PACIFIC RUBIALES ENERGY CORP.
MANAGEMENT DISCUSSION AND ANALYSIS

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For the year ended December 31, 2010

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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 42.

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 consolidated financial statements for the year ended December 31, 2010 and related notes. The preparation of financial information is reported in United States dollars and is in accordance with Canadian generally accepted accounting principles ("GAAP") unless otherwise noted. All comparative percentages are between the years ended December 31, 2010 and December 31, 2009, unless otherwise stated. The following financial measures: (i) EBITDA; (ii) funds flow from operations; and (iii) income from operations, as referred to in this MD&A, are not prescribed by GAAP and are outlined under "Non-GAAP Financial Measures" on page 41. All references to net barrels or net production reflect only the Company's share of production after deducting royalties and the operating partner's working interest. A glossary of oil and gas terms is provided on page 44.

In order to provide the 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 31.

References to "we", "our", "us", "Pacific Rubiales" 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. Pacific Rubiales, a Canadian-based company and producer of natural gas and heavy crude oil, owns 100 percent of Meta Petroleum Corp., a Colombian oil branch which operates the Rubiales/ Piriri and Quifa oil fields in the Llanos Basin in association with Ecopetrol, S.A. ("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. The Company, through an 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 northern Peru. Pacific Rubiales has a current net production of approximately 85,000 boe/d, with working interests in 35 blocks in Colombia, 2 blocks in Guatemala and 3 blocks in Peru.

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 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. Executive Summary

Financial and Operating Summary

In 2010, the Company experienced another twelve months of outstanding production growth and exploratory success, leveraging its technical know-how and operational expertise. The results for the year underline, the strength of the Company's operational activity and its capacity to increase production, as well as management's commitment to deliver robust financial results. Management is focused on achieving challenging operational goals, while pursuing an ambitious exploration and production ("E&P") investment program, under the umbrella of the Company's paramount strategic focus: Growth.

During the year ended December 31, 2010, the Company increased revenues by 160% (Q4 2010 – 245%) to $1.7 billion (Q4 2010 - $516 million), as compared to $639.2 million during the same period in 2009 (Q4 2009 - $211.7 million). This was the result of a considerable increase in production and the optimization of marketing activities, coupled with higher combined crude oil and gas prices. This significant increase in revenues also yield to an increase in net after tax income for the year to $217.6 million (Q4 2010 - $104.7 million), compared to a loss of $125.8 million in 2009 (Q4 2009 - $3 million net income).

EBITDA during the year ended on December 31, 2010 totalled $922.9 million, representing a significant increase of 210%, as compared to 2009 EBITDA of $297.8 million. For the fourth quarter of 2010, EBITDA was $271 million, mainly generated from international sales (88%), while gas and domestic sales contributed 6.5% and 5.5%, respectively.

In 2010, the Company entered into currency risk management contracts, in the form of costless collars, to reduce the currency exposure associated with operating expenses, and general and administrative expenses, incurred in Colombian pesos. These contracts were designated as accounting hedges and had the positive impact of reducing the Company's operating and administrative expenses by $21.7 million, for the year 2010. At the end of 2010, the Company had entered into new currency derivatives totalling $240 million, in notional amount, to manage currency risks for the period January to December 2011.

During the fourth quarter of 2010, the Company commenced paying quarterly dividends to common shareholders. In December 2010, an aggregate amount of $25.1 million (or $0.094 per common share) had been paid as dividends to the Company's shareholders. Provisions of various trust indentures and credit arrangements, to which the Company is a part, restrict the Company's ability to declare and pay dividends to shareholders under certain circumstances, and if such restrictions apply, they may in turn have an impact on the Company's ability to declare and pay dividends. In the management's opinion, such provisions do not currently restrict or alter the Company's ability to declare or pay dividends. On March 10, 2011, the Company's Board of Directors approved a cash dividend in the aggregate of $25 million, or $0.093 per common share. The dividend is payable on March 30, 2011 to shareholders of record as of March 16, 2011; the ex-dividend date is March 14, 2011.

A summary of the financial results for the three and twelve months ended December 31, 2010 and 2009 follows:

(in thousands of US$ except per share amounts or as noted)	Three Months Ended December 31 2010	Three Months Ended December 31 2009 (Restated) [5]	Year ended December 31 2010	Year ended December 31 2009 (Restated) [5]
Oil and gas sales [1]	515,901	211,650	1,661,544	639,201
Income from Operations [2]	200,499	55,726	643,119	99,545
Funds Flow from Operations [2]	196,310	99,727	661,993	225,886
Per share - basic ($)	0.75	0.47	2.52	1.06
- diluted ($)	0.68	0.47	2.28	1.06
EBITDA [2]	270,961	117,039	922,853	297,832
Per share - basic ($)	1.03	0.55	3.51	1.40
- diluted ($)	0.93	0.55	3.18	1.40
Net Income [3]	104,698	3,218	217,606	(125,793)
Per share [4] - basic ($)	0.40	0.02	0.83	(0.59)
- diluted ($)	0.35	0.02	0.75	(0.59)

(1) Income from oil and gas sales includes revenues from the trading of third parties' crude oil totaling $25.6 million for the fourth quarter 2010 and $58.5 million for all of 2010. See additional details explained in the "Commercial Activity" Section on page 17.

(2) See "Non-GAAP Financial Measures" on page 41

(3) Net income for the year of $217.6 million includes a series of non-operating expenses and non-cash items totaling $222.5 million, mainly corresponding to:

a) Non-cash items of $143.5 million (same period of 2009 – $107.6 million), due to unrealized exchange losses resulting from the strengthening of the Canadian dollar and Colombian peso against the US dollar, and unrealized loss on risk management contracts outstanding as of the end of 2010 (which may or may not materialize in future periods) and stock-based compensation costs. The Company entered into foreign exchange hedging contracts to reduce its foreign currency exposure associated with operating expenses incurred in Colombian pesos.

b) Non-operating expenses of $79 million (same period in 2009 – $71.7 million) consisting of interest primarily due to financial costs associated with financing facilities for the development of the infrastructure required to increase the production capacity of the Rubiales field, and other costs.

(4) The basic weighted average number of common shares outstanding for the year ended December 31, 2010 and 2009 was 262,945,271 (fully diluted – 289,836,191) and 213,294,237 (fully diluted –213,294,237), respectively.

(5) The Company has restated its 2009 consolidated financial statements to correct an error that resulted in an overstatement of accounts payable and accrued liabilities at December 31, 2009. This occurred in the fourth quarter of 2009 as a result of the amalgamation of several operating subsidiaries of the Company and enterprise resource planning system conversion.

Operating Summary

The Company produces and sells crude oil and natural gas. It also purchases crude oil from third parties for trading purposes. The following sets out the netback and trading margins for these activities as of December 31, 2010:

a) Operating Netback Crude Oil and Gas

	Year ended December 31 2010 Oil	2010 Gas	2010 Combined	2009 Combined (Restated)
Average daily production sold (boe/day)	58,055	10,021	68,076	35,374
Operating netback ($/boe) [1]				
Crude oil and natural gas sales price	70.64	29.03	64.51	49.47
Cost of Production [2]	5.01	4.10	4.87	5.20
Transportation	6.98	0.32	6.00	9.05
Diluent cost (including Transportation) [3]	13.69	-	11.67	7.07
Other costs [4]	(0.78)	1.99	(0.37)	(0.28)
Overlift/Underlift [5]	0.90	(0.09)	0.76	(0.17)
Operating netback	44.84	22.71	41.58	28.60

(1) Combined operating netback data based on weighted average daily production sold which includes diluents necessary for the upgrading of the Rubiales blend.
(2) Cost of production mainly includes lifting costs and other production costs such as personnel, energy, security, insurance and others. Cost of production for gas includes work over for an amount of $2.1 million ($0.4 per boe) executed during this quarter.
(3) Net blending cost is estimated at $3.12 per boe, considering an average diluent purchase price delivered at the Rubiales field of $77.58 per boe (Light Crude Oil - API 45 with a blending factor around 18.95%), pipeline and handling transportation fees from the Rubiales field to Coveñas of $7.16 per boe and an average Rubiales Blend (Castilla) sale price of $70.72 per barrel
(4) Other costs mainly correspond to royalties on gas production, external road maintenance at Rubiales field, inventory fluctuation, and the net effect of the currency hedges of operating expenses incurred in Colombian pesos during the period. The negative cost for oil of $0.78 per bbl was mainly attributable to the realized hedge gain recognized against operating expenses during this period. See additional comments on page 33 – Risk Management Contracts.
(5) Corresponds to the net effect of the overlift position for the period amounting to $1.8 million, which generated a reduction in the combined production costs of $0.20 per boe as explained in the section "Corporate Development Highlights – Financial Position – Operating Costs" on page 26.

b) Third Party Crude Oil Trading

	Year ended December 31,	
	2010	2009
Total Third Party Crude Oil Traded (bbl/day)	1,916	-
Crude Oil Trading Margin ($/boe) (1)		
Average crude oil sales price	83.67	-
Average purchasing and transportation costs	81.53	-
Trading margin	2.14	-
Gross Crude Oil Trading Margin ($000)	1,499	-

(1) *During the third and fourth quarter of 2010, the Company purchased crude oil from local crude oil producers to trade on the international market. See additional details explained in the section "Commercial Activity" on page 17.*

The total proved and probable oil equivalent reserves (2P) of the Company as of December 31, 2010 were 322.42 million boe gross (before royalties) or 268.98 million boe net to the Company. Production in 2010 was 21.23 million boe (before royalties) and net reserve addition was 9.63 million boe, representing a 11.6 million boe decrease in reserves. Based on the February 28, 2011 updated reserve reports and 2010 production, 2P reserves totalled 316.44 million boe, which represent net additions of 57.09 million boe. This increase represents a 12.8% increase in 2P net reserves compared to the reserves reported for the year 2009.

The net proved reserves (1P) reached 238.43 million boe as at December 31, 2010, representing approximately 1 barrel per outstanding share.

During 2010, the Company drilled a total of 29 exploratory wells, of which 24 were successful, or an 83% success rate. This performance allowed the incorporation of 45 million boe of new 2P gross reserves or 25 million boe of net reserves after royalties. The reserve replacement ratio, from the exploration efforts only, incorporated 1.2 barrels of oil for every barrel produced during 2010.

Average gross production in 2010 reached 144,307 boe/d, 75% higher than in 2009, and is as a result of more than 176 new development wells, mainly in the Rubiales and Quifa fields.

Combined operating netback during the year ended December 31, 2010 was $41.58/boe, higher by $12.98/boe in comparison to the same period of 2009. The 45% increase was the result of higher volumes of oil and gas production, blending costs optimization and improved realized sale prices during 2010, all of which allowed the Company to reach $1.7 billion in revenues during 2010.

Capital expenditures during the year ended December 31, 2010 totaled $954.3 million (2009 - $403.7 million), of which $461.4 million were invested in the expansion and construction of production infrastructure and facilities; $112.5 million went into exploration activities including seismic, aerogravimetry, aeromagnetometry and drilling; $150.6 million were invested in development drilling, $39.8 million were invested in other projects and $190 million were invested in the purchasing of transport rights in the OCENSA transport system. Capital expenditures during the fourth quarter of 2010 totaled $347.7 million.

Exploration

The Company´s exploration portfolio currently covers 6,725,673 hectares (16,619,501 acres), and it remains the largest portfolio of any independent oil and gas company in Colombia, second only to the state-owned Ecopetrol. The Company further expanded its portfolio in 2010 by adding two blocks in the Republic of Guatemala and six in the Llanos-Putumayo basins in Colombia. During 2010, and as part of its exploration drilling campaign, the Company drilled a total of 29 wells: 7 exploratory, 9 appraisal and 13 stratigraphic wells, of which 24 wells were successful, representing a success ratio of 83%.

During the fourth quarter of 2010, the Company continued its exploration campaign in the Quifa, CPE-6, Guama, and Topoyaco Blocks, and started drilling activity in the La Creciente and Buganviles Block, for a total of seven exploratory wells drilled during the period. In Quifa, the Ambar-1 exploratory well was drilled on prospect “F” at the northern part of Quifa. In the CPE-6 Block, the Guairuro-3 and Guairuro-4 stratigraphic wells were drilled in the Guairuro prospect, in the northern part of the block, and in the Buganviles Block, the Visure-1X well was drilled in the southern border of the block. The Company also finished drilling the Pedernalito-1X exploratory well, located in the Pedernalito prospect, in the central part of the Guama Block, as well as the Topoyaco-1 and 2 wells, both located in the prospect “B” of the Topoyaco Block.

In addition, the Company started drilling three new exploratory wells: the Ambar-3 stratigraphic well in the Quifa Block, the Apamate-1X exploratory well in the La Creciente Block, and the Tuqueque-1X exploratory well, in the Buganviles Block. Final depth for these three wells is expected to be reached during the first quarter of 2011. On February 28, the Company announced the discovery of the Apamate-1X well. This well found 35 feet of net pay on the Lower Porquero sandstones and was tested for three days reaching an initial production in excess of 24 MMscfd of gas (4,333 boed). These findings at the well confirm the stratigraphic nature of the LCA-south prospect, and the post-drill maps associated with the gas sandstones from the seismic inversion show an acreage that ranges from 1,124 acres as a minimum to a maximum upside around 5,266 acres and a gas-water contact that is yet to be established. During 2011, the Company plans to drill two additional appraisal wells 500 feet downdip of the Apamate-1 well where the seismic inversion exhibited the strongest anomalies.

The exploration program during the fourth quarter resulted in six new exploratory successes: 1) the Ambar-1 well, located in the Quifa Block showed 16 feet of net pay in the Carbonera Basal sandstones; 2) the Guairuro-3 well, located in the CPE-6 block, which showed presence of hydrocarbons and 6.5 feet of net pay; 3) the Pedernalito-1X, located in the Guama Block, with 29 feet of net pay of gas condensate; 4) the Visure-1X, which showed a total net pay of 114 feet in three intervals: Barzalosa (24.5 feet), Upper Guadalupe (45.5 feet) and Lower Guadalupe (44 feet); 5) the Topoyaco-2X well, located in the Topoyaco Block, with 72 feet of net pay in the Villeta Formation; and 6) the Tuqueque-1X well, which showed during 2010 two prospective intervals in the well upper levels: the Monserrate Formation with 31 feet of net pay; and the El Cobre Formation with 9 feet of net pay, according to updated petrophysical analysis. The Ambar-1, Pedernalito-1X, Visure-1X and Topoyaco-1 wells are in the process of being completed and tested.

Total net exploration expenditure for 2010 was $112.5 million, of which $44.4 million were for the fourth quarter of 2010. For more details please see “Discussion of Fourth Quarter Results and Annual Results – Exploration” on page 8.

Production

The increase in gross operated production of the Company during 2010 was a significant achievement, averaging 144,307 boe/d (56,974 boe/d net after royalties) for an increase of 61,683 boe/d (22,848 boe/d net after royalties), or 75% greater than the production in 2009. This growth in operated production is mostly the result of the increase in production capacity at the Rubiales and Quifa heavy oil fields, in tandem with the construction of new facilities at both fields to process crude oil. Total operated production in all fields reached 192,977 boe/d (85,716 boe/d net after royalties) on December 31, 2010.

Production continues to grow during 2011, the Company had reached the highest historical level of 205,000 boe/d of gross operated production, over 85,000 boe/d, net after royalties, which continues to make the Company the fastest growing oil and gas company in Colombia, as well as the country’s second largest operator.

During 2010, the Company drilled 146 producing wells at the Rubiales field and 30 producing wells at the Quifa field. This, together with the completion of the Central Processing Facility at Quifa ("CPF Quifa") as well as the CPF2 at the Rubiales, allowed the Company to increase its gross production capacity to 220,000 boe/d, which will be fully realized as the expansion of OCENSA pipeline is completed.

For more details please see "Discussion of Fourth Quarter and Annual Results – Production" on page 8.

Commercial Activity

During 2010, the average of the WTI Nymex was $79.61/bbl in comparison to $62.09/bbl in 2009. The average price during the fourth quarter of 2010 was $85.24/bbl in comparison to $76.13/bbl in the fourth quarter of 2009. During 2010 the market was affected by strong volatility triggered by higher crude supply in the market and increased inventory levels. Therefore, the Company decided to minimize this impact by selling volumes to other destinations (Asia and Europe), taking advantage of better prices.

During the year 2010, the Company exported 35 cargoes and 5 small parcels of crude (86% Castilla crude/13% Vasconia crude/1% Rubiales crude), representing a total volume of 20.8 million bbl of crude oil at an average sales price of $71.67/bbl. Total volume exported during 2010 represents more than a two-fold increase in comparison to 2009, generating gross revenues of approximately $1.5 billion. During 2010, the Company sold 1.4 million bbl of Rubiales crude (12.5° API) to the Colombian domestic market at an average sales price of $67.09/bbl. In addition, sales of natural gas produced at La Creciente field to the domestic market averaged 60 mmscf/d at an average price of $4.85/mmbtu. For more details please see "Discussion of Fourth Quarter Results – Commercial Activity" on page 17.

Status of Projects

STAR Project

During 2010, significant progress was achieved in the acquisition of equipment for the production facilities plant, including transfer pumps, air compression system, separators, Strafford plant, knockout drum, and instrumentation. At the same time, the definitions and criteria to evaluate the success of the pilot test were completed. Negotiation of the business terms of an eventual commercial STAR project with Ecopetrol, after the pilot test, is still underway.

The monitoring plan and the design of some specialized tests, such as the 4D seismic runs, were completed, and they are scheduled to begin during the second quarter of 2011. The wells involved in the pilot project, four producers and one injector, following the inverted five pattern spot, have been already designed and they will be drilled as soon as business discussions with Ecopetrol are finalized. This is expected to happen during the second quarter of 2011.

As mentioned in the last quarterly report, the Company continues its commitment to the implementation of this technology, not only because it creates significant value to the Company, its partners, investors and the country, by increasing the reserves and extending the production life of the Rubiales field, but also because it is believed that once in place, STAR will have a powerful impact on the recovery factors for the entire Llanos region.

Llanomulsion Project

In January 2009, the Company initiated the development of a special transport emulsion formula (oil in water), that eliminates the need for diluents as part of the efforts to minimize transportation costs in the ODL pipeline while maximizing line capacity. The patented formula, called Llanomulsion, increases pipeline capacity by reducing fluid viscosity to one-third of the original viscosity of the diluted crude. Tests in the main pumping units of the ODL pipeline have been performed, using a batch of 3,500 bbl of emulsion. The next step in this development is a complete industrial test (a batch of 40,000 bbl of emulsion) in the ODL pipeline, scheduled for the first quarter of 2011. Facilities for this industrial test have been completed in the CPF-1 in the Rubiales field, whereas implementation of dehydration facilities in the Cusiana Station is well underway.

Oleoducto de Los Llanos Pipeline

As of the end of December 2010, the planned 340,000 bbl/d expansion project was 65% completed. This project includes construction of two booster stations along the line, increasing storage capacity at the Rubiales Pumping Station and construction of a pipeline branch to Cusiana Station. In December 2010, the pipeline branch to Cusiana was fully commissioned and started operations successfully. The expected completion date for the first booster station is March 2011, whereas the second one is expected to be completed by July 2011.

Petroeléctrica de los Llanos – Power Transmission Line Project

The Company has incorporated a new legal vehicle, Petroeléctrica de los Llanos, S.A. ("PEL"), which will be responsible for the design, construction and operation of a new power transmission line of 230 Kilovolts that will connect the Rubiales field to Colombia´s national grid. The new transmission line will originate at the Chivor Substation and will have an extension of 260 km to the Rubiales field. 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.

Oleoducto Bicentenario – Bicentennial Pipeline

The Company obtained a 32.88% equity interest in Oleoducto Bicentenario de Colombia ("OBC") in November 2010. OBC is a special purpose vehicle promoted by Ecopetrol, which has a 55.97% interest together with its affiliates, with the participation of other oil producers operating in Colombia, who will control the remaining 11.15% interest. OBC will be responsible for the financing, design, construction and eventual 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 pipeline will add 450,000 bbl/d to the capacity of the existing pipeline systems connecting the Los 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 will be developed in four phases. The Company has committed its participation to Phases 0 and 1 of the project for an initial capacity of 120,000 bbl/d, and the financial commitment estimated at $1.03 billion, excluding financing costs, of which $340 million represents the Company´s share.

Please see "Project Status" on page 19 for more details.

3. Company Overview

Profile

Pacific Rubiales, a Canadian-based company and producer of natural gas and heavy crude oil, owns 100 percent of Meta Petroleum Corp., 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., which operates the wholly-owned La Creciente gas field in the northern part of Colombia and other light and medium oil fields. The Company, through an 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 northern Peru. Pacific Rubiales has a current net production of approximately 85,000 boe/d, with working interests in 35 blocks in Colombia, 2 blocks in Guatemala and 3 blocks in Peru.

Vision

The Company aims 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 the right combination 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 reserve base and growing its production will be achieved through continuous exploration activities in areas where our knowledge and talents can provide a significant advantage in low to mid risk areas, and by the continuous use of the appropriate technology in order to increase and optimize the recovery rates in our existing resource base.

On November 8, 2010, the Company announced a broadening of its comprehensive growth strategy which includes three major components:

i. Continuing growth through exploration, development and production of new and existing reserves.

ii. Securing market access by participating in key oil and gas transportation and infrastructure projects.
   - The Company will have a significant participation in the OBC with Ecopetrol and other oil companies operating in Colombia.
   - The Company also anticipates maintaining its stake in Pacific Infrastructure Inc. (“PII”; formerly known as Lando Industrial Park, S.A.), a company developing a new crude oil and products terminal and also a port in Cartagena, as well as, a new pipeline that will link Covenas with Cartagena.

iii. Integrating downstream assets.
   - The Company will start making inroads on developing the bunker market within Colombia and the supply of finished products to wholesale markets.
   - Through the Company’s investment in Pacific Coal, S.A. (“Pacific Coal”), the Company will also start focusing on the development of an asphaltite deposit, leveraged on its access to a high quality resource base.

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.

4. Discussion of Fourth Quarter and Annual Results

Exploration

During 2010, and as part of its exploration drilling campaign, the Company drilled a total of 29 wells: 7 exploratory, 9 appraisal and 13 stratigraphic wells. During the fourth quarter of 2010, the Company continued its exploration campaign in the Quifa, CPE-6, Guama, and Topoyaco Blocks, and started drilling activity in the La Creciente and Buganviles Blocks for a total of 7 exploratory wells drilled during the period. These exploration projects, in addition to the enormous potential of our entire exploration portfolio, pave the way toward our four to five year target of 500,000 boe/d of gross production. A detail of the exploratory activity follows:

<u>Quifa Block</u>

As a continuation of its exploration/delineation campaign in prospects "A", "F" and "Q" in the Quifa Block, located in the northern part of the block, the Company drilled four wells: (i) the Quifa-6 exploratory well in prospect “A”; (ii) the Jaspe-1 ST2 appraisal well in prospect "A"; (iii) the Ambar-1 exploratory well in prospect "F"; and (iv) the Ambar-3 stratigraphic well, also in prospect "F".

During 2010, the Company focused its exploration drilling campaign in the Quifa field for a total of 17 drilled wells: 2 exploratory, 8 stratigraphic, and 7 appraisal wells. During the fourth quarter of 2010, the exploration campaign in the Quifa Block included the drilling of the Ambar-1 exploratory well, in the northern part of the block, which confirmed the extension of the “F” prospect to the southwest with 16 feet of net pay, located at the northern part of Quifa. The well is currently being tested. Also, during the last quarter of 2010, the Company started the drilling of the Ambar-3 stratigraphic well, which will be reaching the final depth in January 2011. The Company’s total net investment in exploration for the fourth quarter of 2010 for the Quifa Block was $10.2 million. Also, an additional seismic program was acquired in the northern and eastern part of the block, consisting of 294 km of 2D seismic. This seismic will be processed and interpreted during the first quarter of 2011.

As of today, in the northern part of the Quifa Block, the Company has drilled five wells showing commercial hydrocarbon columns: (i) Quifa-6; (ii) Quifa-24X; (iii) Quifa-26X; (iv) Jaspe-1 ST-2; and (v) Ambar-1. Thus far, the exploratory success of the campaign reaffirms the large scale hydrocarbon potential of this part of the Quifa Block, where the Company has already certified 251 mmbbl of gross resources (see the Company's press release dated April 26, 2010). In order to convert these resources into 2P reserves, the Company plans to drill seven additional exploratory/appraisal and stratigraphic wells in this part of the Quifa Block during the first quarter of 2011. The Company is already moving a rig to drill the Zircon-1 location and the Jaspe-2 location. In addition, as part of the exploratory activity in the Quifa Block, the Company has completed 294 km of additional 2D seismic in the furthermost northern and eastern parts of the block, which will aid in the evaluation of the prospectivity of these two areas. The results of the exploration campaign have ensured the petroleum potential of the northern part of the Quifa Block, where the Company is making the necessary investments to allow for large scale production of between 20,000 to 30,000 bbl/d by the end of 2011.

<u>CPE-6 Block</u>

During 2010, the Company started its exploratory campaign in the CPE-6 Block, and drilled four stratigraphic wells. During the fourth quarter of 2010, the Guairuro-3 and Guairuro-4 stratigraphic wells were drilled in the northern part of the block. The Guairuro-3 well reached a total depth of 2,523 feet TVDSS, and found the top of the C7 interval of the Carbonera Formation at 2,408 feet TVDSS, and the top of the Paleozoic Basement at 2,451 feet TVDSS. The Guairuro-4 reached a total depth of 2,486 feet TVDSS, and found the top of the C7 interval of the Carbonera Formation at 2,185 feet TVDSS, and the top of the Paleozoic Basement at 2,402 feet TVDSS. These two wells were the third and fourth wells of the six stratigraphic wells to be drilled in the block, as part of the exploratory commitment for the TEA Contract. The Company is now planning to drill the two additional wells during the first quarter of 2011 to fulfill the minimum work program, and prepare all the documentation to request the conversion of this Technical Evaluation Agreement ("TEA") contract into an E&P Contract to be signed with the Agencia Nacional de Hidrocarburos ("ANH").

With the information obtained from these three wells, a minimum preliminary area of 63,000 acres for the prospect has been estimated with a trap size extended an additional 6,9 and 7.5 km to the south, west, and northeast, respectively, of the previously drilled wells. The Company is also preparing to drill the last well of this initial campaign, the Guairuro-6 well, 10 km south of the Guairuro-4 well, so as to fulfill its contractual commitment with the ANH and to evaluate a possible reservoir compartmentalization of the pay units, as well as the south-headed oil-spilling from the location of the Guairuro-4 well. With the upcoming drilling of the Guairuro-6 well, the Company will complete its commitments under the TEA phase of the CPE- 6 contract.

In the northern zone of the Guairuro prospect, a total of 9 wells have been drilled to date, and in each well we have had reliable evidence that the petroleum system worked for this area and that the oil was able to migrate and to load an area as vast as 63,000 acres or more. These results reaffirm the petroleum potential of the CPE-6 Block, and the Company's belief that in the next exploration phase the CPE-6 Block will prove to be one of the most significant oil finds in the Llanos Basin of Colombia. It must be noted, however, that the campaign is just starting, and as work progresses in the following year and more information is gathered; the certainty and extension of the apparently large accumulation will become clearer.

The Company is currently preparing all the technical documentation and permits to start an exploration/appraisal campaign to further delineate this oil accumulation with exploratory, appraisal and stratigraphic wells that will be drilled in the second half of 2011, subject to obtaining the appropriate licenses.

Guama Block

As part of the exploration activity in the Guama Block, during the fourth quarter of 2010, the Company finished the drilling of the Pedernalito-1X exploratory well, with a target in the thinly laminated sands of the Middle Miocene Porquero Formation on the flank of an incipient diapiric feature with a 2,355 acre closure. The well reached a final depth of 7,100 feet MD, penetrating the massive Porquero from surface down to TD. The well resulted in a new gas discovery, and the petrophysical evaluation indicated a total of 29 feet of net pay in low-resistivity, thinly laminated sands in eight different zones with average porosity of 11% and average water saturation of 59%.

Buganviles Block

In the Buganviles Block, during the fourth quarter of 2010, the Visure-1X exploratory well was drilled in the Visure prospect, located to the southern part of the block. The well resulted in a new discovery with a total net pay of 114 feet in three intervals: Barzalosa (24.5 feet),Upper Guadalupe (45.5 feet) and Lower Guadalupe (44 feet). A well test has been carrying out in the Lower Guadalupe Formation, and to date, the production rate has been at an average of 46 bbl/d with 14 bwpd. The Visure-1X well has now been suspended and the drilling rig released pending evaluation of the test results. Depending of these results, the Company will consider a possible test in the Upper Guadalupe and Barzalosa Formations. Also, during the fourth quarter of 2010, the Company started the drilling of the Tuqueque-1X exploratory well in the Tuqueque prospect, with the Cretaceous Caballos Formation as a main exploratory objective. The preliminary petrophysical evaluation of well log information has shown two additional prospective intervals in the upper levels: the Monserrate Formation with 31 feet of net pay; and the El Cobre Formation with 9 feet of net pay. The final depth of the well is expected to reach during the first quarter of 2011.

La Creciente Block

In the LCA-south prospect, located south of La Creciente "A" and La Creciente "D" gas fields, exploratory well Apamate-1X was spudded on December 1, 2010. The well is targeting gas in Ciénaga de Oro sands with estimated total depth of 12,170 feet MD. The well reached the final depth during February of 2011. Currently, this well was subjected to production test and during the initial test the well achieved a gas production in excess of 24 MMscfd (4,333 boe/d) with a well head flowing pressure of 3,730 psig, restricted by the flow capacity of the test facilities.

Cerrito

The Company is the registered holder of an 81% interest in an Association Contract (the "Cerrito Contract") pursuant to which it is the operator of record of the Cerrito gas field. However, in October 2008, the Company executed a memorandum of understanding (the "Cerrito MOU") with Alange, under which the Company agreed to assign to Alange its interest in the Cerrito Contract for US$7.5 million. The Cerrito MOU and the transactions contained therein is subject to regulatory approvals; until such approvals are obtained, Alange must bear the costs of the Cerrito operation by the Company and is entitled to any profits obtained from such operation. As of December 2010, Alange and the Company were still awaiting assignment approval from the applicable authorities.

Topoyaco Block

In July 2008, the Company executed a memorandum of understanding (the "Topoyaco MOU") with Alange under which the Company acquired 50% of the rights of Alange under the Letter Agreement dated as of May 28, 2008 (the "Letter Agreement") pursuant to which Alange acquired a 100% participating interest in the Topoyaco block. The Topoyaco MOU, the Letter Agreement and the transacations contained therein are still subject to all necessary approvals from the ANH and the successful assignment of certain rights to Alange. Additional 50 km of 2-D seismic were shot during 2009 and two commitment exploration wells were drilled in 2010. Until the necessary approvals are obtained, Trayectoria continues to be the formal operator of the Topoyaco block, under the supervision of Alange and the Company.

As consideration for the participating interest in the Topoyaco block, the Company agreed to pay Alange US$15.5 million, US$8 million of which was paid in cash upon execution of the Topoyaco MOU and US$7.5 million of which was offset against the obligations of Alange in connection with the Cerrito MOU. For further details see the heading entitled "Cerrito Contract" above.

In Topoyaco, two wells were drilled in 2010 as part of the exploratory commitment, on two separate structures identified as "B" and "C", targeting the Cretaceous Villeta and Caballos formations. The Topoyaco-1 was drilled on structure "B" and was tested in sands "U" and "T" of the Villeta formation, resulting in fresh water. The Topoyaco-2 well was drilled on structure "C" and it was tested in three separate intervals: the "C" limestone and "U" sands of the Villeta formation resulting in fresh water, and the upper Villeta N-sands, which the Company now believes could be a sandy facies known in other areas of the Putumayo foothills as the Neme member of the younger Rumiyaco formation, resulting in heavy oil and water. The well was re-evaluated with a high capacity ESP in order to establish the true production potential of the well, which was tested originally with a lower-capacity ESP and resulted in very erratic oil and water production rates. The well is now suspended, awaiting a resource and economic evaluation in order to take a final decision. The exploration campaign in this block will continue during 2011, and the Company is performing all the necessary steps ensure that the operator drills what it is believed to be the largest and deepest prospect of the block, Prospect D, which has been certified with 46.907 mmbbl of prospective resource (best estimate).

Peru Blocks

Exploration activities started in Block 138, located in the Ucayali Basin, on December 9, 2010. The acquisition of 537 km of a 2D seismic program will allow the Company to define the main structural trends in the block and to confirm the presence of several structural leads, which have been identified from three previously acquired regional seismic lines. The Company expects to finish the seismic acquisition during the second quarter of 2011, and then proceed with processing and interpretation.

Guatemala Blocks

In October 6, 2010, the Company secured a Farm-In Agreement in which the Company holds a 55% working interest and acts as operator in the in the "A-7-98" Contract, which corresponds to the area known as "A-7-96", made up of the "N-10-96" and "O-10-96" blocks in Guatemala. The remaining working interest is held by Compañía Petrolera del Atlántico, which in turn is owned by Flamingo Energy Investment (BVI) Ltd. and CHx Guatemala Limitada.

During 2010, the Company started field activities aimed at identifying such aspects as: (a) logistics, access and design of future geologic and geophysical field work; (b) availability of drilling and seismic acquisition companies in Guatemala;

and (c) environmental permits and other support-related areas. All these activities will help the establishment of the exploratory program that will be submitted for approval in the first quarter of 2011.

The exploratory activities for 2011 in Guatemala will include: seismic reprocessing of 300 km of 2D seismic; acquisition and processing of additional 300 km of 2D seismic; 6,800 km of aero-magnetic and aero-gravimetric data; 6,600 km^2 of remote perception surveys; a surface geology campaign (including samples analysis); and the beginning of an integrated geological interpretation to define exploratory prospect locations to be drilled in 2012.

Exploration Milestones

Throughout 2010, the Company's exploratory campaign included the drilling of 29 exploratory wells, the acquisition of 1,609 km of 2D seismic and 401 km^2 of 3D seismic and the acquisition of 13,133 km of high resolution aeromagnetogravimetric surveys. During the fourth quarter of 2010, 7 exploratory wells were drilled (3 of them were spudded in during the third quarter 2010) and 502 km of 2D seismic were acquired.

- The Company achieved an 83% exploration success, with 24 successful wells out of 29 drilled in 2010. This performance allowed the incorporation of 45 mmbbl of 2P gross reserves or 25 mmbbl of net reserves after royalties. The reserve replacement ratio increased solely from the exploration effort, incorporating 1.2 barrels of oil for every produced barrel during 2010.

- In the Quifa Block, the Ambar-1 exploratory well was drilled in prospect "F" which confirmed the extension of the prospect to the southwest with 16 feet of net pay, located in the northern part of Quifa. In addition, a total of 294 km of 2D seismic were acquired in the north and eastern parts of the block.

- At the CPE-6 Block, the Guairuro-3 and Guiaruro-4 stratigraphic wells were drilled in the northern part of the block. The Guairuro-3 confirmed the presence of hydrocarbons with 6.5 feet of net pay in the C-7 interval.

- In October 6, 2010, the Company secured a Farm-In Agreement, by which PRE holds a 55% working interest and acts as operator, in the in the "A-7-98" Contract. This contract corresponds to the area known as "A-7-96", made of the "N-10-96" and "O-10-96" blocks in Guatemala.

- On November 4, 2010, the Company announced the results of the Visure-1X exploratory well, drilled in the Visure prospect and located south of the Buganviles Block. The well resulted in a new discovery with a total net pay of 114 feet, in three intervals: Barzalosa (24.5 feet), Upper Guadalupe (45.5 feet) and Lower Guadalupe (44 feet).

- The exploration program planned for the first quarter of 2011 includes the drilling of the Guairuro-5 and Guairuro-6 wells in the CPE-6 Block; the drilling of the Jaspe-2, Jaspe-3 and Zircon-1 wells in the Quifa Block; and to finishing the drilling of the Ambar-3 in the Quifa Block, the Tuqueque-1X in the Buganviles Block, and the Apamate-1X well in La Creciente Block. Additionally, for the first quarter of 2011, the Company will finish the acquisition of 130 km^2 of 3D seismic in the Arrendajo Block.

Further detailed information with respect to the Company's exploration results in Colombia, Peru and Guatemala was announced on February 3, 2011.

Exploration Capital Expenditures

Net capital expenditures during the year ended December 31, 2010 totaled $112.5 million. For the fourth quarter of 2010, the Company made a net investment of $44.4 million in exploration activities, as follows:

		Q4 2010		YTD 2010	
		In thousands of US$		*In thousands of US$*	
Block	**Working Interest**	**Gross**	**Net**	**Gross**	**Net**
Colombia - Llanos Basin					
CPE6	50%	5,326	2,829	26,192	13,213
CPO1 (1)	50%	(191)	129	6,149	129
CPO12	40%	448	358	10,215	4,173
CPO14	63%	263	154	1,302	806
Quifa	70%	13,858	9,700	45,576	32,376
CPE1	100%	624	624	1,135	1,135
Arauca	100%	518	518	1,830	1,830
				0	0
Colombia - Lower Magdalena				0	0
Guama	100%	9,625	9,625	17,639	17,639
La Creciente	100%	5,236	5,236	13,497	13,497
CR1	60%	485	291	625	518
SSJN-3	100%	1,902	1,902	2,130	2,130
				0	0
Colombia - Putumayo Basin				0	0
Topoyaco	50%	11,638	5,819	32,238	16,119
Tacacho	51%	267	160	1,606	1,123
Terecay	100%	150	150	1,201	1,201
Colombia - Others				0	0
Other exploration projects		19,306	6,900	19,657	6,613
Total		**69,454**	**44,394**	**180,993**	**112,502**

(1) Gross Investment for the CPO1 Block during the year ended December 31, 2010 totaled $6.1 million, and the Company´s net investment of $2.4 million made during the third quarter of 2010 was fully reimbursed by Petroamerica Oil Corp. based on a farm-out agreement signed with this partner.

The Company's exploration program for 2011 is budgeted at $340 million and includes exploration across 26 blocks, in which 20 exploratory wells will be drilled, 36 appraisal wells and 3 stratigraphic wells. In addition, 539 km of 2D seismic and 440 km^2 of 3D seismic is planned during the year.

Production

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

Total operated production during 2010 averaged 144,307 boe/d (56,974 boe/d net after royalties) for an increase of 61,683 boe/d (22,848 boe/d net after royalties) over the same period in 2009. This represents a 75% growth in operated production, which came about mainly through increased production at the Rubiales, Quifa and La Creciente fields.

As of December 31, 2010, the total operated production reached 192,977 boe/d (85,716 boe/d net after royalties), while the gross production capacity stood at 220,000 boe/d, with a net production of over 85,000 boe/d. This represents a 75% increase in relation to the net exit production of 2009 of 48,000 boe/d. Exit production was approximately 8% below the Company's projections as a result of transportation issues at the Rubiales field which has been resolved. The following sets out the average 2010 production at all of the Company's producing fields:

	Average YTD 2010 Production					
	Gross production before royalties		Share before royalties		Share after royalties	
Producing Fields	**2010 boe/d**	**2009 boe/d**	**2010 boe/d**	**2009 boe/d**	**2010 boe/d**	**2009 boe/d**
Rubiales / Piriri (1)	123,581	68,826	53,065	30,514	42,452	24,411
Quifa	4,819	308	2,812	322	2,630	302
La Creciente	10,055	7,382	9,923	7,382	9,920	7,382
Puli (2)	82	77	40	38	32	31
Dindal / Rio Seco (3)	704	821	586	744	470	595
Moriche	167	97	76	100	70	92
Quinchas	47	38	36	27	34	25
Abanico (4)	2,821	2,989	896	819	843	778
Buganviles (5)	16	23	8	14	7	13
Rio Ceibas (2)	1,871	1,965	506	536	405	429
Chipalo	0	3	0	6	0	5
Cerrito(6)	144	95	111	77	111	63
Total	**144,307**	**82,624**	**68,059**	**40,579**	**56,974**	**34,126**

	Average Q4 2010 Production					
	Gross production before royalties		Share before royalties		Share after royalties	
Producing Fields	**Q4 2010 boe/d**	**Q4 2009 boe/d**	**Q4 2010 boe/d**	**Q4 2009 boe/d**	**Q4 2010 boe/d**	**Q4 2009 boe/d**
Rubiales / Piriri (1)	134,160	97,047	56,442	41,153	45,153	32,923
Quifa	12,215	944	7,012	567	6,538	533
La Creciente	10,623	9,391	10,451	9,391	10,449	9,342
Puli (2)	63	101	32	50	25	40
Dindal / Rio Seco (3)	753	770	526	697	425	558
Moriche	309	7	131	6	122	5
Quinchas	88	36	74	26	70	24
Abanico (4)	2,560	2,814	699	823	666	782
Buganviles (5)	40	11	19	6	18	5
Rio Ceibas (2)	1,819	1,949	487	532	389	425
Cerrito(6)	235	86	185	61	185	49
Total	**162,865**	**113,156**	**76,058**	**53,312**	**64,040**	**44,686**

(1) Net of internal consumption at the field.
(2) Corresponds to the Company´s share in non-operated fields.
(3) Gas sales started in November 2010 for a nearby Compressed Vehicular Gas plant which is reflected in the above figures. Remaining gas is currently being injected and used for power generation. The Company is evaluating additional economic uses for this hydrocarbon.
(4) Ecopetrol accepted the commerciality of the northern extension of the Abanico field. This is part of the reasons for the increase in net production in this field. The Company started sales of CO2-free gas, produced by the northernmost wells in the field; and

purchased a CO2 treatment plant that plans to install during Q1, 2011. It is expected that gas sales will increase to 1MMcfd when the installation is complete.

(5) The Samarkanda Field, in the Chipalo Association Contract, has been temporarily shut-in while the Company evaluates technical alternatives for its reactivation.

(6) In October 2008, the Company executed a memorandum of understanding (the "Cerrito MOU") with Alange under which the Company agreed to assign to Alange its interest in the Cerrito Contract for US$ 7.5 million. The Cerrito MOU is subject to all necessary approvals from Ecopetrol. Until such approvals are obtained Alange Corp must bear the costs of the Cerrito operation by the Company and its entitled to its profits.

The increase in operated production during 2010 was mainly attributable to the drilling of 146 producing wells at the Rubiales field and 30 producing wells at the Quifa field. The completion of the CPF-Quifa allowed the Quifa field's production to reach its target of 30,000 bbl/d by the end of 2010; also, the completion of CPF2 at the Rubiales field raised production capacity to 170,000 bbl/d, which will be fully realized as the expansion of the OCENSA pipeline is completed during the first quarter of 2011. La Creciente natural gas field increased its production by 36%, while improving the safety of its operations. After replacement of subsurface safety valves, and construction of additional control and treatment systems, the La Creciente 1 and 2 wells, now account for over 60% of the field's production. The field's production is now only limited by constraints in the natural gas transport network downstream of the field.

Total operated production for the fourth quarter of 2010 averaged 162,865 boe/d (64,040 boe/d net after royalties) for an increase of 49,709 boe/d (19,354 boe/d net after royalties) over the same period of 2009. This represents a 44% growth in operated production during this period in comparison to the fourth quarter of 2009.

New Facilities Construction

During the fourth quarter of 2010, the following new facilities were constructed and brought into operation, which contributed to the increase in production levels:

Rubiales field

- Inauguration of CPF-2, with a capacity of 70,000 bbl/d of oil production, took place on November 17, 2010 with the Colombian Minister of Energy and Mines in attendance, as well as high ranking officers of Ecopetrol and Pacific Rubiales Energy. This increase in production capacity represented 12% of the country's total oil production at the time, a very significant milestone in the development of Rubiales and Quifa fields.
- 49.5 km of new roads.
- 85 km of flow lines.
- 29 new electrical power sub-stations.
- 23 km of new field electric network.
- New water treatment facilities at CPF-1 reaching a total 1.2 mmbbl/d of water from 400,000 bbl/d in 2009.
- 530,000 bbl/d additional water injection capacity.

Quifa field:

- Inauguration of the CPF-Quifa (in parallel with CPF-2), with an oil treatment capacity of 30,000 bbl/d and a water treatment capacity of 100,000 bbl/d.
- 40.1 km of new roads.
- 29.5 km of flow lines between 10" and 24".

La Creciente field:

- Facilities for handling and treating gas in La Creciente, which will secure stable delivery of higher daily volumes of natural gas to the transporter, within the required quality and at a particular dew point. This allowed for a new production record in the field, of 70.2 MMcf/d on December 22, 2010, and a stable production of approximately 60 MMcf/d.
- Additionally, the Company has acquired materials and part of the rights-of-way necessary to build a new gas pipeline for its planned gas export project. The Company expects that this project will solve the downstream constraints that currently limit La Creciente's production.

Historical Production Milestone

Production continued its growth trend, and during 2011 the Company's gross operated production exceeded the historical milestone of 205,000 boe/d, equivalent to over 85,000 boe/d, net after royalties. The 205,000 boe/d milestone is the result of the continuous growth in production of heavy oil in the Rubiales/Piriri and Quifa blocks, supported by the the operation of the ODL pipeline and Company's downstream transportation strategy. This volume also incorporates the development of the Company's light and medium oil blocks, as well as the natural gas volume produced (at a conversion rate of 6,000 standard cubic feet per barrel) from the La Creciente block and other smaller fields.

Royalties

Royalty rates for hydrocarbons produced from the Company's assets range from 5% to 30.01%. Royalties on production represent the entitlement of the respective governments to a portion of the Company´s share of production and are recorded using rates in effect under the contractual terms and applicable laws at the time of production. Royalty for oil is usually paid in kind, while royalty for gas is generally paid in cash.

Supply and Sales Balance

The following is the Company´s reconciliation of boe produced with the boe sold during the fourth quarter of 2010 and as of the year ended on December 31, 2010:

Inventory Movements	**Total boe Net**	**Aver. day Net**
Ending inventory as of September 30,2010	846,690	
Transactions of Q4, 2010		
Net oil and gas production	5,891,680	64,040
Settlement of overlift position from September 2010 (1)	(4,056)	(44)
Purchases of diluents	1,170,403	12,722
Purchases of crude oil for trading (2)	261,426	2,842
Total sales	(7,224,499)	(78,527)
Overlift position as of December 31,2010 (3)	291,825	3,172
Production recovery from Ecopetrol (4)	(9,536)	(104)
Volumetric compensation and operating gain/losses	(19,874)	(216)
Ending inventory as of December 2010 (5)	**1,204,058**	

FY2010

Inventory Movements	**Total boe Net**	**Aver. day Net**
Ending inventory as of December 31, 2009	1,265,858	
Odl Pipeline	(160,879)	(441)
Transactions of Q4, 2010		
Net oil and gas production	20,795,626	56,974
Settlement of overlift position from 2009 (1)	(94,941)	(260)
Purchases of diluents	3,938,822	10,791
Purchases of crude oil for trading (2)	712,226	1,951
Total sales	(25,547,214)	(69,992)
Overlift position as of December 31,2010 (3)	291,825	800
Production recovery from Ecopetrol (4)	58,022	159
Volumetric compensation and operating gain/losses	(55,286)	(151)
Ending inventory as of December 2010 (5)	**1,204,058**	

(1) *This volume corresponds to the settlement of the overlift position for crude oil which resulted in a lower volume of sales during the period it was settled.*

(2) *Corresponds to crude oil purchases from local oil producers for trading purposes in the international market. See additional comments in the "Commercial Activity" section on page 17.*

(3) *This volume corresponds to an overlift position of 291,825 boe of crude oil and gas as of December 31, 2010, which will be settled during future periods.*
(4) *This volume corresponds to the contractual agreement with Ecopetrol to reimburse with production its 25% share at the Abanico Norte field. This agreement commenced on June 16, 2010 and the proceeds of this sale were booked to offset the account receivable to Ecopetrol on the $8 million investment at the field. As of December 31, 2010 the $8 million account receivable has been fully paid by Ecopetrol.*
(5) *Of the 1.2 million barrels of ending inventory as of December 2010, 192,000 bbls corresponded to permanent inventory in the pipeline systems and storage facilities at the field.*

Reconciliation of Volumes Sold vs. Volumes Produced

Fourth Quarter 2010

Production and Sales Reconciliation for fourth quarter of 2010

	Volumes Produced	Volumes Sold	Difference (higher volume sold)	
	Oil and Gas (boe)	**Oil and Gas (boe)**	**Oil and Gas (boe)**	
Total 2010 (4Q)	5,891,680	7,224,499	1,332,820	
Average per day	64,040	78,527	14,487	(a)

(a) The main reason for the higher volume sold in the fourth quarter of 2010 in comparison to the volumes produced is due to:

Production after royalties Q4 2010	(64,040)
Production sold Q4 2010	78,527
Difference	**14,487**
Explanation of the difference	
Begining inventory	9,202
Purchase of diluent	12,722
Purchase of crude oil for trading	2,842
Overlift settlement from Q3 2010	(44)
Production recovery from Ecopetrol	(104)
Volumetric compensation	(216)
Overlift position at the end Q4 2010	3,172
Ending Inventory	(13,087)
Reconciliation of the difference	**14,487**

FY 2010

Production and Sales Reconciliation for year of 2010

	Volumes Produced	Volumes Sold	Difference (higher volume sold)	
	Oil and Gas (boe)	**Oil and Gas (boe)**	**Oil and Gas (boe)**	
Total 2010	20,795,626	25,547,214	4,751,588	
Average per day	56,974	69,992	13,018	(a)

(a) The main reason for the higher volume sold during 2010 in comparison to the volumes produced is due to:

Production after royalties 2010	(56,974)
Volume sold 2010	69,992
Difference	**13,018**
Explanation of the difference	
Begining inventory	3,027
Purchase of diluent	10,791
Purchase of crude oil for trading	1,951
Overlift settlement from 2009	(260)
Production recovery from Ecopetrol	159
Volumetric compensation	(151)
Overlift position at the end 2010	800
Ending Inventory	(3,299)
Reconciliation of the difference	**13,018**

Commercial Activity

Crude Oil and Gas Prices

In 2010, WTI NYMEX reached an average of $79.61/bbl compared to the $62.09/bbl average in 2009, corresponding to a 28% increase. The following describes the average realized crude oil and gas prices during 2010 and the fourth quarter of 2010:

- The average realized oil price for Vasconia crude oil during 2010 was $77.54/bbl, higher by 38% than the $56.21/bbl realized in 2009. During the fourth quarter of 2010, the realized Vasconia price averaged $84.20/bbl, higher by 16% than the $72.41/bbl realized in the fourth quarter of 2009.

- The average realized oil price for Castilla crude oil during 2010 was $70.72/bbl, higher by 2% than the $69.21/bbl realized in the two cargoes sold during the fourth quarter of 2009. During the fourth quarter of 2010 the realized Castilla price averaged $77.68/bbl, higher by 12% than the $69.21/bbl realized in the fourth quarter of 2009

- During the fourth quarter of 2010, we sold two small cargoes trucked from the Rubiales field to the Barranquilla terminal, at an average price of $74.74/bbl, taking advantage of the strength of the WTI price. One of the small cargoes was sold to Nynas, as a trial cargo to explore Rubiales´s crude naphthenic lubs and asphalts capabilities.

- The combined realized oil and gas price for the Company for the 2010 year was $65.04 per boe, higher by 31.% than the $49.51 per boe realized in 2009.

Average benchmark crude oil and natural gas prices for the year ended December 31 of 2010 and 2009 were as follows:

		Year ended December 31,		Q 4 2010
Average Crude Oil Reference Prices	°API	2010 ($/bbl)	2009 ($/bbl)	2010 ($/bbl)
Domestic Market /Bunkers	12.5	67.09	53.90	72.76
WTI NYMEX (Weighted Average of PRE Cargoes)	38	79.87	62.69	85.73
Vasconia (1)	24	77.54	56.21	84.20
Castilla (2)	19	70.72	69.21	77.68
Rubiales Export (3)	12.5	74.74	N/A	74.74
Combined Realized International Oil Sales Price	18.5	71.67	57.74	78.93
PRE Natural Gas Sales ($/mmbtu)	N/A	4.85	4.29	4.84
Combined Realized Oil and Gas Sales Price	N/A	65.04	49.51	71.41
WTI NYMEX ($/Bbl)		$79.61	$62.09	$85.24
Henry Hub average Natural Gas Price ($/MMBTU)		$4.37	$4.06	$3.81

(1) Weighted average price of five Vasconia crude oil cargoes and five parcels exported during 2010.
(2) Weighted average price of 28 Castilla crude oil cargoes exported during 2010 and seven cargoes during the fourth quarter of 2010.
(3) Weighted average price of 2 Rubiales (12.5°API) small cargoes exported during the fourth quarter of 2010.

Crude Oil Sales to International and Local Markets

During 2010, the Company exported 35 cargoes and 5 small parcels of crude (86% Castilla crude/14% Vasconia crude), representing a total volume of 20.8 million bbl of crude oil at an average combined sale price of $71.67/bbl to the United States, Europe, Asia and Africa. The total volume exported during 2010 represents more than a two-fold increase in comparison to 2009, generating gross revenues of $1.7 billion as of December 31, 2010. In addition, sales of natural gas produced at La Creciente field to the domestic market averaged 60 MMscf/d at an average price of $4.85 MMbtu. During the fourth quarter of 2010, the Company exported 11 cargoes, representing a total volume of 6.1 million bbl of crude oil, consisting of six cargoes to the United States, three to Europe, one to Africa, and one to Panama; vie other small parcels were sold through Petrobras and BP to the United States.

The Company also maintained its flexible commercial strategy by selling 1.4 million bbl (3,710 bbl/d) of Rubiales 12.5° API in the Colombian domestic market during 2010, at an average price of $67.09/bbl.

During 2010, the Company increased local purchases of light crude oils (12,731 bbl/d average) in the eastern Llanos for purposes of securing diluents for Rubiales crude oil and to increase exports of crude oil blends as Vasconia through the Company-owned Guaduas facilities. Purchases of light crude oils serve as a substitute diluent for imported naphtha or natural gasoline. In December 2010, three cargoes of natural gasoline (232 thousand bbl) were purchased to ensure an adequate stock of diluents for the increasing production during the year-end holiday season.

Since July 2010, the Company began purchasing crude oil from local oil producers for purposes of trading on the international market. Total volume of crude oil exported as of December 31, 2010 totaled 0.9 million bbl sold at an average price of $84.77/bbl. Total gross revenues generated on this trading activity during this period totaled $58.5 million and the associated profit before taxes totaled $1.5 million. The Company has a strategy in place to continue developing this business venture going forward.

During the fourth quarter of 2010, the Company continued maximizing the utilization of the Guaduas facilities through contracts to handle and transport 9,423 bbl of light/medium crudes from other producers representing an additional income of $2 million. During the year ended December 31, 2010, the Company transported 67,420 bbl/d through the different trucking and pipeline systems, including 8,415 bbl/d of diluents; 82% of this volume was transported via pipeline, generating savings of $15.71/bbl in transportation costs for the Company.

Natural Gas Sales to Local Markets

In 2010, the volume of natural gas sales, increased to an average of 60 MMscf/d of natural gas, from a volume of 44.1 MMscf/d for 2009 (a 36% increase). These sales were mainly from La Creciente field, at an average price of $4.82/MMbtu (equivalent to $4.81/MMscf), representing a premium of 26.3% over the weighted domestic regulated price of $3.84/MMbtu, and 10% over the Henry Hub natural gas prices in the United States during the same period. The 36% increase in gas production during the year ended December 31, 2010, in comparison to the same period in 2009, was mainly due to the continuous investment in production facilities and infrastructure, which allowed the Company to increase production in 2010. The Company replaced the subsurface safety valves in the La Creciente 1 and 2 wells, which now accounts for over 60% of the field’s production.

Natural gas sales during the fourth quarter of 2010 increased by an average of 63.7 MMscf/d of natural gas from 56 MMscf/d in the same period in 2009 (13% increase), at an average price of $4.85/MMbtu, representing a premium of 22% over the weighted domestic regulated price, and 27% over the Henry Hub natural gas prices in the United States.

2010 Market Overview

- During 2010, a gradual tightening in global oil markets supported world oil prices. As a result, WTI Nymex first line prices increased from $62.09/bbl in 2009 to $79.61/bbl in 2010, or $17.5/bbl higher.

- According to EIA, in 2010 there was an increase of 2.1 mmbbl/d in world crude supply. EIA projects the total non-OPEC supply of crude oil grew by 1mmbbl/d to an average 51.5 million bbl/d in 2010, the largest year-over-year increase since 2002. The increase in total non-OPEC supply for the year was the result of higher production in the United States, Brazil, China, and Russia. On the other hand, EIA estimates liquid fuels consumption growth around 2.4 mmbbl/d in 2010, almost doubling the supply growth from non-OPEC countries, as a result of rising demand for OPEC crude oil production and declining global oil inventories. While overall commercial oil inventories in OECD countries remain high, both floating and reported on-shore inventories have been declining supporting firmer oil prices. EIA estimates OPEC crude oil production increased by +0.3MMbbl/d to 29.45MMbbl/d in 2010 to accommodate increasing world oil consumption. Conversely, there has been a reduction in crude production in

Mexico and in Venezuela. Mexico´s heavy crude oil production declined from 3.0mmbbl/d in 2009 to 2.96mmbbl/d in 2010. OPEC figures confirmed that Venezuela's oil output fell by 2.9 percent to 2.25mmbbl/d.

- Nonetheless, one of the most important factors that affected oil prices was the expectation of a growth in demand, which happened in 2010. Global Crude Oil and Liquid Fuels Consumption increased to 86.6mmbbl/d in 2010 from 84.3mmbbl/d in 2009, the second largest annual increase in at least 30 years, following declines in 2008 and 2009. Non-OECD regions, especially China, the Middle East, and Brazil, represent most of the expected growth.

- The factors that affected WTI market conditions in 2010 were linked to fragile United States economic recovery weakened by high unemployment levels, low inflation, low consumer confidence, and currency volatility. The crude oil price was also affected by market sentiment due to weak fundamentals in the United States economy. In the second half of 2010, Dollar vs. Euro parity fluctuation was the result of a currency war, directly affecting crude prices. An important factor that affected the world markets was the monetary policy decisions of the United States, Europe, China, and Japan. Markets were also affected by geopolitical tensions between South and North Korea and by militia attacks in Nigeria to the Trans Nigeria Pipeline. An important factor that caused crude supply constraints in the Mediterranean was an almost month long strike in the oil terminals of Fos-Laverna in France. Nevertheless at the end of 2010, better than expected results in the economic conditions in Europe and the United States created an upward tendency for crude prices, generating a bullish sentiment for investors in the futures market.

- Throughout 2010, the refineries in the United States ran at lower rates due to low refinery margins. The cyclical refinery maintenance programs just before gasoline seasons coupled with unrelated Aruba and Curacao refinery shutdowns during the period meant that more crude was going to inventories. Therefore, Venezuela increased heavy crude oil available in the market due to operational problems with oil belt upgraders and contributed to widening the price differential between light and heavy crude. These conditions generated a higher crude supply in the market and increased inventory levels which created downward pressure on crude oil prices. Refinery margins in the United States were also affected by the economy, causing refineries to extend turnarounds to find alternative uses for refineries, including usage of storage capacity as a terminal. However, refining margins improved in Europe in the last quarter of 2010. Lower temperatures in Europe and the United States and stronger Brent prices vs. WTI created a bullish sentiment in the market, leading to expectations of an increase in demand for heating oil.

- WTI and Dated Brent continue to be the most actively traded spot crude oils in both the physical and paper markets. Declines in the North Sea and increases in Caspian crude production have resulted in changes in Atlantic Basin sweet crude flow patterns. The widening transatlantic spread between the WTI – Brent tendency was observed in the second half of 2010, and may be the result of high inventories at Cushing remaining above 2009 levels, enabling arbitrage opportunities into Asia and Europe.

- Maya crude oil is used as an indicator for heavy, high sulfur crude oil and Mars is used as an indicator for light crude oil on the U.S. Gulf Coast. The Maya price differential to Mars increased from $3.8/bbl in 2009 to $7.9/bbl in 2010, improving coking refining margins for Maya vs. Mars in 2010. In addition, the widening of the WTI-Maya differential from $5.4/bbl in 2009 to $9,5/bbl in 2010, in turn pressured other heavy crude oil prices like those of Castilla. In 2009, the price differential published for Castilla was – $7.29/bbl widening in 2010 to – $8.81/bbl.

5. Project Status

<u>STAR Project</u>

In the fourth quarter of 2010, the Company successfully completed nine combustion, oxidation and acceleration rate tests (ICT/RTO/ARC), which confirmed the potential benefits to the Rubiales field under the STAR process. These tests, together with previously acquired data, confirmed the feasibility and potential of the technology and cleared the way for the next stages of the project. Based on the excellent results and after agreement with our partner Ecopetrol, on April 7, 2010, the Company announced the successful completion of the first phase of the STAR project, and the kick-off of the main activities regarding the second phase of the project.

A complete numerical simulation study was finished using state-of-the art in-reservoir modeling and a thermal simulator, not only to ensure the design of the STAR wells but to enrich the Company's own combustion font control model.

The front-end loading and design of the required infrastructure including compressor and automation systems, steam plant, dehydration and production facilities of the project, among others, were contracted.

During 2010, the construction of the equipment for the production facilities was completed, and shipping and handling to the Rubiales field was finished. The construction of the compressors system and the automated steam injection plant was also finished and transportation to Rubiales field is underway from the United States at this time.

The monitoring strategy and the design of some specialized tests, such as the nitrogen communication test and 4D seismic runs were completed and they are being planned for the first quarter of the 2011. The wells involved in the pilot project, being four producers and one injector under the frame of the inverted five pattern spot, have already been designed. These wells will be drilled as soon as the negotiations with Ecopetrol are completed, which is expected to happen in the second quarter of 2011.

During January 2011, the definitions and criterion to evaluate the success of the pilot test were terminated. Negotiations with Ecopetrol to set out the business management guidelines and criterion which will be the foundation for an eventual commercial STAR project are still underway.

The Company continues its commitment to the implementation of this technology, not only because it creates significant value to the Company, its partners, shareholders and the country, by extending the production life of the Rubiales field, but also because it is believed that once in operation, STAR will have a dramatic impact on the entire Llanos region.

Llanomulsion Project

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

During 2010, tests for a new surfactant developed by Ecopetrol´s research and development affiliate Instituto Colombiano del Petróleo were performed at the Rubiales field pilot plant. The complete industrial test of sending 40,000 bbl of Llanomulsion from the Rubiales field to the Cusiana Station, through the ODL, involves the construction of additional facilities at CPF1, at the Rubiales Pumping Station ODL, and at the Cusiana Station Ocensa. The 40,000 bbl of Llanomulsión will be produced at CPF1, sent to a 50,000 bbl storage tank at the Rubiales Pumping Station, and then pumped in a separate batch to Cusiana, where the emulsion will be processed into produced oil for commercialization. The industrial test is intended to be performed during the first quarter of 2011, once the new extension to Cusiana and the expansion of the OCENSA pipeline to 560,000 bbl/day are operational. In the meantime, design parameters for breaking the emulsion will be developed and tested in the pilot plant.

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.

Oleoducto de Los Llanos Pipeline

The Company has a 35% interest in the ODL pipeline with the balance of 65% owned by Ecopetrol. The ODL pipeline was completed on schedule at a total cost of $558 million. Since October 1, 2009, a total of 56,119,758 bbl of diluted crude have been transported from the Rubiales field to the Monterrey Station.

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 includes construction of two booster stations, increased storage capacity at the Rubiales Pumping Station and construction of a pipeline branch to Cusiana Station. As of the end of December 2010, the expansion project was 65% completed. During the fourth quarter of 2010, the volume from the Company transported through the ODL pipeline totaled 5.04 million bbl.

During 2010, the company decided to pursue a feasibility study for a heated oil line in the ODL pipeline for the purpose of reducing dilution costs. This project, if completed, should increase operating capacity and reduce dependence on truck transportation of diluents.

Petroeléctrica de los Llanos (“PEL”) – Power Transmission Line Project

The Company has incorporated PEL, which is a new legal vehicle and a wholly-owned subsidiary. PEL will be responsible for constructing and operating a new power transmission line of 230 kilovolts to connect the Rubiales field with the country´s electrical grid. The new transmission line will originate at the Chivor Substation and will extend 260 km to the Rubiales field. 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 230 kilovolts that will be used in oil production and transportation activities. Total capital expenditures for this project has been estimated at $135 million of which up to 70% is expected to be project financed.

During the third quarter of 2010, the construction of this power line was approved by UPME ("Unidad de Planificación Minero Energética") which is the governmental entity in charge of planning and approving construction of new power transmission lines in the country. During the same quarter, the Engineering, Procurement & Construction contract ("EPC") was awarded. During the fourth quarter of 2010, acquisition of rights of way started and the environmental impact study was submitted to the Environmental Ministry in Colombia. Construction will start as soon as the environmental license is approved.

<u>Oleoducto Bicentenario – Bicentennial Pipeline</u>

The Company obtained a 32.88% equity interest in OBC in November 2010. OBC is a special purpose vehicle promoted by Ecopetrol, which has a 55.97% interest together with its affiliates, 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 eventual 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 Los 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 OBC project is planned to be executed in four phases:

Phase 0:	Truck off-loading facility in Banadia with a capacity of 40,000 bbl/d - started operations in December 2010
Phase 1:	Pipeline Araguaney - Banadia, 120,000 bbl/d expected for the fourth quarter of 2011
Phase 2-3:	Pipeline Banadia - Coveñas, incremental 330,000 bbl/d for a total of 450,000 bbl/d expected for the fourth quarter 2012

For the Company, the participation in this project is a perfect strategic fit, time and volume-wise, as it moves towards reaching the goal of having a gross production of 500,000 bbl/d in the mid-term.

Under the terms of the participation agreement, the Company has the option to maintain its interest in OBC or have its interest diluted by the time the investment decision is made for Phases 2 and 3. The Company's decision to participate in Phases 2 and 3 will hinge on the coming on-line of production from the STAR project in Rubiales and the development of the CPE-6 Block.

It is estimated that Phases 0 and 1 will require an aggregate investment of US$1.03 billion, excluding financing costs, of which $340 million represents the Company´s share. The partners intend to finance the OBC pipeline project through project financing, with a debt/equity ratio of 70/30. This financing will be structured to maximize the use of export credit agencies and multilateral financing, as well as to access the Colombian capital markets.

The Company will have representation on the board of OBC and will play an active role in the financing and construction of the project. It is expected that equity contributions by the Company in the initial phases of the OBC will be funded through internally generated cash flow.

6. Reserves

Proved and Probable Oil and Gas Reserves

Reserves Update as of February 28, 2011

Using the 2010 Reserves Reports and the 2011 Reserves Updates, the consolidation of the Company's net share of proved developed, proved undeveloped and probable reserves is as follows:

	2P Reserves 2009 Vs February 2011									Oil Equivalent		
	Condensate, Light & Medium			Heavy Oil			Associated & Non-Associated					
	100% (MMbbl)	Gross (MMbbl)	Net (MMbbl)	100% (MMbbl)	Gross (MMbbl)	Net (MMbbl)	100% (Bcf)	Gross (Bcf)	Net (Bcf)	100% (MMboe)	Gross (MMboe)	Net (MMboe)
2009 Reserves	13.66	7.59	6.47	545.92	247.23	204.40	472.43	449.82	418.22	638.32	329.79	280.58
Discoveries Reserves	0.00	0.00	0.00	44.41	19.94	18.49	58.14	58.14	54.45	54.61	30.13	28.04
Net Additions	(5.67)	(4.53)	(3.59)	21.50	(0.29)	1.86	13.98	35.65	33.54	22.42	5.38	7.82
2010 Reserves Plus 2011 incorporations	**7.98**	**3.07**	**2.88**	**611.83**	**266.87**	**224.75**	**544.54**	**543.61**	**506.21**	**715.34**	**365.31**	**316.44**
Production for period	1.72	0.57	0.51	47.10	20.88	16.85	25.26	23.91	22.06	53.25	25.64	21.23
Total Reserves Additions	(3.95)	(3.96)	(3.08)	113.01	40.52	37.20	97.37	117.70	110.04	130.28	61.15	57.09

Notes:

(1) Oil equivalent is calculated using a conversion factor of 5.7 Mbbl/boe. Using a conversion factor of 6.0 Mbbl/boe, the 2009 Oil Equivalent is 329.79 MMboe Gross and 280.58 MMboe Net Reserves and the 2010 Oil Equivalent is 360.53 MMboe Gross and 312.01 MMboe Net Reserves, and production in 2010 was 25.43 MMboe Gross and 21.04 MMboe Net. Starting January 1, 2011, the Company incorporated the conversion rate used to express gas reserves volumes to boe in both 6,000 and 5,700 of per boe to meet the Canadian and local regulatory requirements of the Ministry of Mines in Colombia.

(2) Production represents the twelve-month period ended December 31, 2010.

As at February 28, 2011, the total 2P net reserves of the Company increased by 35.86 MMboe compared to the year-end 2009 reserves and reached 316.44 MMboe. This is a 12.8% increase in 2P net reserves compared with the 2P reserves reported for year-end 2009. For the evaluated period, the Company produced 21.23 MMboe and incorporated 57.09 MMboe.

The estimates of reserves and future net revenues in this press release are based on forecast prices and costs (as set forth in each report noted above) and are estimates only.

Reserves are classified according to the degree of certainty associated with the estimates. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of the proved plus probable plus possible reserves.

2010 Reserves Reports

In 2010, the Company increased its production by 5,984,291 barrels and had a net production of 21.23 MMboe of oil and gas. The reserve replacement ratio, from exploration efforts only, incorporated approximately 1.4 barrels of oil for every barrel produced during 2010 not including the 2011 Reserves Updates with respect to Quifa SW (January 2011) and Apamate (February 2011).

The following table summarizes year-over-year proved plus probable (2P) reserve growth for the Rubiales-Piriri, Quifa, La Creciente, Guaduas, Rio Ceibas, Abanico, Moriche, Puli, Guama and Buganviles blocks:

	2P Reserves 2009 vs. 2010											
	Condensate, L&M Oil			Heavy Oil			Associated & Non-			Oil Equivalent @ 5.7 Mbbl/boe		
	100% (MMbbl)	Gross (MMbbl)	Net (MMbbl)	100% (MMbbl)	Gross (MMbbl)	Net (MMbbl)	100% (Bcf)	Gross (Bcf)	Net (Bcf)	100% (MMboe)	Gross (MMboe)	Net (MMboe)
2009 Reserves	13.66	7.59	6.47	545.92	247.23	204.40	472.43	449.82	418.22	638.32	329.79	280.58
2010 Reserves	7.98	3.07	2.88	516.76	233.40	186.08	490.89	489.97	456.07	610.87	322.42	268.98
Net Reserve Additions	(5.67)	(4.52)	(3.59)	(29.16)	(13.83)	(18.32)	18.46	40.15	37.85	(27.45)	(7.37)	(11.60)
Production	1.72	0.57	0.51	47.10	20.88	16.85	25.26	23.91	22.06	53.25	25.64	21.23
Total Reserve Additions	(3.95)	(3.95)	(3.08)	17.94	7.04	(1.47)	43.72	64.06	59.90	25.80	18.27	9.63

Notes:

(1) 100% reserves are all reserves attributable to the field. The Company does not hold an entire interest in 100% reserves. See table and notes (2) and (3) below.

(2) Gross reserves are the Company's share of the reserve before deduction of royalty payments.

(3) Net reserves are the Company's share of the reserve after deduction of royalty payments.

(4) MMbbl means million barrels.

(5) Bcf means billion cubic feet.

(6) Starting January 1, 2011, the Company incorporated the conversion rate used to express gas reserves volumes to boe in both 6,000 and 5,700 cf per boe to meet the Canadian and local regulatory requirements of the Ministry of Mines in Colombia. Accordingly, the 5,700 cf per boe factor was used to express the 2010 gas production shown in this table. For accounting purposes, the 6,000 cf per boe conversion rate continued to be used to keep consistency with the production reports in the previous quarters of 2010. Starting in 2011, the 5,700 cf per boe factor will be consistently applied for accounting and reporting purposes in both Colombia and Canada.

(7) Using a conversion factor of 6,000 cf per boe, the 2009 Oil Equivalent was 329.79 MMboe Gross and 280.58 MMboe Net Reserves and the 2010 Oil Equivalent was 318.13 MMboe Gross and 264.98 MMboe Net Reserves with a 2010 production of 25.43 MMboe Gross and 21.04 MMboe Net.

The report for the Rubiales-Piriri blocks dated February 2011, effective December 31, 2010, and entitled "Reserves Certification Report for the Rubiales Field, Colombia" and the report for Quifa SW dated February 2011, effective December 31, 2010, and entitled "Reserves Certification Report for the Quifa Field, South West Region, and Colombia" were each prepared by RPS. Petrotech prepared one reserves report entitled "Evaluation of the Proved & Probable Reserves of Pacific Rubiales Energy Corp. in La Creciente, Guaduas, Rio Ceibas, Abanico, Quifa Norte, Moriche, Puli, Guama and Buganviles Blocks in Colombia" with an effective date of December 31, 2010. The 2010 Reserves Reports were prepared in accordance with NI 51-101. A brief summary of each report and certain operational information is provided below. Each of the 2010 Reserves Reports will be published on the Company's website on March 11, 2011.

7. Discussion of Quarterly and Annual Financial Results

Financial Position

Assets

Total assets were $3.8 billion as of December 31, 2010 compared to $2.8 billion as of December 31, 2009. The $3.8 billion in assets consisted primarily of $2.4 billion in oil and gas properties and equipment (December 31, 2009 - $2.0 billion), $608.3 million in cash and cash equivalents (December 31, 2009 - $438.1 million), $300.8 million in accounts receivable (December 31, 2009 - $159.0 million), $215.5 million in investments and other assets, primarily ODL (December 31, 2009 - $74.8 million), and $346.4 million in other assets (December 31, 2009 - $162.1 million). Total assets increased primarily due to an increase in cash and accounts receivable, as a result of increased cash flows from operations.

EBITDA

EBITDA during the twelve months of 2010 totaled $923 million, which represents a significant increase of 210% compared to 2009 EBITDA of $297.8 million. For the fourth quarter of 2010, EBITDA amounted to $271 million, mainly generated from international sales (88%); EBITDA from gas and domestic sales contributed 6.5% and 5.5%, respectively.

Debt

The Company has senior unsecured notes (the "Senior Unsecured Notes") outstanding, with an aggregate principal amount of $450 million and maturity dates of November 10, 2014 (33.3%), November 10, 2015 (33.3%), and November 10, 2016 (33.4%). The Senior Unsecured Notes carry an interest rate of 8.75%, payable on May 10th and November 10th of each year; payment began on May 10, 2010. The Senior Unsecured Notes may be redeemed in whole (but not in part) at any time at the discretion of the Company with a redemption price equal to the greater of: (1) 100% of the principal amount of the Senior Unsecured Notes to be redeemed; and (2) the sum of the present values of the remaining scheduled payments of principal and interest discounted to the date of redemption on a semi-annual basis at the applicable treasury rate plus 75 basis points, in each case plus accrued and unpaid interest on the outstanding principal amount. The Senior Unsecured Notes are senior unsecured and will rank equal in right of payment with all of the Company's existing and future senior indebtedness. The Senior Unsecured Notes are listed on the Official List of the Luxembourg Stock Exchange and are traded on the Euro MTF.

On November 3, 2010, Standard & Poor's Ratings Services raised its corporate credit rating on Pacific Rubiales Energy Corp. to 'BB-' from 'B+'. The outlook is stable. They also raised the rating of Senior Unsecured Notes to 'BB-'. This upgrade is based on the Company's improved financial performance because of a strong growth in its production, adequate liquidity and its ability to generate sufficient operating cash flow to finance most of its required investments.

On July 15, 2010, the Company announced the expiration of its consent solicitation and the receipt of the consents required to amend the indenture relating to the Senior Unsecured Notes pursuant to the Company's Consent Solicitation Statement dated June 30, 2010. The Company solicited consents in order to provide it with needed flexibility to invest in minority equity investments in joint venture entities that are engaged in any business that is related, ancillary or complementary to the business of the Company, and to provide guarantees of the indebtedness of such entities. The Company paid to each holder of Senior Unsecured Notes who validly delivered (and did not revoke) a consent prior to the expiration date, $2.50 for each $1,000 in principal amount of Senior Unsecured Notes with respect to which a consent was delivered, for an aggregate of $0.6 million.

During April 2010, the Company closed the syndication of a $250 million unsecured revolving credit facility (the "Revolving Credit Facility"), further details of which can be found under "Liquidity and Capital Resources" on page 30. As of December 31, 2010; no borrowing has been made on the Revolving Credit Facility. The interest rate for the Revolving Credit Facility is determined in accordance with the ratings assigned to the Company's senior debt securities by Standard & Poor's Ratings Group and Fitch Ratings Inc. Based on the Company's rating as of December 31, 2010 the interest rate would be LIBOR plus 3.25%. In addition, the Company is required to pay commitment fees of 1% on the unutilized portion of any outstanding commitments under the Revolving Credit Facility. Subject to customary acceleration events set out in the credit agreement, or unless terminated earlier by the Company without penalty, repayment of the outstanding principal on the Revolving Credit Facility will be made in full on April 26, 2012. Under the terms of the Revolving Credit Facility, the Company is required to maintain: (1) a debt to EBITDA ratio of less than 3.5;

and (2) an EBITDA to interest expense ratio of greater than 3, further detail of which can be found under "Liquidity and Capital Resources" on page 30. The Company was compliant with these covenants throughout 2010.

As of December 31, 2010, the Company has issued standby and letters of credit for operational commitments for a total of $199.7 million (December 31, 2009 – $110.3 million). Most of these bank guarantees are related to light oil purchases and exploration commitments.

Securities

During the twelve months ended December 31, 2010, $1.1 million of the 8% convertible, unsecured, subordinated debentures (the "Debentures") ($0.9 million in amortized cost) were converted into 84,998 common shares in the capital of the Company. The amortized cost of $0.9 million and the corresponding equity portion of the Debentures of $0.3 million are recorded in common shares as at December 31, 2010.

In the fourth quarter of 2010, the Company paid a cash dividend in the aggregate amount of $25.1 million (or $0.094 per common share). Under the indenture dated August 28, 2008 that governs the debentures (the "Indenture"), the dividend payment on December 16, 2010 triggered an adjustment to the conversion rate applicable to the Debentures. However, in accordance with the provisions of the Indenture, since the adjustment to the conversion rate resulting from the dividend payment was less than 1%, the adjustment was not to be made at the time, but instead will be carried over to the time of any subsequent adjustment. On March 10, 2011, the Company's Board of Directors approved a cash dividend in the aggregate of $25 million, or $0.093 per common share. The dividend is payable on March 30, 2011 to shareholders of record as of March 16, 2011; the ex-dividend date is March 14, 2011.

On December 14, 2009, the Company's proposed offer of a cash payment of C$1.50 per warrant as an incentive for holders of the warrants to exercise their warrants during an early exercise period was approved by shareholders and warrantholders. The period commenced on December 14, 2009 and expired January 20, 2010. Warrantholders were able to exercise their warrants within this period to acquire one common share of the Company per warrant at an exercise price of C$6.30 instead of the original C$7.80 exercise price. As of December 31, 2009, 16,361,293 warrants had been exchanged for common shares under the early exercise program.

On January 12, 2010, the Company announced that greater than 66 2/3% of its publicly-traded warrants outstanding as of December 14, 2009 had been exercised pursuant to the early exercise transaction. As a result of reaching the 66 2/3% threshold, each warrant that had not been so exercised during the 30-day early exercise period was deemed automatically exchanged by the warrantholder, without any further action or payment of additional consideration on the part of the warrantholder (including payment of the exercise price thereof), for consideration payable by the Company of C$0.75 (the "Exchange Payment") plus a fraction of a common share (collectively, the "Exchange Shares") equal to: (A) the volume weighted average trading price of the common shares on the TSX for the five trading days immediately prior to the early exercise expiry date (the "Market Price") minus (B) the current exercise price, divided by (C) the Market Price. Warrants that were held by U.S. warrantholders were not subject to the automatic exchange. In total, 27,295,661 warrants were exchanged for C$170 million in cash and 27,106,081 common shares in the capital of the Company.

Revenues

	Q4		Year to Date	
	2010	2009	2010	2009
Net crude oil and gas sales	490,292	211,650	1,603,039	639,201
Trading revenue	25,609	-	58,505	-
	515,901	**211,650**	**1,661,544**	**639,201**
$ per boe oil and gas	70.39	55.94	64.51	49.51
$ per boe trading	98.82	-	83.67	-

Revenue in 2010 totaled $1.7 billion (2009 - $639.2 million), an increase of 160% in comparison to 2009. Net sales continued to grow mainly due to the 75% increase in production and construction of facilities at the Rubiales, Quifa and La Creciente fields coupled with better realized oil and gas prices throughout 2010 as explained in the table below.

Net sales in the fourth quarter of 2010 totaled $515.9 million (fourth quarter 2009 - $211.7 million), which were significantly higher by $304.3 million, exceeding a two fold increase in comparison to the same period in 2009 due to a significant increase in both volume and price.

Revenue for the trading activity during 2010 was $58.5 million (2009 - $Nil), corresponding to crude oil purchases from local oil producers and sold in the international market. This business activity commenced during the third quarter of 2010 and the average sales price during this period was $83.67/boe.

Summarized below is an analysis of the increase in the revenue due to the change in volume and price for the fourth quarter and entire year 2010 in comparison to the same periods of 2009:

Explanation of Volumes and Price FY 2010

	4Q 2010				Full Year 2010			
	2010	2009	Differences	% Change	2010	2009	Differences	% Change
Total of boe sold (Mboe)	7,225	3,783	3,441	91%	25,547	12,911	12,636	98%
Avg. Combined Price - Oil & gas and trading ($/bbl)	71.41	55.94	15.47	28%	65.04	49.51	15.53	31%
Total Revenue (MUSD$)	515,901	211,650	304,251	144%	1,661,544	639,201	1,022,343	160%

4Q 2010			Full Year 2010		
Reasons for the difference (000$):			**Reasons for the difference (000$):**		
Increase due to Volume	192,509	63%	Increase due to Volume	625,566	61%
Increase due to Price	111,742	37%	Increase due to Price	396,777	39%
	304,251			1,022,343	

Operating Costs

	Q4		Year to Date	
	2010	2009	2010	2009
Oil and Gas Operating Costs	131,982	69,287	550,933	271,687
Trading Operating Cost	24,840	-	57,006	-
Overlift (Underlift)	23,906	1,393	18,833	(2,149)
$ per boe Crude Oil and Gas	18.95	18.31	22.17	21.04
$ per boe Trading Operating	95.85	-	81.53	-
$ per boe Over/Underlift	3.31	0.37	0.76	(0.17)

Notes:

(1) *Overlift or underlift corresponds to any resulting short term imbalance between cumulative production entitlement and cumulative sales attributable to each participant at the reporting date. Lifting or off take arrangements for oil and gas produced in jointly owned operations are frequently such that it is not practicable for each participant to receive or sell its precise share of the overall production during the period. Overlift represents an obligation to transfer future economic benefit (by foregoing the right to receive equivalent future production), and therefore constitutes a liability. Underlift represents a right to future economic benefit (through entitlement to receive equivalent future production) which constitutes an account receivable.*

(2) *The overlift recognized as of the end of December 2010 of $23.9 million is the net balance between the overlift position reflected as of the third quarter of 2010 of $0.4 million (4,056 boe), settled in the fourth quarter of 2010, and the actual overlift as of the end of December 2010 of $23.9 million (280,424 boe). The overlift balance of $23.9 million was valued at the realized price of blend crude oil, and recorded as a liability and a reduction in the operating costs at December 31, 2010. This overlift and its related financial impact will be reversed once the volume is settled in the first quarter of 2011.*

Operating costs for oil and gas during the year ended December 31, 2010 were $550.9 million (2009 - $271.7 million); the increase over the previous period of 2009 is primarily due to the increase in oil production at the Rubiales and Quifa fields. Production costs per boe for 2010 totaled $22.17, which represents a slight increase of 5.4% in comparison to the same period of 2009, mainly explained by the 75% increase in production in 2010 and a $21.7 million reduction to operating expenses resulting from foreign currency risk management contracts. The $22.17 per boe consists of cost of production of $4.87, transportation cost of $6.00, dilution cost of $11.67 and other recovery costs of $(0.37).

Oil and gas operating costs for the fourth quarter of 2010 were $156.8 million (December 31, 2009 - $69.3 million). The increase over the previous period is primarily due to the continuous increase in net oil production at the Rubiales field as explained above. Production costs per boe increased to $22.51, or 23% higher than the same period in 2009.

Operating costs for the crude oil trading activities as of December 2010 were $57.0 million (December 31, 2009 - nil), which mainly corresponds to the average purchasing and transportation costs of the product of $81.53 per boe. This new business activity commenced during the third quarter of 2010.

Depletion, Depreciation and Amortization

	Q4		Year to Date	
	2010	2009	2010	2009
Depletion, depreciation and amortization	94,368	62,706	298,567	196,138
$ per boe	13.06	16.57	11.69	15.19

The increase in depletion, depreciation and amortization over the previous year was primarily due to the increased production and the increase in oil and gas property costs incurred subject to depletion. Included in the costs subject to depletion is $1.6 billion (2009 - $1.1 billion) of future development costs that are estimated to be required to bring proved undeveloped reserves to development The increase was also due to the amortization expense of $3.6 million (2009 - $1.6 million) related to the capitalized costs of the power generation agreements. The amortization is based on the unit of production method over the term of the lease.

For the fourth quarter of 2010 depletion, depreciation and amortization totaled $94.4 million, which was higher by $31.7 million over 2009, primarily due to the increase in capital investments in 2010 for the drilling campaign at the Rubiales and Quifa fields, as well as increased production in 2010 compared to 2009.

General and Administrative

	Q4		Year to Date	
	2010	2009	2010	2009
General and administrative costs	39,372	23,931	111,919	71,831
$ per boe	5.45	6.33	4.38	5.56

General and administrative expenses for the year ended December 31, 2010 were $111.9 million (2009 - $71.8 million), and the increase is mainly attributable to increased salaries and benefits as additional personnel were hired during 2010 to support the increased operations and oil production at the Rubiales and Quifa fields. In addition to the above, the operating costs for this period were also affected by the 7% revaluation of the Colombian peso against the US dollar when compared to the same period of 2009. The majority of the general and administrative costs are incurred in Colombian pesos and therefore subject to fluctuation when converted to the US dollar, after taking into account currency hedging arrangements. The number of direct and indirect employees in 2010 increased 45% to a total of 1,203 compared to 830 in 2009.The number of employees hired on a temporary basis in 2010 also increased to 273 from 197 in 2009.

During 2010, general and administrative expenses on a per boe basis reflected a reduction of $1.18/boe (21%) in comparison to 2009 due to the increased production.

General and administrative expenses for the fourth quarter of 2010 were $39.4 million (fourth quarter 2009 - $23.9 million); the $15.5 million increase from the same period in 2009 is primarily due to additional personnel needed to support the expanding operations to increase oil production at the Rubiales and Quifa fields and the drilling campaign at other exploratory blocks in 2010, as explained above.

Stock-Based Costs

	Q4		Year to Date	
	2010	2009	2010	2009
Stock-based compensation costs	-	27,699	73,327	28,361
$ per boe	-	7.32	2.87	2.20

For the twelve months ended December 31, 2010, stock-based compensation increased to $73.3 million from $28.4 million for the same period in the previous year. The increase is due to 9.6 million stock options granted in 2010 compared to 4.6 million stock options granted in 2009, and an increase in the fair value per option granted. All stock options outstanding as of December 31, 2010 are completely vested and exercisable and the fair values are calculated using the Black-Scholes option pricing model.

For the fourth quarter of 2010, stock-based compensation was $nil compared to $27.7 million in to the same period of 2009 as there were no stock option grants in the fourth quarter of 2010.

Foreign Exchange

	Q4		Year to Date	
	2010	2009	2010	2009
Foreign exchange (loss) gain	30,456	33,686	(11,092)	(59,896)
$ per boe	4.22	8.90	(0.43)	(9.86)

For the twelve months ended December 31, 2010 and 2009, the Colombian peso and the Canadian dollar continued their appreciation trend against the US dollar. During the period, both currencies strengthened by an average of 7% (2009 - 9%) and 6% (2009 - 15%), respectively. As a result the foreign exchange loss decreased to $11.1 million from a loss of $59.9 million in 2009.

During the fourth quarter of 2010, the Colombian peso depreciated 6% (2009 - 6%) and the Canadian dollar appreciated 3% (2009 - 2%) against the US dollar. This fluctuation resulted in a gain during the fourth quarter of 2010 of $30.5 million compared to a gain of $33.7 million during the same period of 2009.

The foreign exchange gain (loss) primarily consisted of the following:

a) Non-cash Colombian peso denominated future income tax liabilities resulted in a $10.5 million loss (2009 - $39.1 million) for the year and $38.2 million gain (2009 - $27.1 million) for the fourth quarter of 2010 upon the conversion to US dollars for financial reporting purposes. The future income tax liability relates to the business acquisitions which generate temporary taxable differences (future income tax liability) when the fair value of the carrying asset is compared with the corresponding tax value of the asset.

b) Debentures in the amount of $186.4 million (denominated in Canadian dollars) resulted in a foreign exchange loss of $8.7 million for the year (2009 - $23.1 million) and $6.2 million (2009 - $3.2 million) for the fourth quarter of 2010.

Interest Expense

	Q4		Year to Date	
	2010	2009	2010	2009
Interest expense	20,664	22,956	76,447	48,150
$ per boe	2.86	6.07	2.99	3.73

Interest expense includes interest on bank loans, convertible debentures, notes and fees on letters of credit. For the year ended December 31, 2010, interest expense totaled $76.5 million (2009 - $48.2 million). The higher interest expense over 2009 is mainly due to the Senior Unsecured Notes offering which was completed on November 10, 2009 and as a result the 2010 interest expense included the full year interest cost on the Senior Unsecured Notes.

Interest expense in the fourth quarter of 2010 increased to $21.7 million compared to $22.9 million for the same period in the previous year. No new long-term debt was incurred in the fourth quarter of 2010.

Income Tax Expense

	Q4		Year to Date	
	2010	2009	2010	2009
Current income tax	48,937	12,322	171,235	30,089
Future income tax	(3,889)	7,512	31,764	15,963
Total	45,048	19,834	202,999	46,052

The tax rates in Canada decreased to 31% from 33% and Colombia remain at 33% of taxable income. The special tax benefit in Colombia for acquisition of qualified assets has been reduced from 40% in 2009 to 30% in 2010. The Colombian Congress passed a tax reform on December 29, 2010 eliminating the 30% special tax benefit starting January 2011. However, the new law allows certain tax payers which had 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. The Company is in the process of having its stabilization contracts reviewed and the Company expects to have a positive outcome before the end of 2011. On December 29, 2010, the Colombian Congress passed a law imposing a surcharge on the current equity tax levied on Colombian companies. This surcharge has the effect of increasing the equity tax rate for the Company from 4.8% to 6%, and is applied on the net taxable equity as at January 1, 2011, the date which the amount becomes payable. The Company's equity tax for 2011 is $83.4 million and will be paid in eight equal semi-annual installments.

Income tax expense increased during the three and twelve month periods ended December 31, 2010, which is in line with increased revenues and operating income. The effective tax rate is greater than the statutory rate of 33% primarily due to the non-deductible costs for tax purposes such as the stock-based compensation costs and loss on risk management contracts.

Current income tax represents the estimated cash income taxes payable for the period. Current income tax increased to $171.3 million from $30.9 million during the same period of 2009, which was primarily due to increased operating income and reduced by the special deduction for investment in assets eligible for the special tax benefit.

Future income tax increased by a net amount of $15.9 million to $31.7 million in the year ended December 31, 2010 as compared to the same period in 2009, primarily due to the accounting recognition of the special tax benefit in the acquisition of qualified assets in Colombia reduced by the effect of the increase in non-deductible depletion and amortization calculated on higher production in 2010 compared to 2009.

Net Income (Loss)

	Q4		Year to Date	
	2010	2009	2010	2009
Net income (loss)	104,698	3,218	217,606	(125,793)
$ per boe	14.49	0.85	8.52	(9.74)

Net income for the twelve months ended December 31, 2010 totaled $217.6 million (2009 - $125.7 million net loss). The significant increase in the results are primarily due to the increase in the sale of oil and gas, which was 75% higher than in 2009, coupled with improved realized prices that were higher by 29% in comparison to the same period of 2009. Net income for the year ended December 31, 2010 was impacted by an increase in the operating costs, DD&A, administrative expenses, stock based compensation, and taxes of $336.2 million, $102.5, $40 million, $45 million, and $156.9 million, respectively, primarily due to increased production and taxable revenues.

During the fourth quarter of 2010, net income totaled $104.7 million (fourth quarter 2009 - $3.2 million), which represents 48% of the total net income of the entire year as a result of higher volume sold and realized oil and gas prices and offset by an increase in the operational costs and expenses, as mentioned above. The net cumulative loss for the same period of 2009 included a number of non-cash items mainly related to exchange losses and a loss in the fair value of management risk contracts; while for this quarter these two items reflected a gain which further improved the results of the fourth quarter of 2010.

Funds Flow from Operations

	Q4		Year to Date	
	2010	2009	2010	2009
Funds flow from operations	196,310	99,727	661,993	225,886
$ per share, diluted	0.70	0.47	2.32	1.06

The Company continued to generate positive cash flow from operations as a result of the 75% increase in production together with the increase in the combined realized oil and gas price. The funds flow from operations during the year ended December 31, 2010 totaled $661 million. This increase is primarily attributable to the 46% increase in the combined net back in 2010 as compared to 2009 ($41.58 per boe in 2010 versus $28.60 per boe in 2009), as well as the significant increase in production. The increase in net back is due to higher realized prices from $49.47 per boe in 2009 to $64.51 per boe in 2010.

Funds flow from operations for the fourth quarter of 2010 increased by $96.6 million over the same period of 2009. As mentioned above, this increase is primarily attributable to the increase in net back due to improved realized prices and significant increase in production.

Liquidity and Capital Resources

Liquidity

Funds provided by operating activities for the year ended December 31, 2010 totaled $828.8 million (2009 – $143.7 million), and for the fourth quarter of 2010 totaled $249.2 million (2009 – $35.8 million). The increase in cash flow in 2010 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, 2010, the Company held debt denominated in Canadian dollars, Colombian pesos, and US dollars totaling $710.9 million compared to $621.1 million as at December 31, 2009.

As of December 31, 2010, the Company had working capital of $176.7 million, mainly composed of $608.3 million of cash and cash equivalents, $300.8 million of account receivables, $56 million of inventory, $2.3 million of income tax receivable, $6.4 million of prepaid expenses, $540.3 million of accounts payable and accrued liabilities, $52.6 million of net risk management liabilities, $110 million of income tax payable, $90 million of current portion of long-term debt and $4.3 million of current portion of capital lease obligations.

On April 27, 2010, the Company closed the syndication of the Revolving Credit Facility in amount of $250 million. As at December 31, 2010, no borrowing has been made under the Revolving Credit Facility. The Company believes it has adequate resources to fund its capital plan for 2011, with the Company's cash flows from operations and current debt facilities. With respect to the Company's broader integration strategy (see "Strategy" section on page 7), the Company will pay for the expansion plan with its own cash flow. However, if additional resources are required, possible sources of funds available to the Company to finance additional capital expenditures and operations include the Revolving Credit Facility, existing working capital and incurring new debt, and the issuance of additional common shares, if necessary.

8. Capital Expenditures

Capital expenditures during the year ended December 31, 2010 totaled $954.3 million (2009 - $403.7 million), of which $461.4 million was invested in the expansion and construction of production infrastructure; $112.5 million went into exploration activities including seismic, aerogravimetry, aeromagnetometry and drilling; $150.6 million were invested in production drilling activities; $39.8 million were invested in other projects and $190 million were invested in transport rights with for the OCENSA pipeline. Capital expenditures during the fourth quarter of 2010 totaled $347.7 million, and a breakdown of the net capital expenditures for the above periods of 2010 and 2009 is as follows:

	Net Capital Expenditures (Thousands of US$)			
	Q4		Year to Date	
	2010	2009	2010	2009
Production facilities	218,286	85,249	461,432	234,700
Exploration drilling includin seismic acq.	44,394	7,223	112,502	48,300
Development drilling	47,068	38,624	150,639	120,700
Other projects (STAR, Llanomulsion, PEL)	37,906	nil	39,722	nil
Transportation rights - Ocensa	-	-	190,000	-
Total Capital Expenditures	**347,654**	**131,096**	**954,295**	**403,700**

Expanded Capital Expenditure Plan for 2011

On January 10, 2011, the Company announced its fully funded capital expenditure budget for 2011 that includes a $1.12 billion capital expenditure program. With this investment program, the Company will significantly increase its gross operated production from the average 2010 production of 144,307 boe/d (56,974 boe/d net) to 265,000 boe/d (112,000 boe/d net) at the end of 2011. The Company's capital expenditure strategy entails two main long-term initiatives: (i) growth based upon discovering, developing and producing new and existing reserves; and (ii) securing market access by participating in key oil and gas transportation and port infrastructure projects. For 2011, the Company has budgeted $340 million for exploration activities as it enters into a more intensive phase in more than 26 of its blocks in Colombia, and begins operations in Peru and Guatemala. The Company plans to invest $438 million in production facilities, mainly at the Quifa and Rubiales fields, as it ramps up production in the Quifa field and continues to expand the fluid handling capacities in the Rubiales field. The expansion of production capacity in all of the fields calls for an investment of $139 million in development drilling. Finally, the Company has earmarked $204 million for projects such as STAR, IT investment and its investment in the transport and port projects. The $1.12 billion capital expenditure program is an increase of $359 million over actual capital expenditures in 2010.

The Company's broader integration strategy (see "Strategy" section on page 7), requires a minimal investment, with the exception of the exploration and production capital expenditures (discussed immediately above) and the OBC project. The latter will have its own financing through a special purpose vehicle project financing structure.

The Company will continue pursuing its strategy of production growth from its producing assets, but also accelerating the addition of new reserves from its exploration assets. On March 10, 2011, the Company announced the independently certified Statement of Reserves Data and Other Oil and Gas Information for the year ended December 31, 2010 in respect to the Rubiales-Piriri, Quifa SW, Quifa Norte, La Creciente, Abanico, Moriche, Guaduas, Rio Ceibas, Buganviles, Guama, and Puli blocks in Colombia. The combined proved plus probable (2P) reserves for these blocks increased by [17]% in 2010. For further information see the heading entitled "Reserves – Proved and Probable Oil and Gas Reserves".

9. 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, some of which are already reflected as liabilities in the consolidated financial statements as of December 31, 2010. 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. Commitments as of December 31, 2010 are summarized in the following table:

	2011	2012	2013	2014	2015	Subsequent to 2016	Total	
Operating leases	$ 7,441	$ 5,605	$ 4,948	$ 4,948	$ 4,948	$ 24,318	$ 52,208	(a)
Transportation and processing commitments	46,980	46,980	46,980	46,980	41,580	83,160	312,660	(b)
Minimum work commitments	82,046	83,058	-	-	-	-	165,104	(c)
Accounts payable	540,292	-	-	-	-	-	540,292	(d)
OBC investment commitment	243,318	-	-	-	-	-	243,318	(e)
Abandonment obligations	1,220	815	106	2,402	377	46,996	51,916	(f)
Short-term bank indebtedness	90,091	-	-	-	-	-	90,091	(g)
Long-term debt	-	-	-	149,985	149,985	150,030	450,000	(h)
Convertible debentures - principal	-	-	-	240,192	-	-	240,192	(i)
Obligations under capital lease	11,306	11,337	11,306	11,306	11,306	5,638	62,199	(j)
Total	$ 1,022,694	$ 147,794	$ 63,340	$ 455,813	$ 208,196	$ 310,142	$ 2,207,980	

The Company has various commitments in place in the ordinary course of business between 2011 and subsequent to 2016:

a) Operating leases of $52.2 million mainly related to the 10-year lease of Bogota offices signed in January 2011.

b) Ship or pay contracts totaling $312.6 million as follows: $291.1 million signed with ODL for the transportation of crude oil from the Rubiales field to Colombia's oil transportation system, and $21.5 million signed with Promigas for gas transportation from the La Creciente field to connect the Cartagena gas pipeline to deliver the product to customers´ facilities.

c) Minimum capital investments agreed in contracts with Ecopetrol and the ANH that include acquisition and processing of seismic data and drilling exploration wells in Colombia.

d) This amount corresponds to the balance as of December 31, 2010, in accordance with our accounts payable terms and procedures.

e) The $243.3 million represents the future commitment to pay in 2011 on the acquisition of a 32.9% interest in OBC for a total investment of $1.03 billion ($340 million being the Company´s share). Of this amount, $95.7 million were accrued in the payable accounts of December 31, 2010. OBC is a corporation established and owned by a consortium of oil producers operating in Colombia, led by Ecopetrol. OBC will build and operate a private-use oil pipeline in Colombia between Casanare and Coveñas with an ultimate capacity of 450,000 barrels per day. The investment in OBC is accounted for using the equity method.

f) The amount of the asset retirement obligation of $51.9 million considers the present as well as the undiscounted future obligations on drilling of wells or construction of facilities.

g) This amount corresponds to the short term bank indebtedness with local banks with maturity dates of 30 or 60 days.

h) Debt repayment of $450 million on the short and long term debt, details of which are in the “Liquidity and Capital Resources” section on page 30. This amount includes the future repayment of the Senior Unsecured Notes of $450 million with maturity dates of November 10, 2014 (33.3%), November 10, 2015 (33.3%), and November 10, 2016 (33.4%).

i) This amount corresponds to the principle outstanding on the convertible debentures, which are payable semi-annually in arrears on June 30 and December 31. The Debentures have been classified into their debt and equity components in the Company’s financial statements.

j) This amount corresponds to a capital lease on a BOOMT (Built, Operate, Own, Maintain and Transfer) contract signed with Energy International Corp. for power generation at the Rubiales and Piriri fields until June 2016. This amount corresponds to the share on the contractual minimum lease payments recognized by the Company as a capital lease. Operational rates include the maintenance and service fees as well as the cost of the equipment throughout the life of the contract.

Disclosure about the Company’s significant commitments can be found in note 13 to the consolidated financial statements. The Company has no off-balance sheet arrangements.

10. Risk Management Contracts

The Company had the following commodity price risk management contracts outstanding:

As of December 31, 2010

Type of Instrm.	Term	Volume	Floor/Ceiling ($/bbl)	Benchmark	Fair value
Zero cost collars	Jan 1, 2011 - Dec 31, 2011	1,842,000	70/98	WTI	$ (8,003)
Zero cost collars	Jan 1, 2011 - Dec 31, 2011	1,842,000	70/98	WTI	(7,949)
Zero cost collars	Jan 1, 2011 - Dec 31, 2011	1,842,000	70/98	WTI	(8,073)
Zero cost collars	Jan 1, 2011 - Mar 31, 2011	525,000	75/100	WTI	(400)
Zero cost collars	Apr 1, 2011 - Dec 31, 2011	2,070,000	75/102	WTI	(9,220)
Zero cost collars	Apr 1, 2011 - Dec 31, 2011	2,739,000	70/98	WTI	(14,192)
Zero cost collars	Jan 1, 2011 - Jun 30, 2011	540,000	70/98	WTI	(1,014)
Zero cost collars	Jan 1, 2011 - Jun 30, 2011	750,000	70/98	WTI	(1,967)
	Total	**12,150,000**			**(50,819)**

Type of Instrm.	Term	Volume	Strike Price ($/bbl)	Premium ($/bbl)	Fair value
Put option	Jan 1, 2011 - Jul 31, 2011	700,000	40	2.45	(1,712)
Put option	Jan 1, 2011 - Jun 30, 2011	585,000	40	1.91	(1,116)
	Total	**1,285,000**			**(2,828)**
	Total				**$ (53,647)**
	Short-term				(53,647)
	Long-term				-
	Total				**$ (53,647)**

For the year ended December 31, 2010, the Company recorded a loss of $40.2 million (2009 - $21.5 million) on commodity price risk management contracts in net income. Included in these amounts were $28.4 million of unrealized loss (2009 – $18.7 million) representing the change in the fair value of the contracts, and $11.8 million of realized loss (2009 - $2.8 million).

If the forward WTI crude oil price estimated at December 31, 2010 had been $1/boe higher or lower, the unrealized loss on these contracts would change by approximately $2.7 million (2009 – $1.3 million) and would be reflected in the statement of operations of the Company.

Foreign currency exchange risk

The Company is exposed to foreign currency fluctuations in Colombian pesos (COP) and Canadian dollars relative to US dollars.

To reduce its foreign currency exposure associated with operating expense incurred in COP, the Company may enter into currency risk management contracts such as foreign exchange forwards, options, and costless collars. The Company has the following currency risk management contracts outstanding as at December 31, 2010, which qualify for cash flow hedge accounting:

Instrument	Settlement date	Notional amount ('000 $)	Floor-ceiling (COP/$)	Fair value ('000 $)
Currency collars	January 2011	$ 20,000	1900-1928 & 1900-1930	$ 105
Currency collars	February 2011	20,000	1900-1928 & 1900-1930	166
Currency collars	March 2011	20,000	1900-1928 & 1900-1930	166
Currency collars	April 2011	20,000	1900-1928 & 1900-1930	164
Currency collars	May 2011	20,000	1900-1928 & 1900-1930	149
Currency collars	June 2011	20,000	1900-1928 & 1900-1930	122
Currency collars	July 2011	20,000	1900-1928 & 1900-1930	95
Currency collars	August 2011	20,000	1900-1928 & 1900-1930	70
Currency collars	September 2011	20,000	1900-1928 & 1900-1930	40
Currency collars	October 2011	20,000	1900-1928 & 1900-1930	16
Currency collars	November 2011	20,000	1900-1928 & 1900-1930	(3)
Currency collars	December 2011	20,000	1900-1928 & 1900-1930	(24)
	Total	**$ 240,000**		**$ 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 to operating expenses in net income in the same period as the hedged operating expenses are incurred. During the year ended December 31, 2010, $21.7 million (2009 - nil) of unrealized gains were recorded in other comprehensive income, and subsequently recorded against operating cost when the gains became realized. The Company excludes changes in fair value due to the time value of options and records these amounts along with hedge ineffectiveness in foreign exchange gains or losses in the period that they arise. During the year ended December 31, 2010, $8 million of ineffectiveness was recorded as foreign exchange loss (2009 - $nil).

11. Selected Quarterly Information

(In thousands of US$ except per share amounts or as noted)	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009 (Restated [4])	Q3 2009	Q2 2009	Q1 2009
Financials:								
Net sales	515,901	405,421	359,700	380,523	211,650	156,557	160,994	110,000
Net income (loss) for the period	104,698	32,856	47,928	32,125	3,218	(63,107)	(118,540)	52,636
Capital expenditures	344,886	198,868	133,636	43,617	114,006	88,141	83,640	100,823
Funds flow from operations [1]	196,310	160,013	154,943	150,727	99,727	55,677	38,934	31,548
Earnings (loss) per share								
- basic	$ 0.40	$ 0.12	$ 0.18	$ 0.13	$ 0.02	$ (0.29)	$ (0.56)	$ 0.25
- diluted	$ 0.35	$ 0.11	$ 0.16	$ 0.13	$ 0.02	$ (0.29)	$ (0.56)	$ 0.25
Operations:								
Operating netback ($/boe) [2]								
Crude oil and natural gas sales price	70.39	60.91	61.45	64.35	55.94	55.31	50.12	35.65
Costs of Production	6.36	4.10	5.05	3.74	4.61	7.61	5.16	3.75
Transportation	5.75	6.13	5.65	6.59	8.13	11.18	10.46	6.76
Upgrading cost (diluent including transportation)	11.53	11.72	10.59	12.85	8.27	7.73	6.19	5.91
Other costs	(1.13)	(0.93)	0.80	(0.14)	(2.69)	0.10	2.85	(0.93)
Overlift/Underlift	3.43	(0.20)	0.18	(0.82)	0.37	(7.89)	6.05	(0.21)
Operating netback	44.45	40.09	39.18	42.14	37.25	36.58	19.41	20.37
Average daily crude oil sold (Bbl/day)	65,096	57,009	54,291	55,734	32,429	24,438	30,405	25,755
Average daily natural gas sold (Boe/day)	10,614	9,464	10,038	9,968	9,145	6,669	5,283	8,528
Average daily oil and gas sold (Boe/day) [3]	75,710	66,473	64,329	65,702	41,574	31,107	35,688	34,283

(1) *Calculated based on cash flow from operations before changes in non-cash operating working capital.*
(2) *Combined operating netback data is based on weighted average daily production sold.*
(3) *Operating netback data based on weighted average daily production sold.*
(4) *The Company has restated its 2009 consolidated financial statements to correct an error that resulted in an overstatement of accounts payable and accrued liabilities as of December 31, 2009. This occurred in the fourth quarter of 2009 as a result of the amalgamation of several operating subsidiaries of the Company and an enterprise resource planning system conversion.*

The following discussion highlights some of the significant factors that impacted the results in the eight most recently completed quarters as of December 31, 2010:

During the fourth quarter of 2010, net sales totaled $515.9 million, which represents 31% of the total revenues of the year. Net sales of the fourth quarter of 2010 were higher by $110.5 million over the prior quarter of 2010, due to an increase in production and better realized crude oil and gas prices. Production continued to increase reaching an average of 64,040 boe/d net during the fourth quarter of 2010; the volume of sales during this period was higher by 9,237 boe/d (14%) net as compared to the prior quarter of 2010. Additionally, the operating costs in the fourth quarter of 2010 slightly increased to $22.25 per barrel, or 6%, mainly attributable to the increase in the production and the net effect of the currency hedge recognized during this period to operating expenses.

During the third quarter of 2010, net sales totaled $405.4 million, which were higher by $45.7 million over the prior quarter of 2010, due to an increase in production and better realized crude oil and gas prices. Production continued to increase reaching an average of 56,404 boe/d net during the third quarter of 2010; the volume of sales during this period was higher by 2,144 boe/d (3%) net as compared to the prior quarter of 2010. Additionally, the operating costs in the third quarter of 2010 slightly reduced to $20.89 per barrel, or 5%, mainly attributable to the increase in the production and the net effect of the currency hedge recognized during this period.

During the second quarter of 2010, net sales totaled $359.7 million, which were lower by $20.8 million over the prior quarter of 2010, due to a reduction of 5% in realized price due to market conditions which put downward pressure on crude oil prices. Although production continued to increase during the second quarter of 2010, the volume of sales during this period was lower by 59,200 boe (1%) as compared to the prior quarter of 2010. Additionally, the operating costs in the second quarter of 2010 slightly increased to $23.46 per barrel, or 1.8%, mainly attributable to the increase in the production and higher dilution cost used to upgrade Rubiales crude oil.

During the first quarter of 2010, net sales totaled $380.5 million, which were higher by $168.8 million over the fourth quarter of 2009, due to the increase in both the combined realized price of $8.41 per barrel (a 15% increase) as well as the volume of sales from 41,574 boe/d net in the fourth quarter of 2009 to 65,702 boe/d net in the first quarter of 2010, representing a 58% increase. Additionally, the operating costs in the third quarter of 2010 slightly increased to $23.04, per barrel, or 1%, mainly attributable to the increase in the production and higher diluents cost as light crude oil used to upgrade Rubiales crude oil is linked to the WTI NYMEX reference price.

During the fourth quarter of 2009, net sales totaled $211.7 million, which were higher by $55.1 million over the previous quarter, due to the $0.63 increase (a 1% increase) in both the combined realized price and the average daily volume of oil and gas sold from 41,574 boe/d net in the third quarter of 2009 to 31,107 boe/d net in the fourth quarter, a 34% increase. This increase in the volume of sales in the fourth quarter is the result of the drilling program initiated during the second quarter of 2009 and the optimization of field facilities to improve the storage and transport capacity at the Rubiales field. Operating netback was increased by $0.67/boe to $37.25, in comparison to the prior quarter, primarily due to the improvement in the realized oil and gas prices and reduction in the production costs and upgrading costs in the fourth quarter as compared to the prior quarter of 2009.

During the third quarter of 2009, net sales totaled $156.6 million, which were lower by $4.4 million over the previous quarter, due to the settlement of the overlift position recognized in the prior period of 455,000 boe amounting to $19.4 million, offset with an increase in the crude and gas production, which resulted in a slight reduction of the volume of sales as compared to the second quarter of 2009 (a 2% reduction). The effect of the lower volume of sales was offset by the increase in the combined realized price of $10.26 per barrel (22%) over the second quarter of 2009.

During the second quarter of 2009, net sales totaled $161.0 million, which were higher by $50.9 million over the previous quarter, due to the increase in both the combined realized price of $14.47 per barrel (a 41% increase) as well as the volume of sales from 34,283 boe/d net in the first quarter of 2009 to 35,688 boe/d net in the second quarter of 2009, a 4% increase. Additionally, the operating costs in the second quarter of 2009 totaled $27.62 per barrel, which was negatively affected by the overlift position of 455,000 boe as of June 30, 2009 amounting to $19.4 million, or $5.44 per barrel.

During the first quarter of 2009, net sales were reduced by $13.2 million to $110.0 million over the previous quarter due to a reduction in realized oil and gas prices. Even though the production sold during this quarter increased by 9% to 3.1 million boe, the average realized price was 18% lower at $35.65 per boe in the first quarter of 2009 in comparison to $43.23 per boe in the fourth quarter of 2008.

12. Outstanding Share Data

Issued and Fully Paid Common Shares

As at December 31, 2010, 267,648,853 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, 2010, 611,682 warrants to acquire an equal number of common shares were outstanding and exercisable (2009 - 27,910,343) and 21,224,129 stock options were outstanding (2009 - 19,223,131), of which all were exercisable.

13. New Accounting Pronouncements

Adopted

a) Business Combinations/Consolidated Financial Statements/Non-Controlling Interests

In January 2009, the CICA issued Handbook Sections 1582, “Business Combinations” (“Section 1582”), 1601, “Consolidated Financial Statements” (“Section 1601”) and 1602, “Non-controlling Interests” (“Section 1602”). Section 1582 replaces CICA Handbook Section 1581, “Business Combinations”, and establishes standards for the accounting for business combinations that are equivalent to the business combination accounting standard under IFRS. Section 1582 is applicable prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011, with early adoption permitted. Section 1601 together with

Section 1602 replaces CICA Handbook Section 1600, "Consolidated Financial Statements". Section 1601 establishes standards for the preparation of consolidated financial statements and Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Sections 1601 and 1602 are applicable for interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011, with early adoption permitted. An entity must adopt Section 1582, 1601 and 1602 at the same time. The Company has adopted these standards effective January 1, 2010 and the adoption did not have a material impact on the results of operations or financial position.

Future accounting changes

International Financial Reporting Standards (IFRS)

In February 2008, the AcSB confirmed the convergence of Canadian GAAP with International Financial Reporting Standards ("IFRS") which are required for interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011, including comparatives with 2010.

The Company has established a dedicated IFRS Project team to address the conversion to IFRS that reports regularly to a steering committee, senior management and the Audit Committee. A complete discussion of the Company's IFRS conversion project was referred to in the third quarter 2010 interim MD&A. As of December 31, 2010, the IFRS conversion project continues to progress according to the changeover plan and timetable established by management. The project team is now in the final stages of finalizing the conversion project and the following key issues were reviewed and concluded to have the most significant impact on the results of operations, financial position and disclosures:

a) IFRS Exemptions Applied

IFRS 1 allows first-time adopters certain exemptions from the general requirement to apply IFRSs in the January 1, 2010 balance sheet opening balance. The Company has elected to apply the following exemptions:

- Business Combinations that took place before January 1, 2010, will not be resetting.
- Not to apply IFRS 2 Share-based Payment to any equity instruments granted on or before November 7, 2002. Likewise, to any other equity instruments granted after November 7, 2002 that were vested before January 1, 2010.
- Cumulative currency translation differences for all foreign operations are deemed to be zero as of January 1, 2010.
- The Company has elected to use the exemption of "full cost as deemed cost" approach to measure oil and gas exploration (E&E) and development and producing assets (D&P) at the date of transition to IFRS. Under this exemption, the D&P assets were allocated to each cash generating unit ("CGU") based on reserves values. Management has established that CGU will be defined at field level.

b) Opening Balance as of January 2010.

As a result of the changes in accounting policies with the adoption of IFRS, management anticipates adjusting the Company's previously reported quarterly net income due principally to lower DD&A and accretion expense, unrealized foreign exchange gains and losses, deferred income taxes (referred to as future income taxes under Canadian GAAP), a change in the accounting for stock-based compensation and the timing of the recognition of gains and losses on the disposal of assets. The Company does not anticipate a change to the previously reported cash flows as a result of adopting IFRS, except for a reclassification of exploration expenditues from an investing activity to an operating activity and a reclassification of financing charges from operating to financing activity.

The following information summarizes the estimated effect on the opening balance as of January 1, 2010 for the IFRS adoption:

	January 1, 2010 - Opening Balance		
(In millions of U.S. dollars)	**Canadian GAAP**	**IFRS Adjustments (*)**	**IFRS**
Current assets	656	(20)	636
Long-term asset [(1)]	2,163	102	2,265
Total assets	**2,819**	**82**	**2,901**
Current liabilities	252	(9)	243
Long-term liabilities [(1)]	1,038	30	1,068
Equity [(1)]	1,529	61	1,590
Total liabilities & equity	**2,819**	**82**	**2,901**

(In millions of U.S. dollars)	**Shareholders' Equity Reconciliation**
Shareholders' equity - Canadian GAAP	**1,529**
Special tax benefit [(1)]	67
Deferred income tax	7
Variable Interest Entity "VIE" deconsolidation	(9)
Asset retirement obligation "ARO" and other	(4)
Shareholders' equity – IFRS	**1,590**

(*) The above adjustments are the best estimated impact based on the work performed as of the date.

(1) The most significant adjustment presented to the Company's opening balance sheet, is related to deferred taxes previously recorded in relation to a special tax deduction in Colombia and the corresponding impact to the adopted IAS 12.

The opening balance as of January 1, 2010 was completed and delivered to the external auditors who are currently auditing the figures.

IFRS Changeover Process

Accounting Policies and Control Environment

The Company is currently finalizing the definition of the IFRS accounting policies which will be consistently applied to reset the January 1, 2010 opening balances and the subsequent IFRS Consolidated Financial Statements presented on a quarterly basis.

The Company will continue to monitor standards development as issued by the IASB and the AcSB as well as, regulatory developments issued by the Canadian Securities Administrators (CSA), which may affect the timing, nature or disclosure of its adoption to IFRS.

Training and Communication

During the fourth quarter 2010, the Company has accomplished comprehensive training sessions to finance personnel, as well as, other key areas of the Company on applicable IFRS accounting policies. Furthermore, the company has scheduled internal workshops sessions throughout 2011 to reinforce the understanding of IFRS policies to ensure accurate application.

IT Support

In October 2010, the Company started an IT project to implement and test all the required ERP customizations to support IFRS reporting under SAP to meet the CSA reporting requirements. Reporting testing is ongoing and the implementation process is scheduled to be completed before the first quarter 2011.

14. Related-Party Transactions

a) In June 2007, the Company entered into a 5-year lease agreement with Blue Pacific for administrative office space in one of its Bogota, Colombia locations. Monthly rent expense of $57 thousand 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. The Company also has accounts receivable of $773 thousand from Blue Pacific related to certain administrative costs paid by the Company on behalf of Blue Pacific. In addition, the Company paid $500 thousand to Blue Pacific during the year for air transportation services received.

b) As at December 31, 2010, the Company had trade accounts receivable of $1.7 million (2009 - $10.5 million) from Proelectrica de Energia de Cartagena & Cia, S.C.A. E.S.P., in which the Company has a 17.7% indirect interest and which is 31.49% owned by Blue Pacific. The Company's and Blue Pacific's indirect interests are held through Ronter Inc. ("Ronter"). Revenue from Proelectrica in the normal course of the Company's business was $12.5 million (2009 - $17.5 million) for the year ended December 31, 2010.

c) During the year ended December 31, 2010, Transportadora Del Meta S.A. ("Transmeta"), a variable interest entity indirectly 100% owned by a director of the Company, paid a dividend of $3.5 million respectively to its shareholder. The Company does not own any shares in the capital of Transmeta, but is the primary beneficiary and therefore consolidates Transmeta. The Transmeta dividend is included in other expense on the statement of operations.

d) During the year ended December 31, 2010, the Company received $565 thousand (2009 - $374 thousand) from companies related by way of a number of directors in common, for reimbursement of general and administrative support expenses for the office premises in Canada. As at December 31, 2010, the Company has accounts receivable of $215 thousand (2009 - $173 thousand) from the above companies, which was repaid in January 2011.

e) Loans receivable from related parties in the aggregate of $524 thousand (2009 – $290 thousand) are due from two directors and four officers (2009 – two officers) of the Company. The loans are non-interest bearing and payable in equal monthly payments over a 48-month term. The loans were issued by the Company to these individuals in connection with costs incurred by these individual as a result of their relocation.

f) On April 19, 2010, the Company acquired a 9.4% interest in PII, a company that was previously wholly-owned by Ronter, for $3.5 million. In September 2010, the Company acquired an additional 4% interest in PII for $2 million from an unrelated party. The Company invested a further $5 million in PII during a private placement offering in November 2010.

g) During the year ended December 31, 2010, the Company acquired a 19.05% interest in Pacific Coal S.A. ("Pacific Coal"), a company controlled by Blue Pacific, for $24 million. Four directors and one officer of the Company are also directors of Pacific Coal.

h) 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 the year, the Company paid $7.7 million (2009 - $1.6 million) in fees as set out under the agreements.

i) The Company received $5.3 million from ODL during 2010 (2009 - nil) with respect to certain administrative services and rental equipment and machinery. The Company has accounts receivable of $0.6 million from ODL with respect to these charges as at December 31, 2010 (2009 - nil).

All these transactions are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

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

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 internal auditor reports to the Audit Committee and the main role of the Internal Auditing department is to provide guidance and expertise in areas including, but not limited to, corporate governance, risk management, fraud policies and prevention, and information technology systems, in addition to the overall internal control. The internal audit process delivers reasonable assurance over the:

- Effectiveness and efficiency of operations,
- Reliability of internal and external reporting, and
- Compliance with applicable laws and regulations.

During 2010, Internal Audit focused its activities 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 addressed by management to mitigate them:

- Regulatory compliance: Some of the areas posing the greatest complexity include maintaining effectiveness of corporate process compliance controls in light of reporting, governance programs, the Corruption of Foreign Public Officials Act ("CFPOA"), anti-money laundering, and data security.

- Credit and liquidity strains: The audit review was focused on hedging capabilities and strategies, improving the automated environment to gain greater control of processing, and centralized cash pooling to improve cash management to capture synergies.

- Potential increased fraud risk: Audit reviews performed to reduce this risk included employee fraud awareness training to help maintaining fraud-resistance, fraud risk assessment within key areas and used the results to prioritized 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 securities, the use of tools to continuous auditing and monitoring, and the strengthening of control IT environment according with the standards.

The internal audit activities for the fourth quarter of 2010 included the following:

- Evaluation of the effectiveness of internal controls, encompassed within the requirements of National Instrument 52-109 ("NI 52-109") issued by the Canadian Securities Administrators (CSA), over the design and operating effectiveness of the ICFR (Internal Controls Over Financial Reporting). During this quarter a control optimization was performed and from the new control matrix of 461 controls, 339 were evaluated to ensure that the information required to be disclosed by the Company is consolidated and communicated to management for timely assessment and certification by the Chief Executive Officer and the Chief Financial Officer.
- Four audit reports were completed by the internal audit team during the quarter. Three other audit projects started and are still in progress at the time of this report. These audit reports included the evaluation of operational effectiveness, controls of core and support business processes in each of the following areas: HSE, Warehouse Management, Finance, Human Resources, and Security of Information Technology and Information Technology organizational structure. The results were reported to management and the Audit Committee and action plans for improvement were agreed to with business process owners.
- The implementation of a Governance, Risk and Compliance (GRC) solution is still in progress. This solution will streamline governance programs, improve accountability and communication, ensuring adoption of corporate governance principles and best practices, and providing a systematic framework for documenting and assessing risks, defining controls, managing audits, identifying issues and implementing recommendations and remediation plans, and it provides an integrated approach to meet cross-industry mandates and regulations.
- As part of the risk management activities the internal audit performed a Fraud Risk Assessment through the organization. As a result of the assessment, management is implementing plans to mitigate the fraud risks identified. Internal audit provides coaching and coordinates Risk Management activities.

The Company concluded that there are opportunities to improve on the design and operation of the ICFR in the following main areas:

- Compliance with the Company`s contracting procedures.
- Compliance with the Company`s purchasing levels of authority.
- Monitoring of tax reporting compliance and
- Assessment of the reliability of password security company standards.

Based on the reviews performed, deficiencies in internal controls were detected over the warehouse stock at the fields. Audit findings were discussed with management who are currently implementing the following corrective actions:

- Stock warehouse physical inventories were performed as of December 31, 2010 at all the field warehouse locations and the results were reconciled to the books. Another exercise is currently being performed at the main warehouse located at the Rubiales field.

- Review and enhancement of the process to include controls for the allocation of materials to projects under new accounting standards to be finalized by end of Q2 2011.
- Review and update warehouse organization to assign roles and responsibilities according to company requirements to be completed by Q2 2011.

The Company will continue to review its processes and procedures in 2011, including the hiring of new resources required for enhancing controls over warehouse stock at all locations, as well as, to ensure the use of existing SAP reporting tools.

Regulatory Policies

Certification of Disclosures Filings

In accordance with NI 52-109, the Company issues, on a quarterly and annual basis, a Certification of 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 related 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.

16. Outlook

The Company will continue working on increasing its production and transportation capacity. Expansion of current facilities and the development of new production wells will allow the Company to increase its production to 265,000 boe/d or 112,000 boe/d net by the end of 2011. The Company will continue pursuing its strategy of production growth from its producing assets, but also accelerating the addition of new reserves from its exploration assets. On March 10, 2011, the Company announced the independently certified Statement of Reserves Data and Other Oil and Gas Information for the year ended December 31, 2010 in respect to the Rubiales-Piriri, Quifa SW, Quifa Norte, La Creciente, Abanico, Moriche, Guaduas, Rio Ceibas, Buganviles, Guama, and Puli blocks in Colombia. The combined proved plus probable (2P) reserves for these blocks increased by [17]% in 2010. For further information see the heading entitled “Reserves – Proved and Probable Oil and Gas Reserves”.

In addition, the broadening of the Company’s growth strategy, including the Company’s downstream integration and participation in infrastructure projects, is anticipated to complement the continued growth of the Company and provide it with secure and stable access to profitable markets.

The Company will continue to sell crude in the international markets, as well as in the domestic market. During the first quarter of 2011, the Company expects to increase its combined sales of oil and gas to an average of 94,000 boe/d total for the Company, including 80,000 boe/d transported via the ODL that allows for transportation of all the Company’s production from the Rubiales field to Monterrey, where it is connected to the main Colombian pipeline system.
The Company will also concentrate on increasing its gas sales from the La Creciente field, and in order to achieve this, the Company is currently negotiating with gas transporters the commercial terms for an expansion of the infrastructure in the area.

The Company’s exploration activities will continue in 2011 and will include exploration across 26 blocks. In total, 20 exploratory wells, 36 appraisal wells and 3 stratigraphic wells will be drilled in 2011. This aggressive drilling campaign also includes the final acquisition of 539 km of 2D seismic and 440km^2 of 3D seismic during 2011 in Colombia and further exploratory development of two blocks in Peru and one in Guatemala.

17. Non-GAAP Financial Measures

This report contains the following financial terms that are not considered measures under Canadian GAAP: operating netback, net operating income from operations, funds flow from operations, and EBITDA.

A) *Reconciliation of cash flow from operating activities to funds flow from operations:*

The following table shows the reconciliation of funds flow from operations to cash flow from operating activities for the fourth quarter 2010 as compared with the fourth quarter of 2009:

	Q4		Year	
	2010	2009	2010	2009
Cash flow from operating activities	249,163	35,862	828,803	143,658
Changes in non-cash working capital	52,853	(63,865)	166,810	(82,228)
Funds flow from operations (non-GAAP)	196,310	99,727	661,993	225,886

B) *Reconciliation of Net Income (Loss) to EBITDA:*

	Q4		Year	
	2010	2009	2010	2009
Net income (loss)	104,698	3,218	217,606	(125,793)
Adjustments to net (loss) income				
Income taxes expense	45,048	19,834	202,999	46,052
Foreign exchange (gain) loss	(30,465)	(33,686)	11,092	59,896
Interest expense	20,664	22,956	76,447	48,150
Realized and unrealized gain on risk management contracts	39,752	6,126	40,230	21,525
Loss (income) from equity investment	1,715	(1,657)	1,634	(1,657)
Other (income) expense	(4,819)	9,843	951	25,160
Stock-based compensation	-	27,699	73,327	28,361
Depletion, depreciation and amortization	94,368	62,706	298,567	196,138
EBITDA	270,961	117,039	922,853	297,832

EBITDA was redefined in 2009 upon the completion of the offering of the Senior Unsecured Notes. The redefined EBITDA represents the EBITDA used in and defined in the covenants of the Senior Unsecured Notes offering. The previous period's EBITDA has been recalculated to conform to the current year's definition.

C) *Income from operations:*

Income from operations includes revenues less oil and gas and trading operating costs, depletion, depreciation & amortization and G&A expenses, and excludes effect of the underlift, stock-based compensation and other income and expenses.

	Q4		Year	
	2010	2009	2010	2009
Revenues	$ 515,901	$ 211,650	$ 1,661,544	$ 639,201
Less				
Operating cost	(181,662)	(69,287)	(607,939)	(271,687)
Depletion, depreciation and amortization	(94,368)	(62,706)	(298,567)	(196,138)
General and administration	(39,372)	(23,931)	(111,919)	(71,831)
Income from operations	$ 200,499	$ 55,726	$ 643,119	$ 99,545

18. 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. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 mcf:1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Estimated values of future net revenue disclosed do not represent fair market value.

19. 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; and
- payment of dividends.

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.

20. Glossary

1P	Proven reserves (also known as P90).
2D seismic	Shows a single cross-section through the earth along a relatively straight line.
2P	Proven reserves + Probable reserves.
3D seismic	3D seismic is shot similar to 2D, except the “shotpoints” are much closer together and are laid out on a grid, instead of in a straight line. The geophones that receive the reflected sound waves are also laid out in a grid.
3P	Proven reserves + Probable reserves + Possible reserves.
Appraisal well	Exploration well drilled near a well already in production as part of an appraisal campaign, which is carried out to determine the physical extent and likely production rate of a field.
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
Core sampling	At depths of interest, the drill bit is replaced by a hollow one that will extract a cylinder of several meters of rock. Confirms rock type, fluid content, dip, porosity and permeability.
Density	Also known as the oil’s gravity – measured in ÅãAPI and indicative of what products the crude can be refined into. The higher the gravity, the lighter the oil.
Development well	A production well drilled to begin production after a reservoir has been discovered and defined. Usually takes place over the area with the largest pay thickness in the reservoir.
Diluent	The addition of a 44iluents enables the diluted fluid to meet pipeline specifications in order for it to be efficiently transported. Typical diluents in this application are naphtha or light oil used with very heavy oil or bitumen.
Dip	The slant of a reservoir.
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
Netbacks	Total of revenues from oil/gas, less all costs associated with getting oil/gas to market. These costs can include importing, transportation, production and refining costs and royalty fees.
Net reservoir thickness/net pay or oil zone	Reservoir vertical extent – thickness measured in feet of the productive portion of a reservoir.
NGL	natural gas liquids
Permeability	Measured in millidarcies (mD), measures how connected the pores are within the rock, indicating how easily oil will flow through it.
Porosity	Percentage of void space versus solid rock, which is the space where oil is potentially trapped.
Possible reserves	Estimates with a probability of 10%-49% under present technical and economical conditions. Also known as P3 when referred to as an individual component.
Primary recovery	Extraction of oil using methods and mechanisms of natural lift or artificial lift.
Probable reserves	Estimates with a probability of 50%-89% under present technical and economical conditions. Also known as P2 when referred to as an individual component.
Proven reserves	Estimates with a probability of 90% or greater under present technical and economical conditions. Also known as P1 when referred to as an individual component.
Recovery factor	Maximum percentage of oil in place which is technically recoverable.

Discovery well	An exploration well that has encountered hydrocarbons.
Dry hole	A well that is drilled does not encounter hydrocarbons.
ESP	Electro-Submersible Pump
Farm-out agreements	The “farmor” agrees to assign acreage to a second company (the “farmee”) in return for the second company performing specified drilling and testing obligations, with the farmor also reserving an interest in the acreage assigned and in the production from the wells drilled by the second company.
Geophysics	See Gravity survey – Magnetic survey – Seismic survey.
Gravity survey	A study of the earth’s gravity, which varies with changes in density of subsurface rock.
Gross pay	Average thickness of the entire reservoir.
Heavy crude	Oil with a low gravity density (generally <25Åã API).
km	kilometers
Light crude	Oil with a high gravity density (generally >30Åã API).
Magnetic survey	A study of the earth’s magnetism. Most oil is contained in nonmagnetic sedimentary rocks (igneous & metamorphic rocks are magnetic and contain no oil).
Mbbl	thousand barrels
Mboe	thousand barrels of oil equivalent
Mcf/d	thousand cubic feet per day
Mcf	thousand cubic feet
MD	Measured depth
Reservoir rock	A porous and permeable rock for hydrocarbons to accumulate in.
Secondary recovery	Involves “push” mechanisms that attempt to maintain or increase reservoir pressure when primary recovery production rates fall. Water flooding is the most commonly used method.
Seismic survey	Works on the principle of the time it takes for reflected sound waves to travel through rock of varying densities. 2D or 3D seismic surveys create virtual images of what a reservoir looks like.
Service contracts	Flat fee paid by mineral rights owner to E&P company to carry out the E&P. Only paid if production takes place.
Source rock	Rich in dead, organic material (kerogen) buried deep enough for heat and pressure to change it into hydrocarbons.
Spudding	Initial stage of drilling.
Stratigraphic traps	Stratigraphic traps form when other beds seal a reservoir bed or when the permeability changes within the reservoir bed itself. Examples of stratigraphic traps are a) unconformity traps, b) pinchout traps, and c) lens traps.
Structural traps	Structural traps form because of a deformation in the rock layer that contains the hydrocarbons. Examples of structural traps are a) anticlinal traps, b) fault traps, and c) salt dome.
Tcf	trillion cubic feet
TD	True depth
TVDSS	True vertical depth below sea level
Viscosity	Inside the reservoir, viscosity is measured in poise (P); outside the reservoir, measured in centistoke (cS). Viscosity indicates how easily oil will flow.
WTI	West Texas Intermediate index