting mainly the European crude oil balance. In turn, Saudi Arabia, the United Arab Emirates (the "**UAE**") and Angola increased their production levels to accommodate increasing world oil consumption, causing OPEC´s spare capacity to fall to 2.3 MMbbl/d from a previously estimated 4.0 MMbbl/d. Although in the second half of 2011 there was stronger economic growth lead by employment improvement in the United States, there was lower than expected economic growth in China, and deepening of the European debt crisis, dampening the world economic growth, creating uncertainty and risk aversion in the markets. At the end of the fourth quarter, the International Atomic Energy Agency (the "**IAEA**") released a nuclear report about Iran´s uranium enrichment program which created tension amongst the international community and Iranian crude export sanctions.

- According to U.S. Energy Information Agency (the "**EIA**"), in 2011 there was an incremental rise in world crude supply of +0.58 MMbbl/d to 87.64 MMbbl/d. EIA projects the total non-OPEC supply of crude oil grew by 0.1 MMbbl/d to an average 51.9 MMbbl/d in 2011. The increase in total non-OPEC supply for the year was the result of higher production in the United States, Canada, Colombia, China, India, and Russia. On the other hand, Mexico had relatively healthy output in 2011 of 2.88 MMbbl/d where supply remained steady on the back of output stabilization efforts. According to OPEC, Venezuela maintained its production levels around 2.38 MMbbl/d. The EIA estimates that world oil consumption grew by 1.0 MMbbl/d in 2011 to 88.1 MMbbl/d, meanwhile OECD consumption fell by 0.42 MMbbl/d, and non-OECD consumption grew 1.5 MMbbl/d in 2011. As a result of rising demand for OPEC crude oil there was a decline in global oil inventories.

- In 2011, OPEC production increased to 30 MMbbl/d from 29.2 MMbbl/d in 2010, led primarily by Saudi Arabia and the UAE. Due to falling inventories in the OECD countries, supply was not enough to cover the loss of light sweet Libyan oil in the first half of 2011.

- However, a gradual tightening in global oil markets supported world oil prices. WTI prices increased in 2011 to $95.11/bbl from $79.61/bbl in 2010 (+ $15.50/bbl); meanwhile Brent prices reached $110.91/bbl vs. $80.34/bbl in 2010 (+ $30.57/bbl). In turn, the WTI-Brent spread widened to a negative $15.80/bbl differential from negative $0.73/bbl in 2010 ($15.07/bbl), enabling market arbitrage opportunities into Asia and Europe. WTI and Brent continue to be the most actively traded spot crude oils in both the physical and paper markets. A light sweet crude deficit in North Africa and the bottlenecks (mainly due to limited transportation facilities to distribute the crude from Cushing to the refineries), caused a disconnection of WTI to other physical markets. There was mid-sour and heavy crude scarcity and a marginal improvement in refining margins in the U.S. Gulf Coast, creating support for Castilla crude demand and prices. There was also additional coking capacity added to the market with new cokers of Repsol in Spain (+86,000 bbl/d), Port Arthur refinery of Total (+50,000 bbl/d), Minatitlan refinery in Mexico (56,000 bbl/d), and Araucaria refinery in Brazil (+30,000 bbl/d). Additionally, the Wood River coking refinery capacity in Delaware was increased 50,000 bbl/d and the Valero's Aruba refinery (235,000 bbl/d) was reactivated.

- As a consequence, Latin American and USGC crude prices increased their values vs. WTI in 2011. For example, Maya crude oil was traded at an average of WTI + $3.5/bbl vs. WTI negative $9.5/bbl in 2010 (+$13/bbl).

<u>Crude Oil and Gas sales</u>

- In 2011, the Company exported 28 Suezmax (700 – 1000 Mbbl) and four Aframax (500 Mbbl) cargoes of Castilla crude oil, four Aframax cargoes of Vasconia crude oil (500 Mbbl), 24 small cargoes of Rubiales 12.5 API (40- 120 Mbbl) and 56 small parcels of Rubiales crude oil sold through third parties.

- Total volume of Castilla blend crude sold was approx. 25.8 MMbbl (79%), 4 MMbbl of Vasconia blend crude (13%), 2.5 MMbbl of Rubiales 12.5º API (8%), representing a total volume of 32.3 MMbl.

- During the fourth quarter, the Company exported five Suezmax and three Aframax cargoes of Castilla crude oil, two Aframax cargoes and 16 parcels of Vasconia crude oil and eight small parcels of Rubiales crude oil, representing a total volume of 8.97 MMbbl.

- The average realized oil price for Castilla blend crude oil during 2011 was $97.23/bbl, higher by 37% than the $70.72/bbl realized during 2010. The average differential vs. WTI NYMEX improved to a premium of +$3.27/bbl in 2011 vs. negative $9.02 in 2010. During 2011, the Company exported 12 cargoes of Castilla to the US Gulf Coast, seven to the Caribbean/Panama, seven to Europe and six to Asia. The Company exported four cargoes of the Vasconia blend crude oil at an average price of $107.95 bbl.

- The Company sold 2.5 MMbbl in 24 small cargoes of 12.5°API crude oil trucked from the Rubiales field to the Atlantic Oil Terminal in Barranquilla, at an average price of $97.19/bbl, taking advantage of the strengthening of fuel oil prices. 16 cargoes were delivered the US Gulf Coast and eight to the Caribbean/Panama.

- During 2011, the Company maintained its flexible commercial strategy, selling 453 MMbbl of Rubiales 12.5°API in the Colombian domestic market, at an average price of $94.73/bbl, higher by 41% than the $67.09/bbl in the previous year.

- For the purpose of securing diluents for blending Rubiales crude oil, the Company continued local purchases of light crude oils (37°API average) in the eastern Llanos (10,647 bbl/d average vs. 8,412 bbl/d average in the 2010), supplemented with 81.6 °API natural gasoline (2,938 bbl/d average). Net blending cost is estimated at $3.14 per bbl of Rubiales crude (vs. $3.12/bbl of 2010), considering an average diluent purchase price delivered at the Rubiales field of $103.13/bbl (Light Crude Oil 37º API and natural gasoline at 81.6ºAPI), plus pipeline fees from the Rubiales field to Coveñas of $7.76 per bbl, less the average Rubiales Blend (Castilla) sale price of $97.23 per bbl, times the Rubiales average blending ratio of 23%.

- In 2011, the Company continued purchasing crude oil from local oil producers for purposes of trading on the international market. Third parties crude oil exported as of December 31, 2011 totaled 1.3 MMbbl sold as Vasconia at an average price of $107.95/bbl. Gross revenues generated on this trading activity during this period totaled $138 million and net profit before taxes totaled $4.6 million ($3.56/bbl trading margin). Also, the Company continued the strategy to maximize utilization of PF2 and OGD facilities providing handling and pipeline transportation services to third parties. During this period third parties transported around 4.2 MMbbl, generating net profit before taxes of $7.4 million ($1.76/bbl service margin).

- In 2011, the volume of natural gas sales increased to an average of 63.5 MMscf/d, from 60 MMscf/d for 2010 representing a 7% increase. These sales were mainly from La Creciente field, at an average price of $6.09/MMbtu (equivalent to $6.10/MMscf), representing a premium of 25% over the weighted domestic regulated price of $4.88/MMbtu, and 51% over the Henry Hub natural gas prices in the United States during the same period.

- During the fourth quarter of 2011, the volume of natural gas sold to the local market reached an average of 63.95 MMscf/d, compared to a volume of 63.7 MMscf/d during the same period in 2010. These sales were mainly from La Creciente field, at an average price of $7.06/MMbtu, representing a premium of 22% over the average Maximum Regulated Price ("**MRP**") of $5.81/MMbtu, and 103% over the Henry Hub natural gas prices during the same period.

Average benchmark crude oil and natural gas prices for the year and three months ended December 31, 2011 were as follows:

Average Crude Oil and Gas Prices	Year 2011 ($/bbl)	Year 2010 ($/bbl)	Q4 2011 ($/bbl)	°API
Domestic Market	$94.73	$67.09	$97.34	12.5
WTI NYMEX (Weighted Average of PRE Cargoes)	$94.57	$79.87	$94.57	38
Vasconia (Weighted Average of PRE Cargoes and Parcels) (1)	$107.95	$77.54	$110.86	24
Castilla (Weighted Average of 9 Cargoes PRE) (2)	$97.23	$70.72	$106.69	19
Rubiales Export. 12.5º (Weighted Average of PRE Cargoes) (3)	$97.19	$74.74	$101.55	12.5
Combined Realized International Oil Sales Price	**$98.63**	**$71.67**	**$106.95**	
PRE Natural Gas Sales ($/MMBTU)	**$6.09**	**$4.85**	**$7.06**	
Regulated Gas Price ($/MMBTU) (4)	**$4.88**	**$3.84**	**$5.81**	
Combined Realized Oil and Gas Sales Price	**$92.21**	**$65.04**	**$101.60**	
Regulated Gas Price ($/MMbtu)	$4.88	$3.84	$5.81	
WTI NYMEX ($/bbl)	$95.11	$79.61	$94.06	
Henry Hub average Natural Gas Price ($/MMbtu)	$4.03	$4.38	$3.48	
BRENT ($/bbl)	$110.91	$80.34	$109.02	

(1) Weighted average price of 4 cargoes and 56 parcels of Vasconia crude oil through third parties during 2011.
(2) Weighted average price of 32 Castilla crude oil cargoes during 2011 and 8 cargoes during the fourth quarter of 2011.
(3) Weighted average price of 24 Rubiales (12.5°API) small cargoes during 2011 and 8 small cargoes during the fourth quarter of 2011.
(4) The domestic natural gas sales price is referenced to MRP for gas produced in La Guajira field. The MRP is modified every six months based on the previous half-year variation of the US Gulf Coast Residual Fuel No.6 1.0% sulphur, Platts.

Transport of Hydrocarbons

- During the fourth quarter, the Company transported 118,525 bbl/d through the different pipelines and trucking systems, including 10,553 bbl/d of diluents; 6,363 bbl/d of third party crude oil through the Guaduas Facility; 66,921 bbl/d transported via ODL-Ocensa pipeline system (12% over the Company transportation capacity which represents savings of $10.6 million); and 15,632 bbl/d through the ODC pipeline (representing savings of $18 million).

- Also during 2011, the Company transported 116,384 bbl/d through the different pipelines and trucking systems which an average of 71,573 bbl/d was transported through ODL-Ocensa pipeline maximizing 11,573 bbl/d generating savings of $75.70 million in transportation costs in comparison with trucking costs via Barranquilla. The transport of the above volume was made with no injuries or environmental incidents.

- The Guaduas Facility handled and transported 25,395 bbl/d of crude oil from the Company and third parties. This operation handled 17,907 bbl/d, from third companies consolidating it as an important node for the oil transporting system in the country, generating an operational profit of $2.3/bbl for the Company and totaling profits of $15 million without operational or environmental incidents during the year.

6. Project Status

STAR Project in the Quifa Field

In March 2011, Pacific Rubiales and Ecopetrol agreed to advance with the STAR (Synchronized Thermal Additional Recovery) project in the Quifa SW field as a preliminary step to expanding the technology in the future. The project will make full utilization of all production facilities and infrastructure already acquired for the Quifa and Rubiales fields and carry out the main specialized studies and lab tests under a fast track strategy. This pilot test will be executed under the existing terms and conditions of the Ecopetrol Association Contract in Quifa.

STAR is a technology based on in-situ combustion concepts, developed by Pacific Rubiales to increase the recoverable reserves in heavy oil reservoirs like Quifa and Rubiales, which are highly affected by a strong water drive. STAR is also based on synchronization operational processes not only to determine the position of the combustion front but to control it. A uniform combustion front is extremely important in this kind of process. It is responsible for an efficient oil displacement from the air injector to the producers and determines the volumetric sweep efficiency of the process. The Company understands this process very well and has developed a unique synchronizing integrated model which will allow us to control a uniform combustion front to meet the reserve recovery expectations.

The pilot test area was selected at Quifa SW, where the reservoir represents similar or average conditions of the entire Quifa field. Initial reservoir numerical simulations have been done using the existing geological and reservoir model. Results have corroborated the feasibility of carrying out the pilot test in the Quifa field, and the additional recovery factors, which will add significant secondary recovery reserves.

As of the date hereof, eight out of the nine wells have been drilled using a nine pattern spot inverted in two main clusters in a 25 acre test area. All reservoir, geological and petrophisycal data have been gathered and the initial cold production evaluation program, under primary conditions, has been initiated successfully. Total cold production has reached more than 2,000 bbl/d, excluding air injection, which is a good early sign for this stage.

Production and air compression facilities have been constructed and installed in the Quifa pilot area. A three air compressor system, one production pad, automation and instrumentation system, gas treatment plant and all accessories have been fully commissioned.

After completing geological and reservoir data evaluation, a new static model has been generated and new reservoir simulations have been initiated not only to review and refine the production forecast and reserve determination, but to also to prepare the injector well for further tests before starting the ignition process.

The Company continues its commitment to the implementation of this technology, not only because it creates significant value to the Company, its partners and shareholders, but also because it is believed that once in operation, STAR will have a significant impact on the entire Llanos heavy oil region and Colombia itself.

ODL Pipeline

The Company has a 35% interest in the ODL Pipeline with the balance of 65% owned by Ecopetrol. The ODL Pipeline was completed in 2009 at a total cost of $558 million. By the end of 2011, a total of 132 MMbbl of diluted crude have been transported from the Rubiales field to the Monterrey Station.

Expansion Project

In November 2009, the ODL board of directors approved an expansion of the pipeline from 170,000 bbl/d to 340,000 bbl/d. The project included construction of a pipeline branch to Cusiana Station (already in operation), construction of two booster stations and increased storage capacity at the Rubiales Pumping Station. As of December 31, 2011, all construction and expansion was completed.

During 2011, the pipeline system pumped a total of 76 MMbbl and 35% of this volume corresponds to the Company's crude oil share.

Cusiana – Araguaney Project

This new project involves an extension of the existing pipeline and comprises a new 85 km and 36 inch diameter pipeline with capacity to transport up to 460,000 bbl/d between Cusiana and Araguaney. This will allow the connection of the ODL Pipeline to OBC Pipeline. Once this project is in operation, oil production from the Company's blocks in the Llanos Basin will have access to the export terminal of Coveñas through the existing Caño Limón pipeline. Engineering and Environmental permits for an extension of the ODL Pipeline started in 2011.

Heated Pipeline Feasibility Study

The ODL partners have conducted a feasibility study for a heated oil pipeline with the intention of increasing operating capacity and reducing dependence on truck transportation of diluents. The results of this study show the possibility of using existing proven technologies such as direct fired heaters, thermal oil heating and electric process heaters for this purpose. Conceptual engineering will be carried out this year.

<u>OBC Pipeline</u>

In December 2010, the Company acquired a 32.88% equity interest in OBC. OBC is a special purpose company promoted by Ecopetrol, which has a 55.97% interest in the OBC Pipeline, with the participation of other oil producers operating in Colombia, who control the remaining 11.15% interest. OBC will be responsible for the financing, design, construction and operation of Colombia's newest oil pipeline transportation system, which will run from Araguaney, in the Casanare Department of central Colombia, to the Coveñas Export Terminal in the Caribbean.

The new pipelines will add 450,000 bbl/d to the capacity of the existing pipeline systems connecting the Eastern Llanos Basin to the export markets, which are projected to reach full capacity as the increase in planned production from Colombian producers materializes in the mid-term. The project, which will be constructed in phases, includes a new pipeline from Araguaney Station to Coveñas export terminal. Total extension of this new pipeline is estimated to be 976 km with different sections of 30, 36 and 42 inch diameter line.

For the Company, the participation in this project is a good strategic fit, time and volume-wise, as it moves towards reaching its production goals in the mid-term.

It is estimated that Phase 1 of this project will require an aggregate investment of $1.2 billion, excluding financing costs. The partners intend to finance the OBC Pipeline project through project financing, with a debt/equity ratio of 70/30.

The Company has representation on the board of OBC and plays an active role in the financing and construction of the project. It is expected that the Company's equity contributions in the initial phases of the OBC will be funded through internally generated cash flow. Construction of Phase 1 is in progress and it is expected to be operational by the second half of 2012.

Phase 1 includes:

i. The construction of a 230 km pipeline with (42 inch diameter), between the stations of Araguaney and Banadía. The overall capacity of this section is 600,000 bbl/d.
ii. The construction of two tanks at the Araguaney storage station with capacity of 150,000 bbl each.
iii. A third storage tank at the Banadía station with capacity of 50,000 bbl
iv. Two storage tanks with a capacity of 600,000 bbl at the Coveñas export terminal.

<u>Petroeléctrica de los Llanos ("**PEL**") – Power Transmission Line Project.</u>

The Company incorporated PEL, a wholly-owned subsidiary, in 2010. PEL is responsible for constructing and operating a new power transmission line of 230 kilovolts to connect the Rubiales field and the ODL pipeline with Colombia´s electrical grid. The new 260 km transmission line will originate at the Chivor power plant in the Boyaca Department. The line includes two substations to supply power to the booster stations of the ODL Pipeline, as well as a main substation for the Rubiales and Quifa fields. The new power line will be able to supply up to 220 MVA that will be used in oil production and transportation activities.

The main activities carried out for the project during 2011 included:

- Purchase of long lead items such as transformers and aluminum conductors.
- Completed fabrication of 66% of "suspension towers".

- 91% of rights of ways (221 land negotiations) were acquired.
- Environmental license process was granted as of the date of this report.

An important milestone for this project was reached on December 21, 2011, after the entering into of the leasing agreement with Banco de Bogotá and BBVA for the amount of COP 200,000 million (equivalent to $107 million).

PEL is a strategic piece of infrastructure for the Company as it will lever the development of Rubiales, Quifa and other nearby fields in the Llanos basis such as Sabanero and CPE-6 blocks.

Llanomulsion Project

In January 2009, the Company started the development of a special transport emulsion formula (oil in water), which could reduce or eliminate the need for diluents. The formula, called "Llanomulsion", increases pipeline capacity by reducing fluid viscosity to one-third of the original viscosity of the diluted crude.

At the end of 2011, the commissioning process for facilities for manufacturing Llanomulsion in CPF-1 was completed. O&M procedures and the protocol for the industrial test was conveyed to the stakeholders: Pacific Rubiales, ODL, OCENSA and Ecopetrol, in order to make the decision to perform an industrial test in the second half of 2012. In the meantime, the design parameters for breaking the emulsion, engineering and construction continue being developed.

Successful implementation of this technology is expected to have a significant impact on the transportation costs for the Rubiales and Quifa fields, and could represent a breakthrough for the development of the Llanos Basin.

7. Capital Expenditures

Capital expenditures during the year ended December 31, 2011, totaled $1,096.0 million ($954.3 million in 2010), of which $469.7 million were invested in the expansion and construction of production infrastructure; $267.1 million went into exploration activities (including drilling, seismic and other geophysical) in Colombia, Peru and Guatemala; $63.4 million for the acquisition cost of the 49.999% interest in Maurel & Prom Colombia; $206.7 million for development drilling; and $89.1 million in other projects including the STAR project. Details on the capital expenditure program for 2011 and 2010 are as follows:

	Year Ended December 31		**Three Months Ended December 31**	
(in thousands of US$ except per share amounts or as noted)	2011	2010	2011	2010
Production facilities	469,744	461,432	174,454	218,286
Exploration drilling including seismic acquisition (1)	267,112	112,502	107,274	44,394
Acquistion costs of M&P exploration blocks (2)	63,400	-	-	-
Development drilling	206,666	150,639	47,749	47,068
Other projects (STAR, Llanomulsion, Gas export, PEL)	89,083	39,722	20,605	37,906
Transportation rights - Ocensa	-	190,000	-	190,000
Total Capital Expenditures	**1,096,005**	**954,295**	**350,082**	**537,654**

(1) Includes the carry exploration investment of $74.3 million on Maurel & Prom Colombia blocks.
(2) Corresponds to acquisition cost of $63.4 million investment on certain Maurel & Prom Colombian blocks.

8. Proved and Probable Oil and Gas Reserves

For the year ended December 31, 2011, the Company received independent certified reserve evaluation reports for all its assets, establishing that total net 2P reserves have grown to 407 MMboe from 269 MMboe, representing a 52% year-on-year growth. This growth represents a 547% reserve replacement with net 2P reserve additions of 5.5 boe per boe produced. Total net proved reserves ("**1P**") reserves grew by 34% in the same period to 318 MMboe, equivalent to 1.1 boe per outstanding share (compared to 0.89 per share at December 31, 2010); 78% of 2P reserves are 1P reserves, and the Company's RLI increased to 13.0 from 11.5. Reserve additions include the first 2P (Probable) net reserves of 44 MMboe from the CPE-6 E&P block. At year-end 2011, the Rubiales field represents 29% of total 2P reserves (down from 51% a year ago), demonstrating successful diversification of the Company's reserve base.

	2P Reserves @ December 31 , 2011									Oil Equivalent		
	Condensate, Light & Medium			Heavy Oil			Associated & Non-Associated					
	100% (3)	Gross	Net	100% (3)	Gross	Net	100% (3)	Gross	Net	100% (3)	Gross	Net
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(Bcf)	(Bcf)	(Mmboe)(1)	(Mmboe)(1)	(Mmboe)(1)
At Dec. 31/2010	7.98	3.07	2.88	516.76	237.42	186.04	489.97	489.14	455.31	610.70	326.30	268.80
Discoveries and Revision Reserves	(1.03)	(0.22)	(0.19)	283.30	168.77	139.68	0.81	(5.44)	(5.49)	282.41	167.60	138.52
Production 2011	1.38	0.39	0.34	74.05	33.56	26.96	22.90	22.61	21.06	79.45	37.91	31.00
At Dec. 31/2011 (2)	**6.95**	**2.85**	**2.69**	**800.05**	**406.19**	**325.72**	**490.78**	**483.70**	**449.82**	**893.11**	**493.89**	**407.32**
Total Reserves Incorporated	0.35	0.18	0.15	357.34	202.32	166.64	23.71	17.17	15.57	361.86	205.51	169.52

(1) *The term "boe" is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet to barrels is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A we have expressed boe using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy.*
(2) *Pre-Psie Cooperatief U.A. holds a 49.999% participation in Maurel & Prom Colombia B.V., which indirectly owns a 49.999% working interest in the Sabanero block. Pre-Psie Cooperatief U.A. is a wholly owned subsidiary of the Company.*
(3) *In the table above, 100% refers to total 100% field interest; Gross refers to working interest before royalties; Net refers to working interest after royalties.*

The reserves reports for the Rubiales-Piriri and for the Quifa Southwest Field were carried out by RPS Energy Canada Ltd. ("**RPS**") as at December 31, 2011, while the reserves reports for the Quifa North, Sabanero, CPE-6, La Creciente, Guaduas, Guama, Puli, Abanico, Buganviles and Cerrito Blocks were prepared by Petrotech Engineering Ltd. ("**Petrotech**") issued February 23, 2012 with an effective date as of December 31, 2011.

9. Discussion of 2011 Fourth Quarter and Annual Financial Results

Revenues

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2011	2010	2011	2010
Net crude oil and gas sales	$ 3,380,819	$ 1,661,544	$ 1,011,476	$ 516,731
$ per boe oil and gas	92.21	65.04	101.61	71.52

Net crude oil and gas sales in 2011 were significantly higher by $1,719.3 million; exceeding a two-fold increase in comparison to 2010. Net sales continued to grow mainly due to the 52% increase in net production resulting from the construction of facilities at the Rubiales, Quifa and La Creciente fields, coupled with better realized oil and gas prices throughout 2011. The drivers of the revenue increase during the fourth quarter and through 2011 are explained in the table below:

	Full Year 2011			
	2011	**2010**	**Differences**	**% Change**
Total of boe sold (Mboe)	36,663	25,547	11,116	44%
Avg. Combined Price - oil & gas and trading ($/bbl)	92.21	65.04	27.17	42%
Total Revenue (000$)	3,380,819	1,661,544	1,719,275	103%

Revenue increase due to the change in volume and price for the year end of 2011 in comparison to the year end of 2010 is as follows:

Reasons for the difference (000$):		
Increase due to Volume	722,943	42%
Increase due to Price	996,332	58%
	1,719,275	

	4Q 2011			
	2011	2010	Differences	% Change
Total of boe sold (Mboe)	9,955	7,224	2,731	38%
Avg. Combined Price - oil & gas and trading ($/bbl)	101.61	71.52	30.09	42%
Total Revenue (000$)	1,011,476	516,731	494,745	96%

Revenue increase due to the change in volume and price for the fourth quarter of 2011 in comparison to the same period of 2010 is as follows:

Reasons for the difference (000$):		
Increase due to Volume	195,295	39%
Increase due to Price	299,450	61%
	494,745	

Net sales in the fourth quarter of 2011 were higher by $494.7 million in comparison to the 2010 due to a significant increase in both volume and price.

Operating Costs

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2011	2010	2011	2010
Oil and Gas Operating Costs	$ 1,239,104	$ 611,539	$ 379,733	$ 179,618
Overlift (Underlift)	6,405	18,833	(6,365)	23,906
Total Cost	**1,245,509**	**$ 630,372**	**373,368**	**$ 203,524**
$ per boe Crude Oil and Gas	33.80	23.94	38.15	24.86
$ per boe Over/Underlift	0.17	0.74	(0.64)	3.31
$ per boe Total Cost	**33.97**	**24.68**	**37.51**	**28.17**

Operating costs per boe for 2011 increased 38% to $33.97 in comparison to the same period of 2010. The increase is primarily due to a 22% increase in the cost of diluents required to upgrade the Rubiales crude oil from 12.5° to 18.5° API, which are in line with the increased international WTI prices. Transportation costs for 2011 also increased by 71% in comparison to 2010 primarily attributed to higher volume through the pipelines and trucking systems, an increase in the overall trucking and pipeline transport costs in Colombia, and the foreign exchange effect of Colombian pesos conversion to US dollars. The $33.97 per boe consists of production cost of $5.29, transportation cost of $10.41, dilution cost of $13.80, overlift of $0.17 and other costs of $4.30.

Operating costs for the fourth quarter of 2011 increased over the same period of 2010 primarily due to the continuous increase in of the volume transported through the different pipelines and trucking systems and the higher volume of crude oil from local oil producers handled for purposes of trading in the international market. Production costs per boe increased to $37.51 or 33% higher than the same period in 2010.

Depletion, Depreciation and Amortization

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2011	2010	2011	2010
Depletion, depreciation and amortization	$ 656,474	$ 394,308	$ 180,146	$ 117,448
$ per boe	17.91	15.43	18.10	16.26

Depletion, depreciation and amortization costs during 2011 were $656.5 million ($394.3 million in 2010). The increase over 2010 was primarily due to an increase in oil and gas property costs incurred subject to depletion and increase in production. Included in the costs subject to depletion is $800 million ($921 million in 2010) of future development costs that are estimated to be required to bring proved undeveloped reserves to development. Depletion, depreciation and amortization costs increased by 66% as compared to 2010 due to the net effect of higher costs subject of depletion, depreciation and amortization and the increase in the Company´s reserves issued as of December 31, 2011. See additional comments in Section 8, “Proved and Probable Oil and Gas Reserves”.

For the fourth quarter of 2011 depletion, depreciation and amortization totaled $180.1 million, which was higher by $62.7 million over 2010, primarily due to the increase in capital investments in 2011 for the drilling campaign at the Rubiales and Quifa fields, as well as increased production in 2011 compared to 2010.

General and Administrative

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2011	2010	2011	2010
General and administrative costs	$ 188,722	$ 107,109	$ 77,443	$ 37,847
$ per boe	5.15	4.19	7.78	5.24

General and administrative expenses for the year ended December 31, 2011 were $188.7 million ($107.1 million in 2010). The increase is mainly attributable to the net effect of:

- The significant increase in operations that resulted in hiring of new personnel and adjustment of salaries according to market standards. The number of direct and indirect employees in 2011 increased 19% to a total of 1,713 compared to 1,441 in the same period in 2010.
- Increase in the cost of banking transactions in Colombia as a result of a 0.4% tax contribution on fund transfers.
- Increase in the cost of back office, field personnel and technical assistant to support the growth of production and explication activities.
- The accelerated depreciation of administrative equipment ($8 million in 2011), due to the anticipated relocation of offices to a new building in Bogota, Colombia and the additional depreciation for the new offices.

General and administrative expenses for the fourth quarter of 2011 were $77.4 million (fourth quarter 2010 - $37.8 million) representing a $39.6 million increase from the same period in 2010 which is primarily due to additional personnel needed to support the expanding operations to increase oil production at fields and the drilling campaign at exploratory blocks in 2011, as explained above.

Share-Based Compensation

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2011	2010	2011	2010
Share-based compensation	$ 48,783	$ 73,327	$ 316	$ -
$ per boe	1.33	2.87	0.03	-

For the year ended December 31, 2011 share-based compensation decreased by $24.5 million or 33.5% to $48.8 million as compared to $73.3 million for 2010. During 2011 a total of 4.6 million employee stock options were granted compared to 9.6 million stock options granted in 2010. The weighted averaged fair value for the stock options granted in 2011 was C$10.46 per option versus C$7.97 for the stock options granted in 2010.

Finance Cost

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2011	2010	2011	2010
Finance costs	$ 86,469	$ 77,383	$ 15,501	$ 21,515
$ per boe	2.36	3.03	1.56	2.98

Finance cost includes interest on bank loans, Debentures, Senior Notes, revolving credit commitment fees, finance leases and fees on letters of credit. For the year ended December 31, 2011, interest expense totaled $86.5 million compared to $77.4 million for the same period 2010. The higher interest expense over 2010 is mainly due to interest incurred on commitment fees paid on the unused portion of the Company's Revolving Credit Facility and other fees.

Interest expense in the fourth quarter of 2011 decreased to $15.5 million compared to $21.5 million for the same period in 2010 mainly due to the early conversion of C$236.2 million of the Debentures. As of December 31, 2011 the Company had outstanding Debentures of C$2.7 million (C$238.9 million in 2010).

Equity Tax Expense

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2011	2010	2011	2010
Equity Tax	$ 68,446	$ 2,088	$ -	$ 522
$ per boe	1.87	0.08	-	0.07

On December 29, 2010 the Colombian Congress passed a law which imposes a surcharge on the existing equity tax levied on Colombian companies. This surcharge increased the equity tax rate for the Company from 4.8% to 6% and is applied on the net taxable equity as of January 1, 2011. The Company's total equity tax payable for the years 2011 to 2014 is $83.4 million, to be paid in eight equal installments.

In contrast to previous equity tax legislation, the newly calculated equity tax is payable even in the event that the Company ceases to have taxable equity in subsequent years. As such, the Company has recognized the equity tax payable on the consolidated statement of financial position with a corresponding expense in the current year. The amount recognized is calculated by discounting the eight future equity tax payments by the Company's weighted cost of capital at 10.8%.

Foreign Exchange

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2011	2010	2011	2010
Foreign exchange (loss) gain	$ (39,894)	$ 33,851	$ 1,947	$ 8,201
$ per boe	(1.09)	1.33	0.20	1.14

Foreign exchange gains or losses primarily result from the translation of monetary assets or liabilities that are denominated in a foreign currency. The foreign exchange loss in the fourth quarter of 2011 was primarily due to the depreciation of the Colombian peso against the U.S. dollar.

The foreign exchange loss incurred for the year ended December 31, 2011 was due to the depreciation of the Colombian peso against the U.S. dollar. In addition, the Canadian dollar depreciated against the U.S. dollar during the same period resulting in a translation loss related to the U.S. denominated debts.

Incentive for early conversion of debentures

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2011	2010	2011	2010
Incentive for early conversion of debentures	$ 46,489	$ -	$ 46,489	$ -
$ per boe	1.27	-	4.67	-

During the fourth quarter of 2011 the Company recognized the fair value of $46.5 million (nil in 2010) of the incentive provided for the C$236.2 million (or 98.9%) of the Debentures that were converted under the early conversion program. Debenture holders who did not convert during the early conversion period were not entitled to the benefit of the incentive conversion rate nor to receive the additional common shares.

Income Tax Expense

(in thousands of US$)	Year Ended December 31 2011	2010	Three Months Ended December 31 2011	2010
Current income tax	$ 513,302	$ 171,101	$ 186,540	$ 48,804
Deferred income tax	(65,152)	(55,122)	3,018	5,086
Total	448,150	115,979	189,558	53,890
$ per boe	12.22	4.54	19.04	7.46

The income tax rate in Canada is 28.25% and in Colombia 33%. The Colombian Congress passed a tax reform on December 29, 2010 eliminating the 30% special tax benefit previously available on qualified capital expenditures, effective January 2011. However, the new law allows certain taxpayers that have submitted a tax stabilization contract prior to November 1, 2010 to maintain this benefit for another three years once it has been approved by the applicable governmental authority and once the contract has been signed. The Company submitted updates to the applications requested by government and our stabilization contracts are currently under evaluation. The final decision is expected to be reached during the first half 2012. The Company has not recognized any benefit in 2011 of the 30% special tax benefit on 2011 qualified capital expenditures as the benefit will be recognized upon the Colombian Government's approval of the Company's tax stabilization application.

Income tax expense increased during the three and twelve month periods ended December 31, 2011, which is in line with the increase in revenues and operating income. The effective tax rate is higher than the statutory rate of 33% primarily due to the non-deductible costs for tax purposes such as share-based compensation costs, equity tax and gain on risk management contracts.

Current income tax represents the estimated cash income taxes paid and payable for the period. Current income tax increased to $513.3 million from $171.1 million during the same period of 2010, which was primarily due to increased operating income and the exclusion of the 2011 special tax benefit on qualified capital expenditures.

Net Earnings (Loss)

(in thousands of US$)	Year Ended December 31 2011	2010	Three Months Ended December 31 2011	2010
Net earnings (loss)	$ 554,336	$ 265,087	$ 80,834	$ 61,370
$ per boe	15.12	10.38	8.12	8.49

Net earnings for the year ended December 31, 2011 totaled $554.3 million ($265.1 million in 2010). Net earnings for the year ended 2011 were impacted by a number of non-cash items totaling $194.8 million. These non-cash items are related to equity tax of $68.4 million, share-based compensation of $48.8 million, incentive for early conversion of Debentures of $46.5 million, foreign exchange loss of $39.9 million and gain on risk management contracts $8.8 million. These non-cash items may or may not materialize in future periods. Excluding these items, the Company's adjusted net earnings were $749.1 million ($346.9 million in 2010) or $2.75 per basic common share ($1.32 in 2010). The increase in adjusted net earnings is primarily due to an increase in net oil and gas sales.

Cash Flow from Operations

(in thousands of US$)	Year Ended December 31 2011	2010	Three Months Ended December 31 2011	2010
Cash flow from operations	$ 1,219,057	$ 939,929	$ 477,530	$ 353,433
$ per share, basic	4.48	3.57	1.70	1.32

The Company continued to generate positive cash flow from operations as a result of the increase in production together with the increase in the combined realized oil and gas price. The cash flow from operations during 2011 totaled $1,219.1 million. This increase is primarily attributable to the 44% increase in the combined net back in 2011 as compared to the same period in 2010 ($58.24 per boe in 2011 versus $40.36 per boe in 2010), as well as the significant increase in production. The increase in combined net back is due to higher realized prices from $65.04 per boe in 2010 to $92.21 per boe in 2011.

Financial Position

EBITDA

EBITDA for the year ended December 31, 2011 totaled $1,946.6 million, which represents a significant increase of 111% compared to $924.1 million in 2010. The increase is attributable to increased revenue, mainly generated from international sales 86%; EBITDA from gas and domestic sales contributed 11% and 3%, respectively. The 2011 EBITDA represents a 58% margin in comparison to total revenues for the period (56% margin in 2010); the higher margin can be attributed to higher operating netback per boe in 2011. EBITDA for the three months of ended December 31, 2011 totaled $560.7 million, 104% higher as compared to the same period of 2010. The increase is primarily due to the increased revenue.

Debts

As a result of the restructuring of the Company's long term debts described below, the Company was able to improve its financial position by securing more favorable credit terms and extending the term to maturity, and is now in a better position to implement its business strategy.

Early Conversion of Debentures

On November 30, 2011, the Company announced the results of its temporary incentive conversion rate increase for its Debentures. During the early conversion period, C$236.2 million (or 98.9%) of the Debentures were converted, representing an issuance of 20,450,600 common shares in the capital of the Company, of which 2,040,352 represents the incentive common shares. Debenture holders who did not convert during the early conversion period were not entitled to the benefit of the incentive conversion rate nor to receive the additional common shares. Included on the consolidated statement of income for the year ended December 31, 2011 was a $46.5 million expense representing the fair value of the incentive provided for the debentures that were converted under the early conversion program. As of December 31, 2011 the Company had outstanding Debentures of C$2.7 million (C$238.9 million in 2010) due August 29, 2013. The outstanding Debentures are convertible into common shares of the Company at the rate of C$12.83 (C$13 in 2010) per share, being equivalent to 77.9423 (76.9231 in 2010) common shares per C$1,000 face amount of debentures, subject to adjustments pursuant to the indenture. The Debentures bear interest at 8% annually and are payable semi-annually in arrears on June 30 and December 31.

Senior Notes Exchange Offer

On January 4, 2012, the Company announced the final results of the exchange offer that commenced on December 5, 2011 and ended on January 3, 2012 whereby it offered to exchange any and all of its $450 million 8.75% senior notes due 2016 ("2009 Senior Notes") for newly issued 7.25% senior notes due 2021 ("2011 Senior Notes"). The exchange offer resulted in $358.5 million aggregate principal amount of 2009 Senior Notes being validly tendered and accepted for $412.3 million of 2011 Senior Notes. This represents approximately 80% of the total outstanding Existing Notes.

In conjunction with the exchange offer, the Company also solicited consents to proposed amendments to the indenture governing the 2009 Senior Notes. The proposed amendments were adopted on December 20, 2011 as a result of the requisite consents being obtained from a majority of the holders of the 2009 Senior Notes. The purpose of the consent solicitation was to modify or eliminate certain provisions, including certain restrictive covenants, events of default and certain other provisions under the existing indenture.

The remaining $91.5 million of 2009 Senior Notes continue to carry interest at 8.75% with maturity dates of November 10, 2014 (33.3%), November 10, 2015 (33.3%), and November 10, 2016 (33.4%).

Issuance of Senior Notes Maturing in 2021

In addition to the $412.3 million 2011 Senior Notes issued under the exchange offer, the Company closed an offering of an additional $300 million senior notes on December 12, 2011. Both the $300 million in additional senior notes and the senior notes issued under the exchange offer (collectively the "2011 Senior Notes") carry the same terms and covenants.

Letters of Credit

As of December 31, 2011, the Company had issued standby letters of credit for operational and exploration commitments for a total of $194 million ($198 million in 2010). Most of these bank guarantees are related to light oil purchases and exploration commitments.

Securities

During the three months ended December 31, 2011, C$236.2 million, or 98.9% of the Debentures were converted, representing an issuance of 20,450,600 common shares in the capital of the Company, of which 2,040,352 represents the incentive common shares.

On December 9, 2011, the Company announced a cash dividend in the aggregate of $27.2 million, or $0.093 per common share.

Outstanding Share Data

Common Shares

As at December 31, 2011, 292,178,055 common shares were issued and outstanding.

The Company does not have shares subject to escrow restrictions or pooling agreements.

Stock Options and Warrants

As at December 31, 2011, 14,450 warrants to acquire an equal number of common shares were outstanding and exercisable and 22,365,509 stock options were outstanding, of which all were exercisable.

Liquidity and Capital Resources

Liquidity

Funds provided by operating activities for the year ended December 31, 2011 totaled $1,219.1 million ($939.9 million in 2010). The increase in cash flow in 2011 was the result of the increase in production and higher combined crude oil and gas sale prices. The Company has been generating cash flows from operations from the sale of crude oil and natural gas and continues to plan for increased future production.

As of December 31, 2011, the Company had working capital of $614.6 million, mainly comprised of $729.7 million of cash and cash equivalents, $774.8 million of account receivables, $181.3 million of inventory, $18.7 million of income tax receivable, $2.5 million of prepaid expenses, $702.9 million of accounts payable and accrued liabilities, $367.7 million of income tax payable, $4.7 million of current portion of long term debt and $17.1 million of finance lease obligations.

As at December 31, 2011 the Company has drawn down $193 million under the $350 million Revolving Credit Facility.

The Company believes it has adequate resources to fund its capital plan for 2012, with the Company's cash flows from operations and current debt facilities. With respect to the Company's broader integration strategy (see section entitled "Strategy" on page 7), the Company will pay for the expansion plan with its own cash flow. However, if additional resources are required, there are possible sources of funds available to the Company to finance additional capital expenditures and operations including the revolving credit facility, existing working capital and incurring new debt, and the issuance of additional common shares, if necessary.

10. Commitments and Contingencies

As part of the Company's normal course of business, the Company entered into arrangements that will impact the Company's future operations and liquidity. The principal commitments of the Company are ship or pay arrangements on crude oil and gas transportation, asset retirement obligations, debt repayments, service contracts with suppliers in relation with the exploration and operation of oil properties and engineering and construction contracts, among others.

Disclosure concerning the Company's significant commitments can be found in note 19 to the consolidated financial statements. The Company has no off-balance sheet arrangements.

11. Risk Management Contracts

The Company enters into derivative financial instruments to reduce the exposure to unfavorable movements in commodity prices, interest rates and foreign exchange rates. The Company has established a system of internal control to minimize risks associated with its derivative program and does not intend to use derivative financial instruments for speculative purposes.

Commodity price risk

The Company has elected not to designate WTI risk management contracts as accounting hedges, and recognizes the fair value of the WTI contracts as assets or liabilities on the statement of financial position with the change recorded as gain or loss on risk management contracts in the statement of income. The Company has the following commodity price risk management contracts outstanding:

As at December 31, 2011

Instrument	Term	Volume (bbl)	Floor/ceiling or strike price ($/bbl)	Benchmark		Fair value
Call option	February 2012 to December 2012	8,790,000	109.50 -118.80	WTI	$	(29,353)
Sold put	August 2012 - December 2012	5,350,000	61.5 - 64	WTI	$	(8,732)
Zero cost collars	January 2012 to December 2012	10,051,404	70-80 / 120 - 121	WTI		(1,798)
	Total				**$**	**(39,883)**
	Short-term				$	(39,883)
	Total				**$**	**(39,883)**

As at December 31, 2010

Instrument	Term	Volume (bbl)	Floor/ceiling or strike price ($/bbl)	Benchmark		Fair value
Zero cost collars	January to December 2011	12,150,000	70-75 / 98-102	WTI	$	(50,819)
Put option	January to July 2011	1,285,000	40	WTI		(2,828)
	Total				**$**	**(53,647)**
	Short-term				$	(53,647)
	Total				**$**	**(53,647)**

For the year ended December 31, 2011, the Company recorded a gain of $8.8 million (loss of $40.2 million in 2010) on commodity price risk management contracts in net earnings. Included in these amounts were $13.4 million of unrealized gain (unrealized loss of $28.4 million in 2010) representing the change in the fair value of the contracts, and $4.6 million ($11.8 million in 2010) of realized loss resulting from premiums paid.

If the forward WTI crude oil price estimated at December 31, 2011 had been $1/bbl higher or lower, the unrealized gain or loss on these contracts would change by approximately $0.7 million ($1.5 million in 2010).

Foreign currency exchange risk

The Company is exposed to foreign currency fluctuations in COP. To reduce its foreign currency exposure associated with operating expenses incurred in COP, the Company may enter into currency risk management contracts such as foreign exchange forwards, options, and costless collars. The Company had the following currency risk management contracts outstanding that qualify for cash flow hedge accounting:

As at December 31, 2011

Instrument	Term	Notional amount	Floor-ceiling (COP/$)	Fair value
Currency collar	January to December 2012	650,400	1805 - 1975	(30,546)
Currency collar	January to December 2013	120,000	1870 - 1930	(2,355)
		$ 770,400		$ (32,901)
		Current		$ (27,504)
		Non-current		(5,397)
		Total		$ (32,901)

As at December 31, 2010

Instrument	Term	Notional amount	Floor-ceiling (COP/$)	Fair value
Currency collars	January to December 2011	$ 240,000	1900 - 1930	$ 1,066

The effective portion of the change in the fair value of the above currency hedges is recognized in other comprehensive income as unrealized gains or losses on cash flow hedges. The effective portion is reclassified as production and operating expenses in net earnings in the same period as the hedged operating expenses are incurred. During the year ended December 31, 2011, $14.5 million ($21.7 million in 2010) of unrealized gains were initially recorded in other comprehensive income, and $9.6 million ($21.7 million in 2010) were subsequently transferred to production and operating cost when the gains became realized. The Company excludes changes in fair value due to the time value of the investments and records these amounts along with hedge ineffectiveness in foreign exchange gains or losses in the period that they arise. During 2011, $19.5 million ($8 million in 2010) of ineffectiveness was recorded as foreign exchange loss.

Additional disclosure about the Company's risk management policies and contracts can be found in Note 22 to the audited consolidated financial statements. The Company has no off-balance sheet arrangements.

12. Selected Quarterly Information

	2011				2010			
(in thousands of US$)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financials:								
Net sales	$ 1,011,476	$ 828,285	$ 957,509	$ 583,549	$ 516,731	$ 408,534	$ 356,848	$ 379,431
Net earnings (loss) for the period	80,834	193,720	349,375	(69,593)	61,370	113,152	14,438	76,127
Earnings (loss) per share								
- basic	$ 0.29	$ 0.71	$ 1.30	$ (0.26)	$ 0.23	$ 0.43	$ 0.05	$ 0.30
- diluted	$ 0.28	$ 0.65	$ 1.17	$ (0.26)	$ 0.22	$ 0.41	$ 0.05	$ 0.28

13. New Accounting Pronouncements

First Time Adoption of IFRS

The Company's consolidated financial statements for the year ended December 31, 2011 have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. The Company adopted IFRS for the first time in 2011, with a transition date of January 1, 2010. Prior to the adoption of IFRS, the Company prepared its consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). A summary of the significant changes to the Company's accounting policies is disclosed in Note 25 of the consolidated financial statements.

Reconciliations from Canadian GAAP to IFRS

In preparing the consolidated financial statements the Company has adjusted amounts reported previously in its consolidated financial statements prepared under Canadian GAAP. An explanation of how the transition from Canadian GAAP to IFRS has impacted the Company's consolidated statement of financial position, consolidated statement of income and shareholders' equity is included in the following reconciliations and notes.

Reconciliation of Consolidated Statement of Financial Position as of January 1, 2010

	Jan. 1, 2010 CAN GAAP	O&G assets	Transmeta	ARO	Defered income tax	Land acquisition	Equity inventment	Functional currency	Jan. 1, 2010 IFRS
Current assets	$ 656,296	$ -	$ (13,925)	$ -	$ (2,693)	$ (3,926)	$ -	$ -	$ 635,752
Non-current assets	2,162,814	-	(3,495)	-	100,732	3,536	28,123	(124)	2,291,586
Total assets	**$ 2,819,110**	**$ -**	**$ (17,420)**	**$ -**	**$ 98,039**	**$ (390)**	**$ 28,123**	**(124)**	**2,927,338**
Current liabilities	250,938	-	(7,990)	-	(846)	126	-	-	242,228
Non-current liabilities	1,039,414	-	108	253	22,091	-	-	-	1,061,866
Total liabilities	**$ 1,290,352**	**$ -**	**$ (7,882)**	**$ 253**	**$ 21,245**	**$ 126**	**$ -**	**-**	**1,304,094**
Shareholders' equity	1,528,758	-	(9,538)	(253)	76,794	(516)	28,123	(124)	1,623,244
Total Liabilities and shareholders' equity	**$ 2,819,110**	**$ -**	**$ (17,420)**	**$ -**	**$ 98,039**	**$ (390)**	**$ 28,123**	**(124)**	**2,927,338**

Reconciliation of Consolidated Statement of Financial Position as of December 31, 2010

	Dec. 31, 2010 CAN GAAP	O&G assets	Transmeta	ARO	Defered income tax	Land acquisition	Equity inventment	Functional currency	Dec. 31, 2010 IFRS
Current assets	$ 984,393	$ 690	$ (9,366)	$ -	$ (2,669)	$ (5,324)	$ -	$ -	$ 967,724
Non-current assets	2,870,693	(81,951)	(11,093)	2,644	166,142	4,431	34,798	741	2,986,405
Total assets	**$ 3,855,086**	**$ (81,261)**	**$ (20,459)**	**$ 2,644**	**$ 163,473**	**$ (893)**	**$ 34,798**	**741**	**3,954,129**
Current liabilities	801,712	-	(14,273)	-	(3,396)	(111)	-	-	783,932
Non-current liabilities	1,018,302	-	114	2,177	4,779	-	-	-	1,025,372
Total liabilities	**$ 1,820,014**	**$ -**	**$ (14,159)**	**$ 2,177**	**$ 1,383**	**$ (111)**	**$ -**	**-**	**1,809,304**
Shareholders' equity	2,035,072	(81,261)	(6,300)	467	162,090	(782)	34,798	741	2,144,825
Total Liabilities and shareholders' equity	**$ 3,855,086**	**$ (81,261)**	**$ (20,459)**	**$ 2,644**	**$ 163,473**	**$ (893)**	**$ 34,798**	**741**	**3,954,129**

Reconciliation of Consolidated Statement of Income for the year ended December, 2010

	Dec. 31, 2010 Cdn GAAP	O&G assets	Transmeta	ARO	Deferred income tax	Land acquisition	Equity investment	Funcional currency	Dec. 31, 2010 IFRS
Total revenue	$ 1,661,544	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,661,544
Total expense	1,240,939	81,260	(3,152)	(720)	1,639	266	(9,100)	(30,654)	1,280,478
Income before taxes	**420,605**	**(81,260)**	**3,152**	**720**	**(1,639)**	**(266)**	**9,100**	**30,654**	**381,066**
Income taxes	(202,999)	-	133	-	86,887	-	-	-	(115,979)
Net income	**$ 217,606**	**$ (81,260)**	**$ 3,285**	**$ 720**	**$ 85,248**	**$ (266)**	**$ 9,100**	**$ 30,654**	**$ 265,087**

Notes for reconciliations from Canadian GAAP to IFRS

1. Oil and gas properties and exploration and evaluation assets

The Company has elected to apply the exemption under IFRS 1 to deem the cost of oil and gas properties and exploration and evaluation assets as at January 1, 2010 equal to the net book value of property, plant and equipment recorded under Canadian GAAP.

Under Canadian GAAP, depreciation, depletion and amortization of oil and gas properties is determined on a unit-of-production basis with Colombia being considered one cost centre. Under IAS 16 *Property, Plant and Equipment*, depletion, depreciation and amortization is calculated at the level of the cash generating unit, which the Company has determined to be the major producing fields.

Depreciation charged against certain administrative assets related to oil producing fields is now included under cost of operations rather than general and administrative expenses.

All oil and gas properties and exploration and evaluation assets were tested for impairment as at January 1, 2010 and no impairment was recognized.

2. Consolidation of Transmeta

Under Canadian GAAP, the Company consolidated Transportadora del Meta S.A. ("**Transmeta**") as a variable interest entity. Under SIC 12 requirements, consolidation of special purpose entities is determined based on control. The Company has concluded it does not control Transmeta as of January 1, 2010 and therefore consolidation has been reversed.

3. Asset retirement obligation

As the Company elected to use the full cost as deemed cost exemption as described above, the asset retirement obligation has been re-measured as at January 1, 2010 using the guidance in IAS 37. In re-measuring the asset retirement obligation, expected future cash outflows were estimated and discounted to January 1, 2010 using the risk free rate of 4% with the offset recorded to retained earnings.

4. Deferred income tax

a) Under Canadian GAAP the Company recognized a deferred income tax arising from the bonus depreciation "superdeduction" related to qualifying new investments in Colombia. This type of benefit is not within the scope of IAS 20 and is therefore not treated as part of the tax base. Instead, the deduction is recognized as a reduction to income tax expense in the current period.

b) Under Canadian GAAP, deferred income tax assets and liabilities were classified between current and non-current, based on the classification of the underlying assets and liabilities that gave rise to the differences. IAS 12 requires that deferred taxation amounts be classified as non-current assets and liabilities only.

c) Deferred income tax assets and liabilities have been adjusted for the changes to net book values of oil and gas properties arising as a result of the adjustments for first time adoption of IFRS as discussed in 1 above. Under Canadian GAAP, deferred tax was not recognized for temporary differences resulting from differences between the functional currency and the currency in which the Company's taxes are denominated, being the Colombian peso. Under IFRS, such temporary tax differences are recognized as part of the deferred tax expense or recovery in the consolidated statement of income.

d) Under IFRS, a temporary difference is calculated on the difference between the accounting base and the tax base of the convertible debenture. The tax effect calculated on the equity component of the convertible debenture is recorded as a deferred tax liability with a corresponding adjustment to the equity component at the time of issue. The tax effect on the subsequent change in the temporary difference related to the debt component of the convertible debenture is recognized as deferred tax expense or recovery in the consolidated statement of income.

5. Land acquisition

Certain advances made for the acquisition of land that were included in accounts receivable under Canadian GAAP have been reclassified to oil and gas properties, as the title of the land has been transferred to a trust that is considered to be a special purpose entity subject to consolidation pursuant to the requirements of SIC 12.

6. Equity-accounted investments

The Company determined that the effect of the changeover to IFRS on the financial statements of the Company's equity-accounted investments as at January 1, 2010 was an increase to the carrying amount of the investments by $28.1 million with a corresponding adjustment to retained earnings. The carrying amounts of property, plant and equipment of ODL and PII were adjusted for IFRS requirements, including the effect of the accounting for the superdeduction related to qualifying investments in Colombia.

7. Functional currency

The Company's functional currency under Canadian GAAP was the U.S. dollar. The Company has determined that its functional currency is the Canadian dollar upon transition to IFRS. The Company's presentation currency continues to be the U.S. dollar. The effect of this change is primarily related to the translation of the Company's cash and debts on the consolidated statement of financial position and the resulting foreign exchange gains and losses on the consolidated statement of income. Unrealized gains and losses resulting from the translation to the U.S. dollar presentation currency have been included in other comprehensive income.

8. Reconciliation of the statement of cash flows from Canadian GAAP to IFRS

The transition from Canadian GAAP to IFRS did not materially change the underlying cash flows of the Company with the exception that the Company no longer consolidates the operating results of Transmeta as described in 2 above. As a result of the reversal of consolidation of Transmeta, the Company's net cash provided by operating activities was reduced by $8.3 million for the year ended December 31, 2010.

14. Related-Party Transactions

Parties are considered related if one party has the ability to control (financially or by share capital) the other party or have significant influence (management) on the other party in making financial, commercial and operational decisions.

Related party transactions are measured at the carrying amount, unless it is in the normal course of business and has commercial substance or, if it is not in the normal course of business, the change in the ownership of interests in the item transferred or the benefit of a service provided is substantive and the exchange amount is supported by independent evidence. In these instances, related party transactions are measured at the exchange amount:

a) In June 2007, the Company entered into a 5-year lease agreement with Blue Pacific Assets Corp. ("**Blue Pacific**") for administrative office space in one of its Bogota, Colombia locations. Monthly rent expense of $57 is payable to Blue Pacific under this agreement. Three directors and officers of the Company control, or provide investment advice to the holders of, 67.2% of the shares of Blue Pacific. During 2011, the lease was amended to include additional space in Bogota for a 10-year term with a monthly rent of $0.4 million, and assignment of lessor to an entity controlled by Blue Pacific.

   The Company does not have any outstanding accounts receivable from Blue Pacific as at December 31, 2011 (December 31, 2010 - $773; January 1, 2010 - nil) related to certain administrative costs paid by the Company on behalf of Blue Pacific. In addition, the Company paid $0.4 million to Blue Pacific during the year ended December 31, 2011 ($0.5 million in 2010) for air transportation services.

b) As at December 31, 2011, the Company had trade accounts receivable of $2.4 million (December 31, 2010 - $1.7 million; January 1, 2010 - $10.5 million) from Proelectrica, in which the Company has a 20.2% indirect interest and which is 31.49% owned by Blue Pacific. The Company's and Blue Pacific's indirect interests are held through Pacific Power. Revenue from Proelectrica in the normal course of the Company's business was $25.6 million for the year ended December 31, 2011 ($12.5 million in 2010).

c) During the year ended December 31, 2011, the Company paid $47.1 million ($40.2 million in 2010) to Transmeta in crude oil transportation costs. In addition the Company has accounts receivable of $3.2 million (December 31, 2010 - $4.1 million; January 1, 2010 - $5 million) from of $5.5 million (December 31, 2010 - $4.6 million; January 1, 2010 – nil) to Transmeta as at December 31, 2011. Transmeta is controlled by a director of the Company.

d) Loans receivable in the aggregate amount of $490 (December 31, 2010 - $524; January 1, 2010 - $290) are due from three management directors and three officers of the Company as at December 31, 2011. The loans are non-interest bearing and payable in equal monthly payments over 48 months. The loans were issued by the Company to these individuals in connection with costs incurred by these individuals as a result of their relocation.

e) The Company has entered into aircraft transportation agreements with Petroleum Aviation Services S.A.S., a company controlled by a director of the Company. During 2011, the Company paid $9.5 million ($7.7 million in 2010) in fees as set out under the transportation agreements.

f) During the year ended, December 31, 2011, the Company paid $80.2 million to ODL ($44.6 million in 2010) for crude oil transport services under the pipeline take or pay agreement and has accounts payable of $1 million (December 31, 2010 and January 1, 2010 – nil) to ODL as at December 31, 2011. In addition, the Company received $1.6 million from ODL during the year ended December 31, 2011 ($6.6 million in 2010) with respect to certain administrative services and rental equipment and machinery. The Company does not have any outstanding accounts receivable from ODL as at December 31, 2011 (December 31, 2010 - $3.1 million; January 1, 2010 - nil).

g) As at December 31, 2011 the Company has a short-term advance of $8 million (December 31, 2010 and January 1, 2010 – nil) to OBC to fund on-going work commitments, which will be repaid upon OBC's closing of financing.

h) As at December 31, 2011 the Company has account receivable of $20 (December 31, 2010 and January 1, 2010 - nil) from PII for the sale of certain administrative assets.

i) As at December 31, 2011, the Company has accounts payable of $0.4 million (December 31, 2010 and January 1, 2010 - nil) due to Helicol with respect to air transportation services and paid during the year $1.3 million for this service (nil in 2010). Helicol is controlled by a director of the Company.

All related party transactions are recognized at terms equivalent to those that prevail in arm's length transactions.

15. Internal Controls over Financial Reporting ("ICFR")

In accordance with Multilateral Instrument 52-109 ("**NI 52-102**") of the Canadian Securities Administrators ("**CSA**"), quarterly the Company issues a "Certification of Interim Filings" ("**Certification**"). The Certification requires certifying officers to state that they are responsible for establishing and maintaining disclosure controls and procedures ("**DC&P**") and **ICFR**.

The Certification requires certifying officers to state that they designed DC&P, or caused it to be designed under their supervision, to provide reasonable assurance that: (i) material information relating to the Company is made known to the certifying officers by others; (ii) information required to be disclosed by the Company in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian securities legislation. In addition, the Certification requires certifying officers to state that they have designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes.

The Company´s internal audit department provides support to the Board of Directors, Audit Committee, and management, and contributes to the continuous improvement strategies of the organization. The corporate audit process provides reasonable assurance over the:

- Evaluation of design and operating effectiveness of internal controls over financial reporting and disclosure controls and procedures as promulgated by NI 52-109 as issued by the CSA,
- Effectiveness and efficiency of operations,
- Reliability of internal and external reporting, and
- Compliance with applicable laws and regulations.

During 2011, Corporate Audit continued activities focused on identifying, evaluating, and addressing critical and material risks for the organization. Following are some of the most significant risks reviewed, as well as the actions initiated by management to mitigate them:

- Regulatory compliance: Some of the activities included the review and update of the governance programs which included the Business Code of Ethics and Corruption of Foreign Public Officials Act ("**CFPOA**"), anti-money laundering, and data security.
- Credit and liquidity strains: The audit review was focused on client risk rating process and strategies, improving the automated environment to gain greater control of processing.
- Potential increased fraud risk: Audit reviews were performed to reduce this risk and included employee fraud awareness training to help maintaining fraud-resistance and fraud risk assessment within key areas. The results were used to prioritize fraud detection efforts toward key current fraud risks, and review of segregation of duties controls and other fraud controls.
- Data security and privacy protection: The audit review was focused on the implementation of tools to protect the access to the network and the implementation of application security, the use of tools to continuous auditing and monitoring, and the strengthening of the IT control environment in accordance with the standards.
- Labor relations: The audit reviewed the compliance with labor regulations by contractors and service providers to strengthen relationship with communities and workers.

As well, Corporate Audit evaluated the effectiveness of internal controls, encompassed within the requirements of NI 52-109, over the design and operating effectiveness of the ICFR. During this quarter an evaluation was performed on operating effectiveness of the ICFR for 288 controls over 32 processes.

From this evaluation the Company concluded that there are no material weaknesses or significant deficiencies in the design and effectiveness of the controls evaluated. The identified control deficiencies and opportunities to improve the ICFR are in the following main areas:

- Contracting procedures and supplier´s database
- Suppliers' performance evaluation
- Project management documentation and commissioning
- Investor relations communication and documentation

- Financial closing and reporting procedure
- Business Continuity Plan

- As part of the risk management activities, a Risk Analysis for each of the Corporate Risks was conducted with the participation of all of the Company´s expert teams to establish mitigation plans and refresh risk indicators. Corporate Audit provides coaching and coordinates Risk Management activities.

- The Company has continually had in place systems relating to DC&P and ICFR and will continue to monitor such procedures as the Company's business evolves.

16. Outlook

The Company will continue working on increasing its reserves base, production and transportation capacity. Capital spending in 2012 is focused on: (1) expanding the Company's production in its flagship Rubiales/Piriri and Quifa SW oil fields; (2) growing production at the newly commissioned Quifa North and Sabanero oil blocks; (3) advancing its CPE-6 property toward commercial oil production; and (4) continuing drilling and seismic activities on its extensive high impact exploration portfolio in Colombia, Peru and Guatemala.

Highlights of the 2012 program include:

- Expected production growth of 15-35% against an estimated 86 Mboe/d net produced in 2011, largely driven by increased production in the Quifa, Sabanero and Rubiales heavy oil fields. Essentially all the expected production growth will be oil.

- Total capital expenditures of $1.2 billion, a small increase over 2011, with exploration accounting for approximately 30% of the total budget. The capital program is expected to be entirely funded from internally generated funds and cash on hand in an expected oil price environment between $80 - $90 WTI.

- Exploration expenditures of $340 million, a similar level to 2011, drilling approximately 60 gross wells (32 net) and seismic data acquisition. Significant exploration and appraisal drilling is planned for the Quifa North, Sabanero, CPE-6, and CPO-12 heavy oil blocks. In the total drill program, approximately 14 gross (9 net) exploration wells are targeting high impact prospects, including the Company's first well in Peru.

- $285 million drilling a planned 285 gross (150 net) development wells, a significant increase over 2011, with activity driven by development of the Quifa SW field, the Quifa North and Sabanero blocks, and on-going infill drilling at Rubiales/Piriri.

- $560 million facilities expenditure, with approximately 40% directed to Quifa, 30% to Rubiales/Piriri, and the remainder to Sabanero, with provision for advance and early progress on CPE-6

17. Additional Financial Measures

This report contains the following financial terms that are not considered measures under IFRS: operating netback, net adjusted net earnings from operations, funds flow from operations, adjusted earnings from operations and EBITDA. These non-IFRS measures do not have any standardized meaning and therefore are unlikely to be compared to similar measures presented by other companies. These non-IFRS financial measures are included because management uses the information to analyze operating performance, leverage and liquidity. Therefore, these non-IFRS financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS.

The following table shows the reconciliation of funds flow from operations to cash flow from operating activities for the year and three month periods 2011 and 2010:

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2011	2010	2011	2010
Cash flow from operating activities	$ 1,219,057	$ 939,929	$ 477,530	$ 353,433
Changes in non-cash working capital	(149,542)	272,160	125,770	144,862
Funds flow from operations	1,368,599	667,769	351,760	208,571

A reconciliation of Net Earnings (Loss) to EBITDA follows:

(in thousands of US$)	Year Ended December 31 2011	Year Ended December 31 2010	Three Months Ended December 31 2011	Three Months Ended December 31 2010
Net earnings	$ 554,336	$ 265,087	$ 80,834	$ 61,370
Adjustments to net earnings				
Income taxes expense	448,150	115,979	189,558	53,890
Foreign exchange loss (gain)	39,894	(33,851)	(1,947)	(8,201)
Finance cost	86,469	77,383	15,501	21,515
Incentive for early conversion of debenture	46,489	-	46,489	-
Loss (gain) on risk management contracts	(8,831)	40,230	46,458	39,752
Loss (gain) from equity investment	(6,829)	(7,770)	(5,059)	(6,910)
Other expense (income)	13,207	(2,718)	8,369	(4,026)
Share-based compensation	48,783	73,327	316	-
Equity tax	68,446	2,088	-	522
Depletion, depreciation and amortization	656,474	394,308	180,146	117,448
EBITDA	1,946,588	924,063	560,665	275,360

18. Sustainability Policies

The Company has established guidelines and management systems to comply with the laws and regulations of Colombia and other countries in which it operates, and to ensure that sustainable development is one of the Company's priorities. In the past, the Company has engaged with various stakeholders to ensure that as the Company grow, its consideration for the environment, its employees and other stakeholders also continues to grow. The Company devotes significant time and resources to achieve its environmental and safety performance goals. The Company has dedicated employees responsible for all matters affecting the environment and local communities. The Company has instituted social programs specific to the areas in which it operates, which are carried out by employees or staff in Colombia. The Company's social workers visit the various municipalities where the Company operates to determine each community's needs and to formulate the Company's programs to meet the requirements of each particular area. The Company has been involved in the provision of educational and health supplies, the building of schools and funding of hospitals, and the sponsorship of other local, cultural, sporting and other organizations and events.

In June 2011, the Company announced its support for the Extractive Industries Transparency Initiative (the "**EITI**"). The EITI is an international non-profit organization formed in 2002 at the World Summit for Sustainable Development in South Africa. The EITI supports improved governance in resource-rich countries through the verification and full publication of company payments and government revenues from oil, gas and mining. The EITI standards are implemented by governments with an international multi-stakeholder structure at the core of the initiative. Currently, more than fifty of the largest oil, gas and mining companies have chosen to become EITI supporting companies. The EITI's initiatives aim for good governance so that the exploitation of resources can generate revenues to foster growth and reduce poverty.

Pacific Rubiales was the first company in Colombia to implement the EITI standards and is committed to taking a leading role in the implementation of EITI in Colombia by collaborating with all stakeholders within the EITI. In Canada, which is an EITI supporting country, and Peru and Guatemala, which are EITI candidate countries, Pacific Rubiales is committed to actively supporting EITI processes.

With respect to how the Company manages the impacts of climate change, Pacific Rubiales aims to implement the Carbon Disclosure Project in 2012. Accordingly, Pacific Rubiales would integrate into its business strategy the need to document, control and eventually reduce carbon emissions.

In 2012, the Board of Directors appointed a Sustainability Committee to assist the Board of Directors in carrying out the Company's corporate sustainability policies, including environmental, social, health, safety and ethical matters, and is responsible for advising the Board of Directors, committees of the Board of Directors and executive management on such matters.

For further details regarding the Company's sustainability policies, please see our Sustainability Report, which is available on our website.

19. Legal Notice – Forward-Looking Information and Statements

Certain statements in this MD&A constitute forward-looking statements. Often, but not always, forward-looking statements use words or phrases such as: "expects", "does not expect" or "is expected", "anticipates" or "does not anticipate", "plans" or "planned", "estimates" or "estimated", "projects" or "projected", "forecasts" or "forecasted", "believes", "intends", "likely", "possible", "probable", "scheduled", "positioned", "goal", "objective" or state that certain actions, events or results "may", "could", "would", "might" or "will" be taken, occur or be achieved. Such forward-looking statements, including but not limited to statements with respect to anticipated levels of production, the estimated costs and timing of the Company's planned work programs and reserves determination involve known and unknown risks, uncertainties and other factors which may cause the actual levels of production, costs and results to be materially different from estimated levels of production, costs or results expressed or implied by such forward-looking statements. The Company believes the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. Factors that could cause actual results to differ materially from those anticipated in these forward-looking statements are described under the caption “Risks and Uncertainties”. Although the Company has attempted to take into account important factors that could cause actual costs or operating results to differ materially, there may be other unforeseen factors to cause costs to the Company's program and results may not to be as anticipated, estimated or intended.

Statements concerning oil and gas reserve estimates may also be deemed to constitute forward-looking statements to the extent they involve estimates of the oil and gas that will be encountered if the property is developed. The estimated values disclosed in this MD&A do not represent fair market value. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Certain financial information already filed under Canadian GAAP for 2010 may vary with information presented in this period, due to adjustments in the first time adoption of IFRS as discussed in Section 13 – New Accounting Pronouncements.

20. Risks and Uncertainties

The business and operations of the Company will be subject to a number of risks. The Company considers the risks set out below to be the most significant to potential investors in the Company, but does not include all of the risks associated with an investment in securities of the Company:

- Fluctuating oil and gas prices;
- Cash flows and additional funding requirements;
- Global financial conditions;
- Exploration and development;
- Operating hazards and risks;
- Reserve estimates;
- Transportation costs;
- Disruptions in production;
- Political risk;
- Environmental factors;
- Title matters;
- Dependence on management;
- Changes in legislation;
- Repatriation of earnings;
- Enforcement of civil liabilities;
- Competition;
- Payment of dividends;
- Environmental Licenses & Required Permits;
- Security;
- Partner relationship;
- Oil & Gas Transportation;
- Availability of Diluents;
- Water Disposal;
- Talent Attraction & Retention;

- Labor Relations;
- HSE Works;
- Community Relations;
- Fraud;
- FX rate fluctuation;
- Business Continuity;
- Regulatory Compliance;
- Shareholder relations.

If any of these risks materialize into actual events or circumstances or other possible additional risks and uncertainties of which the Company is currently unaware or which it considers not to be material in relation to the Company's business, actually occur, the Company's assets, liabilities, financial condition, results of operations (including future results of operations), business and business prospects, are likely to be materially and adversely affected. In such circumstances, the price of the Company's securities could decline and investors may lose all or part of their investment. For more information, please see the Company's Annual Information Form which is available at www.sedar.com.

21. Advisories

Prospective Resources

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates, assuming their discovery and development, and may be sub-classified based on project maturity. There is no certainty that any portion of the resources will be discovered. If discovered, and they would be technically and economically viable to recover; there is no certainty that the Prospective Resource will be discovered. If discovered, there is no certainty that any discovery will be technically or economically viable to produce any portion of the resources

Reserves Replacement

Production replacement is calculated by dividing reserves additions by production in the same period. Reserves additions over a given period, in this case 2011, are calculated by summing one or more of revisions and improved recovery, extensions and discoveries, acquisitions and divestitures. Reserve replacement cost is calculated by dividing total capital invested in finding, development and acquisitions net of divestitures by reserve additions in the same period.

Finding Costs

The aggregate of the finding costs incurred in the most recent financial year and the change during that year in estimated future finding costs generally will not reflect total finding costs related to reserves additions for that year.

Boe Conversion

Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 5.7 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

22. Abbreviations

The following list of abbreviations is used in this document

1P	Proved reserves (also known as P90).
2P	Proved reserves + Probable reserves.
3P	Proved reserves + Probable reserves + Possible reserves.
Bbl	Barrels
bbl/d	Barrels per day
Bcf	Billion cubic feet
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
Btu	British thermal units
Bwpd	Barrels of water per day
ESP	Electro-Submersible Pump
km	kilometers
Mbbl	thousand barrels include millions MMbbl
Mboe	thousand barrels of oil equivalent include millions (MMboe)
Mcf/d	thousand cubic feet per day
MMcf/d	Million cubic feet per day
Mcf	thousand cubic feet
MD	Measured depth
OOIP	Original oil in place
MMbbl	million barrels
Mmboe	Million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Mmscf/d	Million standard cubic feet per day
Mw	Megawatts
NGL	natural gas liquids
Tcf	trillion cubic feet
TD	Total depth
TVDSS	True vertical depth below sea level
WTI	West Texas Intermediate index